Winter 2011-12 U.S. Natural Gas Production and Supply Outlook

Prepared for Natural Gas Supply Association by:

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Introduction

This report presents ICF's current view of upstream industry activity, production, storage, and imports for the upcoming winter heating season. The horizontal shale gas revolution continues, driving the U.S. to a record level of gas production. The analysis presented here supports the high level of optimism for natural gas in America's energy future.

The rapid expansion of horizontal shale gas development continued in 2011. Production from plays such as the Marcellus and Haynesville is increasing rapidly. The Eagle Ford shale play in Texas has the highest total rig activity. A great deal of activity also focused on "tight oil" plays in the Northern Plains, Rockies, and Texas, and the wet gas (gas and condensate) portion of several shale gas plays. Production from the Williston Bakken oil play continues to grow and natural gas liquids production from several plays is having a large impact on the gas processing sector and eventually the U.S. petrochemical industry because of increased production of ethane and other NGLs.

U.S. overall rig activity continues to increase. Interestingly, a rapid shift has occurred toward oil-directed rigs to take advantage of higher oil prices. There are now more oil rigs than gas rigs operating, while in recent years the oil count typically has been about one-half of the gas rig count. The oil rig count continues to increase rapidly, and new tight oil plays are emerging.

In recent months wellhead prices have been in the $4.00 per MMBtu range at Henry Hub, Louisiana while oil has been $85 per barrel. This means that oil is receiving a much higher price on an energy content basis, and this differential is driving activity patterns towards liquids-rich areas. Plays such as the Marcellus, Eagle Ford, Granite Wash, and Anadarko Woodford with high liquids areas are benefitting, as well as tight oil plays that produce crude and associated gas.

Significant developments in North American gas supply since our last report in the fall of 2010 are:

- Large increase in overall U.S. gas production (4.0 Bcf/d comparing third quarters of 2011 and 2010)
- Gradual decline in gas imports from Canada
- Lower LNG imports
- Large gas production increases from shale and tight plays
- Large increase in activity in tight oil, primarily in the Bakken/Three Forks Shale (ND) and West Texas shales. The Bakken is currently producing about 350,000 b/d and 275 MMcfd. The Niobrara Shale (CO and WY) is also emerging.
- Gradual decline in Gulf of Mexico gas production
- Decline in gas rigs and large increase in oil rigs
- Horizontal gas wells becoming more complex with longer laterals and more stages; wide range of drilling and completion innovations and technology
- Low wellhead prices continue
- Rapid growth in Appalachian Marcellus Shale gas production
- Rapid growth in Haynesville Shale gas production
- Growth in Eagle Ford gas and liquids production; high level of activity
- Slow increase in BC Horn River shale gas due to infrastructure and other factors

- Plans to possibly export some gas as LNG from Western Canada and U.S.
- Continued growth in gas deliverability from shale plays and continued drilling to hold leases in some areas
- Emergence of Utica horizontal oil and gas play in Ohio, the Mississippi Lime horizontal oil play in Oklahoma, and West Texas Permian oil plays.
- Expansion of gathering and processing infrastructure near shale plays

ICF forecasts that 2011 Lower-48 gas production will be 22.5 Tcf, about 6.3 percent higher than in 2010. This is a much higher annual production increase than was the case in recent years. Going forward into next year we are forecasting a 3.8 percent increase, primarily reflecting a modest gas well completion slowdown for the remainder of 2011 and 2012.

Data Sources and Approach

The production analysis presented here is based upon analysis of data from commercial data, state agencies, and the Energy Information Administration (EIA). It incorporates a procedure to estimate recent production where reported production is not yet complete due to a reporting lag. Historic gas production at the play level is based upon ICF analysis of state agency and commercial well level production data, as well as company reports. The gas production forecast presented here is consistent with the *ICF Natural Gas Market Compass* forecast, a detailed 25 year forecast and gas market analysis of North America that is developed quarterly. [1] Forecasts of gas storage fill, pipeline imports, and LNG imports are from *Compass*. For consistency between historic data and forecasts, some of the historic data shown differ slightly from EIA data.

[1] Data area from the Fall, 2011 ICF Natural Gas Market Compass.

Drilling Activity

U.S. drilling activity in recent years peaked in September, 2008. This was followed by one of the steepest and largest drops in history, bottoming in June, 2009. The large swing in activity corresponded to a decline in the U.S. economy, along with gas deliverability additions. Gas drilling activity rebounded significantly in 2010 and 2011 and total activity (including oil rigs) is now near the recent 2008 peak of over 2,000 rigs.

U.S. total oil and gas rig activity (Baker-Hughes) in August 2011 averaged 1,951 rigs, which was 20 percent higher than in August of 2010. The increase was driven during the year largely by shale gas activity in the Haynesville, Marcellus, and Eagle Ford plays and Bakken tight oil. Haynesville rig activity has declined slightly in recent months because of the general shift to more liquids-rich plays. However, gas production from the play continues to increase rapidly.

The increase in oil-targeted activity includes shale and tight sand plays that have liquid components such as the Eagle Ford play in Texas, the Granite Wash sandstone play in the Mid-Continent, and parts of the Marcellus shale. This trend has been driven by large price differences between oil and gas on an energy-equivalent basis. With $4.00 gas and $85 per barrel oil, the energy equivalent price ratio is 3.7 ($14.65 per MMBtu for oil vs. $4.00 per MMBtu for gas). This is a very high ratio historically. Tight oil (crude oil) plays include the Williston Bakken/ Three Forks Shale and the Niobrara Shale in eastern Colorado and Wyoming. Very significant tight oil activity is taking place in the Permian Basin of Texas and New Mexico as well as western Oklahoma.

Exhibit 1 presents 2011 trends in gas drilling activity by region. The overall increase in August was 20 percent relative to last year. All major areas except Louisiana experienced increased activity. Haynesville Shale activity in Louisiana declined somewhat during the year because of an apparent reduction in “leasehold” drilling.

Exhibit 1

U.S. and Canadian Drilling Trends

August Data - Total Rigs (Oil and Gas)

Source: Baker Hughes	Total Rigs Aug 2010	Total Rigs Aug 2011	Total Rigs Change (%)
Regional U.S. Rig Trends			
Rockies	142	155	9%
North Dakota	126	171	36%
Midcontinent	189	253	34%
Texas	709	882	24%
Louisiana	184	171	-7%
Gulf of Mexico	20	35	75%
Appalachia	124	145	17%
Other	138	139	1%
Lower-48	1,632	1,951	20%

Exhibit 2 compares rig activity in 2010 and 2011. Looking at the U.S. rig counts for the first eight months of 2011, the average was 896 rigs. This can be compared to an average of 934 gas rigs during the same months last year, a decline of 4.1 percent. On a calendar year basis, ICF is forecasting an average of 906 gas rigs this year, a decline of 4.0 percent.

Exhibit 2

Historical and Forecast Gas Rigs

	Gas Rigs 2010	Gas Rigs 2011	Gas Rigs change
January through August (actual)	934	896	-4.1%
Annual average (2011 forecast)	944	906	-4.0%

A large factor driving rig activity has been the need to hold new leases in many areas of the large unconventional gas plays. Leases that are not held by production must be drilled or they will expire. However, it appears from rig counts and other information sources that that this activity has started to decline.

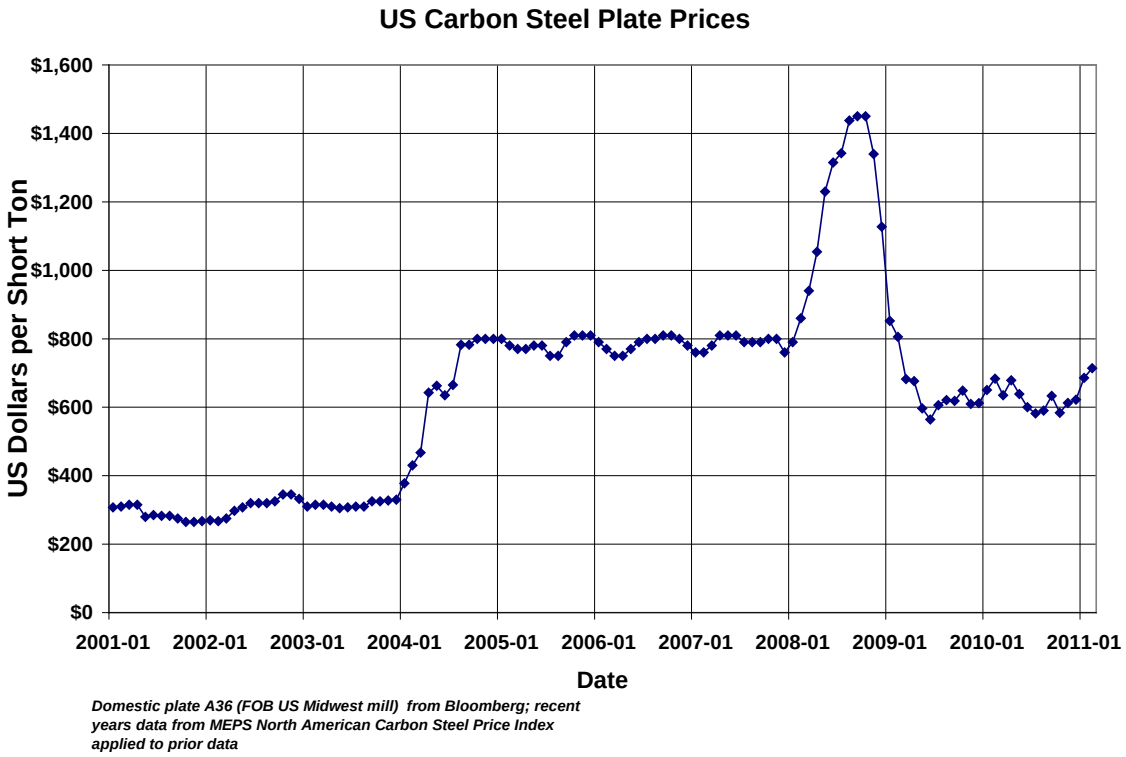
Drilling Cost Trends

In the mid-2000's there were large increases in the cost of upstream activity, including drilling, stimulation, and completion. This was driven by various factors such as demand for specialized drilling rigs and equipment, material costs, labor costs, and increased commodity costs.

There were steep increases in the cost of materials and labor used in the construction of all types of energy infrastructure, including power plants, pipelines and oil and gas wells. These cost trends peaked in the first half of 2008, subsequently declined, and are once again rising.

As an indicator of oil field commodity costs, **Exhibit 3** shows the trends in cost per ton of carbon steel plate (used in line pipe, casing, pressure vessels, etc.). There was a peak in 2008. Since then, steel prices have stabilized at mid-2000s levels.

Exhibit 3

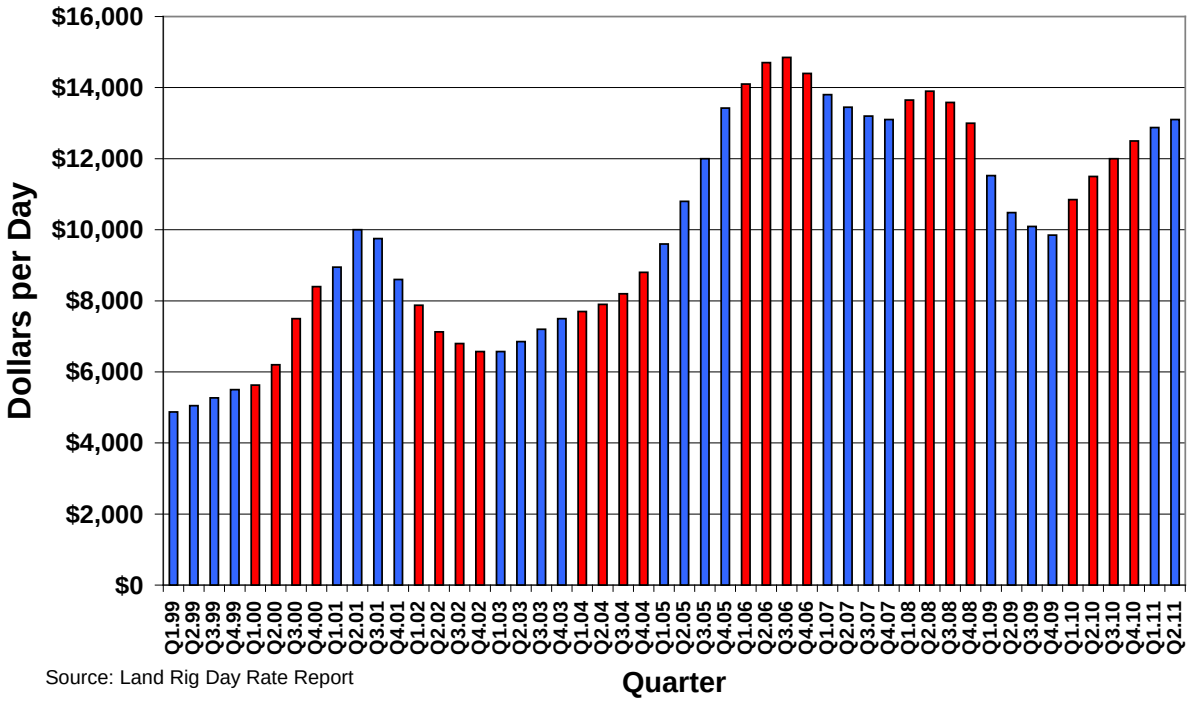


Domestic plate A36 (FOB US Midwest mill) from Bloomberg; recent years data from MEPS North American Carbon Steel Price Index applied to prior data

Exhibit 4 shows the average day rate for onshore drilling rigs in the U.S. This is a key component of U.S. drilling costs. The average day rate essentially doubled between 2003 and 2006. This had a major impact on overall resource development costs, especially when combined with cost increases for materials. There was a sharp decline in 2009. This was followed by a sharp increase over the past year and a half. The recent rig rate increase parallels the increase in shale-directed drilling (for gas and oil), and reflects the demand for the type of rigs capable of drilling these plays.

Exhibit 4

Average Onshore U.S. Drilling Rig Day Rate Through 2Q 2011

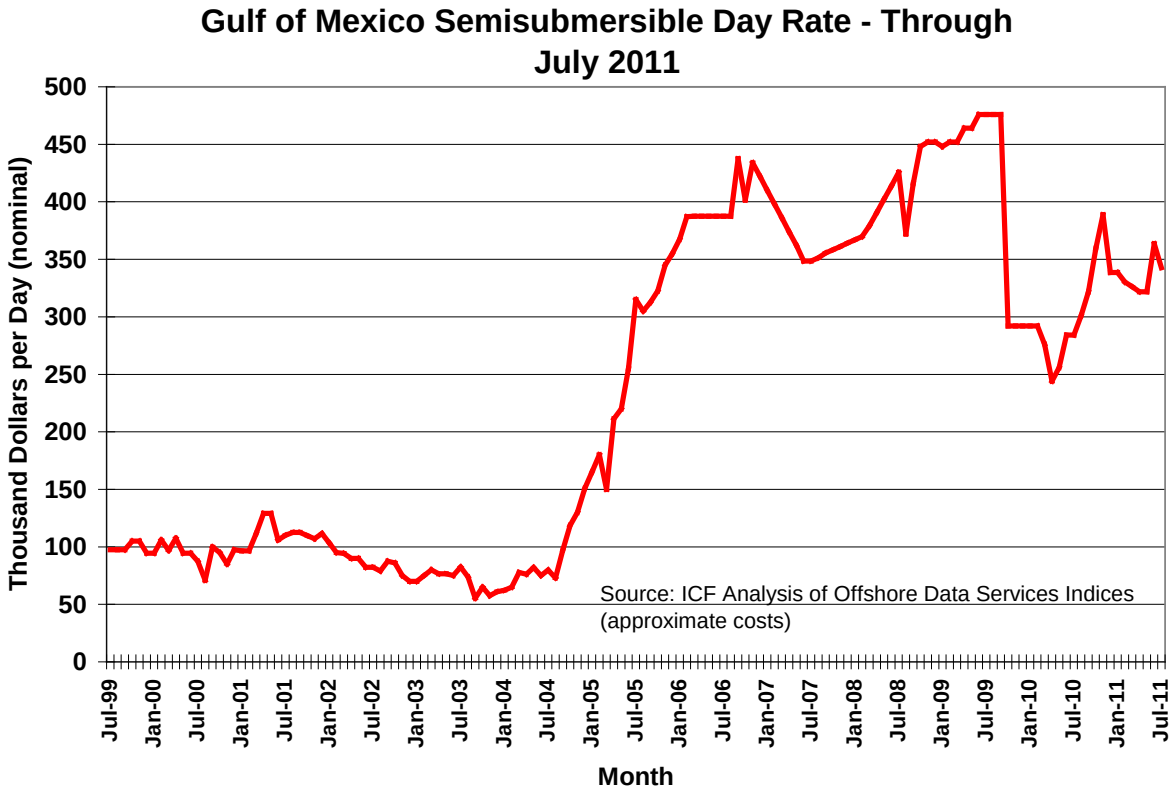


Source: Land Rig Day Rate Report

The cost of onshore wells, while primarily driven by the rig day rate, is also impacted by other costs. For example, as operators drill deeper for shale and tight gas, drilling costs per foot increase. The reservoir stimulation component of completed well costs has also increased greatly, as a result of expensive, specialized multi-stage fracturing. Industry outlays for drilling are affected by the number of high cost unconventional wells, well configurations (especially lateral length and number of stages), day rate, and stimulation costs per stage. As a result of these trends, cost per well has increased and industry capital outlays for development have been very high.

Exhibit 5 shows historic rig rates for offshore deepwater semisubmersibles. These day rates more than quadrupled since 2003, peaking in 2009. Since that time, rates have fallen by about 30 percent.

Exhibit 5



Gas Well Completions

Exhibit 6 shows monthly U.S. gas well completion statistics from the EIA Monthly Energy Review. Completion activity in 2011 is slightly lower than the last half of 2010. The number of monthly gas completions is impacted by rig count, well depth, well complexity and activity by region.

Exhibit 6

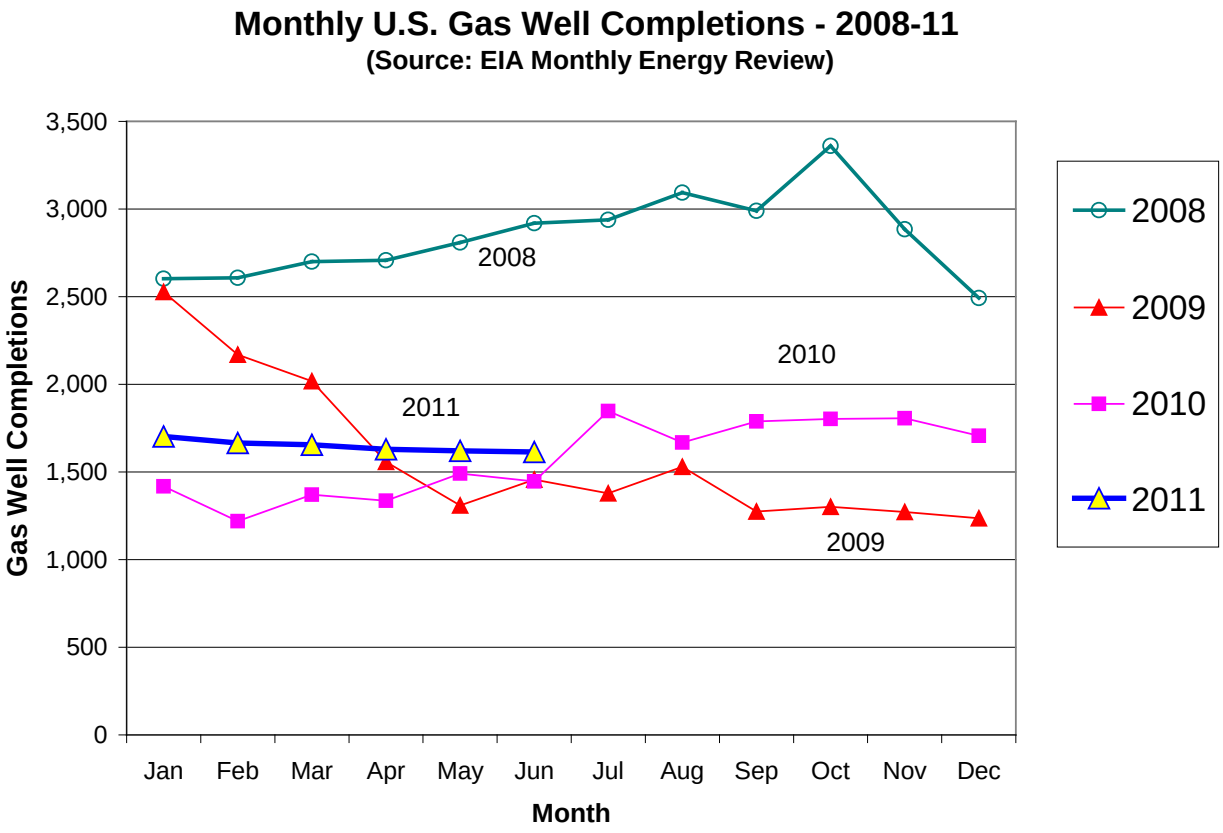


Exhibit 7 presents Lower-48 gas well completion statistics starting with the first quarter of 2008. The table presents EIA Monthly Energy Review data, API Quarterly Completion Report data, and ICF estimates. ICF is forecasting the completion of about 15,300 Lower-48 gas wells in 2011. This represents an increase of 2 percent from the estimated 14,982 wells completed in 2010. The actual count for 2010 was lower than forecast last year. This was apparently due to a decline in vertical completions in conventional plays, because shale completions increased.

Exhibit 7

Comparison of Quarterly Lower 48 Completion Counts

Estimated Gas Well Completions

Sources: EIA Monthly Energy Review and API Completion Report.

	EIA Monthly Energy Review Estimated	API Quarterly Comp. Report Estimated	ICF With Forecast
2008 Q1	7,911	6,919	6,919
2008 Q2	8,436	7,315	7,315
2008 Q3	9,023	7,818	7,818
2008 Q4	8,737	7,276	7,276
2009 Q1	6,626	5,869	5,869
2009 Q2	4,135	3,592	3,592
2009 Q3	4,074	3,606	3,606
2009 Q4	4,280	3,409	3,409
2010 Q1	4,007	3,480	3,480
2010 Q2	4,273	3,460	3,460
2010 Q3	5,077	3,967	3,967
2010 Q4	5,315	4,075	4,075
2011 Q1	5,024	3,611	4,000
2011 Q2	4,863	3,477	3,900
2011 Q3			3,700
2011 Q4			3,700

Annual Totals

				% chg.
2008	34,107	29,328	29,328	-1.7%
2009	19,115	16,476	16,476	-43.8%
2010	18,672	14,982	14,982	-9.1%
2011	---	---	15,300	2.1%

Natural Gas Production

There has been a continued increase in gas production from onshore non-conventional gas plays and new production from emerging unconventional plays. Shale and tight gas development continues to dominate activity.

Exhibits 8a and 8b illustrate gas production trends from a selected significant onshore plays. Included in **Exhibit 8a** are the Barnett Shale in the Fort Worth Basin, the Eagle Ford Shale in south Texas, the Bossier Tight Sandstone in East Texas, the Fayetteville Shale in Arkansas, the Woodford Shale in Eastern Oklahoma, the Jonah and Pinedale tight gas fields in Southwestern Wyoming, the Piceance Basin tight gas in Colorado, the Haynesville Shale of Northern Louisiana and East Texas, the Marcellus Shale in Appalachia and the Powder River Basin coalbed methane. These plays have experienced an increase in gas production of over 20 Bcf per day since 2000. During the same period, Lower-48 dry gas production increased, but at a much lower rate. Thus, these plays have been contributing a growing percentage of production. At year-end 2010, production from these plays accounted for 40 percent of Lower-48 gas production, as shown in **Exhibit 8b**.

Exhibit 8c shows the shale plays separately. Through 2008, the Fort Worth Barnett Shale was the dominant play. Since 2009, most of the growth has been in other plays, with the Fayetteville and Haynesville contributing the most. At year-end 2010, the Marcellus was producing at about 2 Bcf/d and growing rapidly, and the Haynesville was producing more than 3.5 Bcf/d. Lower-48 shale gas production was 14.5 Bcf/d at year-end 2010, representing 26 percent of Lower-48 gas production.

Exhibit 8a

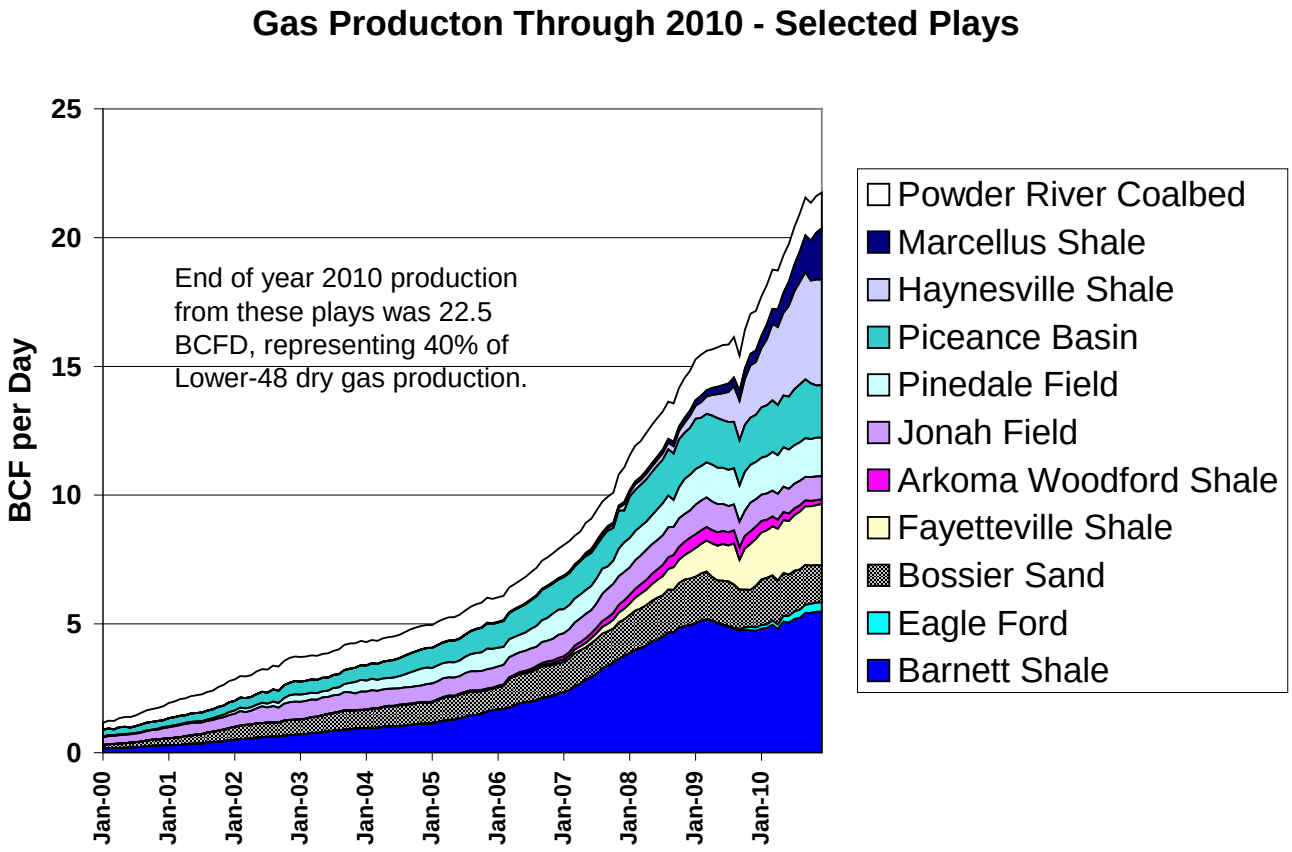

Gas Producton Through 2010 - Selected Plays
BCF per Day
25
20
15
10
5
0
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
End of year 2010 production from these plays was 22.5 BCFD, representing 40% of Lower-48 dry gas production.
Powder River Coalbed
Marcellus Shale
Haynesville Shale
Piceance Basin
Pinedale Field
Jonah Field
Arkoma Woodford Shale
Fayetteville Shale
Bossier Sand
Eagle Ford
Barnett Shale

Exhibit 8b

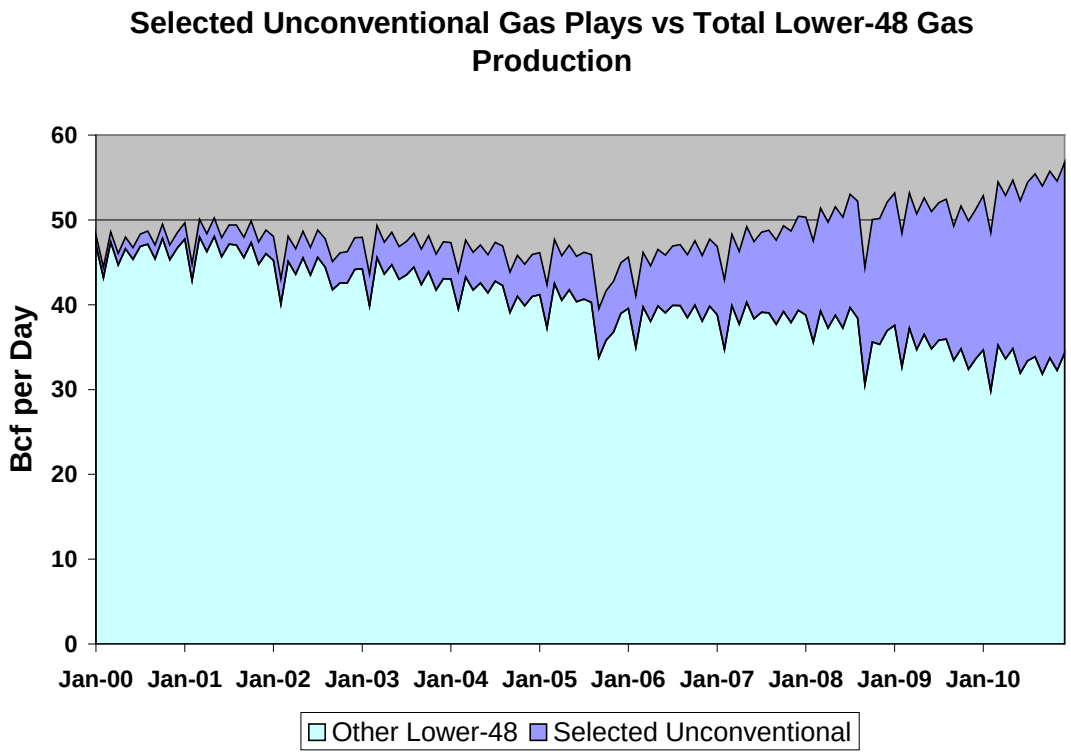
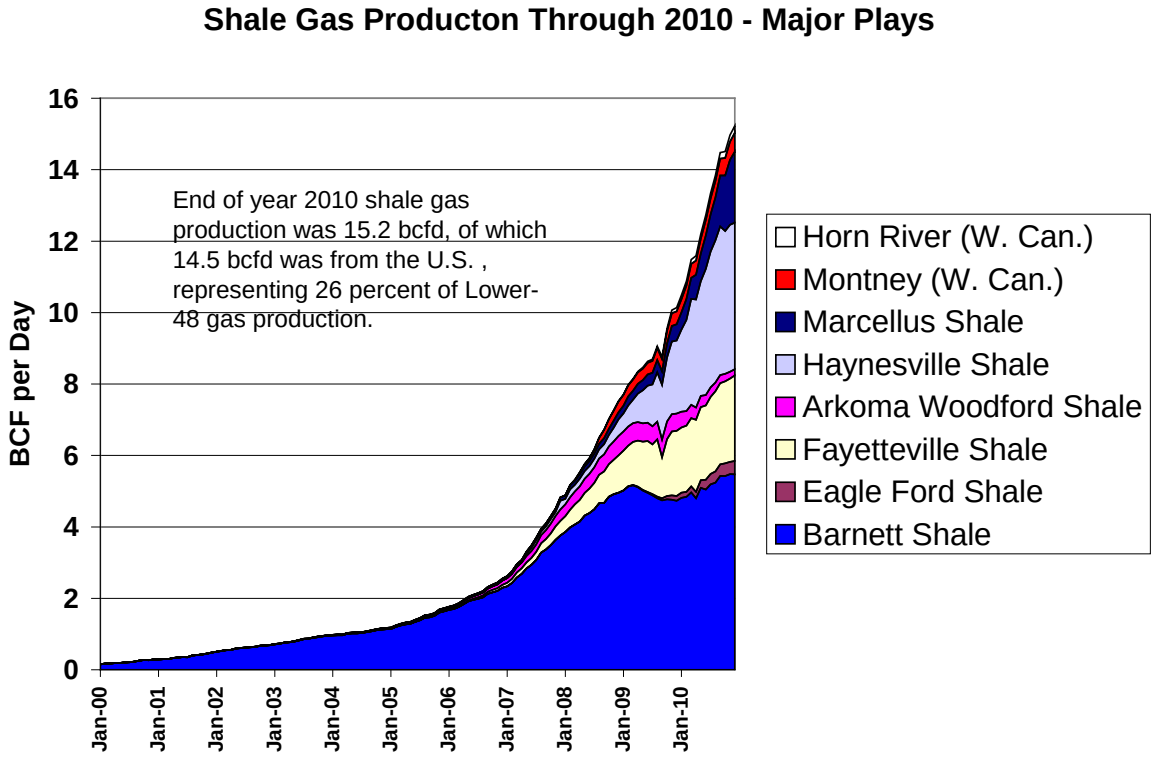


Exhibit 8c



Exhibits 9 through 11 present the ICF Lower-48 natural gas production analysis and forecast. Lower-48 gas production in the third quarter of 2011 is expected in this analysis to average 61.9 Bcf per day, up significantly from 57.8 Bcf/d in the third quarter of last year. Historic and forecast production levels are presented graphically in **Exhibit 10**. Lower-48 production since 2009 has increased by about 6 Bcf/d.

The previous high rate of U.S. gas production in history occurred during the early 1970s, when dry gas production was approximately 60 Bcf per day. It appears that we are now producing gas at a record or near-record rate.

The lower portion of **Exhibit 9** presents an annual summary and shows the percentage change in Lower-48 production. ICF estimates that 2011 production will average 61.5 Bcf/d (22.5 Tcf), a 6.3 percent increase over 2010. The forecast for 2012 is for an average of 63.9 Bcf/d, a 3.8 percent increase over this year.

Exhibit 11 presents the details of winter monthly natural gas production since November 2009 and the ICF forecast for the upcoming winter. The forecast is for Lower-48 production to average 63.1 Bcf/d this winter through March of 2012. This is about 3.1 Bcf/d higher than last year.

Exhibit 9

ICF Analysis of Lower-48 Quarterly Wellhead Gas Production

Dry marketed total gas - Bcf per day

Quarterly averages

		Bcf per day *	Quarterly Bcfd Change	Quarterly Pct. Chg.
2008	1Q08	55.13	2.18	4.1%
	2Q08	55.36	0.23	0.4%
	3Q08	53.70	-1.66	-3.0%
	4Q08	53.50	-0.20	-0.4%
2009	1Q09	55.25	1.75	3.3%
	2Q09	55.79	0.54	1.0%
	3Q09	56.12	0.33	0.6%
	4Q09	55.60	-0.52	-0.9%
2010	1Q10	57.03	1.43	2.6%
	2Q10	57.05	0.02	0.0%
	3Q10	57.84	0.79	1.4%
	4Q10	59.57	1.73	3.0%
2011	1Q11	60.34	0.77	1.3%
	2Q11	61.27	0.93	1.5%
	3Q11	61.85	0.58	0.9%
	4Q11	62.54	0.69	1.1%
2012	1Q12	63.27	0.73	1.2%
	2Q12	63.77	0.50	0.8%
	3Q12	63.96	0.19	0.3%
	4Q12	64.41	0.45	0.7%

Annual averages

	Bcf per day	Bcfd Change	Annual Pct. Chg.	Annual Production Bcf/Yr.	Annual Change Bcf
2007	53.22	2.12	4.15%	19,425	774
2008	54.42	1.20	2.25%	19,918	492
2009	55.69	1.27	2.33%	20,327	409
2010	57.88	2.19	3.93%	21,126	799
2011	61.51	3.63	6.27%	22,451	1,325
2012	63.86	2.35	3.82%	23,373	922

* Production excludes approximately 1.0 Bcfd of marketed Alaska gas production and 200 MMcfd of supplemental gas production consisting of coal gas and propane-air.

Exhibit 10

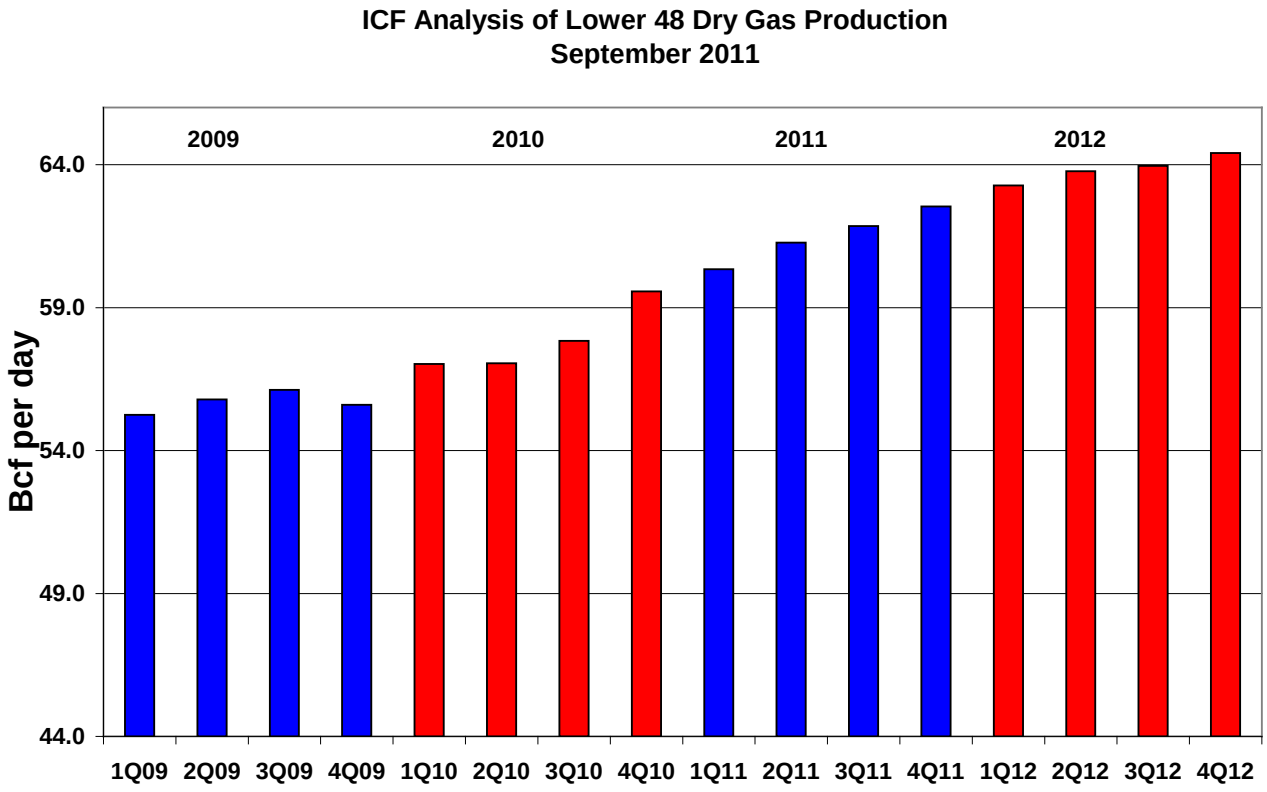

ICF Analysis of Lower 48 Dry Gas Production
September 2011
2009
2010
2011
2012
64.0
59.0
54.0
49.0
44.0
Bcf per day
1Q09
2Q09
3Q09
4Q09
1Q10
2Q10
3Q10
4Q10
1Q11
2Q11
3Q11
4Q11
1Q12
2Q12
3Q12
4Q12

Exhibit 11

Historical and Forecast Winter Monthly Production
November - March
Source: ICF Database and Models

Bcf

Historical 2009-10			Historical 2010-11			ICF Forecast for this winter		
		Bcf			Bcf			Bcf
Nov	2009	1,669	Nov	2010	1,796	Nov	2011	1,879
Dec	2009	1,691	Dec	2010	1,833	Dec	2011	1,951
Jan	2010	1,721	Jan	2011	1,874	Jan	2012	1,957
Feb	2010	1,618	Feb	2011	1,675	Feb	2012	1,834
Mar	2010	1,793	Mar	2011	1,882	Mar	2012	1,967
total		8,493			9,060			9,588

Bcf per day

Historical 2009-10			Historical 2010-11			ICF Forecast for this winter		
		Bcfd			Bcfd			Bcfd
Nov	2009	55.6	Nov	2010	59.9	Nov	2011	62.6
Dec	2009	54.6	Dec	2010	59.1	Dec	2011	62.9
Jan	2010	55.5	Jan	2011	60.5	Jan	2012	63.1
Feb	2010	57.8	Feb	2011	59.8	Feb	2012	63.2
Mar	2010	57.8	Mar	2011	60.7	Mar	2012	63.5
average		56.2			60.0			63.1

Comparison with EIA Short-Term Forecast

EIA publishes a short-term forecast each month with quarterly estimates of U.S. natural gas production and imports. **Exhibit 12** presents the EIA and ICF quarterly production averages for the Lower-48. EIA is forecasting a 2011 Lower-48 gas production increase of 6.0 percent. This compares to an increase of 6.3 percent in the ICF analysis. The EIA forecast for 2012 is for a 0.9 percent increase, compared with our 3.8 percent increase.

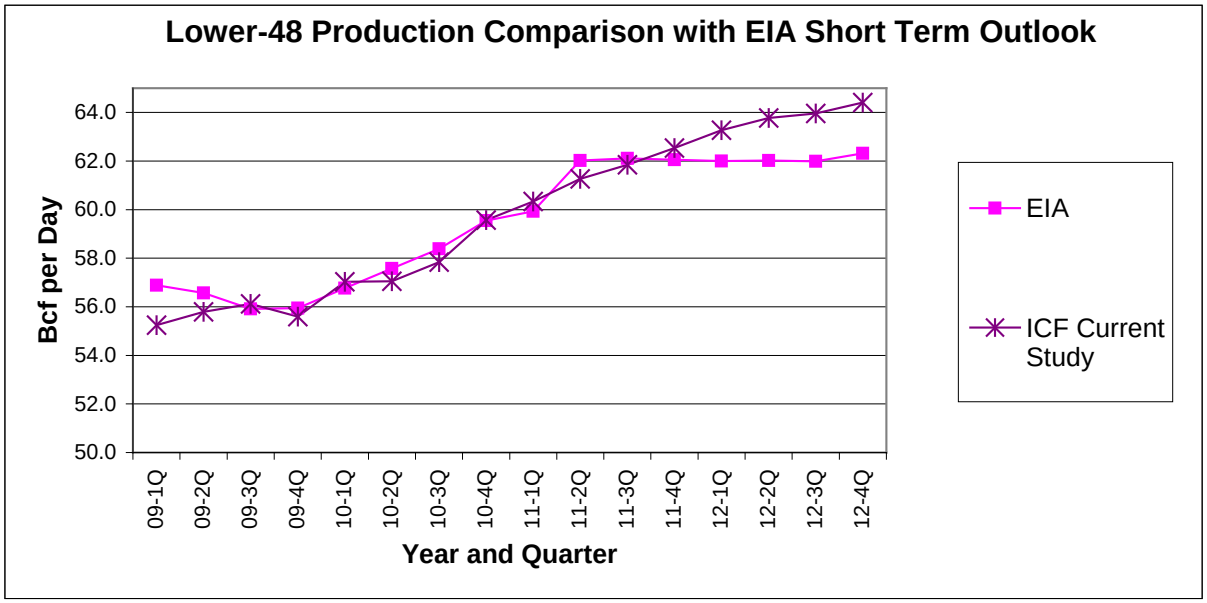
Exhibit 12

Comparison with EIA Short Term Outlook

Bcf per day; Lower-48 and U.S. Total Dry Gas Production
ICF Current Study vs. EIA Short Term Outlook

	ICF (Lower 48)	EIA (U.S. Total)	EIA (Lower 48)	Lower 48 Difference ICF vs.EIA
2009				
1Q	55.25	58.11	56.89	-1.64
2Q	55.79	57.63	56.57	-0.78
3Q	56.12	56.84	55.91	0.21
4Q	55.60	57.08	55.94	-0.34
2010				
1Q	57.03	57.93	56.77	0.26
2Q	57.05	58.56	57.58	-0.53
3Q	57.84	59.28	58.39	-0.55
4Q	59.57	60.66	59.55	0.02
2011				
1Q	60.34	61.05	59.93	0.41
2Q	61.27	63.01	62.02	-0.75
3Q	61.85	63.06	62.11	-0.26
4Q	62.54	63.13	62.05	0.49
2012				
1Q	63.27	63.15	62.00	1.27
2Q	63.77	62.96	62.02	1.75
3Q	63.96	62.96	61.99	1.97
4Q	64.41	63.41	62.32	2.09

		% chg.			% chg.	Difference
2009	55.69	1.16%	57.41	56.32	-1.16%	-0.63
2010	57.88	3.93%	59.12	58.08	3.12%	-0.20
2011	61.51	6.27%	62.57	61.53	5.95%	-0.02
2012	63.86	3.82%	63.12	62.08	0.89%	1.78



Storage Injection

At the end of August 2011, U.S. inventories of working natural gas in storage stood at 3.01 Tcf, or 60 Bcf below the five-year average of 3.07 Tcf and 140 Bcf below the 3.15 Tcf at the end of August, 2010. As shown in **Exhibit 13 (a),** storage volumes were just below the five year average during the first half of 2011. The current ICF forecast is for the storage level on November 1 to be approximately 3.76 Tcf. This can be compared to 3.85 Tcf last year. **Exhibit 13 (b)** presents the monthly working gas storage data. The ICF forecast represents average storage additions of approximately 12 bcf per day in September and October.

EIA estimated that so-called "demonstrated peak storage capacity" in the U.S. as of April, 2011 was 4.103 Tcf, which was 54 Bcf higher than in April, 2010. [2] As defined by EIA, demonstrated peak storage capacity is the sum of the highest actual facility level working gas storage volumes reported over the prior five year period. EIA estimated that working gas "design capacity" as of April was 4.39 Tcf. Design capacity is a measure of capacity based upon the physical characteristics of the reservoir, installed equipment, and other factors.

ICF estimates that U.S. working gas storage capacity is 4.14 Tcf. This estimate is based upon project level analysis, including estimates for expected startups this year. The method involves evaluation of historical storage fill in older facilities combined with design capacity for facilities without a history of storage. This estimate is generally equivalent in definition to the EIA "demonstrated capacity" estimate above. The current ICF forecast of peak storage this fall of 3.76 Tcf represents 91 percent of our estimate of storage capacity. Last year's peak of 3.85 was higher than forecast and represented about 96% utilization using our capacity estimate. Based on capacity only, peak storage this year

[2] U.S. Energy Information Administration, 2011, "Peak Underground Working Natural Gas Storage Capacity," August, 2011. http://www.eia.gov/naturalgas/storagecapacity/

could be higher than 3.76 Tcf. However, ICF considered several factors other than capacity in the analysis.

Exhibit 13 (a)

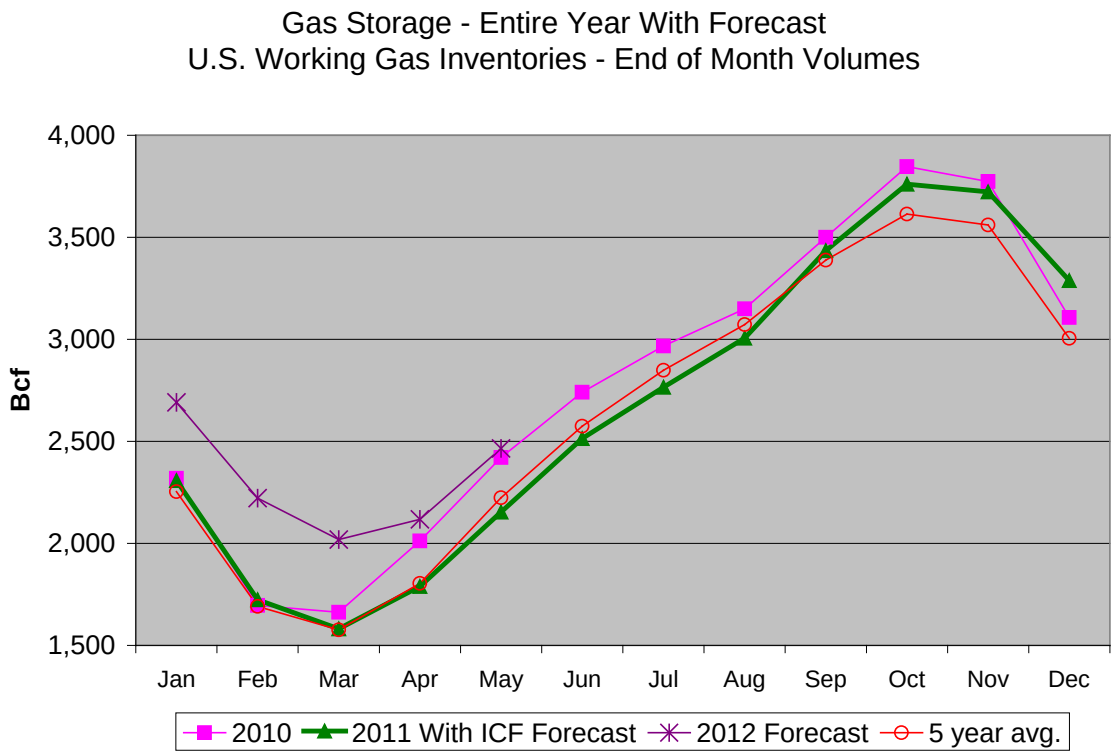


Exhibit 13 (b)

Underground Natural Gas Storage - BCF Working Gas - End of Month					
	2009	2010	2011 With ICF Forecast	2012 Forecast	5 year avg.
Jan	2,137	2,319	**2,308**	**2,691**	2,253
Feb	1,757	1,696	**1,724**	**2,222**	1,691
Mar	1,656	1,662	**1,581**	**2,019**	1,576
Apr	1,903	2,012	**1,789**	**2,118**	1,804
May	2,367	2,421	**2,153**	**2,465**	2,224
Jun	2,752	2,741	**2,514**	---	2,574
Jul	3,086	2,967	**2,765**	---	2,849
Aug	3,353	3,150	**3,006**	---	3,072
Sep	3,643	3,500	**3,435**	---	3,388
Oct	3,807	3,847	**3,760**	---	3,614
Nov	3,833	3,773	**3,723**	---	3,560
Dec	3,131	3,107	**3,288**	---	3,005

Pipeline Imports and Exports

Exhibit 14 shows the winter pipeline imports from Canada and exports to Mexico, starting with the winter of 2009-10. Import data are net to the U.S. The historical Canadian import data are taken from the *ICF Natural Gas Market Compass* and are a combination of Stats Canada data and pipeline bulletin boards.

Net imports from Canada last winter (2010-11) averaged 6.11 Bcf per day, about 12 percent lower than the previous winter's average.

This winter we forecast that imports from Canada will average 5.9 Bcf per day, a decline of 4 percent or 0.23 Bcf/d relative to last winter. The volume of Canadian pipeline imports depends on WCSB gas production and demand in both Canada and the U.S. Western Canada production has been declining, and this will continue in the near-term. Also, gas demand in Alberta has increased, primarily due to oil sands processing needs. Thus, net exports have declined at a greater rate than production. Shale gas and tight gas in BC and Alberta will likely turn this situation around in coming years.

Exhibit 14

Pipeline Imports from Canada and Exports to Mexico

November though March
Sources: ICF Compass for forecast; history from Natural Gas Monthly

Net Imports from Canada
Bcf per day positive = net imports

Historical 2009-10		Bcf/d	Historical 2010-11		Bcf/d	ICF Forecast for this winter 2011-12		Bcf/d
Nov	2009	6.27	Nov	2010	4.72	Nov	2011	6.44
Dec	2009	6.62	Dec	2010	5.81	Dec	2011	6.40
Jan	2010	7.07	Jan	2011	6.77	Jan	2012	5.78
Feb	2010	8.13	Feb	2011	7.16	Feb	2012	5.35
Mar	2010	6.64	Mar	2011	6.17	Mar	2012	5.43
average		6.92			6.11			5.88

Net Exports to Mexico
Bcf per day negative = net exports

Historical 2009-10		Bcf/d	Historical 2010-11		Bcf/d	ICF Forecast for this winter 2011-12		Bcf/d
Nov	2009	-0.96	Nov	2010	-1.00	Nov	2011	-1.19
Dec	2009	-0.80	Dec	2010	-1.20	Dec	2011	-1.21
Jan	2010	-0.71	Jan	2011	-1.16	Jan	2012	-1.22
Feb	2010	-0.77	Feb	2011	-1.28	Feb	2012	-1.22
Mar	2010	-0.50	Mar	2011	-1.31	Mar	2012	-1.04
average		-0.75			-1.19			-1.17

Winter LNG Imports

In recent years, the U.S. has typically imported 1.0 to 1.5 Bcf/d of LNG during the winter months. We have historically imported more LNG in the summer months when there is less demand in Europe and Asia. Prior to the boom in shale gas, most analysts believed that LNG imports to the U.S. would ramp up greatly in coming years to fill a supply gap. While LNG is still expected to be a major source of incremental world supply over the long term, it is not expected to contribute greatly in the U.S. for many years due to surging U.S. gas production. There have also been applications to export LNG from Western Canada, the Gulf Coast, and the Atlantic Coast.

Exhibit 15 shows the recent history of worldwide LNG shipments and world gas production. LNG imports to North America (primarily to the U.S.) increased in 2010 to 761 Bcf, up from 658 Bcf in 2009. U.S. imports (not shown) declined to 432 Bcf in 2010 from 452 Bcf in 2009.

World production of LNG increased to 10,509 Bcf and world gas production increased from 106 Tcf to 113 Tcf.

LNG shipments to Europe, Asia, and South America increased in 2010.

Exhibit 15

World LNG Imports and Gas Production

EIA data through 2005; BP Statistical Review for 2006 forward

	LNG Imports						Gas Production	
	North America Bcf	Europe Bcf	Asia - Pacific Bcf	Other Bcf	Total Bcf	LNG Post-2000 Increase Bcf	World Gas Production Tcf	Post-2000 Increase Tcf
2000	239	1,150	3,544		4,933	0	85.4	0.0
2001	261	1,157	3,776		5,194	261	87.6	2.2
2002	253	1,386	3,671		5,310	377	89.1	3.7
2003	544	1,390	3,978		5,912	979	92.4	7.0
2004	683	1,423	4,347		6,453	1,520	94.9	9.5
2005	664	1,668	4,495		6,827	1,894	98.2	12.8
2006	652	2,028	4,774		7,454	2,521	101.7	16.3
2007	886	1,883	5,225		7,994	3,061	104.3	18.9
2008	524	1,949	5,502		7,975	3,042	107.8	22.4
2009	658	2,437	5,376	100	8,571	3,638	105.5	20.1
2010	761	3,099	6,277	372	10,509	5,576	112.8	27.4
Percentage of world LNG imports								
2000	4.8%	23.3%	71.8%	0.0%	100.0%			
2001	5.0%	22.3%	72.7%	0.0%	100.0%			
2002	4.8%	26.1%	69.1%	0.0%	100.0%			
2003	9.2%	23.5%	67.3%	0.0%	100.0%			
2004	10.6%	22.1%	67.4%	0.0%	100.0%			
2005	9.7%	24.4%	65.8%	0.0%	100.0%			
2006	8.7%	27.2%	64.0%	0.0%	100.0%			
2007	11.1%	23.6%	65.4%	0.0%	100.0%			
2008	6.6%	24.4%	69.0%	0.0%	100.0%			
2009	7.7%	28.4%	62.7%	1.2%	100.0%			
2010	7.2%	29.5%	59.7%	3.5%	100.0%			

Exhibit 16 shows monthly LNG gross imports for the past two winters and the ICF forecast for this winter. The winter total volume imported for 2009-10 was 190 Bcf, or 1.26 Bcf per day. Last winter, the volume was 197 Bcf, or 1.30 Bcf/d. For the upcoming winter, ICF is forecasting a volume of only 93 Bcf, or 0.61 Bcf/d – roughly half of last winter's volume.

Exhibit 16

Historical and Forecast Winter LNG Imports

November - March; Gross Imports - Not Net of Alaska Exports
Source of historical data: EIA Natural Gas Monthly and ICF
Source of forecast: ICF Compass

Bcf

Historical 2009-10		Bcf	Historical 2010-11		Bcf	ICF Forecast for this winter 2011-12		Bcf
Nov	2009	30.1	Nov	2010	34.1	Nov	2011	16
Dec	2009	44.2	Dec	2010	44.3	Dec	2011	19
Jan	2010	48.9	Jan	2011	49.3	Jan	2012	18
Feb	2010	33.8	Feb	2011	38.2	Feb	2012	16
Mar	2010	32.8	Mar	2011	30.6	Mar	2012	23
total		189.7			196.6			93

Bcf per day

Historical 2009-10		Bcf/d	Historical 2010-11		Bcf/d	ICF Forecast for this winter 2011-12		Bcf/d
Nov	2009	1.00	Nov	2010	1.14	Nov	2011	0.55
Dec	2009	1.43	Dec	2010	1.43	Dec	2011	0.63
Jan	2010	1.58	Jan	2011	1.59	Jan	2012	0.59
Feb	2010	1.21	Feb	2011	1.37	Feb	2012	0.55
Mar	2010	1.06	Mar	2011	0.99	Mar	2012	0.74
average		1.26			1.30			0.61

Summary

Exhibit 17 summarizes the results of the supply analysis and forecast.

Exhibit 17

Supply Outlook for Winter 2011-12

	source	2010-11	2011-12	change	percent change
U.S. production vs previous year (trend)	1	---	Up	---	---
Annual well completions (2010 to 2011)	2	14,982	15,300	318	2.1%
Annual gas rig count (2010 to 2011)	3	944	906	-38	-4.0%
Winter LNG imports (Bcf/d - Nov. - March)	4	1.30	0.61	-0.69	-53.1%
Winter average gas production (Bcf/d - Lower 48)	5	60.0	63.1	3.10	5.2%
Working gas in storage (Tcf - Nov.1)	6	3.85	3.76	-0.09	-2.3%
Net pipeline imports from Canada (Bcf/d - Nov. - Mar.)	7	6.11	5.88	-0.23	-3.8%

Sources:
1. ICF - Current Study - State and federal data with ICF adjustments and forecast.
2. API Quarterly Completion Report with ICF estimates.
3. Baker Hughes gas rigs with ICF forecast through December.
4. Historical data from EIA Natural Gas Monthly; Forecast from ICF Compass.
5. Historical and forecast from current study. Derived from state and federal data with adjustments and forecast
6. Historical data from EIA; Forecast from ICF Compass
7. Historical data from StatsCanada and bulletin boards; Forecast from ICF Compass