Outlook for Natural Gas Supply and Demand for 2015-2016 Winter

Energy Ventures Analysis, Inc. (EVA)

Executive Summary

Natural gas supplies will be adequate to meet expected demand this winter. This is the net result of (1) lower demand this winter than either of the last two winters and (2) an increase in domestic production levels that are partially offset by lower net imports. The net effect of these two factors is that storage withdrawals should be about 1.1 BCFD less than withdrawals for last winter, as noted in Exhibit 1.

Exhibit 1. Outlook For Winter Supply and Demand[1]

	Coming Winter (2015/2016)		Last Winter (2014/2015)		Change	
Sector	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**
I. Natural Gas Demand						
Residential	3,511	23.1	3,731	24.7	(220)	(1.6)
Commercial	2,098	13.8	2,224	14.7	(126)	(0.9)
Industrial	3,469	22.8	3,409	22.6	60	0.2
Electric	3,509	23.1	3,317	22.0	192	1.1
Lease, Plant and Pipeline Fuel	1,126	7.4	1,133	7.5	(7)	(0.1)
Total	**13,713**	**90.2**	**13,814**	**91.5**	**(101)**	**(1.3)**
II. Lower-48 Supply						
Lower-48 Production[2]	11,314	74.4	11,021	73.0	293	1.5
Net Imports	356	2.3	572	3.8	(216)	(1.5)
Storage Withdrawals	1,956	12.9	2,106	14.0	(150)	(1.1)
Total	**13,626**	**89.6**	**13,699**	**90.7**	**(73)**	**(1.1)**

(1) Figures may not add due to rounding.
(2) Excludes Alaska production, which is approximately 138 BCF, or 0.91 BCFD in 2015/2016 and 132 BCF, or 0.9 BCFD in 2014/2015.

With respect to the anticipated decline in demand this winter, this occurs because the forthcoming winter is projected to be a relatively mild winter (i.e., 6.9 percent milder than last winter and 2.8 percent below normal). This results in declines in consumption for both the residential and commercial sectors, with increases in industrial and electric sector demand only partially offsetting these declines.

With respect to increases in domestic production, the combination of declines in both gas and oil prices has resulted in significant declines in both gas-directed and oil-directed drilling activity (i.e., 41 percent and 58 percent, respectively). This, in turn, has resulted in flat to declining natural gas production on a month-over-month basis. However, on a year-over-year basis gas production is still increasing, which is the reason for the 1.5 BCFD increase in gas production in this winter.

The decline in net imports is the result of the combination of (1) increased exports to Mexico; (2) the start of LNG exports from the L-48 this winter; and (3) a reduction in Canadian imports.

Exhibit 1 provides both cumulative demand and supply for the winter season in BCF and average daily demand for the winter period in BCFD. The latter is a common unit in the industry and will be the primary unit throughout this report. Also, the primary focus for supply is on the Lower-48, with Alaskan production footnoted for completeness.

Outlook For Winter Demand

Overview

This winter currently is projected to be a relatively mild winter,[1] this will result in reduced weather-related demand within the residential and commercial sectors, which will be partially offset by the increase in structural demand within the industrial and electric sectors.[2] With respect to the electric sector there are offsetting variances, namely (1) reduced weather-related demand, and (2) increased levels of coal-to-gas fuel switching which occurs because of the outlook for lower gas prices this winter. The net result is that this winter's total natural gas demand is projected to be 1.3 BCFD, or 0.7 percent, less than last winter's record demand levels of 91.5 BCFD (see Exhibit 2).

Exhibit 2. Outlook For Winter Gas Demand[(1)]

	Coming Winter (2015/2016)		Last Winter (2014/2015)		Change	
Sector	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**
Residential	3,511	23.1	3,731	24.7	(220)	(1.6)
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Lease, Plant and Pipeline Fuel	1,126	7.4	1,133	7.5	(7)	(0.1)
Total	**13,713**	**90.2**	**13,814**	**91.5**	**(101)**	**(1.3)**

(1) Figures may not add due to rounding.

Exhibit 2 provides both cumulative demand for the winter season in BCF and average daily demand for the winter period in BCFD. The latter is a common unit in the industry and will be the primary focus of this report, because of the ease of comparing BCFD to other industry statistics.[3]

By far the greatest area of uncertainty is the outlook for the winter weather. However, determining the net impact in variances in the winter weather can be very challenging.

[1] The forthcoming winter is projected by NOAA to be about 6.9 percent milder than last winter (i.e., 253 fewer heating degree days (HDD)) and overall 2.8 percent lower than the 30-year average.

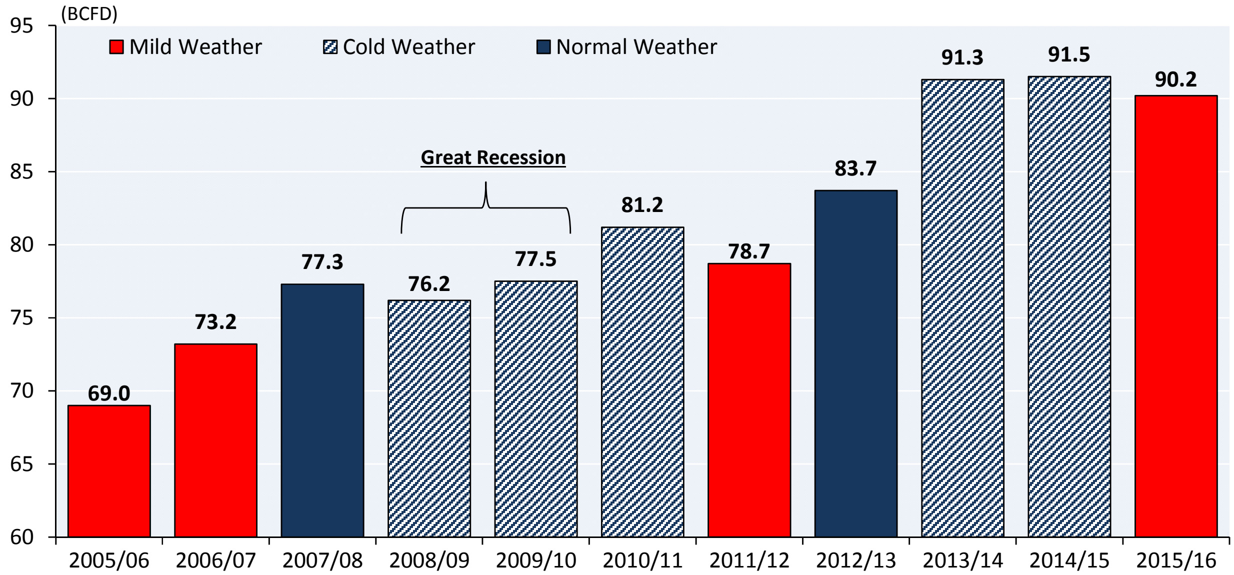
[2] Annual increases in demand within the gas industry typically are categorized as either (1) increases due to weather events (i.e., seasonal demand) or (2) increases due to structural changes within the industry (e.g., increased capacity), which are permanent in nature and are referred to as structural demand changes.

[3] The winter of 2014/2015 had 151 days, while the winter of 2015/2016 will have the more normal 152 days.

Nevertheless, if the winter were to turn out to be very cold, or similar to last winter,[4] winter gas demand would be about 2.5 BCFD higher than projected, when the additional structural demand for the industrial sector is included. If this were to happen, storage inventories likely still would be adequate, however season ending storage levels (March 31, 2016) would be reduced and end the season closer to 2015 levels.

Lastly, Exhibit 3 compares and contrasts the current winter outlook with actual results over the last decade.

Exhibit 3. Winter Natural Gas Demand For All Sectors



Residential And Commercial Sectors

As illustrated in Exhibit 4, changes in the winter weather can have a significant impact on gas demand within these two sectors. For example, the difference in gas demand for the winters of 2013/2014 and 2011/2012 (i.e., 1,855 BCF, or 16 percent) is a classic example, as are the three winters at the beginning of the last decade (i.e., about 937 BCF, or 16 percent).[5]

With respect to the forthcoming winter, it is projected to be about 6.9 percent milder than last winter, or 2.8 percent below normal. With respect to last winter, the significant cold weather was concentrated in February, which on a national population weighted basis, was the coldest in 30 years and was 13.6%, or 100 HDD, above the 30 year average. One of the regions with particularly severe weather was New England with its “snow gate”.

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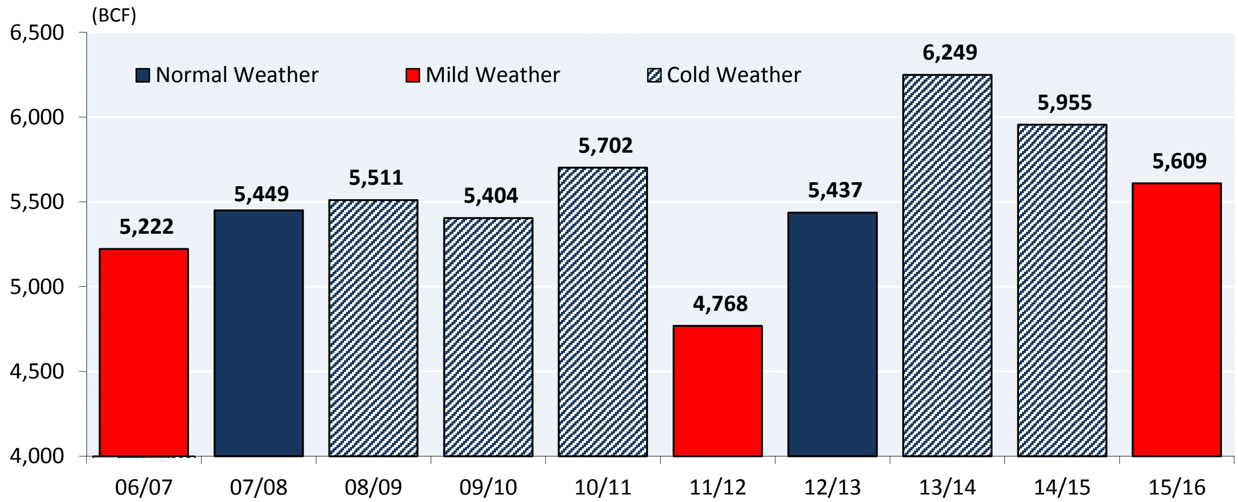
[4] While the winter of 2014/2015 was only the sixth coldest in the last 20 years, the underlying increase in structural demand resulted in record winter gas demand.
[5] Not included in Exhibit 3.

Exhibit 4. Comparison Of Winter Gas Demand For Residential And Commercial Sectors



HDDs vs Norm	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
	-5.1%	1.1%	2.7%	2.7%	5.9%	-15.3%	-1.8%	9.4%	4.3%	-2.8%

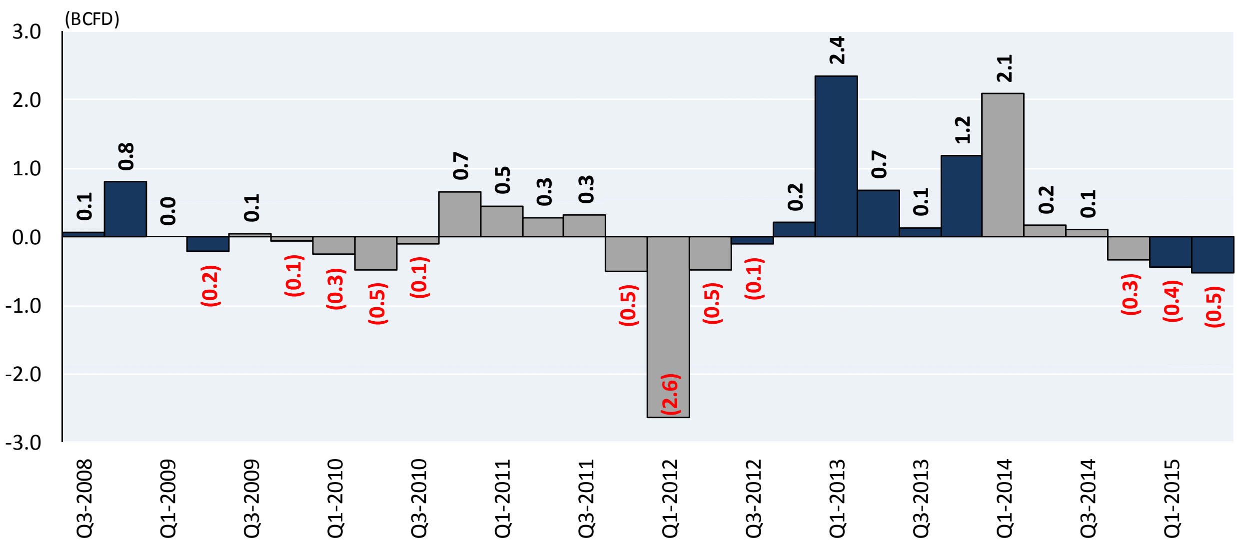
Note: 2015/2016 is forecasted. Source: EIA and EVA.

Within the residential sector the three basic drivers of winter gas demand are (1) the severity of the winter weather, (2) customer growth and (3) conservation, or intensity of use. Concerning the latter two factors, over the recent past, the annual increases in the number of residential customers have been offset by decreases in the intensity of use. With respect to the former, the growth rate in the number of residential customers has been declining for most of the last decade, with 2005 being the sole exception. One factor in this decline has been the impact of the Great Recession on new housing completions, which are still well below 2005 levels.

With respect to the average home, its consumption has been declining. While the two last winters may have been exceptions, because of the severe winter weather, the general trend over the last 20 years, with rare exception, has been a decline in consumption per customer on a weather-adjusted basis, with current consumption per customer near an all-time low (i.e., from 95 to 76 MCF per customer, or about 20 percent). There are a series of factors behind this decline, which include (1) higher energy efficiency in space heating equipment, (2) the turnover of U.S. housing stock with more energy efficiency equipment, and (3) population migration to warmer winter climates. By far the most significant of these factors is the higher energy efficiency in space heating equipment, which has occurred primarily as a result of governmental regulations on new appliances. This factor accounts for over half of the decline in the intensity of use per customer. With respect to behavioral conservation (e.g., setting the thermostat lower and wearing a sweater) that initially occurred during the era of high gas prices (e.g., 2008) and then continued both during and for a while after the Great Recession, because of the impairment to the financial well-being of many families caused by the Great Recession.

While winter gas demand within the commercial sector is impacted heavily by the severity of the winter weather, the other factor affecting changes in gas demand within the sector is the recovery from the recent recession. Exhibit 5 presents the year-over-year changes in commercial sector gas demand for the last several years. While commercial sector demand underwent a decline in 2009, which primarily was caused by the impact of the Great Recession, it began to respond to the rebound in economic growth in 2013 and continues to do such, albeit at a modest rate.[6] While the recent declines in late 2014 and 2015 largely are due to weather-related factors, there are embedded declines due to economic factors.

Exhibit 5. Quarterly Change In Natural Gas Demand For The Commercial Sector From Previous Year



Source: EIA.

With respect to the regional nature of gas demand for these two sectors, a graphic in the appendix highlights the gas demand for the residential and commercial sectors by census region for the winter season.

Industrial Sector

The key factor driving the growth in the industrial sector is a series of capacity expansions by a few key industries. In addition, economic growth can impact the level of demand within the sector. However, recently the limited growth in the U.S. economy has not resulted in increases in gas demand within the industrial sector. Instead the opposite has occurred with gas demand for existing industrial facilities actually declining, which has offset the increases occurring because of capacity expansions in a few industries. The net result is that industrial sector this winter likely will increase only 1.8 percent.

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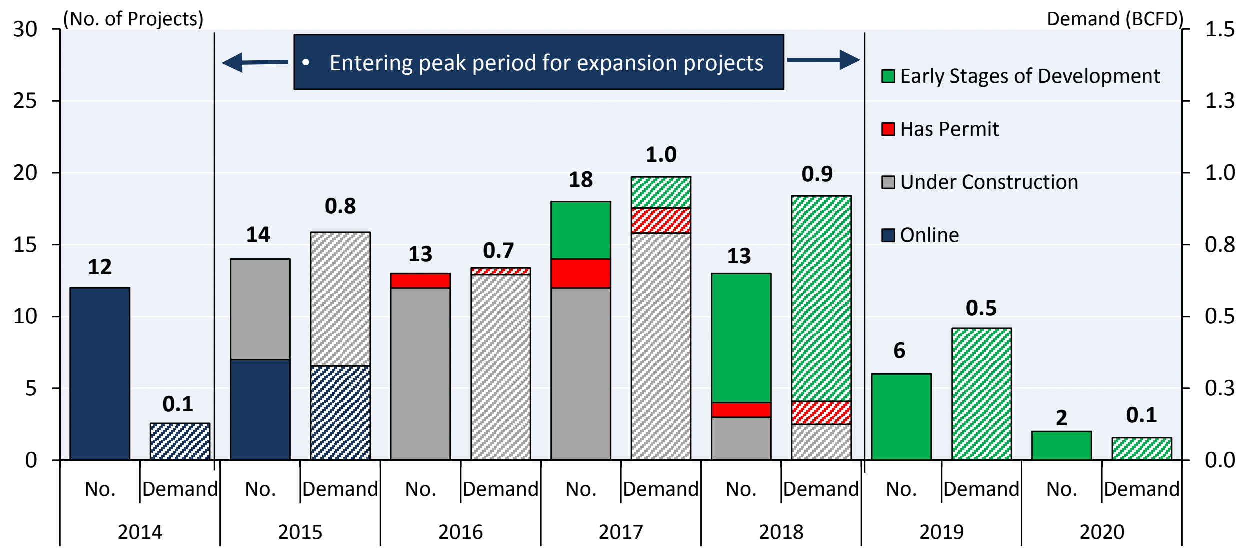
[6] While annual commercial sector gas demand can be affected significantly by seasonal factors (i.e., winter weather), average annual summer demand for the commercial sector has increased only 0.6 percent per annum since 2008.

Capacity Expansions

With respect to the series of capacity expansions occurring within the industrial sector, which are being built to take advantage of the relatively low cost gas in the U.S. in 2015 the industrial sector started into the peak period for the annual additions of these projects. This is illustrated in Exhibit 6. For the most part these projects are expanding capacity in selected industries, in order to use relatively inexpensive U.S. natural gas to produce products (e.g., petrochemicals and fertilizer) that either increase U.S. exports or alternatively reduce U.S. imports.

Exhibit 6. Industrial Capacity Expansion Projects(1)



1. For period 2015 to 2020, 66 projects to come online (3.9 BCFD).

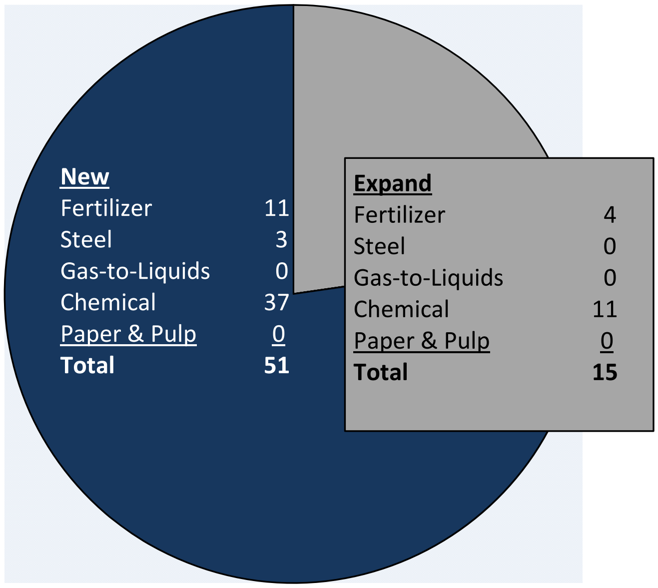
While there have been some additions and deletions to the list of industrial capacity expansion projects, at present for the period 2015 to 2020 there are 66 likely capacity addition projects in the fertilizer, petrochemical, methanol and steel industries. In addition to these 66 projects, 37 projects came online in the 2010 to 2014 period.[7]

With respect to the 66 projects scheduled to come online between 2015 and 2020, Exhibit 7 provides a summary of these projects by both (1) type of expansion (e.g., new facility or expansion of an existing facility) and (2) type of industry. Similarly, Exhibit 8 summarizes the incremental gas demand associated with these 66 projects.

With respect to 2015, this year will receive the benefit of the full year impact of the 12 projects that came online in 2014, plus the partial year impact of 14 additional projects scheduled to come online in 2015. The net result is that gas demand within the industrial sector is expected to increase approximately 0.45 BCFD in 2015, as a result of these capacity expansion projects coming online. However, this increase has been largely offset by the lack of economic growth for the industrial sector, which has caused gas demand for existing plants to decline.

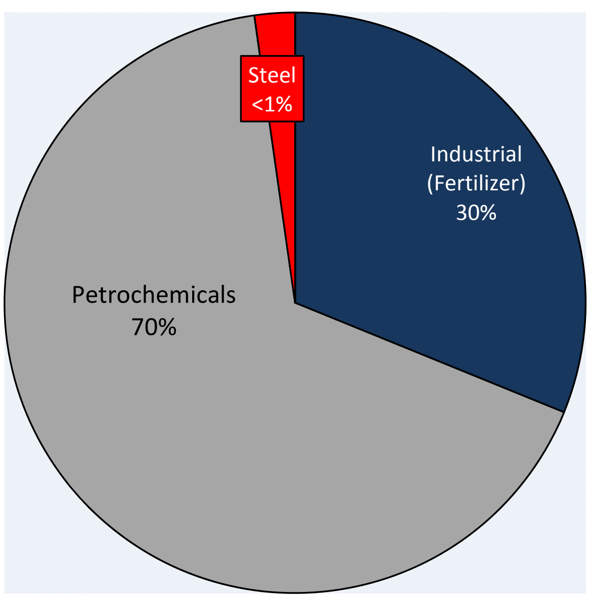
[7] See Addendum I for a more complete assessment of these industrial capacity expansion projects.

Exhibit 7. Comparison Of Project Type Count For Various Industries (2015 to 2020)



Total Projects = 66

Exhibit 8. Impact of Capacity Expansion On Industrial Gas Demand (2015 to 2020)



Total = 3.9 BCFD

This list of 66 projects, which separates some projects into phases in order to better assess the timing of new capacity coming online, is a fully vetted list. Key to this vetting process is the tracking of project milestones, which is a continuous process at EVA. This enables one to eliminate projects that are merely 'paper announcements' that never proceed beyond that stage. The latter phenomenon is readily apparent within the fertilizer industry, as there are several announcements of new facilities by co-ops or small firms that merely disappear after one of the major fertilizer producers announces and proceeds with a large expansion of an existing plant. In essence, the sponsors of these smaller projects know they cannot compete with the economies of scale that exist for the larger facilities. In addition, this list of 66 projects focuses upon projects that are major consumers of natural gas (e.g., use gas as a feedstock or use significant quantities of gas as an energy source).[8]

Economic Growth

With respect to existing industrial facilities, gas demand has been declining because of the limited overall economic growth, particularly within the industrial sector. Concerning the latter, the industrial production indices for three of the six energy intensive industries have been flat for most of 2015, as illustrated in Exhibit 9. With respect to the remaining three energy intensive industries, the production indices for two of them in general, have been declining, while the index for non-metallic metals has been increasing.

With respect to the outlook for economic growth, Exhibit 10 summarizes the current range of views for U.S. economic growth, with average expectations for the fourth and first quarters being 3.1 and 3.0 percent per annum, respective.[9] As a point of perspective, GDP growth for the first quarter for the last two years has been negative.

Summary

With respect to the integrated outlook for industrial sector gas demand this winter, it is expected to increase 0.2 BCFD, or 1.8 percent, over last year’s level. As an added point of perspective, Exhibit 11 compares and contrasts, on an annual basis, the expected outlook for this winter’s industrial sector gas demand with the consumption levels for the sector for selected years since 2006. As illustrated, there has been relatively steady growth for industrial sector demand, since 2008/2009, which is when the Great Recession occurred. At present industrial sector gas demand is at record levels.

Electric Sector

The combination of additional coal-to-gas fuel switching this winter and the retirement of a significant amount of coal-fired capacity for the last two years (i.e., about 25 GW) will offset the declines in gas-fired generation due to seasonal factors (i.e., a milder winter). The result is that electric sector gas demand this winter is expected to increase 1.1 BCFD, or 5.8 percent.

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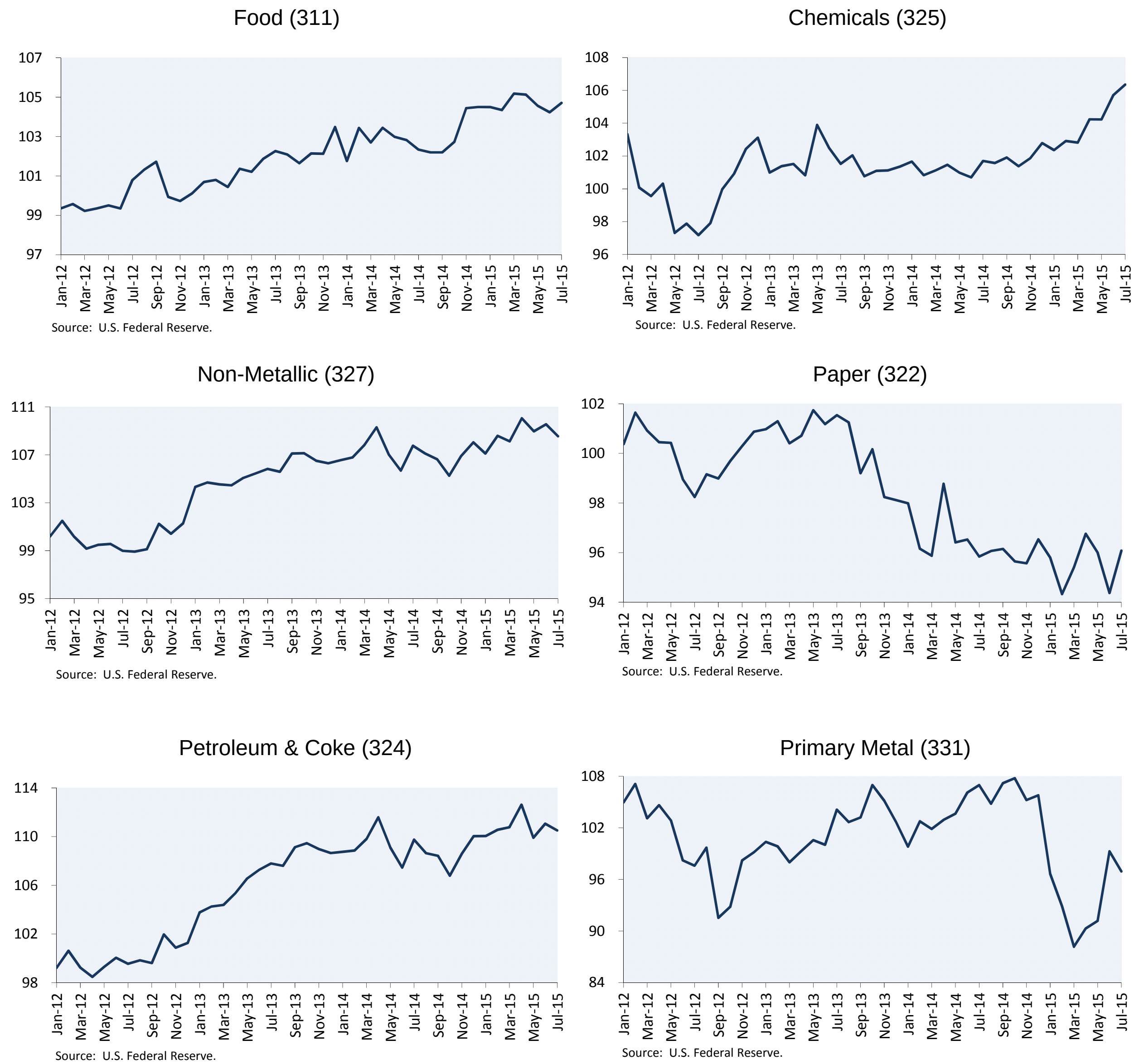
[8] As a result, the number of capacity expansion projects summarized in Exhibit 7 is significantly below other lists circulating within the industry. While some of these lists contain over 120 projects, many of these projects are either mere 'paper announcements' or projects that are not significant consumers of natural gas - for example, assembly plants.

[9] Range in GDP projections for the fourth and first quarters is 2.3 to 4.5 percent and 1.9 to 5.6 percent, respectively.

Exhibit 9. Performance Of The Six Key Energy Intensive Industries



Fuel Switching

Last winter coal-to-gas fuel switching was relatively low because of the high gas prices during the winter, particularly in the fourth quarter (i.e., average prices were $3.69/MMBTU). However, the outlook for gas prices this winter, particularly in the fourth quarter are expected to be lower. As a result, overall fuel switching this winter is expected to be higher than last winter (i.e., about 0.8 BCFD), which will offset some of the decline in electric gas demand due to less seasonal demand because of milder winter weather.[10] Exhibit 13 provides a summary of recent coal-to-gas fuel switching.

[10] From about 4.8 BCFD last winter to about 5.6 BCFD this winter.

Exhibit 10. U.S. Real GDP Short-Term Forecast Comparison

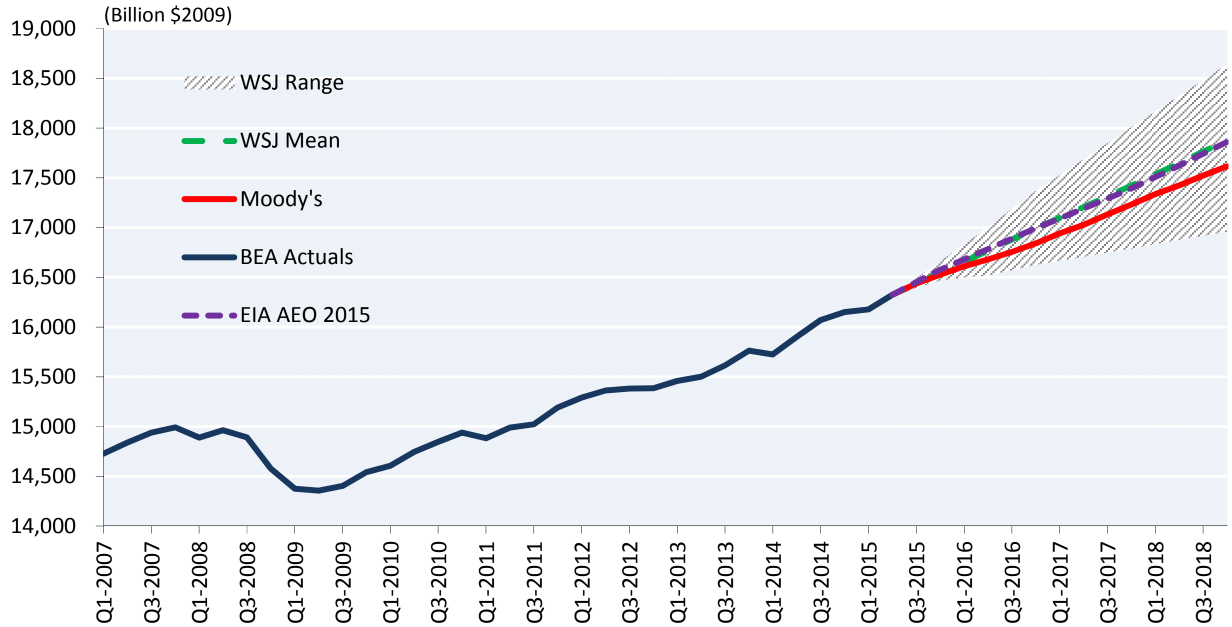
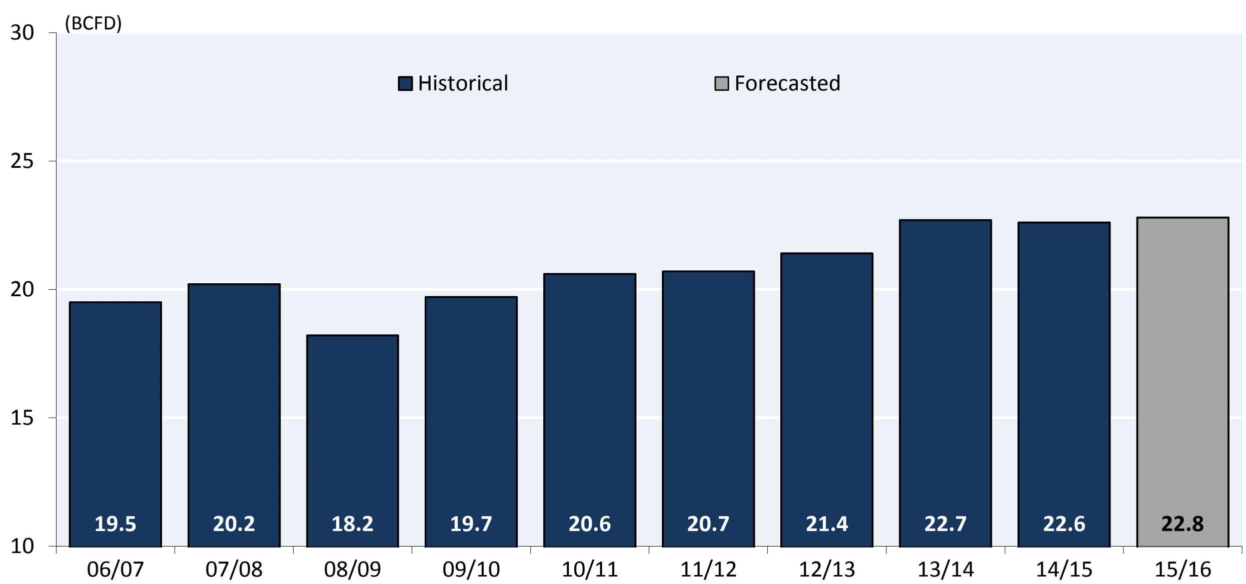


Exhibit 11. Winter Natural Gas Demand For The Industrial And Transportation Sectors



Source: EIA and EVA, Inc.

Exhibit 12. Winter Natural Gas Demand For The Electric Sector

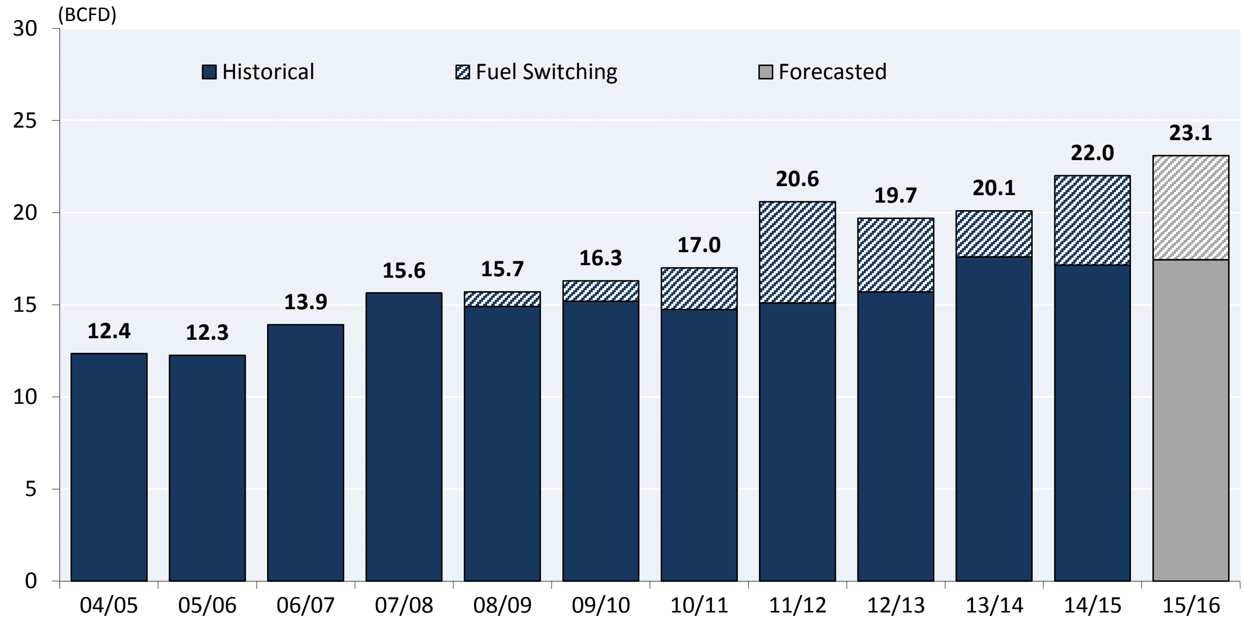
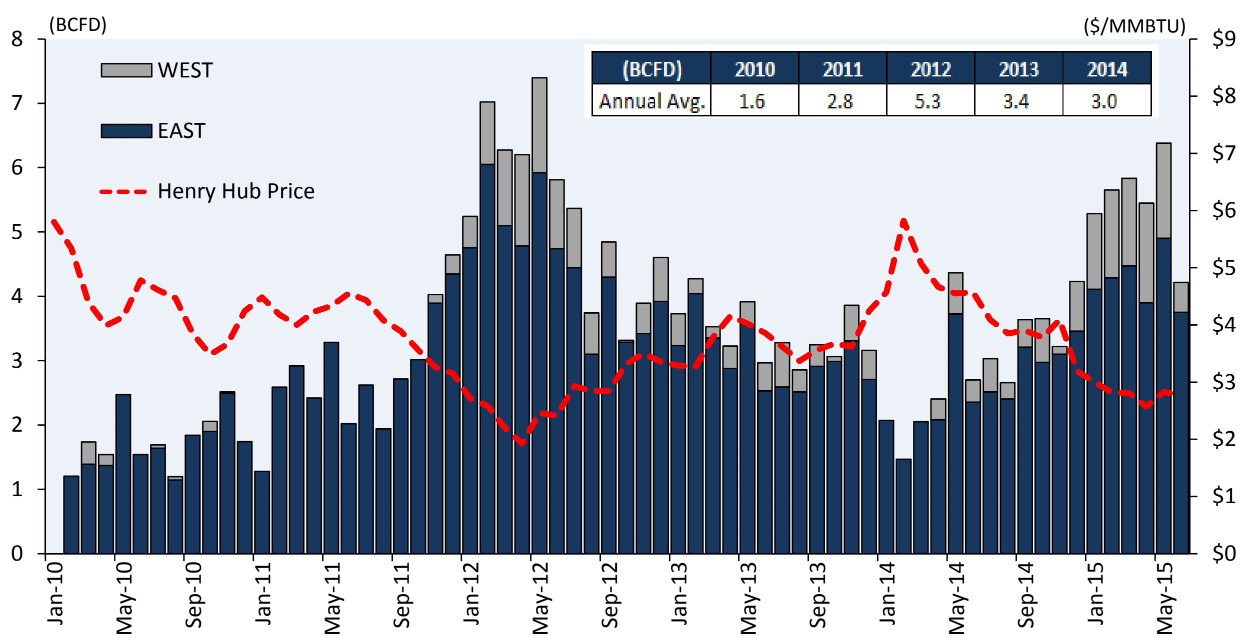


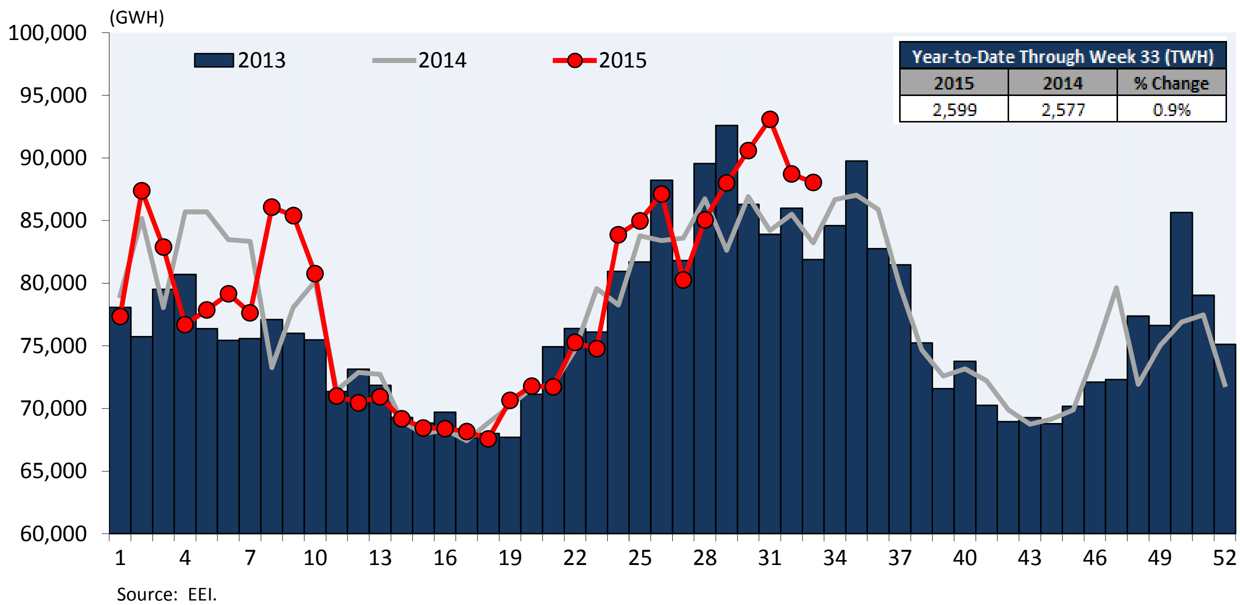
Exhibit 13. Estimated Impact of Coal-To-Gas Fuel Switching On Natural Gas Consumption



Electricity Sales

Among the other factors that historically have influenced power sector gas demand is the overall growth in electricity sales. During periods of significant sales growth, this can be a significant factor in determining overall power sector gas demand, because gas-fired generation tends to be at the margin in most regions. However, for 2015 there has been only limited growth in electricity sales as noted in Exhibit 14.

Exhibit 14. Total Weekly Electric Output (L48-States)



As illustrated in Exhibit 14 for both 2014 and 2015, electricity sales have very limited growth (i.e., 0.5 percent in 2014 and 0.9 percent for year-to-date 2015). With respect to the winter season, the increased electricity sales that occurred last winter because of the severe winter weather are not expected to be repeated for the winter of 2015/2016. As a result, electric sector demand due to this single factor likely will decline this winter.

Capacity Additions

Finally, while it is unlikely that the addition of new gas-fired capacity will have a significant impact on this winter's electric sector gas demand, trends in new gas-fired additions are meaningful for assessing the intermediate-term outlook for gas demand within this sector and thus, provide an additional point of perspective. Exhibit 15 summarizes recent historical capacity additions, as well as the current outlook for capacity additions for 2015 and 2016. In addition to gas-fired capacity additions, capacity additions are included for wind and solar units, which are the two key competitors to gas-fired generation. Also, noted are the retirements for coal-fired and nuclear capacity.

Exhibit 15. New U.S. Generation Capacity

(MW)	2011	2012	2013	2014	Projected 2015	2016
Coal-Fired	**2,665**	**3,760**	**1,507**	**580**	**-**	**-**
Solar	**534**	**1,702**	**2,959**	**1,724**	**2,540**	2,530
Wind(1)	**6,800**	**12,885**	**1,032**	**2,028**	**6,190**	**5,334**
Gas Combined Cycle	7,259	6,713	3,511	6,383	4,797	11,122
Gas Peaking	1,752	2,334	3,332	250	1,413	1,023
Total Gas-Fired	**9,011**	**9,047**	**6,843**	**6,633**	**6,210**	**12,145**
Grand Total	**19,010**	**27,394**	**12,341**	**10,965**	**14,940**	**20,009**
Retirements (Coal)	3,280	10,891	6,951	5,003	20,204	8,770
Retirements (Nuclear)	-	-	2,716	620	-	-

(1) Wind capacity for 2015 and 2016 estimated, as proposed projects significantly exceed these estimates.

While the implementation of EPA's MATS[11] regulations technically was delayed by the courts, industry plans to retain some existing coal-fired units remained the same.

With respect to wind capacity addition as a point of perspective, it is difficult to estimate the forthcoming addition in wind capacity, because of the uncertainty over federal wind subsidies. At present there is uncertainty over whether the current federal wind subsidies, which in effect expire at year-end 2015, will be renewed. When a similar situation occurred in 2013, there was a rush to complete wind projects in the fourth quarter 2012 and a sharp reduction in the financing for these projects in 2013. A similar situation is likely to occur in 2015, if the uncertainty over the possibility of renewing these subsidies persists.

As illustrated in Exhibit 16, gas-fired combined cycle (CCGT) capacity will increase significantly in 2016, with net capacity additions being greater than any of the last five years. Furthermore, since 2010 gas-fired CCGT units and wind have accounted for over 75 percent of the capacity additions, when the peaking units are excluded, with CCGT units and wind each accounting for about 40 percent of the increase in non-peaking capacity.

Finally, with respect to the regionality of gas-fired capacity additions over the 2015 to 2016 timeframe, it is summarized in Exhibit 16. As illustrated, the South census region, which includes Texas, accounts for over one-third of the CCGT capacity additions and nearly two-thirds of the capacity additions for peaking units.

Conclusions

As is the case for most projections for the winter period gas demand, the area of greatest uncertainty for the forecast of gas demand is the severity of the winter weather. Exhibit 17 compares and contrasts the outlook for gas demand for the forthcoming winter with that for a series of winters over the recent past. As illustrated, gas demand this winter is expected to be below last winter's record demand (i.e., 1.3 BCFD, or 0.7 percent, below last winter's results).

[11] Mercury Air Toxic Standards.

Exhibit 16. Gas-Fired Capacity Additions By Census Region (2014-2017)

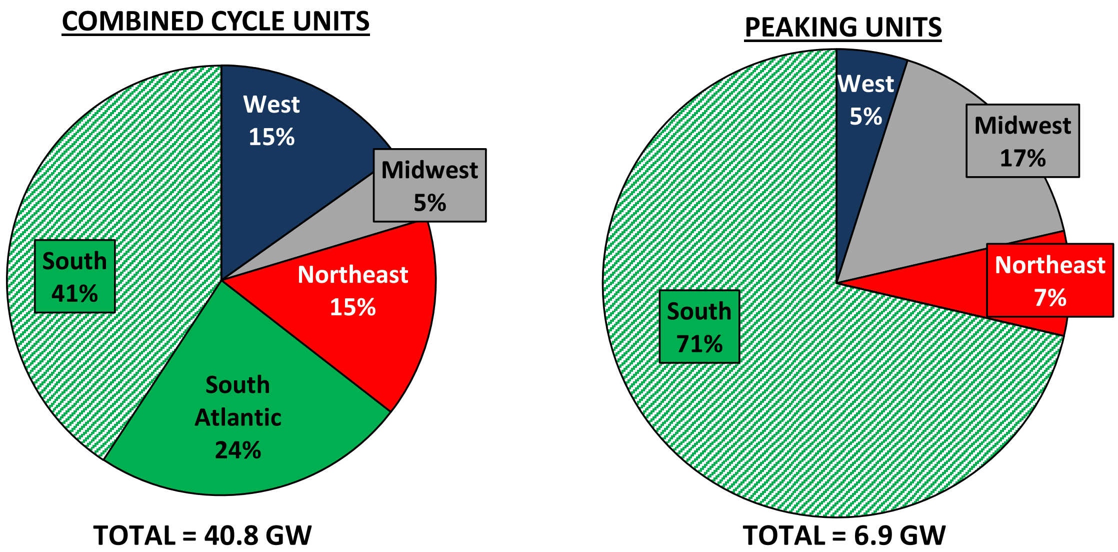
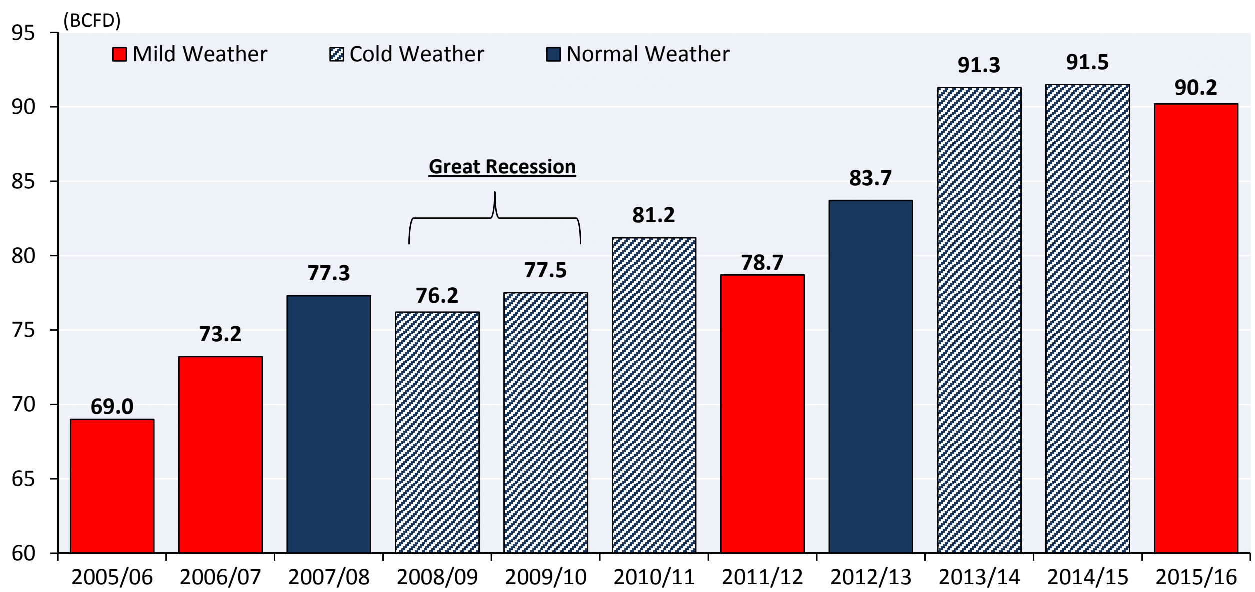


Exhibit 17. Winter Natural Gas Demand For All Sectors



Outlook For Winter Supply

Overview

Total natural gas supply for the forthcoming winter will be less than last winter, because of the expected reduction in winter gas consumption, as illustrated in Exhibit 18. This decline occurs in two areas, namely (1) a reduction in net imports and (2) a reduction in storage withdrawals. While the latter is primarily due to the reduction in the projected demand for winter, the reduction in net imports is due to a combination of (1) increased exports to Mexico; (2) the initiation of U.S. LNG exports; and (3) reduced levels of Canadian imports. With respect to domestic production, the increase, while significant (i.e., 1.5 BCFD, or 2.7 percent) is less than in prior years, which reflects the flattening out of U.S. production on a month-over-month basis. The latter is in directed response to the 40 percent decline in gas-directed drilling activity.

There are two areas of uncertainty concerning the outlook for gas supplies this winter, with the area of greatest uncertainty being the level of storage withdrawals. The latter is dependent heavily on the winter weather outlook varying from current projections and its impact on demand. The other area of significant uncertainty is the level of increase in flowing gas supplies that will occur over the November to January period, as a result of new pipeline capacity coming online and providing takeaway capacity for stranded gas supplies (i.e., an infrastructure event). [12]

Exhibit 18. Outlook For Winter Supply[(2)]

	Coming Winter (2015/2016)		Last Winter (2014/2015)		Change	
Supply Component	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**
Lower-48 Production[(1)]	11,314	74.4	11,021	73.0	293	1.5
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(1) Excludes Alaska production, which is approximately 138 BCF, or 0.9 BCFD in 2015/2016 and 132 BCF, or 0.9 BCFD in 2014/2015.
(2) Figures may not add due to rounding.

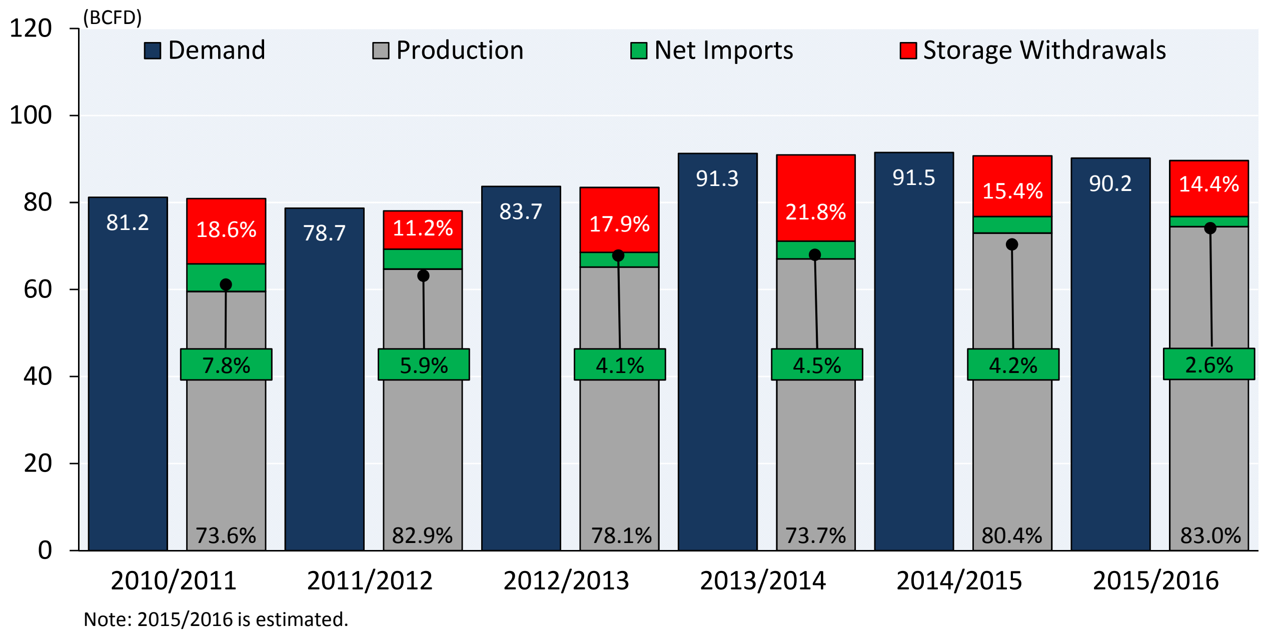
As discussed in subsequent sections of this report, the current assumption is that this infrastructure event will increase flowing gas supplies about 1.9 BCFD, however this assessment is debatable because of the minimal data available concerning the current stranded gas supplies.[13]

In order to provide the reader with an additional perspective on the supply outlook for the forthcoming winter, Exhibit 19 compares and contrasts these supply projections with actual results over the last several winters. There are a few very apparent trends in the data summarized in Exhibit 19, namely (1) the growth in U.S. production (i.e., approximately 14.9 BCFD over the five year period); and (2) the decline in net imports (i.e., approximately 4.0 BCFD over the five year period). With respect to the former trend, the increase in domestic production is entirely

[12] The bringing online of new pipeline capacity (i.e., an infrastructure event) can provide takeaway capacity for previously stranded gas supplies, which would increase overall flow gas supplies.
[13] In the fourth quarter of 2013 infrastructure events increased production 1.55 BCFD, whereas in the fourth quarter of 2014 these events increased production 2.2 BCFD.

due to increasing shale gas production, which has both increased in response to demand increases and increased to offset declines in conventional production. Lastly, the sharp increase in the reliance on storage withdrawals for the winter of 2013/2014 was due to the near record cold weather.

Exhibit 19. Summary Of Winter Supply



U.S. Production

Overview

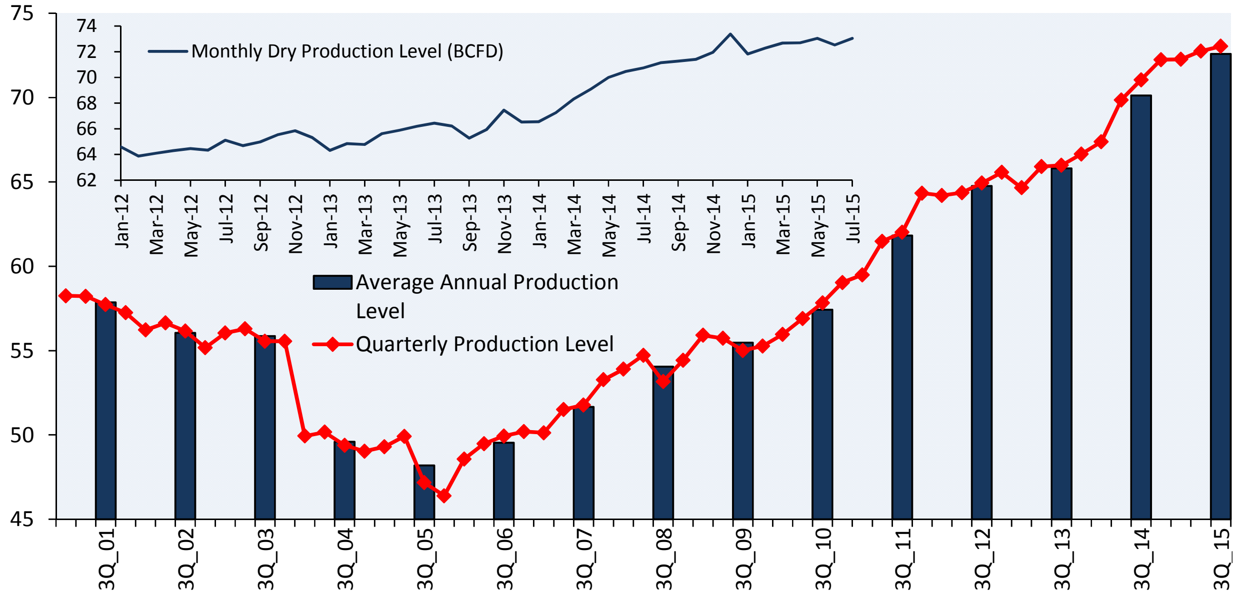
Currently increases in flowing gas supplies can occur via two different mechanisms, namely (1) directly from drilling activity and (2) from infrastructure events, which provide additional takeaway capacity for previously stranded gas supplies. The impact that both have on the outlook for the forthcoming winter's gas supplies is discussed below.

Current Assessment

With respect to current domestic production levels, Exhibits 20 and 21 summarize recent trends. Included in Exhibit 20 are annual and quarterly production levels for the Lower-48 (L-48) plus monthly trends for the last few years in the inset. In addition, Exhibit 21 provides daily production trends for the L-48 since November 2014, with December representing the peak for 2014 production levels. The latter occurred because of the significant increase in flowing gas production levels that occurred as a result of the November/December 2014 infrastructure event.

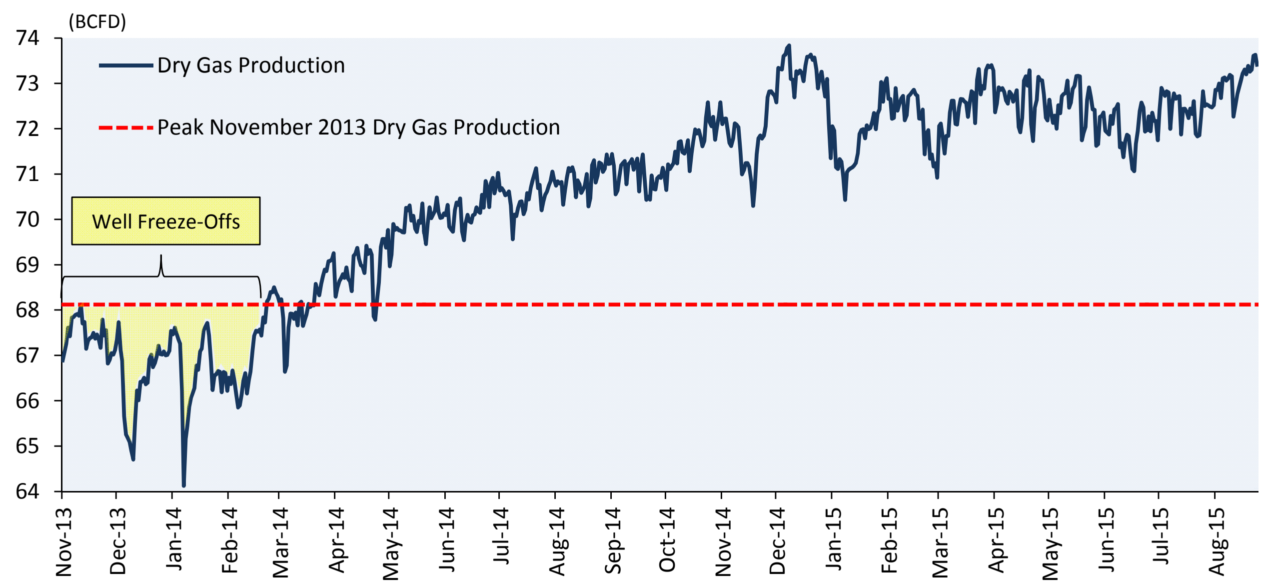
As noted in Exhibit 21, at the present time the industry is having difficulty in matching on a consistent basis the peak production levels attained in early December 2014. This is primarily the result of the 40 percent decline in gas-directed drilling activity, which has resulted in flat to declining production on a month-over-month basis, although annual increases are still occurring. Also, noted in Exhibit 21 is the impact of well freeze-offs last winter (i.e., about 1.0 BCFD on average), with the erratic nature of production trends since the end of last winter due primarily to pipeline and NGL plant maintenance.

Exhibit 20. Lower-48 Natural Gas Wellhead Production



Source: PointLogic Energy, Inc. and EVA.

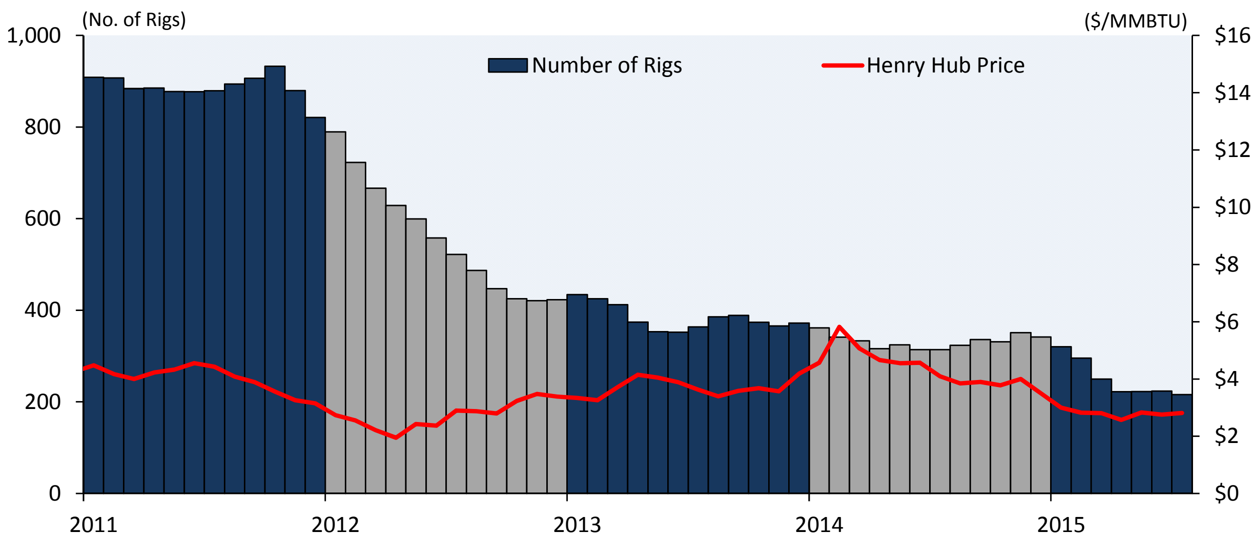
Exhibit 21. Lower-48 Daily Dry Gas Production



Drilling Activity

At present gas-directed drilling activity is near an all-time low (see Exhibit 22) and is expected to either stay near this level, or decline, throughout the winter period. There are several factors causing this phenomenon – one of which is the sharp decline in industry operating cash flow as a result of both the decline in oil and gas prices.[14] In addition, the industry, for the most part, is resistant to commence active dry gas drilling programs until natural gas prices increase.

Exhibit 22. Rig Count For Gas Wells And Henry Hub Price



Source: NGW.

A key component of the rig count in Exhibit 22 is the horizontal rig count for the major shales. Since late 2014, the horizontal rig count for the seven major shale plays has declined 30 percent, with declines between 25 to 75 percent occurring for every one of the seven major shale plays, except for the Woodford shale play where activity is primarily driven by oil-directed drilling.

Infrastructure Events[15]

The other means of increasing flowing gas supplies is infrastructure events, which provide takeaway capacity for previously stranded gas supplies. While there have been a couple of these in the past, the most significant ones were in the fourth quarters of 2013 and 2014 when flowing gas supplies increased about 1.5 and 2.2 BCFD, respectively, as a result of new pipeline capacity coming online. Furthermore, it is likely that a similar infrastructure event will occur in the fourth quarter of 2015.[16] Exhibit 23 compares and contrasts the pipeline capacity additions that occurred for the prior infrastructure events with those that are scheduled to occur in the fourth quarter of 2015. As illustrated, the number of pipeline projects and capacity expected to come online this forthcoming fourth quarter is greater than for either of the prior infrastructure events. Concerning the latter, the cumulative capacity addition is not always a good measure, because it does not indicate the net capacity of a single transmission flow path.[17] Perhaps the most insightful comparison is the number and capacity of the major pipeline projects.

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[14] WTI oil prices have declined approximately 63 percent, since there peak level in June 2014, while oil-directed drilling activity has declined 58 percent, since peak levels in 2014.

[15] An addendum to this report provides additional discussion on both past and expected infrastructure events.

[16] Technically the Constitution Pipeline (0.65 BCFD) is scheduled to come online in early January 2016.

[17] For example, a major gathering system plus a pipeline project could connect to another pipeline project, which form a single transmission path. The cumulative capacity of the three projects would be greater than the capacity of the single net transmission path.

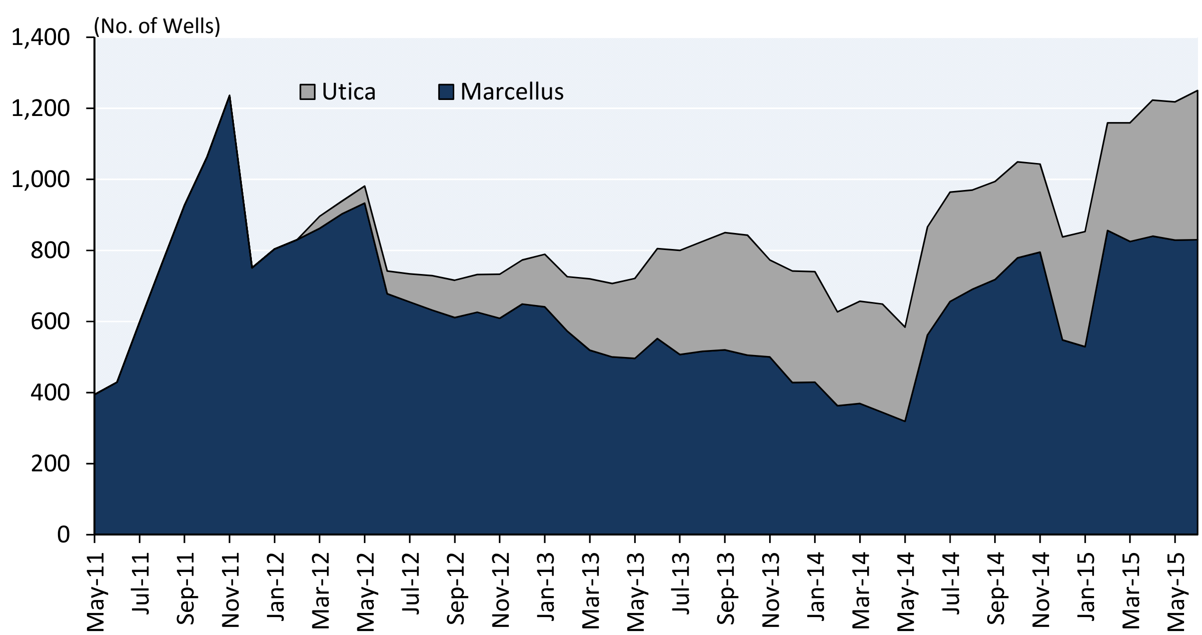
Exhibit 23. Comparison Of New Pipeline Projects For The 4Q of 2013, 2014 And 2015

	2013	2014	2015
Number of Pipeline Projects Online	13	15	14
Capacity of New Pipeline Projects (BCFD)	3.3	3.2	5.1
Number of Major Pipeline Projects Online	4	5	7
Capacity of Major Pipeline Projects (BCFD)	2.2	2.0	4.7

While it is known that there will be significant additions of pipeline projects in the fourth quarter of 2015, the key dilemma in estimating the impact of this new pipeline capacity on flowing gas supplies is that there is not any data on either the level of stranded gas supplies or how much of these stranded gas supplies will be affected by the new pipeline capacity. Nevertheless, some insight can be obtained by analyzing the inventory, or backlog, of drilled but not yet connected wells. Exhibit 24 summarizes the history of the inventory of such wells for the two most significant shale plays affected by this phenomenon. As illustrated, the well inventory for the Marcellus and Utica shale plays has been increasing, however some of the more recent monthly data is based upon estimates that have a history of being revised downward.

Lastly, the data presented in Exhibit 24 can be divided into two categories, namely (1) those wells that are completed but not yet producing and (2) those wells that are waiting to be fracked. The former category, which represents about 60 percent of the total inventory, represents those wells that are most likely to come online during this year’s infrastructure event.

Exhibit 24. Inventory of Drilled But Not Yet Connected Wells



1. Gas wells waiting on completion or completed - not producing.

Integrating all of the above information, even though some of it is imprecise, yields an estimate of the impact of the forthcoming fourth quarter of 2015 infrastructure event which is that it will increase flowing gas supplies about 1.9 BCFD. This estimate is at the mid-point of the last two major infrastructure events.

Lower-48 Production

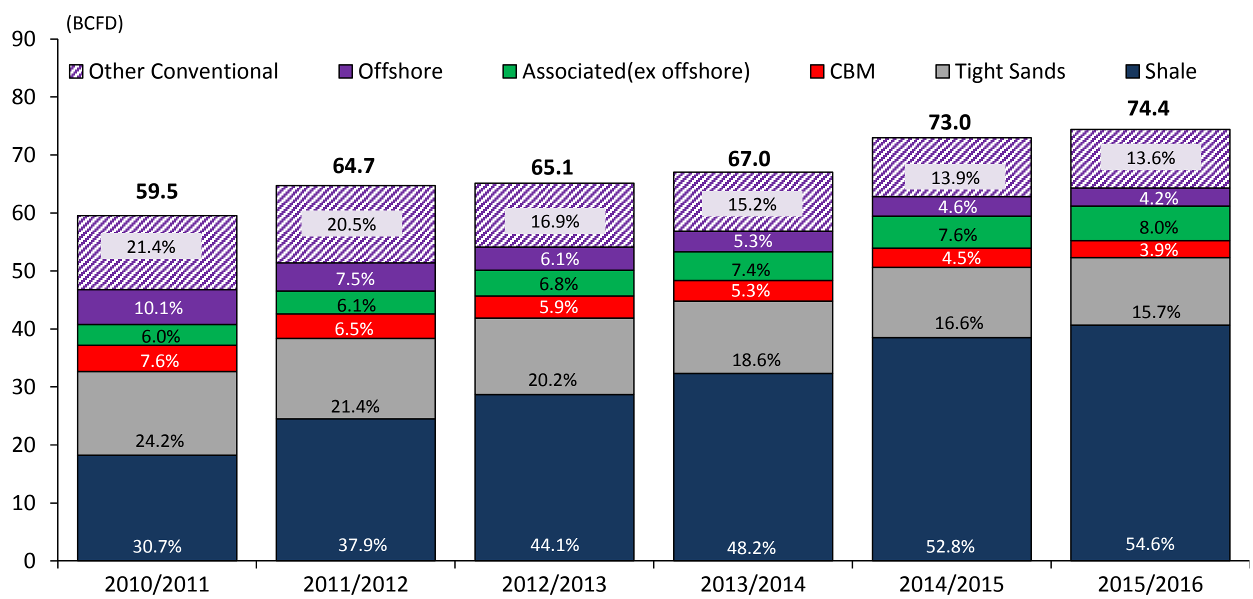
Exhibit 25 summarizes the outlook for L-48 production for the forthcoming winter, which includes both the impact of drilling activity and infrastructure events. This exhibit also compares and contrasts the outlook for domestic production with that for previous winters.

Several key trends are readily apparent in Exhibit 25 and include the following:

- **Increasing Production:** Over the last five winters domestic production has increased about 14.9 BCFD, which equates to about a 4.6 percent per annum growth rate. However, the rate of growth on an annual basis is slowing down.

- **Shale Production Surges:** All of this increase in domestic production is due to increases in shale production, which has met increases in demand, as well as offset declines in other forms of production. Overall shale production has increased approximately 22 BCFD, which equates to about a 17 percent per annum growth rate over the last five winters, with shale production now accounting for about 55 percent of total production.

Exhibit 25. Lower-48 Production Outlook For Winter



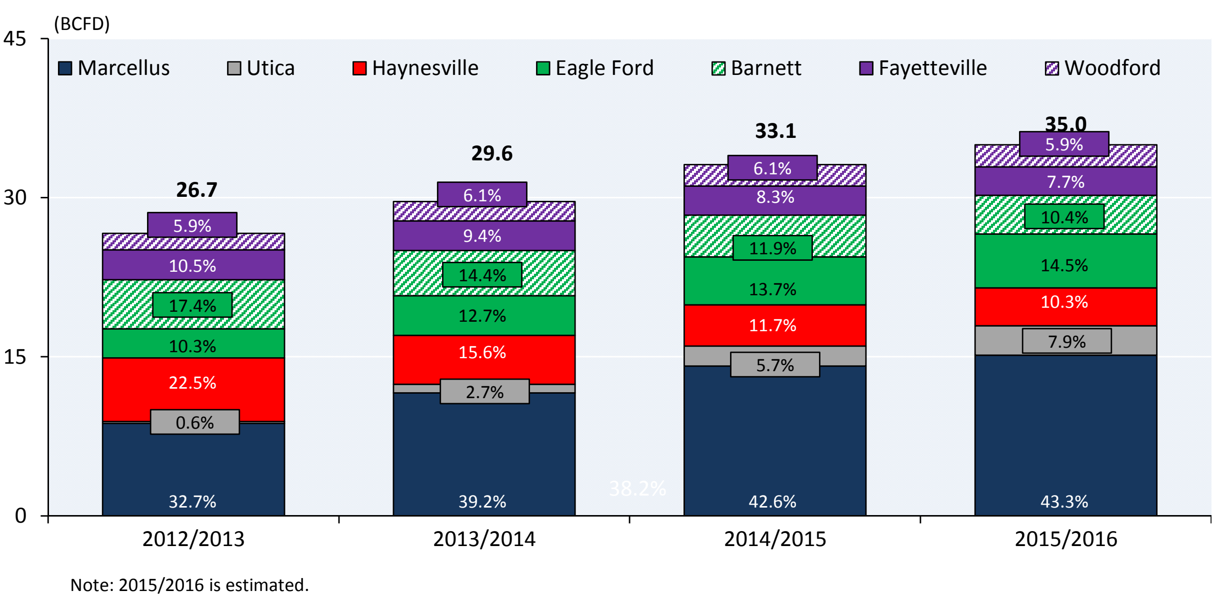
- **Associated Gas**, which is gas production from oil wells, has increased about 2.3 BCFD, which equates to about a 11 percent per annum growth rate. However, this figure excludes the Eagle Ford shale play, which has an oil zone, a liquids zone and a dry gas zone, because the Eagle Ford play is already incorporated in the above assessment of shale production.[18]

- **<u>Other Categories Declining</u>:** Gas production from conventional resources, as well as tight sands and coalbed methane (CBM), has been declining – 5.5 BCFD (7.2 percent per annum); 2.7 BCFD (4.3 percent per annum); and 1.6 BCFD (9.0 percent per annum), respectively. As a point of perspective, the one apparent bright spot for conventional production is the ongoing recovery in offshore production, following the de facto moratorium for offshore drilling following the BP Macondo oil spill (e.g., 17 offshore development projects are expected to come online in 2014, while nine offshore projects are expected to come online in 2015. This compares to just six projects in 2013).

Shale Production

Exhibit 26 provides additional granularity on the increases in shale production during winter periods. As noted in Exhibit 26 the greatest growth among the major seven shale plays has occurred for the Marcellus shale, which now accounts for about 43 percent of the shale production from the major shale plays. Also, increasing over the last three winters are the Eagle Ford and Utica shale plays.

Exhibit 26. Winter Shale Production For The Seven Major Shale Plays



As to the other shale plays, production from the Haynesville, Barnett and Fayetteville shale plays have been declining, although the production decline for Fayetteville has been rather limited. Lastly, production for the Woodford shale play is increasing moderately, however, this is largely an oil driven play.

[18] Including Eagle Ford gas production within the associated gas category would result in a significantly higher growth rate for this category of gas.

With respect to the individual trends for each of the seven major shale plays over the last several years, Exhibit 27 provides an overview of (1) production trends, (2) drilling activity, and (3) a few highlights for each play.

Gas Well Completions

Another indicator of overall gas-directed drilling activity is the number of gas well completions. These are illustrated on both a monthly and annual basis in Exhibit 28.[19] As illustrated, there has been a decline in well completions in 2015.

While there is a time lag between changes in the gas-directed rig count and gas well completions, the basic pattern for both metrics for gas-directed drilling activity is very similar. More specifically, between late 2011 through mid-2013 monthly well completions declined rather dramatically and then were relatively flat until early 2015. This is consistent with the evolution of the shale revolution within the industry and shift away from less production conventional resources. However, since early 2015 well completions have been declining, which is reflective of the significant decline in drilling activity within the industry.

With respect to the overall decline in well completions there are several factors driving these trends towards fewer gas well completions. Included in these factors are the following:

- **Shift in Industry Focus:** Initially this decline was attributable to the industry switching from developing conventional gas resources to developing shale gas resources. The well productivity of shale gas resources is much higher than that for conventional gas resources, which resulted in the need for fewer gas wells.

- **End of an Era:** The era of over drilling, when E&P firms were focused primarily on preserving their acreage positions, has come to an end. At present the industry as a whole seems to be much more judicious about when to develop gas wells, particularly for those plays without significant liquids credits. The latter occurs because in most cases gas prices at present are inadequate of and by themselves to yield acceptable returns.

- **Additional Improvements in Technology:** More recently the industry has begun to adopt further improvements in drilling and completion technology, which improves overall efficiency and thus, further reduces the need for additional gas wells. Examples of such improvements in technology include the use of mega-pads, particularly for the development for stacked plays.[20]

[19] See the Appendix for a tabular presentation of the data.

[20] The industry has started to adopt the practice of drilling stacked plays, which can significantly lower well economics. In the case of the southwest region for the Marcellus it is possible to develop three different formations (Upper Devonian, Marcellus and Utica) from the same well pad, or mega-pad. While the EUR for least attractive formations likely will be well below that for the most attractive formation, the reduction in costs to drill the additional well from the same pad is substantial, since there are no additional acreage costs, plus roads, water management, gas lines and compressor stations already are installed and rig movement and downtime is minimal. This approach can cut the cost of the incremental two wells by two-thirds. At present the industry is testing drilling up to 30 wells from a single mega-pad.

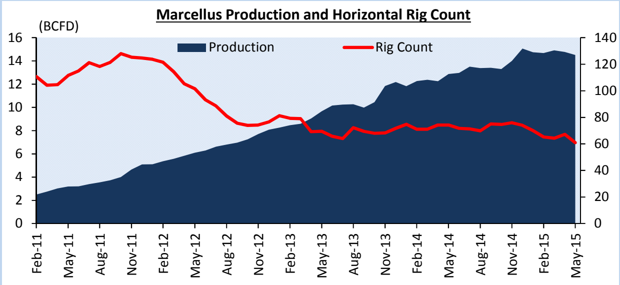
Exhibit 27. Overview Of Seven Major Shale Plays

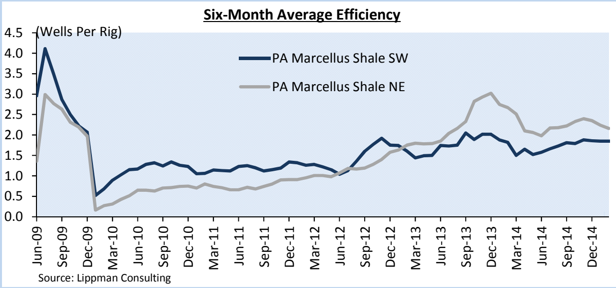
MARCELLUS SHALE PROFILE

Drilling activity for the Marcellus shale has declined as a result of the combination of (1) low gas prices, (2) significant negative basis differentials and (3) the sharp decline in NGL prices, which has occurred because of the near 50% decline in oil prices. This decline in drilling activity has been more significant in the dry gas segment of the play (i.e., NE Penn), where the rig count is now 50% below the recent October 2014 peak. However, in the liquids-rich segment of the play (i.e., SW Penn/WV), the rig count has only declined 6%, or four rigs. At present it is expected that Marcellus production in 2015 and 2016 will continue to increase at about 1.5 and 0.4 BCFD/yr, respectively, or 12 and 3%/annum, which is well below the almost unprecedented growth over the last six years.

A key factor driving the continued drilling activity in the Marcellus, despite low prices, is the continued improvement in well productivity, as a result of improving technology. Included in the latter are (1) extended laterals (i.e., from 5,000 to up to 8,000 ft); (2) shorter stage lengths (SSL) - from 300 to 150 ft; (3) reduced cluster spacing (RCS) - from 60 to 30 ft; and (4) reduced spacing between laterals in the thicker portions of the play. The net effect of the first three advances in technology is to increase the points of entry (or fracturing points) into the formation from about 150 to nearly 500. This, in turn, has resulted in the case of Consol IPs increasing 40% and EURs increasing 15-20%.

Additive to this in the southwestern part of the play is the steady evolution of stacked plays, which enable operators from a single well pad to access reserves from the Upper Devonian (Rhinestreet & Barkett), Marcellus and Utica formations. The net effect is that eight wells can be drilled from a single pad location with a significant decline in the average capital cost per well and a major increase in the EUR per well pad.





Assessing the typical well economics for the Marcellus shale has become rather complex, as the two core areas (i.e., NE Penn. & SW Penn./W. VA) now need to be divided into six segments involving dry gas, wet gas and super-rich liquids. While several operators in the dry gas NE Penn. area have breakeven well economics greater than current gas prices, particularly with the low basis differentials in the region, Cabot, which has acreage in the super-thick dry gas area, reports 80% ROR at $2.80/MMBTU gas prices. Similarly, Energy Corp of Am. reports obtaining a 20% ROR with field gas prices being in the mid $1.00/MMBTU range (i.e., Henry Hub gas price plus regional basis differential). With respect to the SW Penn./W. VA area, which has four segments, at current oil prices and at $3/MMBTU gas prices RORs range from 10 to 24%, while at $4/MMBTU gas RORs range from 18 to 43%, with very wet gas plays having the higher RORs.

Going forward it is expected that the Big six for the play - namely Range, Antero, EQT and SW in SW Penn./WA and Cabot, Chesapeake and SW in NE Penn. - will account for the majority of the future production growth, as other firms have reduced activity or stopped drilling in the play (e.g., Carrizo, Hess, Ultra Petro, Chevron, Anadarko, and Newfield).

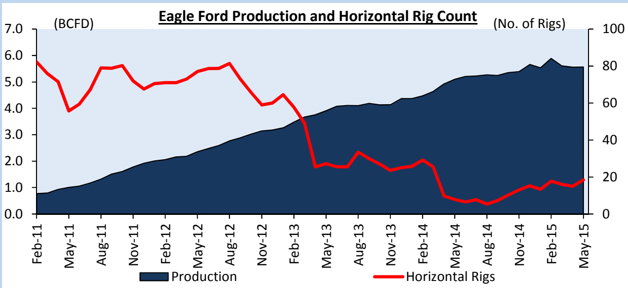
EAGLE FORD SHALE PROFILE

While the Eagle Ford shale play primarily is an oil play, the amount of associated gas is significant and has been growing at about one BCFD/year over the last three years. However, this growth is expected to slow and potentially even decline, as the rig count for the play has declined 57% since its recent November 2014 peak. With respect to the oil production for the play, which is an early indicator of potential changes in the growth profile for associated gas, it has not yet returned to its December peak production levels, after rebounding from the impact of winter well freeze-offs.

The wild card in projecting future near-term trends for the Eagle Ford play is that it is reported that there are approximately 1,400 drilled, but not completed, wells in the region. If producers were to complete these wells, it would easily offset in the near term the impact of the decline in drilling activity. However, if producers delay completing these wells, as several have announced, then both oil production and associated gas could start to decline on a month-over-month basis.

As a point of perspective, more than 50% of the Eagle Ford oil production comes from 10% of the 20,000 square miles that compose the Eagle Ford shale play, with Dewitt, Karnes, Live Oak and Gonzales counties representing much of the core area. As a result of the decline in oil prices, some of the non-core areas are no longer economic to drill, while the core areas appear to be economic even at $40/BBL (i.e., EOG Resources, which is the leading firm in the play).

In addition to the traditional oil window and liquids-rich window within the Eagle Ford play, the industry has begun to examine the potential of two other areas, namely the Eaglebine and Fasken dry gas. The new Eaglebine segment is to the north of traditional drilling and has good well economics at $80/BBL, but probably limited economic viability at $50/BBL. A key component of the Eaglebine segment is the potential for stacked plays. Eight firms were pursuing this segment with 25 rigs active in the fourth quarter. With respect to the Fasken dry gas play this is in Webb county and is being pursued by Swift Energy. Initial indications (i.e., 14 wells) are the IPs will average about 20 MCFD and breakeven well economics will be 2.78/MCF.



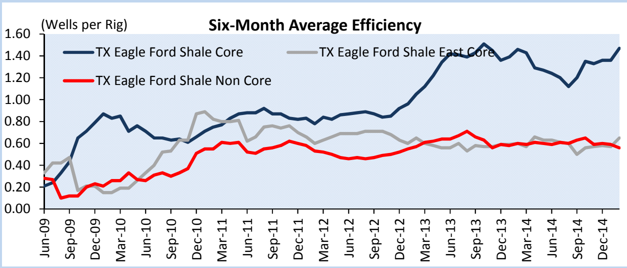


Exhibit 27. Overview Of Seven Major Shale Plays

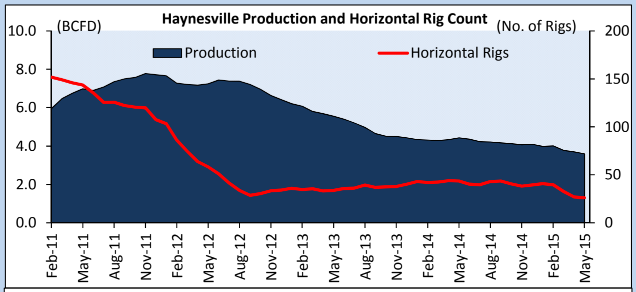
HAYNESVILLE SHALE PROFILE

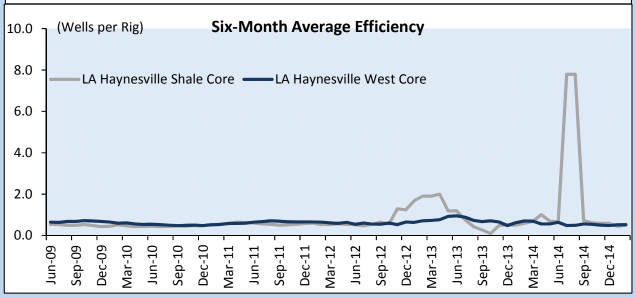
The Haynesville shale play, which is a dry gas play, has declined approximately 2.7 BCFD from its peak production levels, with 0.9 BCFD of this decline occurring in 2014. In addition, drilling activity has declined 28% since the recent November 2014 peak. As a result, expectations are for further declines in both 2015 and 2016 (i.e., about 0.4 and 0.2 BCFD/yr, respectively).

While Chesapeake, which is the largest producer and acreage holder in the play, continues to pursue drilling activity in the core area (De Soto Parrish) of the play, in general, current gas prices are below breakeven well economics for much of the play and likely will remain that way until 2017 at the earliest.

Unique to Chesapeake is the likelihood that it has an additional incentive to continue drilling in the Haynesville play in that it is seeking to avoid penalty payments of $180 to $200MM for not meeting volume commitments to pipelines. In addition, Chesapeake is improving its drilling techniques for the play and may be achieving acceptable RORs at current prices in the core area. Shell, which was one of the play's largest producers and acreage holders, has sold its acreage to the Vine Oil and Gas/Blackstone consortium for $1.2 billion. Similarly, Hess has exited the play.

With respect to the longer term outlook for the play both Chesapeake and Comstock are examining re-fracturing existing wells. Comstock plans to re-frack 10 wells in 2015, while Chesapeake already has re-fracked several wells, which has resulted in production rates increasing from a few MMCFD to 4 MMCFD. It appears that the technology for re-fracturing is still evolving and will take some time to develop. Chesapeake plans to proceed with re-fracturing at a modest pace.

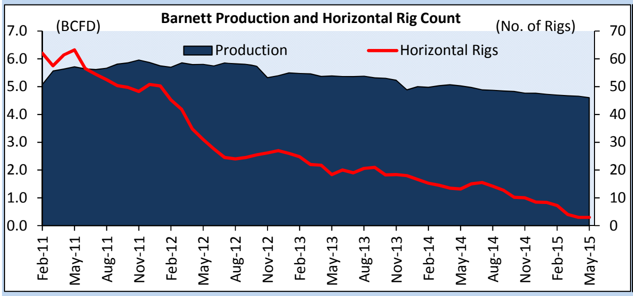




BARNETT SHALE PROFILE

Barnett shale production has declined approximately 0.8 BCFD from its peak production levels, with annual declines over the last two years of 0.4 BCFD/annum. This trend is expected to continue into 2015 and 2016 primarily because of a continued decline in drilling activity.

More specifically, drilling activity has declined about 74% since its recent November 2014 peak. At present there are only three gas-directed and three oil-directed rigs operating in the play. The only segment of the play that has been attractive is the Barnett Combo play (i.e., liquids-rich), which is to the north. However, with the recent decline in oil prices the Barnett Combo's well economics are now in question, as is drilling elsewhere in the play.



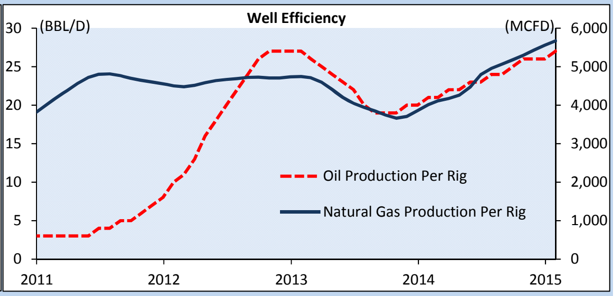
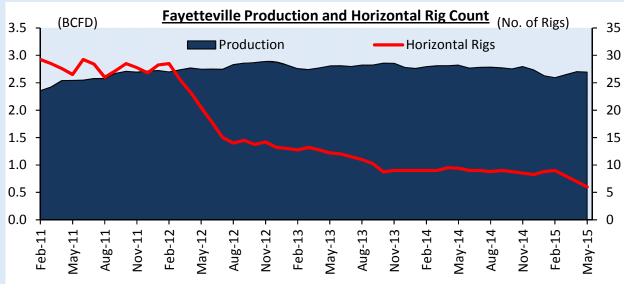


Exhibit 27. Overview Of Seven Major Shale Plays

FAYETTEVILLE SHALE

Production from the Fayetteville shale has flattened out over the last two years, with even a modest decline recorded in 2014. This basic trend is expected to continue in both 2015 and 2016, as there is only one firm that is still active in the play, namely the industry leader Southwestern Energy. At present there are only eight rigs operating in the Fayetteville play (i.e., an 11% decline since November 2014).

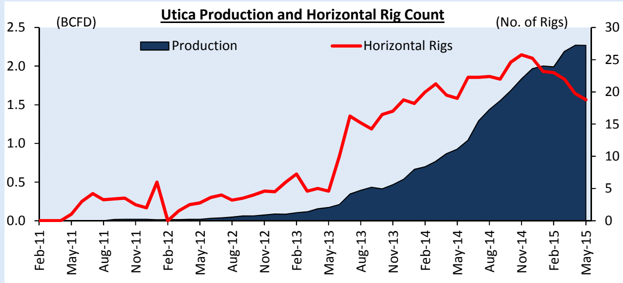
Southwest represents about 60% of the play's total production and controls the core segment of the play with 900M net acres. Southwest, which has reduced steadily capital costs and improved well performance, is able to economically drill wells in the core area at under $3/MMBTU, whereas the economics for the non-core areas are well above this level. Lastly, Southwest has started a pilot program (i.e., 15 wells in 2014 and 45 wells planned for 2015) to examine the Upper Fayetteville formation. Initial results indicate IPs at about 4 MMCFD.



UTICA SHALE

While the development of the Utica shale is still evolving, production levels increased significantly in 2014 (i.e., about one BCFD) However, since the recent November 2014 peak in drilling activity, the overall rig count has declined 42%, with only 26 rigs (i.e., 19 for gas and seven for oil) currently operating for the play.

Despite this decline in drilling activity, production is expected to increase in 2015 primarily because of a large inventory of already drilled, but not yet completed, wells for the play. A significant portion of these wells likely will come online in the 4Q, as new pipeline capacity comes online (i.e., the 4Q infrastructure event).



In general, the play can be divided into three segments, namely (1) Ohio-wet, (2) Ohio-dry and (3) PA/WV-dry. EURs for these three segments are estimated to be 13.3, 19.2 and 9.0 BCFe, respectively. Furthermore, breakeven well economics for the Ohio-wet, or liquids-rich, segment range from $0.00 to $1.15/MMBTU, as the industry is recording some very high production rates for numerous wells. Included in the latter is Range Resources' recent record well, which had an IP of 59 MMCFD, which is a show stopper (e.g., at $2.50/MMBTU and with a 50% first year decline rate gross annual revenues would be about $25MM). At present there are eight firms active in the play with each having approximately 300M net acres.

WOODFORD SHALE

While gas drilling activity in the greater Woodford play has declined (i.e., 60% to just two rigs), oil drilling activity has increased 50% to 51 rigs, as the oil well economics, in general, are attractive. Primarily because the oil drilling activity does generate some associated gas, overall gas production for the play is expected to increase moderately, about 6.5%/annum over the next two years.

In addition to the oil component for the Woodford shale there are two other segments, namely a liquids-rich segment and a dry gas segment. Primarily because of the decline in NGL prices, returns for the liquids rich segment are approximately 15% or less, while the dry gas segments have breakeven well economics well above current gas prices. At present the industry is investigating the South-Central Oklahoma (SCOOP) play. This is a relatively deep play (i.e., 10,000 ft) with the potential for the use of stacked play technology that has significant associated gas (i.e., 36%).

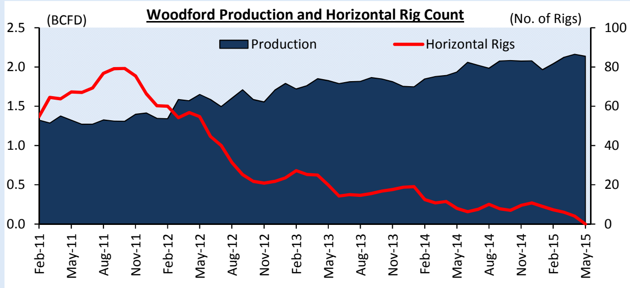
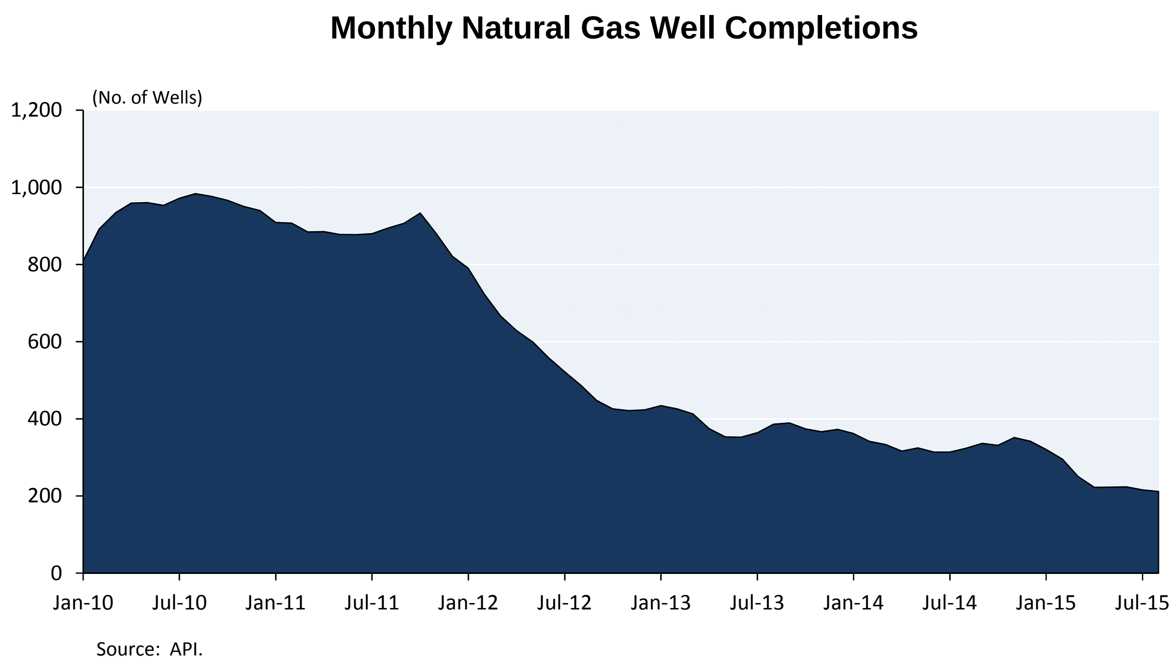
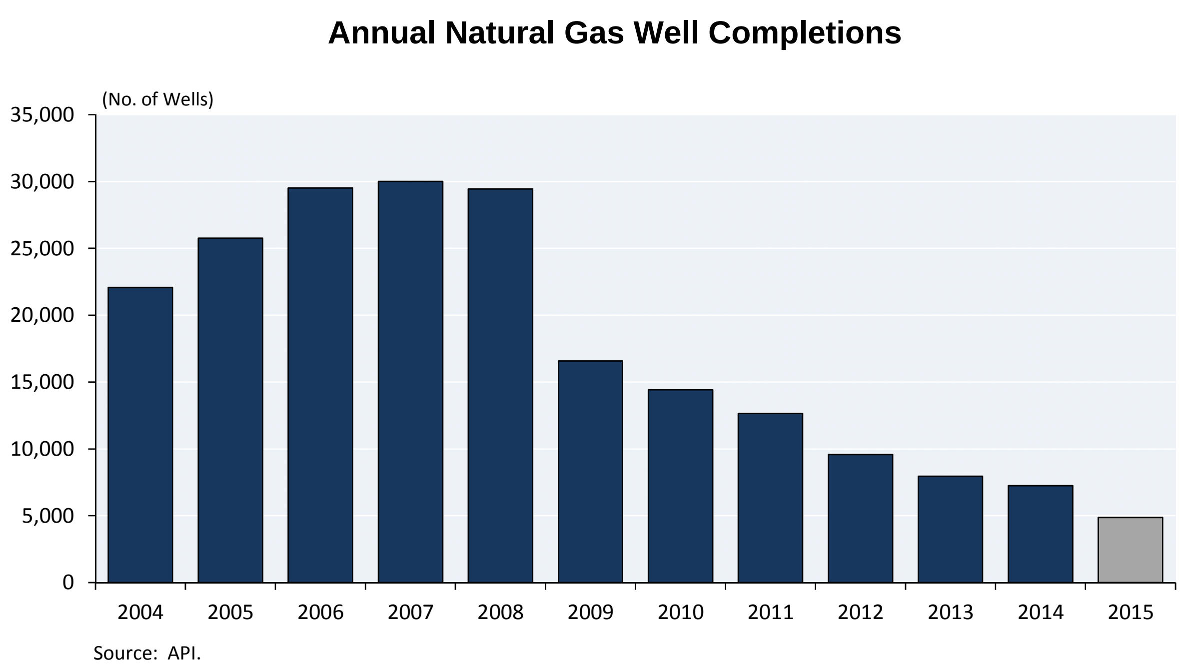


Exhibit 28. Natural Gas Well Completions



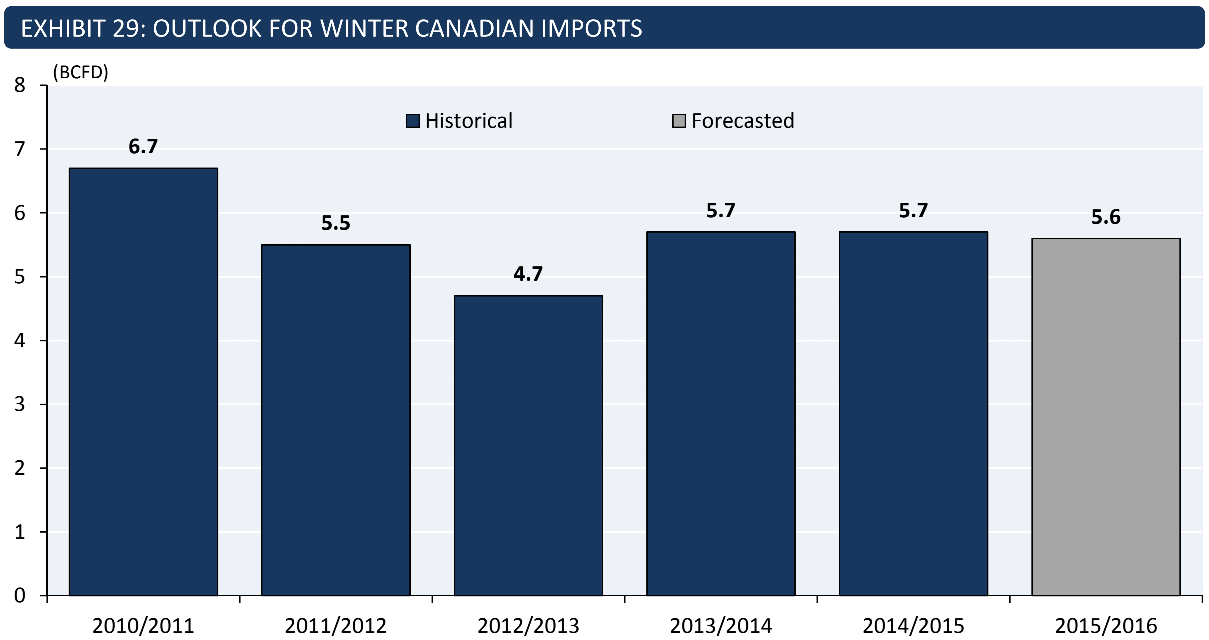


Imports/Exports

Canadian Imports

Net Canadian imports this winter likely will be below the level of Canadian imports last winter (see Exhibit 29). This modest decline is in part due to the lower demand expected for this winter.

Exhibit 29. Outlook For Net Winter Canadian Imports

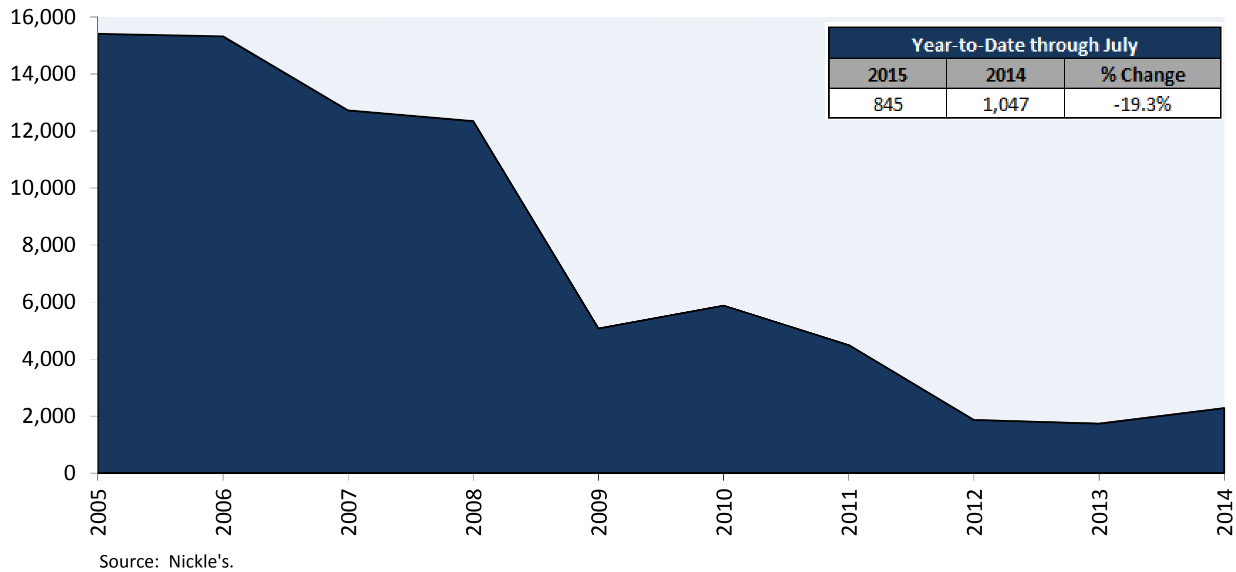


With respect to the longer term trends for Canadian imports, on an annual basis they have been declining for most of the last eight years, which primarily is a reflection of declining production in Canada. However, in both 2014 and 2015 production levels have increased, albeit moderately. The latter primarily is attributable to increases in production from Canada's prolific shale plays,[21] as conventional production in Canada continues to decline. With respect to the latter, conventional production for Canada, particularly in Alberta, represents one of the major marginal sources of production.

Underlying this modest growth in Canada production has been a halt to the steady downward trend for Canadian well completions, with modest increases in 2014 followed by some declines in 2015 (i.e., Exhibit 30). With this flattening in Canadian well completions the increase in gas production due to improvements in rig and well efficiency has become more apparent.

[21] Canada has five very prolific shale plays, namely the Montney, Horn River, Cordova Embayment, Duvernay and Laird Basin plays. At present the Montney and Duvernay are the most economically viable.

Exhibit 30. Canadian Gas Well Completions (Number of Wells)



Going forward Canadian imports will continue to be challenged by increasing Marcellus and Utica shale production, although seasonal factors, such as severe winters, could result in occasional increases. Concerning the impact of the increases in Marcellus and Utica production, the tension for market share between the two sources of supply likely will continue to increase once a series of new pipeline projects come online over the next year.[22]

Mexican Exports

As illustrated in Exhibit 31, net exports to Mexico have been increasing and are expected to continue this trend during the forthcoming winter.

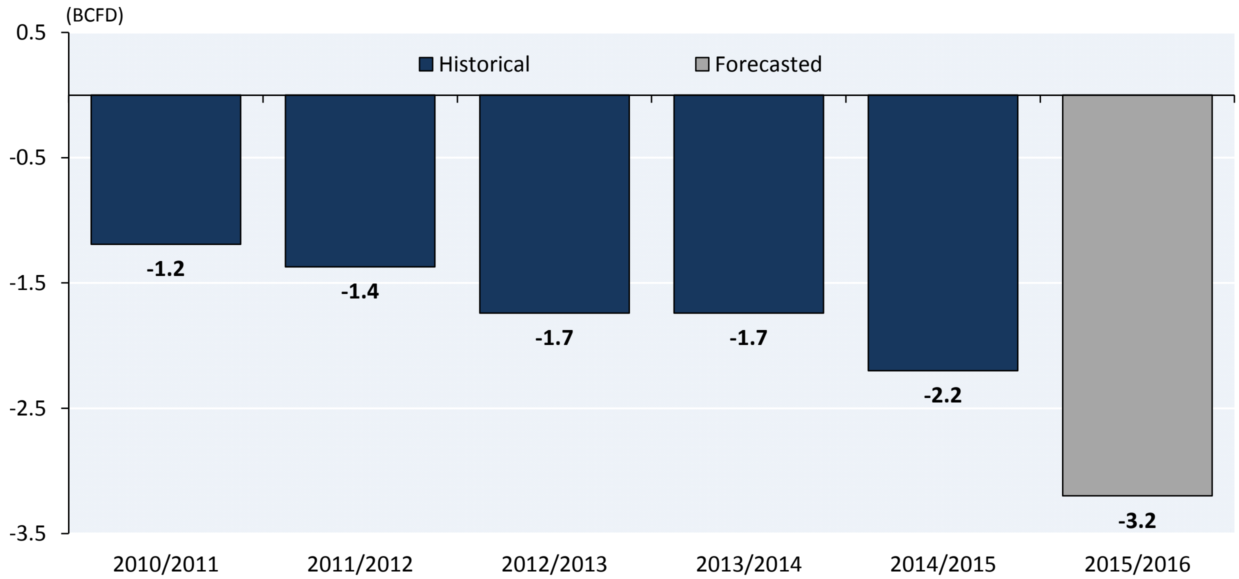
The primary reason for this increase in Mexican exports is that the Mexican economy is fairly robust, which has caused gas demand within the country to grow, particularly in the electric and industrial sectors. At the same time Mexico's domestic production is flat to declining. While these fundamentals within Mexico create a need for more imports from the U.S., the key elements facilitating this increase in imports are (1) a major expansion in Mexico's pipeline infrastructure and (2) the shale gas revolution within the U.S. and, in particular, in the Eagle Ford shale play.

With respect to the expansion of Mexico's pipeline infrastructure, historically there has been significant export capability from the U.S. to Mexico, however inadequate takeaway capacity within Mexico has limited exports to Mexico. Mexico is now in the process of relieving this bottleneck with the construction of new pipeline systems. The infrastructure expansion within Mexico can be divided into two phases. With respect to the first phase, this involved the construction of three major pipeline systems within Mexico, namely the Northwest Pipeline

[22] Included in this series of pipeline projects are the Tennessee and National Fuel projects to Niagara (Nov 2015, 0.5 BCFD) and the Rover/Vector projects (Jan 2017; 1.75 BCFD) and the Nexus project (Nov 2017, 1.5 BCFD).

System, the Chihuahua Pipeline System and the Los Ramones Pipeline System, which have a total capacity of 4.8 BCFD. All these systems either already online or will be online by 2016.

Exhibit 31. Outlook For Winter Net Mexican Exports



With respect to the second phase of the expansion of Mexican gas pipeline capacity, Mexico recently authorized five new systems, namely:

- The Waha to San Elizario pipeline (1.35 BCFD; Jan 2017), which connects to the San Isidro-Samalayuca system.
- The Waha to Presidilo pipeline (1.35 BCFD; 2017), which connects to the Ojinaga to El Encino pipeline noted below.
- The El Encino pipeline (1.135 BCFD; July 2017).
- The El Encino to La Laguna pipeline (1.35 BCFD).
- Ramal Tula (0.485 BCFD).

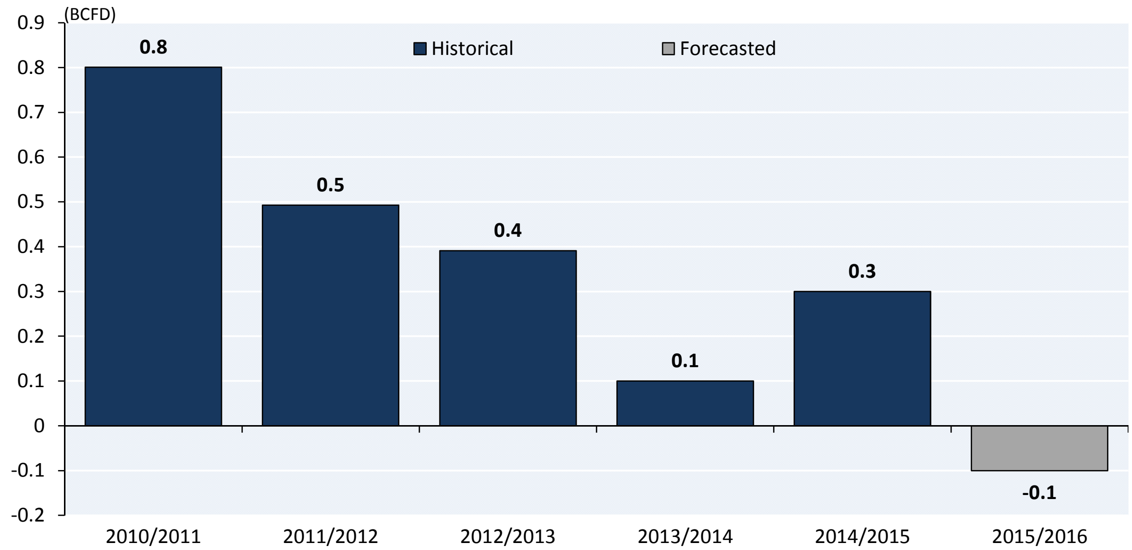
These five additional major systems, which cost approximately $2.2 billion, will be completed in phases. In addition, Mexico will use these imports to initially displace LNG imports at Altamira and eventually at Manzanillo.

LNG Imports

This winter will mark the first time that the U.S. will be exported from the L-48. However, the level of LNG exports is expected to be relatively small, with an initial test cargo occurring potentially as early as late December from Train 1 of the Sabine Pass liquefaction facility. While additional commercial cargoes could occur in the latter part of the winter, the occurrence of L-48 LNG exports in earnest is not expected until April 2016, when the expansion of the Panama Canal is scheduled to be completed.

In addition, during the winter LNG imports in New England are expected to continue and help meet the unique supply requirements of this region. Exhibit 32 compares and contrasts the estimates for net LNG imports/exports for this winter with those for the prior six years. As noted there has been a steady decline in LNG imports and then for the forthcoming winter the transition to net LNG exports for the L-48.

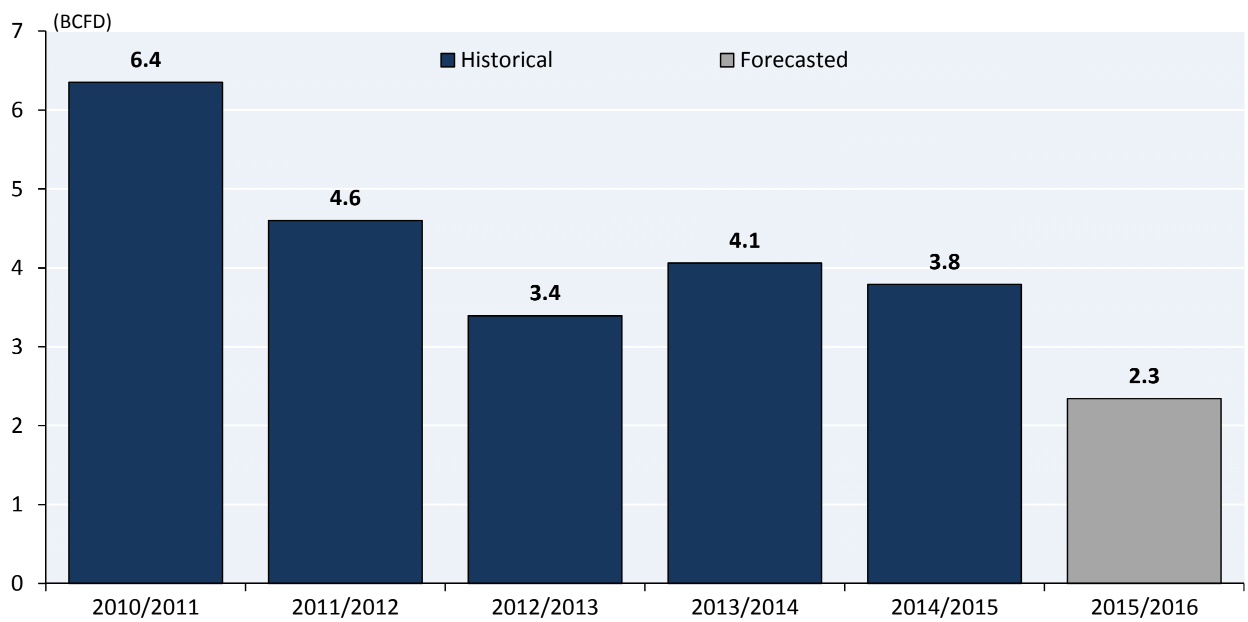
Exhibit 32. Outlook For Winter Net LNG Imports



Composite Summary

Net imports for the forthcoming winter will decline as indicated in Exhibit 33. This decline is due to the combination of (1) increased exports to Mexico; (2) the transition from net LNG imports to net LNG exports; and (3) reduced Canadian imports.

Exhibit 33. Outlook For Winter Net Imports

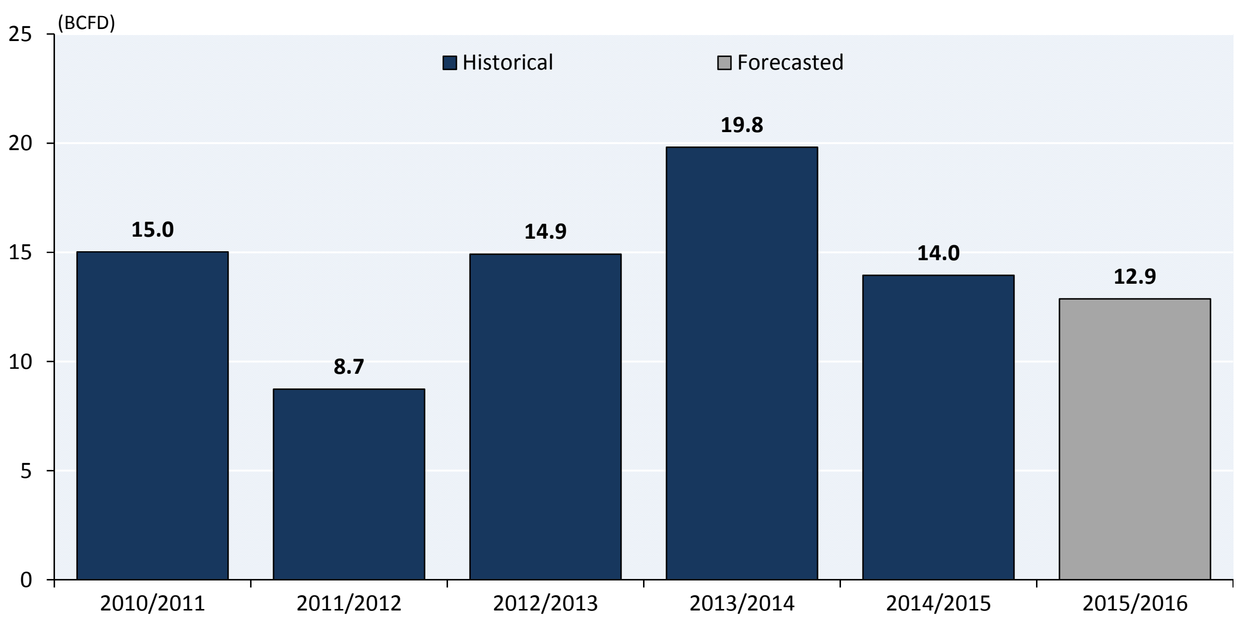


Storage Withdrawals

Storage withdrawals are the supply component that will be most affected by changes in the outlook for winter weather. As a result, there is more uncertainty about this supply component than any of the other supply components. Assuming slightly warmer than normal winter weather, storage withdrawals this winter are expected to be well below storage withdrawals for the prior winter.

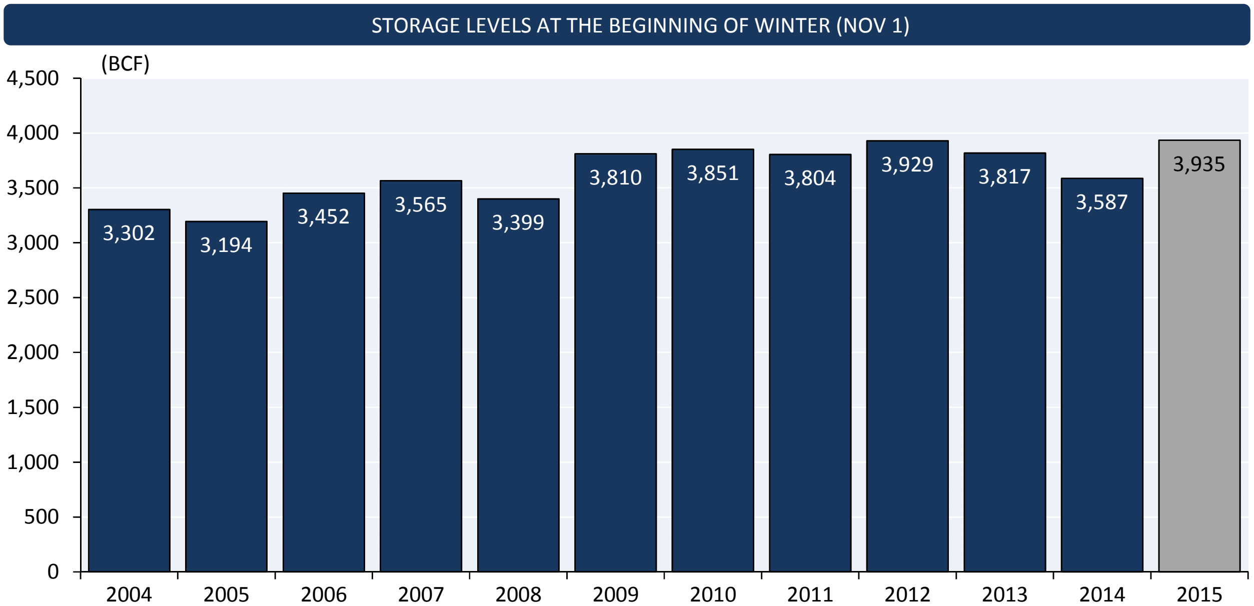
More specifically, the current projections are for about a 1.1 BCFD, or 7.7 percent, decline in storage withdrawals. As noted in Exhibit 34, there have been considerable variations in storage withdrawals over the last several winters, with most of this variance attributable to the difference in the severity of the winter weather.

Exhibit 34. Outlook For Storage Withdrawals



With respect to the outlook for storage levels at the beginning of the winter season (November 1st), they are expected to be slightly higher than the levels that occurred for November 1, 2012, and thus, would represent a record for recent times, as noted in the top portion of Exhibits 35 and 36. In addition, storage inventories currently are expected to increase, albeit moderately, during the first two weeks of November. However, this does assume the start of the winter season is relatively mild.

Exhibit 35. Projected U.S. Natural Gas Storage Levels



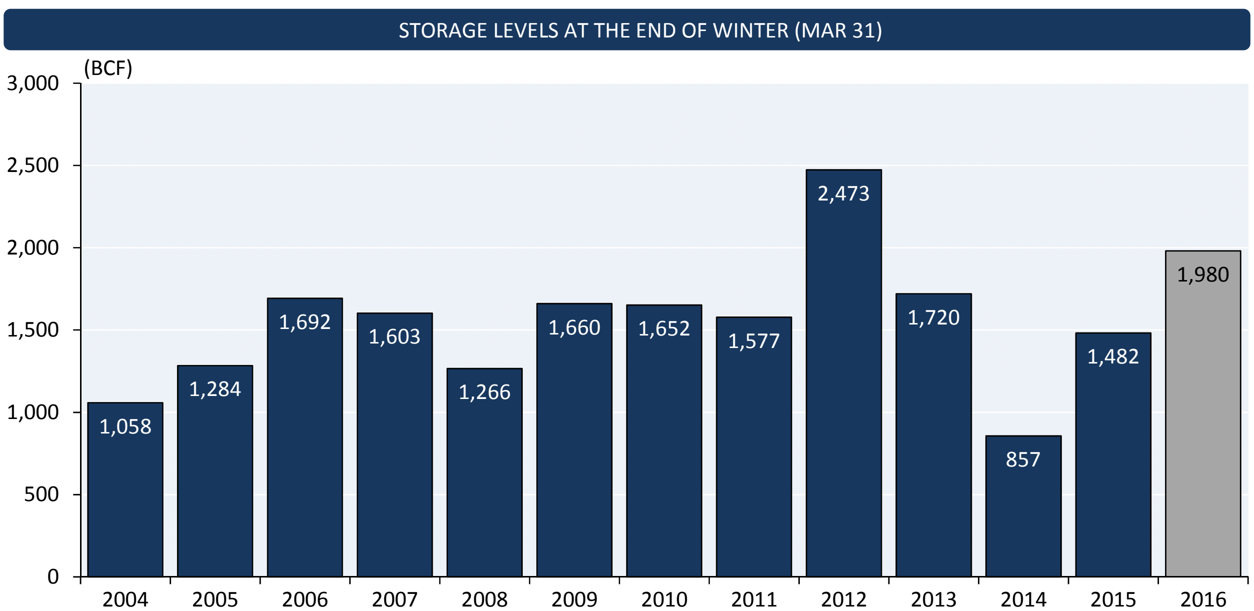


Exhibit 36. Projected U.S. Natural Gas Storage Levels

A. Projected U.S. Natural Gas Storage Capacity and Beginning of Winter Storage Levels

	Actual							Est
	2008	2009	2010	2011	2012	2013	2014	2015
Total Working Gas Capacity at Start of Injection Season[1]	3,665	3,754	3,925	4,049	4,103	4,265	4,333	4,336
Annual Capacity Additions	89	171	124	54	162	68	3	10
Total Working Gas Capacity at End of Injection Season	3,754	3,925	4,049	4,103	4,265	4,333	4,336	4,346
Storage Level at the Start of Winter (Nov 1)	3,399	3,810	3,851	3,804	3,929	3,817	3,587	3,935
Percent of Capacity	91%	97%	95%	93%	92%	88%	83%	91%

(1) Effective maximum usable working capacity.

B. Projected U.S. Natural Gas Storage Capacity and Beginning of Spring Storage Levels

	Actual							Est
	2009	2010	2011	2012	2013	2014	2015	2016
Total Working Gas Capacity at Start of Injection Season[1]	3,754	3,925	4,049	4,103	4,265	4,333	4,336	4,346
Annual Capacity Additions	171	124	54	162	68	3	10	0
Total Working Gas Capacity at End of Injection Season	3,925	4,049	4,103	4,265	4,333	4,336	4,346	4,346
Storage Level at the Start of Spring (April 1)	1,660	1,652	1,577	2,473	1,720	857	1,482	1,980
Percent of Capacity	42%	41%	38%	58%	40%	20%	34%	46%

(1) Effective maximum usable working capacity.

While the confidence level for the November 1st storage levels is fairly high, the same cannot be noted for the projection for the storage levels noted in Exhibits 35 and 36 for the end of the winter season (March 31, 2016). This projection for the March 31st storage level is dependent upon assumptions for two critical factors, namely (1) the severity of the winter weather and (2) the impact of the fourth quarter infrastructure event on domestic production. Concerning the former, a shift from the forecasted mild winter to a severe winter, potentially could increase storage withdrawals about four BCFD, which will reduce March 31st storage levels about 600 BCF. This reduced storage level from the relatively high levels noted in Exhibit 35 from 1,980 to about 1,380, which would be closer to the levels that occurred in 2015.

With respect to the second factor, namely the impact of the fourth quarter infrastructure event, the assessment is more complex, because March 31st storage levels could be either higher or lower, as noted in Exhibit 37. While the net change in March 31st storage levels is not as dramatic as the change from a mild to a severe winter, the increase in storage levels to over 2 TCF is significant.

Exhibit 37. Impact of 4Q Infrastructure Event on March 31, 2016 Storage Levels

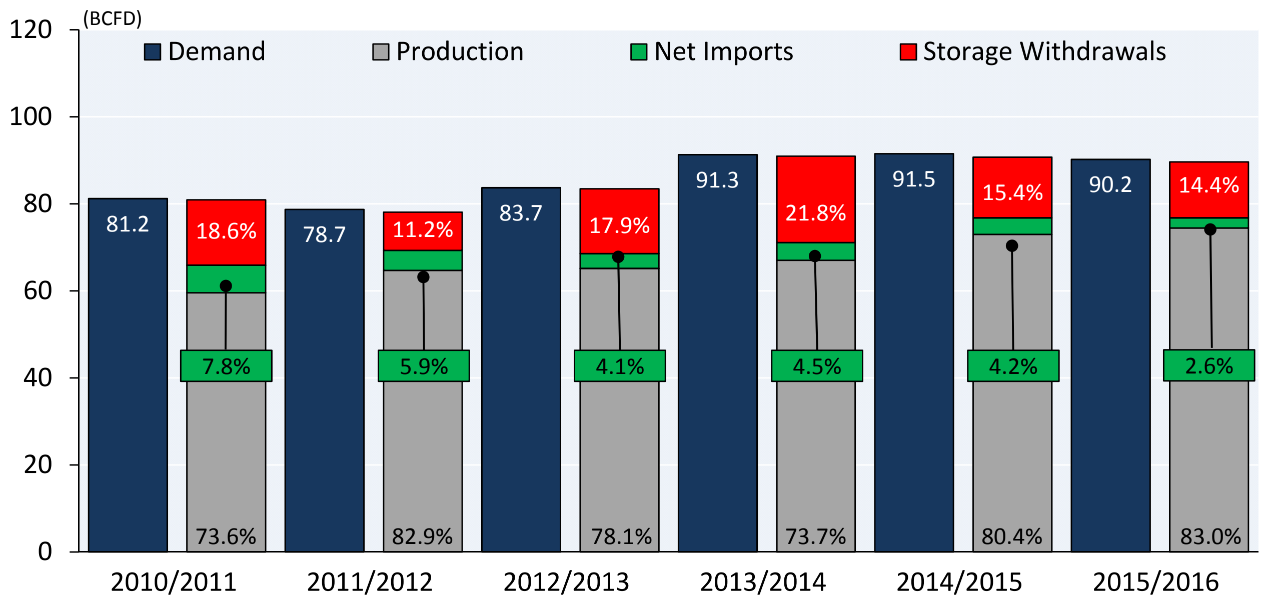
Magnitude of Infrastructure Event	March 31, 2016 Storage Levels (BCF)
1.55 BCFD[1]	1,931
1.87 BCFD	1,980
2.2 BCFD[2]	2,030

1. Results from 2013 4Q infrastructure event.
2. Results from 2014 4Q infrastructure event.

Conclusions

Assuming a warmer than normal weather for the forthcoming winter, natural gas supply should be below the record supply levels that existed for the prior two winters (i.e., see Exhibit 38). More specifically, there will be reductions in both storage withdrawals and net imports that will be partially offset by a 1.5 BCFD increase in domestic production.

Exhibit 38. Summary Of Winter Supply



Note: 2015/2016 is estimated.

ADDENDUM I:

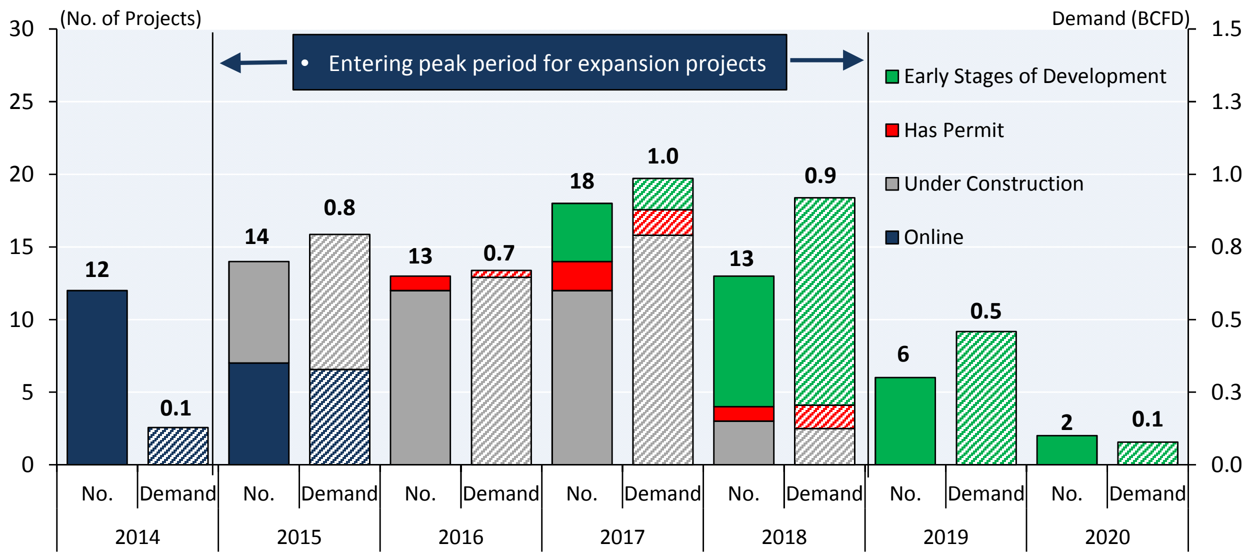
OUTLOOK FOR CAPACITY EXPANSIONS FOR THE INDUSTRIAL SECTOR

Overview for Capacity Expansions for the Industrial Sector

Overview

As noted in the body of the report, the rate of industrial capacity expansion projects coming online is entering its peak period. More specifically, between 2015 and 2018, on average, 14.5 projects will come online each year, as illustrated in Exhibit Add I-1. Furthermore, these projects will result, on average, in an incremental increase in industrial sector gas demand of approximately 0.84 BCFD per annum, or a total of 3.9 BCFD over the four year period, assuming a 100 percent capacity factor. Using a more realistic average 85 percent capacity factor for these projects yields slightly less than 3.3 BCFD over the four year period. As an added point of perspective, the 37 industrial capacity expansions brought online between 2010 and 2014 increased industrial sector gas demand approximately 0.9 BCFD at a 100 percent capacity factor, or 0.8 BCFD at a 85 percent capacity factor. Furthermore, the estimated capital cost of these 2010 through 2014 projects was about $17 billion.

Exhibit Add I-1. Industrial Capacity Expansion Projects[(1),(2)]

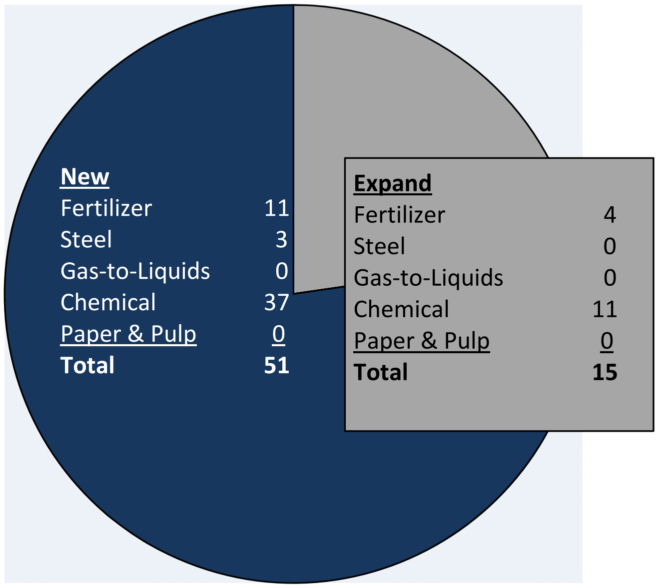


1. For period 2015 to 2020, 66 projects to come online (3.9 BCFD).

Outlook for 2015 to 2020

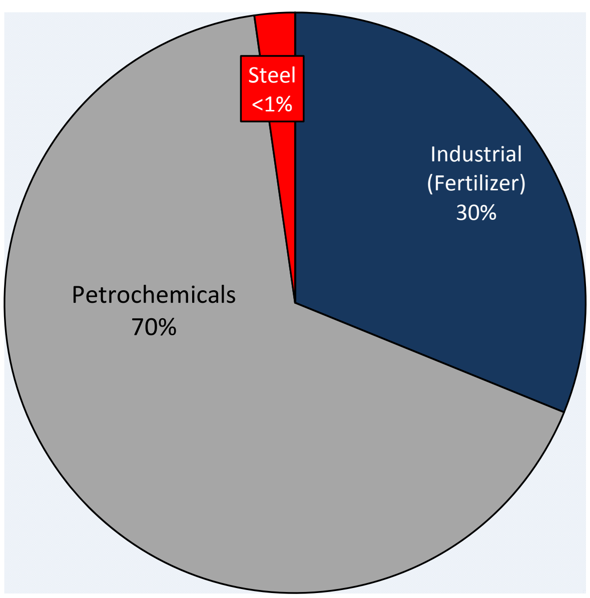
With respect to the period 2015 to 2020, 66 capacity expansion projects are expected to come online. These capacity expansion projects consist of both new facilities and expansions of existing facilities in the fertilizer, petrochemical, methanol and steel industries, as illustrated in Exhibit Add I-2. Furthermore, the anticipated increase in industrial sector gas demand associated with these projects is about 3.9 BCFD at a 100 percent capacity factor (i.e., see Exhibit Add I-3) or at an 85 percent capacity factor approximately 3.3 BCFD.

Exhibit Add I-2. Comparison of Project Type by Count For Various Industries (2015 to 2020)



Total Projects = 66

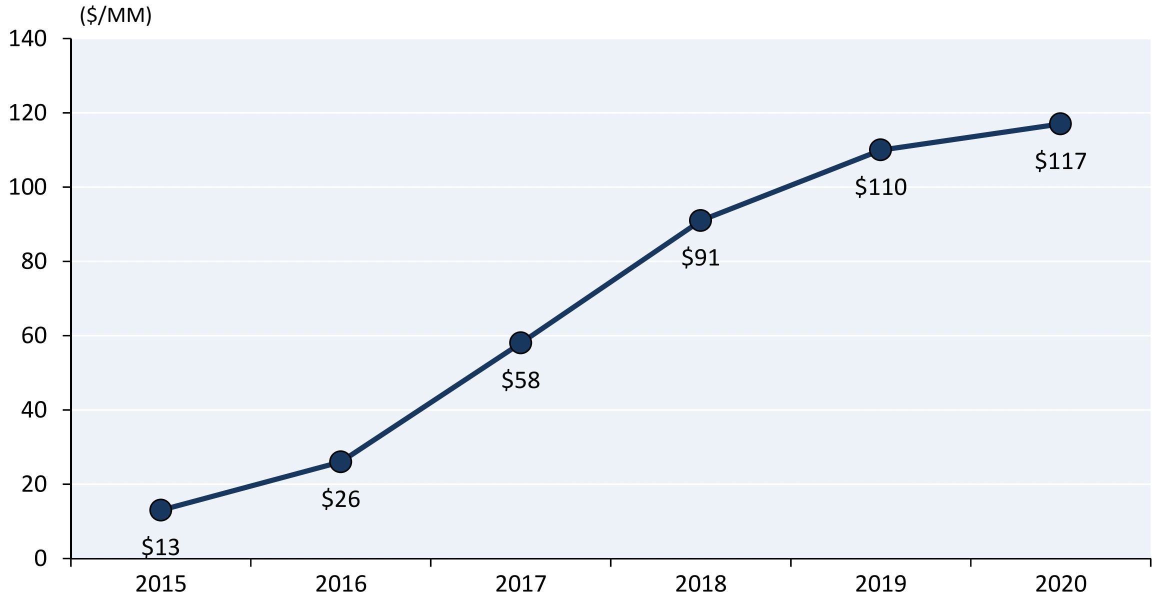
Exhibit Add I-3. Impact of Capacity Expansions on Industrial Gas Demand (2015 to 2020)



Total = 3.9 BCFD

With respect to the estimated cost for these projects, it is approximately $117 billion as illustrated in Exhibit Add I-4.

Exhibit Add I-4. Capital Cost Industrial Expansion Projects (2015 to 2020)



Note: Excludes $16.9 MM for the 39 projects brought online between 2010 and 2014.
Costs are cumulative for period, not annual.

Outlook by Sector

In general the industrial capacity expansion projects coming online in the 2015 to 2020 timeframe can be divided into the following three broad categories:

- **Petrochemical** projects, which use the NGLs (i.e., ethane and propane) associated with natural gas for feedstocks, as well as use natural gas for energy.
- **Methanol and fertilizer** projects, which use natural gas for feedstocks.
- **Other** projects, which use natural gas for energy.

The current outlook for each category is noted below.

Petrochemical Projects

As illustrated in Exhibit Add I-5, there are 37 planned petrochemical projects, which on a cumulative basis would increase industrial sector gas demand about 1.3 BCFD at a 100 percent capacity factor. Of these projects, 5 percent already are online and another 57 percent are under construction. With respect to the remaining 14, or 38 percent, of the petrochemical projects, they either already have obtained their air permits or are in the earlier stages of development. The estimated cost of this series of projects is approximately $78 billion. Lastly, as might be expected, the vast majority (i.e., 87 percent) are located along the Gulf Coast in Texas and Louisiana.

Exhibit Add I-5. Petrochemical Projects

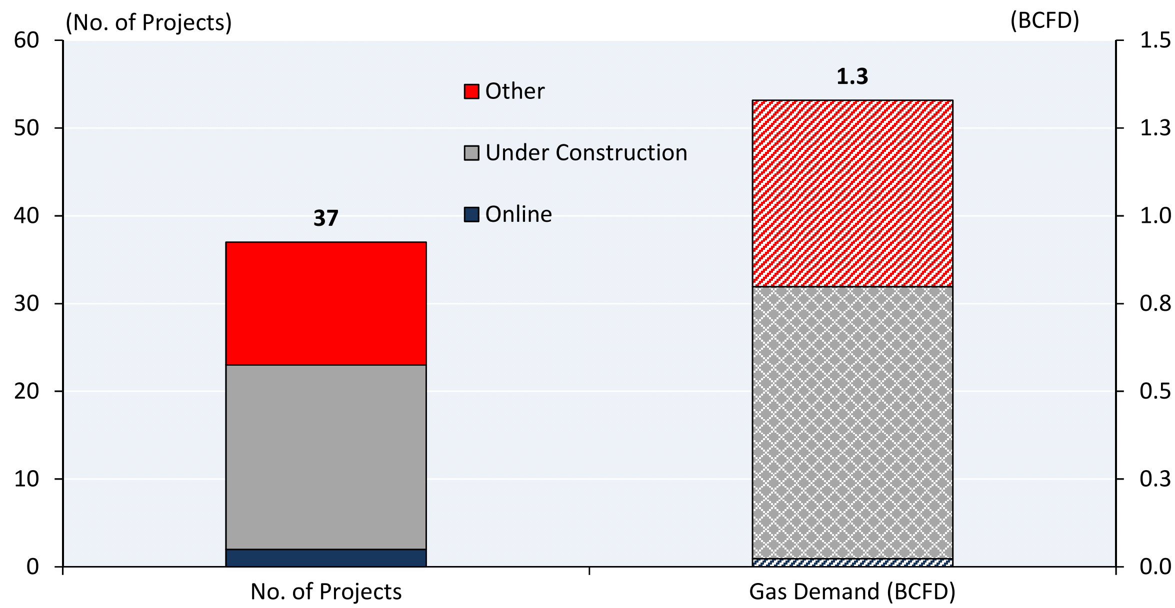
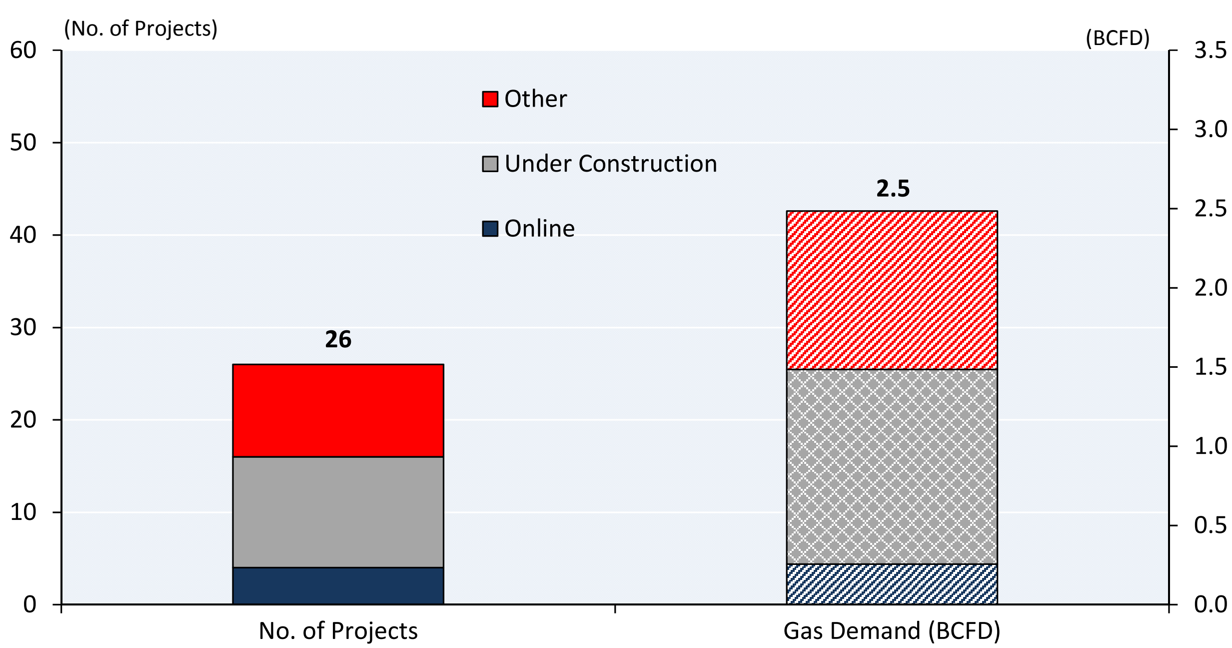


Exhibit Add I-6. Methanol and Fertilizer Projects



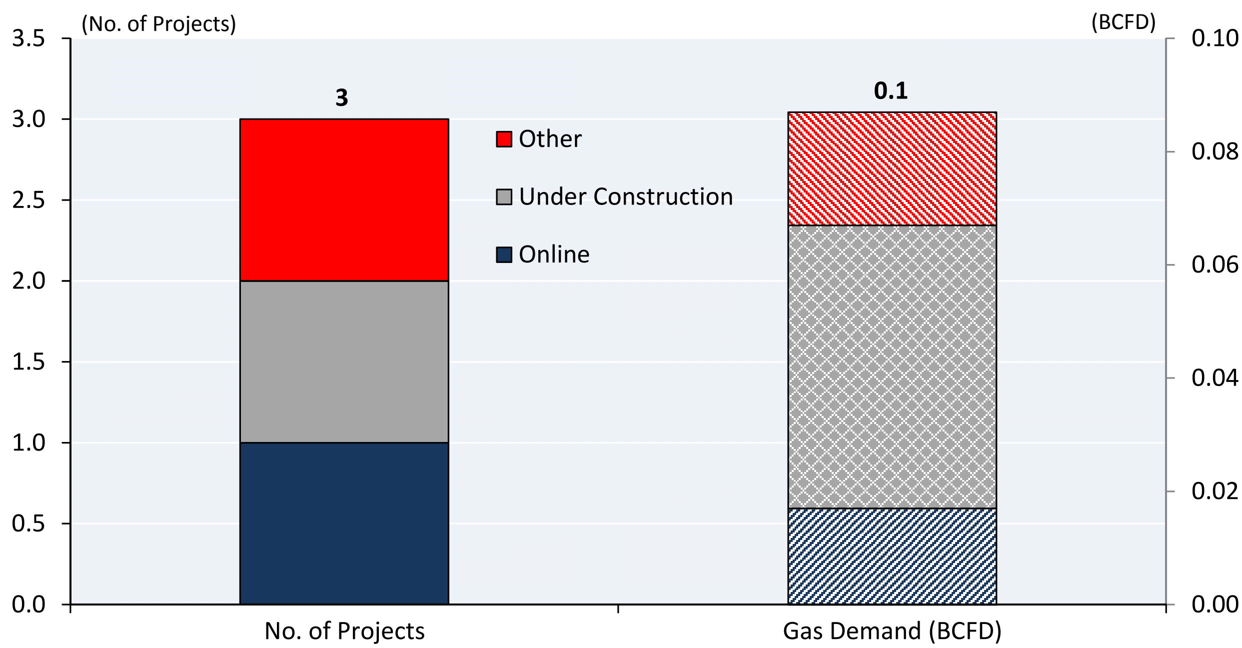
Methanol and Fertilizer Projects

The category of projects that has the greatest impact in industrial sector gas demand – by far – is the methanol and fertilizer projects. As illustrated in Exhibit Add I-6, there are 26 projects in this category which would increase industrial sector demand about 2.5 BCFD at a 100 percent capacity factor. Of these 26 projects, 15 percent already are online, while another 46 percent are under construction. Of the remaining 10, or 39 percent, of these projects, two already have obtained air permits, while the others are still in the early stages of development. While the geographic distribution of these projects is more diverse than that for the petrochemical projects, 65 percent of them still are located in Texas and Louisiana.

Other Projects

The category 'Other' projects consists primarily of steel facilities converting to natural gas for energy. There are only 3 projects in this category and their cumulative impact on industrial sector gas demand is only 0.1 BCFD (i.e., see Exhibit Add I-7).

Exhibit Add I-7. Other Projects



Ownership

As a further point of perspective concerning these 66 projects, approximately 36 percent of them are either owned by foreign firms or have foreign firms involved in a joint venture. The net result is that foreign capital is financing a significant segment of these capacity expansion projects.

ADDENDUM II:

U.S. LNG EXPORTS

U.S. LNG Exports

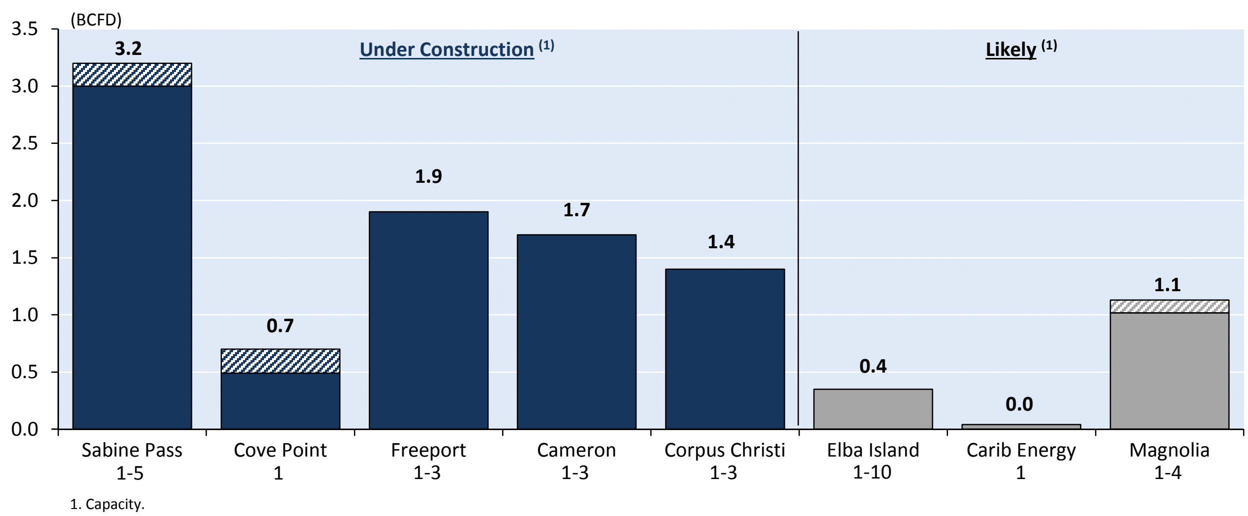
Overview

The initiation of LNG exports from the L-48 this winter represents the first stage in a longer term significant increase in U.S. LNG exports. With respect to the longer term, U.S. LNG exports likely will occur in two phases, namely (a) pre-2020, which will cause LNG export capacity to reach approximately 10.8 BCFD; and (b) post-2020, which includes Alaska and should result in total U.S. LNG exports reaching 17.6 BCFD.

Phase I

As illustrated in Exhibit Add II-1, at present there are five L-48 liquidation terminals either under construction or close to it. These five terminals consist of 14 trains (8.9 BCFD) that are scheduled to come online between YE2015 and 2020. Furthermore, for the most part, these projects have long-term takeaway contracts for all of their capacity. In addition to these five projects there are three other liquefaction terminals (i.e., seven trains with a capacity of 1.5 BCFD) that appear likely to be completed, as they have the required export permits and significant takeaway contracts - although they still are waiting for either FERC or Coast Guard authorization to start construction.[1] The combination of these eight projects represents the first phase of expansion for U.S. LNG exports and at about an 85% capacity factor should result in exports of 8.7 BCFD.

Exhibit Add II-1. U.S. Liquefaction Projects Online In The First Phase For U.S. Exports



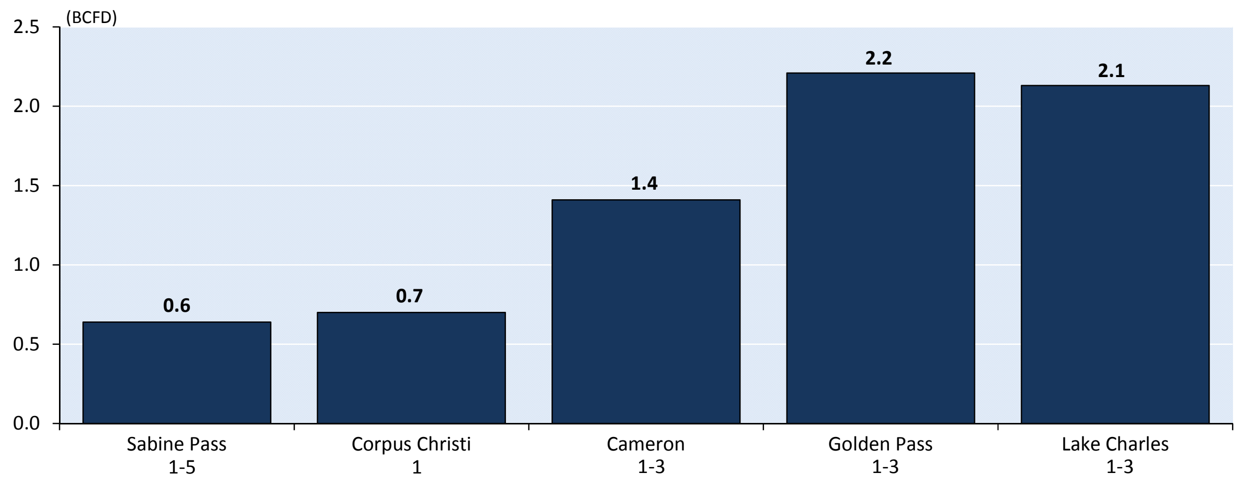
[1] At present there are 35 proposed L-48 liquefaction projects consisting of 111 trains and having a capacity of 47 BCFD. This excludes two projects that either have been cancelled or put on hold. Several of the 33 proposed projects have no hope of being completed even in a high case scenario.

Phase II

The combination of the U.S. increasing global liquefaction capacity 10.4 BCFD by 2020 and the rest of the world adding another 18 BCFD[2] over the 2014 to 2020 timeframe will result in a surplus of LNG supply for a number of years. However, after approximately 2025 the world likely will require additional LNG supply. This need for additional LNG supply likely will create a second phase of the expansion in U.S. LNG export capacity, as several of the U.S. projects will be economical competitive and there is a desire by many consuming nations to maintain a diversification of supply.

While it is a crowded field filled with some uncertainty for each proposed project, Exhibit Add II-2 summarizes EVA's base case for which U.S. LNG projects will come online for this second phase. As illustrated, it is anticipated that 11 L-48 trains (6.8 BCFD) will come online. Additive to this is the Alaskan LNG project (three trains; 2.55 BCFD). Of the 11 L-48 trains, four represent expansions of projects noted in the first phase (2.5 BCFD), while the remaining seven trains are associated with two new projects, namely the brownfield Lake Charles project (i.e., Shell/BG; 2.1 BCFD) and the greenfield Golden Pass project (i.e., Exxon; 2.2 BCFD).

Exhibit Add II-2. U.S. Liquefaction Projects Online In The Second Phase For U.S. LNG Exports



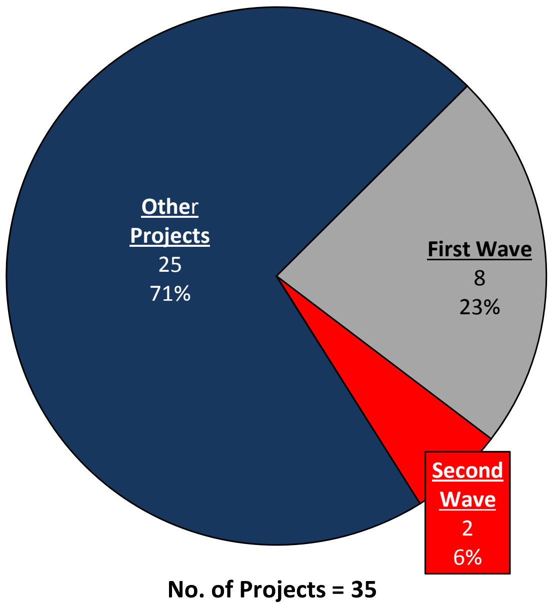
The combination of the first and second phase expansions of U.S. liquefaction would result in the U.S. becoming the largest LNG exporting nation in the world - exceeding both Australia and Qatar.

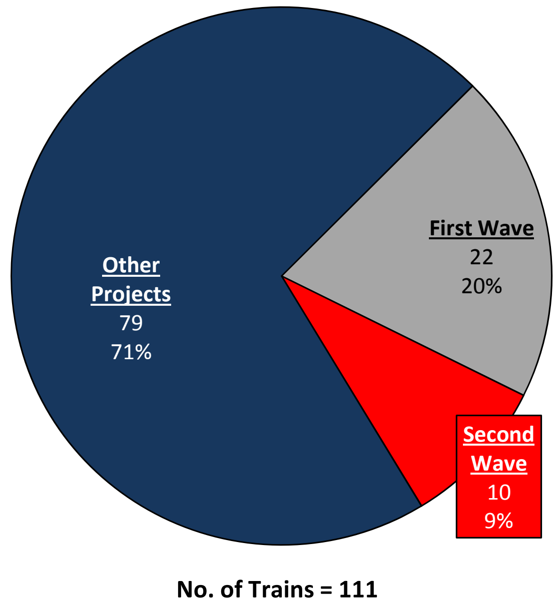
Other U.S. Projects

While the combination of the Phase I and Phase II increases in U.S. liquefaction capacity represent a large number of projects and a major global accomplishment, there are a very large number of proposed U.S. liquefaction projects that are assumed never to be completed. This is illustrated in Exhibit Add II-3.

[2] Over the 2014 to 2020 timeframe it is expected that 10 nations other than the U.S. will bring online 24 liquefaction terminals, which will have 37 trains with a capacity of 18.1 BCFD - many of which either are already online or under construction. Approximately 60% of this capacity will come from seven Australian projects.

Exhibit Add II-3. Summary of Proposed U.S. Liquefaction Projects

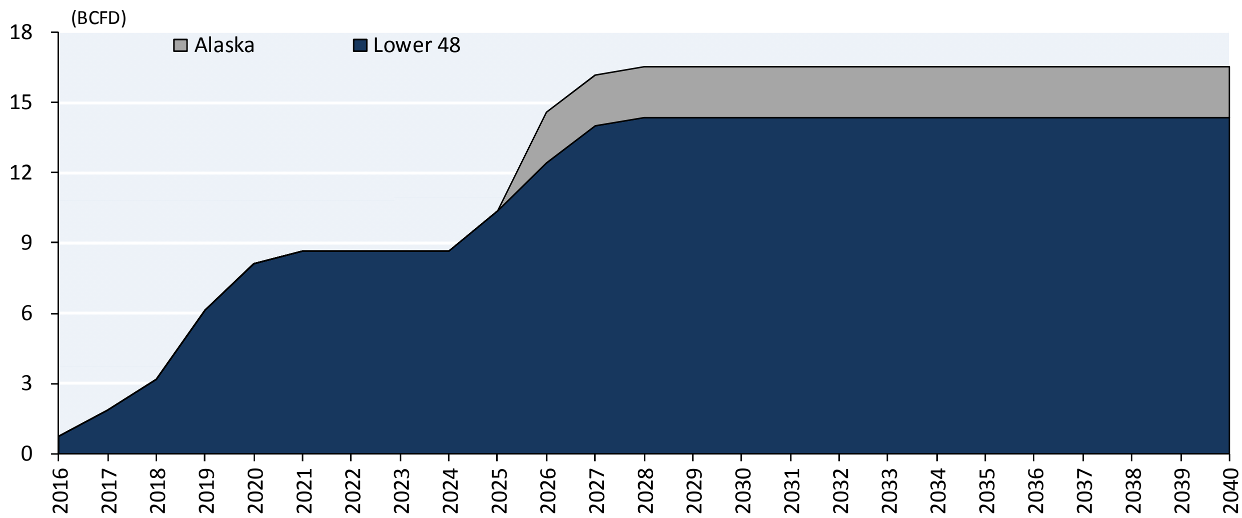




U.S. LNG Exports

As illustrated in Exhibit Add II-4, U.S. LNG exports are expected to ramp up steadily from YE2015 to 2021, as 21 trains are brought online, to about 8.7 BCFD (i.e., assuming an average 85% capacity factor). After that they will remain at this level until the second phase of the expansion of U.S. LNG capacity begins in 2025. At that time another ramp up phase begins with 14 additional trains coming online - including Alaska - which will result in about 2028 U.S. LNG exports reaching approximately 16.5 BCFD.

Exhibit Add II-4. U.S. LNG Exports



Note: Assumes 85% capacity factor.

Canada And Mexico LNG

At present there are 22 proposed Canadian liquefaction projects (36 BCFD) and discussions of converting the Costa Azul regasification plant to a liquefaction terminal.[3] While most of these projects will not be completed, one unique subset of these projects is Mexico's potential Costa Azul project and the two east coast Canada projects (i.e., Bear Head and Goldboro), which if completed would rely upon U.S. gas supplies, as they are located close to the U.S. border.[4]

With respect to the 19 projects (40.5 BCFD) located in western Canada, they are struggling to accomplish significant project milestones other than obtaining permits. Among the numerous problems facing these projects are the following:

- **First Nations:** There has been significant push back from the First Nations group over the use of their lands for gas pipelines and sites for LNG terminals. For example, the Lax Ku'alaams have refused to let Petronas locate its Pacific Northwest LNG terminal on their lands because of the potential to disturb salmon habitats. Similarly, the Prince Rupert transmission line requires the approval of 23 separate First Nations groups. Also, a series of Canadian court decisions have established rather clearly that in addition to an NEB permit to export LNG that developers must obtain the approvals of the affected First Nations groups.

- **High Cost/Decline in Oil Prices:** All of the proposed Canadian liquefaction projects are greenfield projects, which have higher capital costs than U.S. brownfield projects. As a result, the proposed Canadian projects had focused on oil-linked LNG prices, rather than gas-linked LNG prices, which is the case for the U.S. This has inhibited the ability of the proposed Canadian projects to obtain takeaway contracts. Furthermore, with the recent 40 to 50% decline in oil prices the economics of many of the proposed Canadian projects are now in question.

- **Taxes:** The combination of British Colombia's (BC) adoption of royalty on all LNG exports and Canada's existing tax regime result in significant impairment to the economics for the proposed projects and for a substantial period of time inhibited their development. The concept of royalty, which would have raised BC's revenues, was unique among LNG exporting nations and a significant economic cost. In addition, Canada's tax regime required LNG facilities to depreciate investment over 27 years versus the 13 years used in the U.S. and Australia. While the royalty concept was dropped in 2014 and Canada revised its tax code in late 2014, the prior existence of these added economic burdens slowed the development of the proposed Canadian projects.

With the exception of Petronas' Pacific Northwest project (1.7 BCFD; 2019) and one relatively small project Canada has missed the window of opportunity for the first phase of expansions in global LNG capacity. Missing this window of opportunity enabled the U.S. projects to increase

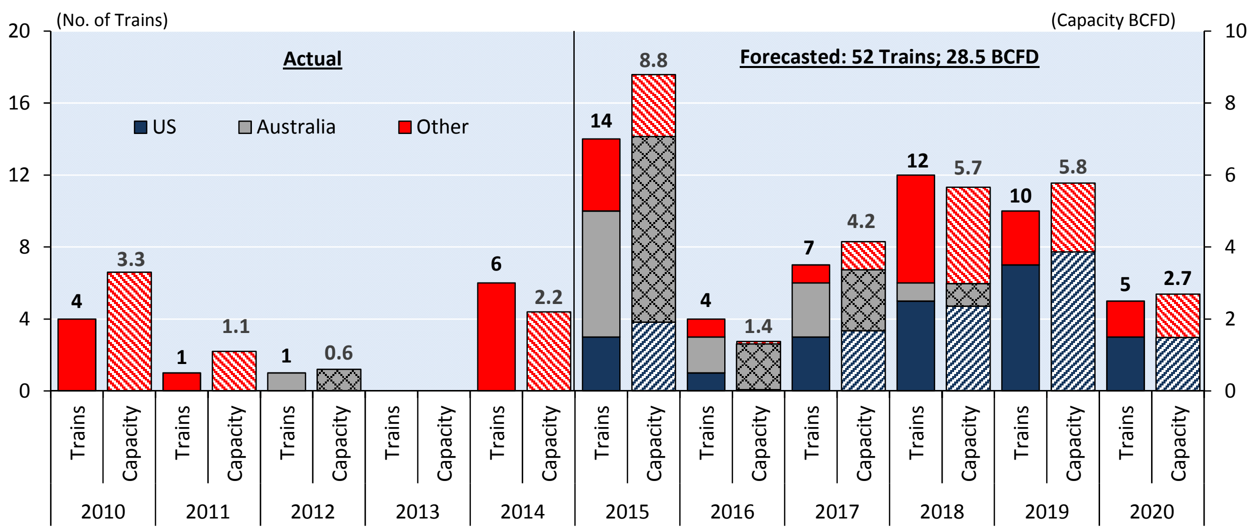
[3] At present there are 22 proposed Canadian projects that consist of 54 trains with a capacity of 36.3 BCFD. This excludes the, in effect, cancellation of British Gas' large Prince Rupert project.
[4] The capacity of the Bear Head project is 1.1 BCFD, while the capacity of the Goldboro project is 1.4 BCFD. Both projects are located in Nova Scotia. The size of the Costa Azul project has not yet been determined.

their market share within the global LNG market. With respect to Canada participating in the second phase of expansions, it is unclear how many, if any, of the proposed Canadian projects will be part of the second phase of expansions, despite having significant shale resources. At this point in time the best case has only one other large western Canada liquefaction project being completed post-2020, with the added possibility that one of the east coast Canada projects will proceed (i.e., the Goldboro project; 1.4 BCFD).

Global Overview

As previously noted, the world LNG industry is starting to enter a period of excess supply, because of the significant amount of new capacity that will come online between 2015 and 2020. This is illustrated in Exhibit Add II-5, which compares and contrasts the results over the prior five years (i.e., 12 trains, 7.2 BCFD) with the outlook for 2015 to 2020 (i.e., 52 trains, 28.5 BCFD). The increase in LNG supply in the 2015 to 2020 period is expected to be about four times that of the prior five years. As an additional point of perspective, U.S. and Australia will account for about 70 percent of the increase in capacity over the 2015 to 2020 period, with the U.S. alone accounting for about 40 percent.

Exhibit Add II-5. Annual Additions Of Liquefaction Capacity



ADDENDUM III:

ASSOCIATED GAS

Associated Gas

Overview

The purpose of this addendum is to provide an assessment of the current status of associated gas production and insights for the likely outlook for associated gas production over the near term. One key dilemma for this assessment is that there is not a universal assessment of the term ‘associated gas’. Traditionally associated gas was defined rather rigorously as gas associated with the production from an oil well – although there can be a fine line between what constitutes an oil well and what constitutes a gas well. With the emergence of the shale plays some industry observers have deviated from this traditional definition and have either included shale gas production for certain plays or treated gas production from shales as a separate item. Furthermore, the EIA in late 2014, changed the definition it uses for associated gas production in its annual gas statistics. The new EIA definition results in gas being produced from any shale formation being incorporated into a new category referred to as ‘shale gas wells’.

Realizing this lack of uniformity in the definition of associated gas, this addendum attempts to assess separately most of the major components of what might be included in the definition of associated gas. In this manner each reader can assemble the various components into the definition that is appropriate for themselves, as well as obtain a broad overview on the topic. With respect to the major components addressed in this addendum, they include:

- **Traditional:** The traditional associated gas category, which represents about 12 percent of L-48 production.

- **Bakken:** The Bakken shale/tight oil play.

- **Permian:** The entire Permian basin gas production, which consists of several segments, namely (a) associated gas, (b) shale gas (i.e., Wolfcamp and Bone Spring); and (c) the Sprayberry trend.

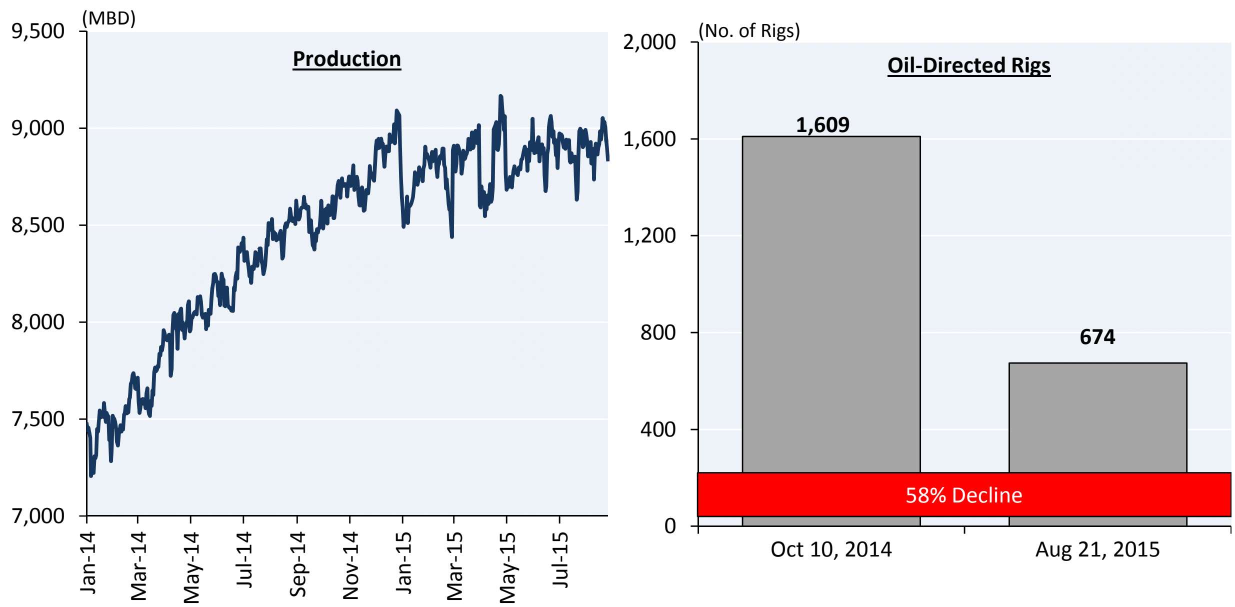
- **Eagle Ford:** The entire Eagle Ford shale play, which has (a) an oil-prone area; (b) a gas-prone area; and (c) a liquids-rich prone area in between the other two areas.

Oil Production

Associated gas production, for the most part, is directly connected to oil production. Currently U.S. oil production on a month-over-month basis is flat to declining, with the outlook for 2016 being in a more distinct pattern of decline.

Exhibit Add III-1 summarizes the recent history for L-48 oil production. The notable increase in late April oil production is due to the offshore Hardin South and Lucius platforms in the Keathley Canyon coming online. Absent the one-off Keathley Canyon event, L-48 production after recovering from the impact of the winter well freeze-offs has not been able to return to its December peak level. The latter phenomenon is evidence that the combination of (a) a 58 percent decline in oil drilling activity and (b) the adoption of the strategy by several producers not to complete wells that already have been drilled[27] is having a significant impact on the month-over-month growth in L-48 oil production. This reduction in growth of L-48 oil production is occurring despite the high grading of new wells and advances in drilling and completion technology.

Exhibit Add III-1. L-48 Production and Rig Count



Associated Gas (Traditional Definition)

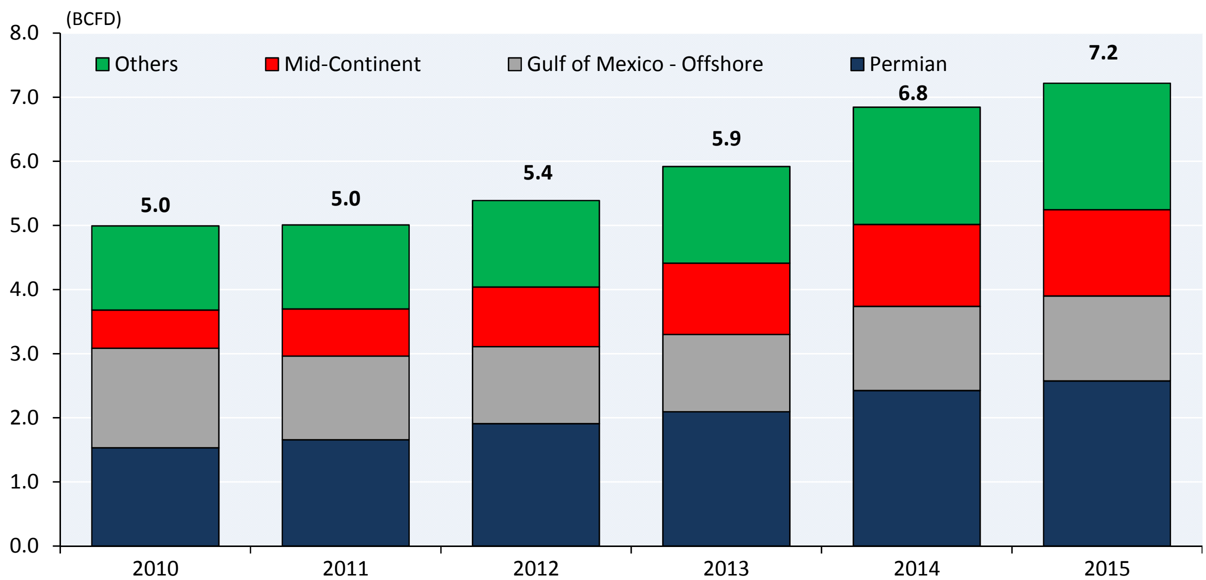
While there are some unique attributes for the assessment of associated gas production, this lack of growth and likely decline in 2016 in L-48 oil production eventually will have an impact on the outlook for most of the components of associated gas production. With respect to historical associated gas production, Exhibit Add III-2 summarizes historical trends for the traditional definition of associated gas.

While prior to 2011 associated gas production had been relatively flat, since then it has increased 44 percent (i.e., 9.6 percent per annum growth rate), as a result of the strong underlying growth in oil production on a year-over-year basis. However, in 2016 this recent trend likely will be broken.

In addition, as illustrated in Exhibit Add III-2, under the traditional definition for associated gas production the Permian basin associated gas production currently accounts for about 36 percent, while the offshore region and the Mid-Continent account for 19 and 18 percent, respectively.

[27] Five producers (i.e., Apache, SM Energy, EOG, Chesapeake and Cabot) have announced that they will defer completing approximately 720 wells. Estimated IPs for these wells are about 0.5 BCFD and 0.4 MMBD.

Exhibit Add III-2. Summary of Associated Gas Production (Traditional Definition)



While there definitely will be year-over-year growth for associated gas production, the prospects for month-over-month changes for the remainder of 2015 and into 2016 point to declines in associated gas production, because of the decline in oil drilling activity and slowdown in well completions for already drilled wells.

Other Potential Components

Among the most significant additional components that some observers include in the definition of associated gas, are (1) the Bakken shale/tight oil play; (2) the Eagle Ford shale play; and (3) the Permian basin. Each of these is discussed separately in the material below. The combination of the gas production for these three potential components currently represents about 12 percent of total L-48 gas production, although some of the Permian basin production is included in the traditional associated gas component.

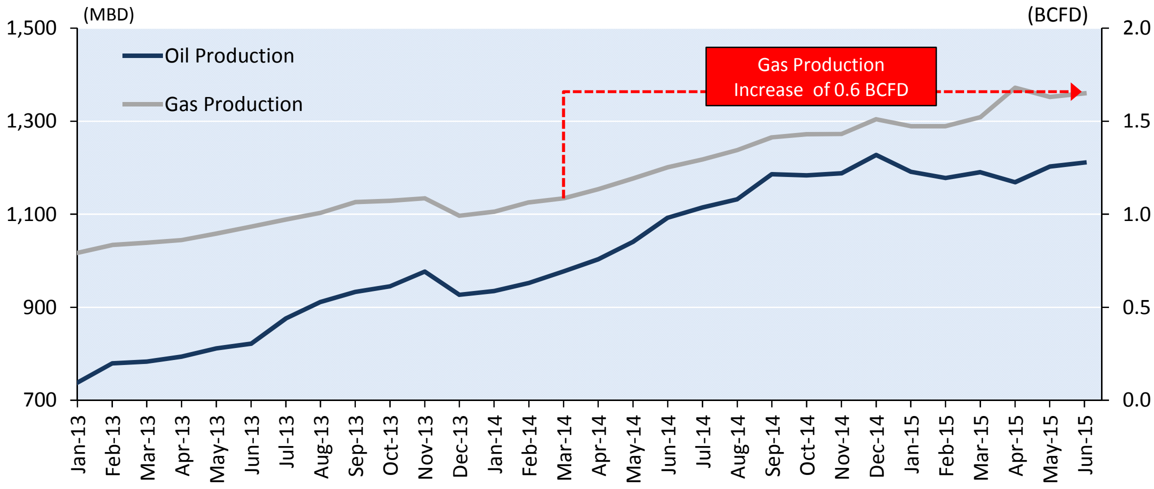
Bakken

For the Bakken shale/tight oil play natural dry gas production represents approximately 1.5 percent of total L-48 production. Also, while for most plays there is a relatively close correlation between oil production and gas production, in the past this has not been true for the Bakken play, because of the flaring of natural gas. At present E&P firms in the Bakken play are in the process of implementing North Dakota's anti-flaring regulations Under these regulations, if specific annual targets are not met, producers are required to shut-in all production from the affected wells, including oil production.[28] The enforcement of these regulations at the beginning of this year resulted in five producers shutting in 30 wells (i.e., approximately 3 MBD).[29]

[28] As of January 2015 the new regulations require that 77 percent of the produced gas be captured (i.e., not flared). This metric increases to 85 percent in January 2016 and 90 percent for October 2020.
[29] MBD is thousand barrels per day.

Exhibit Add III-3 summarizes both monthly oil and gas production for North Dakota. As illustrated, while oil production declined in January and February of 2015 (i.e., primarily due to well freeze-offs), gas production was flat. This slight disconnect between oil and gas production for the Bakken shale/tight oil play is expected to continue until the anti-flaring regulations are fully implemented.

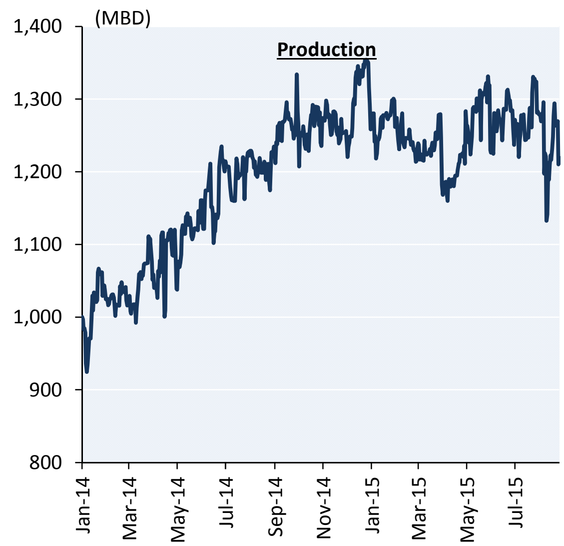
Exhibit Add III-3. North Dakota Natural Gas and Oil Production

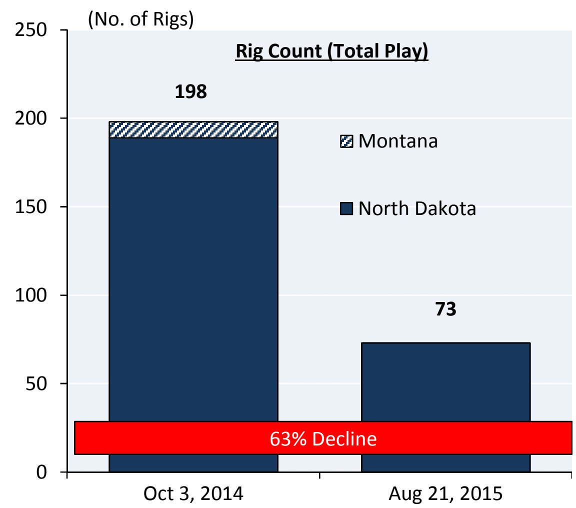


Note: June 2015 is preliminary.
Source: ND State Industrial Commission.

Despite this unique attribute for Bakken gas production, over the longer term the primary driver behind the Bakken gas production will be the oil production for the play. Exhibit Add III-4 summarizes both the daily oil production for the Bakken play and current drilling activity. As illustrated, Bakken oil production after recovering from this winter's well freeze-offs has not yet fully reached its peak December production levels. This flattening oil profile and the likely future decline in Bakken oil production is primarily due to a 63 percent decline in drilling

Exhibit Add III-4. Bakken Production and Rig Count





activity since October. Furthermore, in 2016 it is expected that there will be further declines in drilling activity for the Bakken play. Additive to this decline in drilling activity is the deferment of the completion of some wells that already have been drilled.

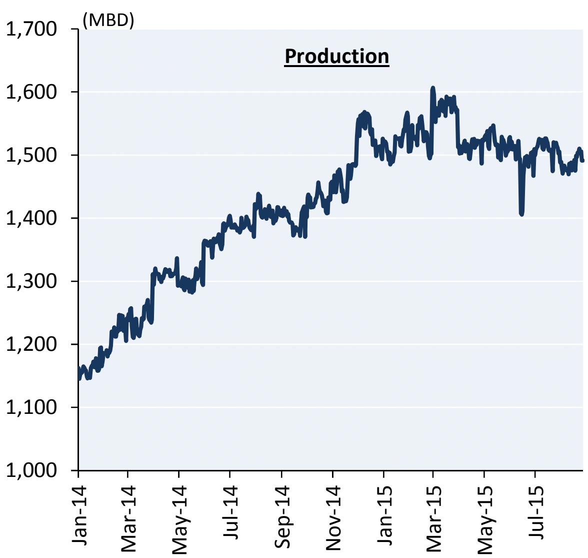
With respect to drilling activity within the Bakken play, the decline in Bakken drilling activity initially was concentrated on the non-core areas, as producers are high grading their new drilling activity. However, more recently there have been significant declines in both the core and non-core areas.[30]

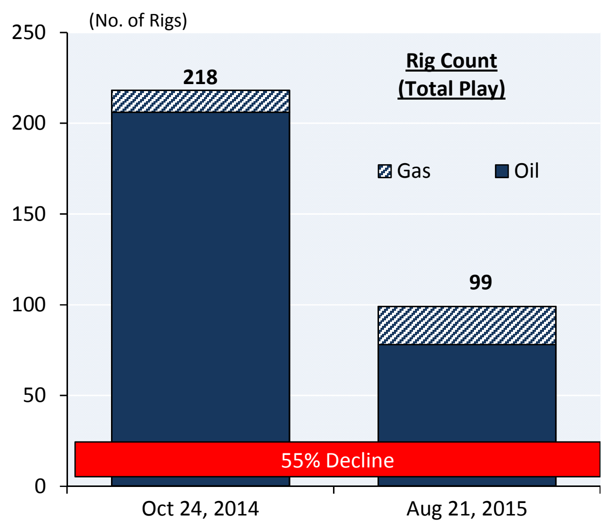
Finally, with respect to gas production for the Bakken play, while there likely will be further increases, albeit modest increases, because of the continuing implementation of the anti-flaring regulations, in general gas production is expected to decline as drilling activity declines.

Eagle Ford

For the total Eagle Ford shale play dry natural gas represents about 12 percent of total L-48 production. As illustrated in Exhibit Add III-5, Eagle Ford oil production, despite recovering from this winter's well freeze-offs, has not yet returned to its peak December production levels. This change in trend from five years of dramatic growth is primarily due to the 55 percent decline in total drilling activity, since its October peak. In the Eagle Ford this decline in drilling activity is spread almost equally across the core and non-core oil-prone areas. Also, unique to the Eagle Ford is that gas-directed drilling activity, while still relatively small, has increased over the last seven months, as three producers have taken significant interest in the new Eaglebine play (i.e., gas prone).

Exhibit Add III-5. Eagle Ford Production And Rig Count





With respect to the outlook for gas production from the Eagle Ford shale play, which currently is driven by the oil-prone segment of the play, based upon the current level of drilling activity it would be expected to decline. However, there is another factor that could significantly impact

[30] Production in McKenzie and Williams counties has accounted for over 60 percent of total Bakken oil production.

the near-term outlook for this play, namely the timing of the completion of a significant inventory of drilled, but not yet completed wells. At present it is estimated that there is an inventory of approximately 1,400 already drilled, but not yet completed wells.[31] Furthermore, this inventory is spread across a large number of producers. Exactly what strategy each producer will adopt for completing its share of this inventory is an imponderable at this time.

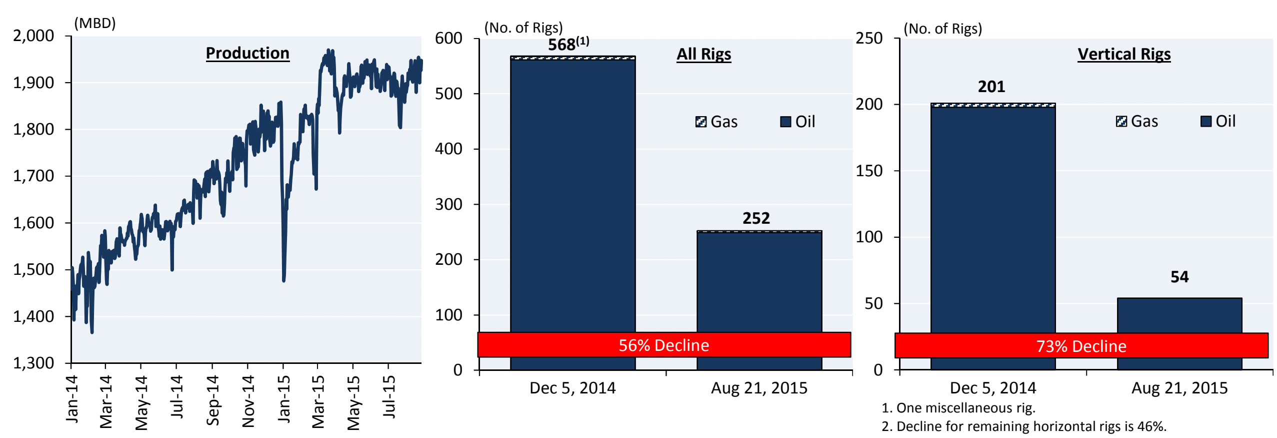
As a result, it is difficult to ascertain with any certainty the net near-term result of these three factors, namely (1) a significant decline in drilling activity, which by itself would lead to declines in associated gas; (2) the anticipated further decline in Eagle Ford drilling activity in 2016; and (3) the timing of the completion of this large inventory of uncompleted wells, which if accelerated would of and by itself lead to an increase in associated gas.

Permian Basin

Overview

With respect to the overall Permian basin oil production, since its recovery from this winter's well freeze-offs, production has risen to a level that almost equals its December peak production level (i.e., only 0.4 percent below). Exhibit Add III-6 summarizes both the history of oil production and current drilling activity for the Permian basin as a whole. With respect to the latter, drilling activity has declined approximately 56 percent since the December peak for the basin. However, further declines in drilling activity are expected in 2016.

Exhibit Add III-6. Permian Basin Production and Rig Count



This decline in drilling activity is more pronounced for vertical well drilling (i.e., 73 percent decline), than it is for horizontal well drilling (i.e., 46 percent). In general, vertical wells in the basin are less economic than horizontal wells, which represents an effort by the industry to high grade its new drilling sites. Furthermore, this high grading of drilling efforts in the basin is further borne out by anecdotal evidence of the actions of specific producers. For example, Pioneer, which is a major producer in the basin, has written off the reserves associated with its Sprayberry vertical locations, while Parsley Energy has shifted its drilling program from exclusively vertical wells to horizontal wells in the Wolfcamp formation.

[31] "IHS: Eagle Ford completions pending", *Oil & Gas Journal*, April 20, 2015, p. 28.

Segments Within the Permian Basin

The Permian basin is a very large basin with a number of formations, or plays, that currently are being pursued by the industry. Furthermore, the Permian basin consists of two major sub-basins, namely the Midland basin in West Texas and the Delaware basin in southeastern New Mexico and West Texas. For the purposes of this assessment the Permian basin is subdivided into the four segments, or plays, noted in Exhibit Add III-7.

Exhibit Add III-7. Major Segments for the Permian Basins[1]

	Oil Production (MBD)			2015 Dry Gas Production[2]	
Segments or Plays	**March 2014 Peak**	**Aug 2015**	**Difference**	**Amount (BCFD)**	**Percent of Total**
Wolfcamp/Bone Spring Shale Plays	553	535	(18)	1.96	32%
Sprayberry Trend	575	553	(22)	1.42	23%
Legacy Associated Gas	866	831	(35)	1.64	27%
Non-Associated Gas	9	8	(1)	1.09	18%
Total Permian Basin	**2,003**	**1,926**	**(77)**	**6.10**	**100%**

1. Figures may not add due to rounding. Source: PointLogic.
2. 2015 estimation.

With respect to its Legacy Associated Gas and Sprayberry segments, which represent 50 percent of the Permian basin's gas production (i.e., 72 percent of its oil production), these segments technically are a part of the traditional definition of associated gas. As a result, for those industry observers that include the entire Permian basin in their definition of associated gas, they are, in essence, adding an additional 3.1 BCFD of gas production (i.e., the shales and non-associated gas plays) – assuming that they do not double count for the legacy associated gas within the Permian basin.

Outlook

With respect to the near-term outlook for gas production within the Permian basin, at current levels of drilling activity gas production on a month-over-month basis for the remainder of the year likely will enter a period of modest decline, and then in 2016 even greater declines, assuming oil-directed drilling activity continues to decline. This assessment would consist of likely declines for the Legacy Associated Gas and Non-Associated Gas segment, plus flat to declining production for the shale and Sprayberry segments.

Summary

While there are a number of imponderables for the near-term outlook for the broad definition of associated gas, this assessment foresees overall a modest decline in month-over-month associated gas production (i.e., all potential categories) starting in 2015, primarily because of the overall decline in drilling activity with further decline in 2016. Exhibit Add III-8 provides an overview of this assessment by individual category. As noted in Exhibit Add III-8, associated gas under the traditional definition represents approximately 10 percent of total L-48 dry gas production, however when other potential categories are included this metric increases to approximately 22 percent.

Exhibit Add III-8. Near-Term Outlook for Associated Gas (Broad Definition)

Category	**2015 Production[2] (BCFD)**	**Imponderable**	**Outlook for 2015**
Traditional Associated Gas			
• Permian			
o Sprayberry	1.43	-	Flat to declining.
o Other Associated	1.64	-	Declining.
• Offshore	1.33	-	Declining.[1]
• Mid-Continent	1.35	-	Declining.
• All Others[3]	1.47	-	Declining.
Subtotal	7.22	-	Overall net decline.
Bakken Shale	1.00	Implementation of anti-flaring regulations.	Declining.
Eagle Ford Shale	4.85	Timing for large inventory of uncompleted wells.	Declining
Permian Basin Shale	3.03	-	Modest decline, with flat shales production offset by declines for non-associated gas.
Total	**16.1**		**Declining.**

(1) Decline is from May production levels, which include the Keathley Canyon platforms coming online.
(2) 2015 estimated.
(3) Includes associated offshore.

ADDENDUM IV

INFRASTRUCTURE EVENTS

Infrastructure Events

Background

In November 2013 flowing gas supplies increased 1.55 BCFD within a period of a few days because a series of new pipeline projects were brought online that provided take away capacity for previously stranded gas supplies. Then in the fourth quarter of 2014 natural gas production increased 2.2 BCFD as a result of the same phenomenon, except that the new pipeline capacity came online in stages over the quarter. For the fourth quarter of 2015 a similar infrastructure event is expected because of a series of new pipeline projects that will come online. Exhibit Add IV-1 compares and contrasts on a full year basis the number of pipeline projects coming online for individual years for the period 2013 to 2018.

Exhibit Add IV-1. Projected Gas Pipeline Capacity Additions

	Northeast Region		Other Regions		Total Industry	
Year	No. of Projects	Capacity (BCFD)	No. of Projects	Capacity (BCFD)	No. of Projects	Capacity (BCFD)
2013	13	3.3	7	1.2	20	4.5
2014	15	3.2	16	2.1	31	5.3
2015	14	5.1	17	4.4	31	9.5
2016	16	6.5	12	8.1	28	14.6
2017	19	12.4	22	17.3	41	29.7
2018	9	10.3	6	7.2	15	17.7
Total	**86**	**40.8**	**80**	**40.3**	**166**	**81.1**

As illustrated in Exhibit Add IV-1 slightly over 50 percent of the new pipeline projects over the six year period are occurring in the Northeast and are designed primarily to accommodate the significant increases in Marcellus and Utica shale production. With respect to the pipeline projects for the other regions, these include (1) pipelines to support new LNG liquefaction projects; (2) pipelines to support increased exports to Mexico; and (3) other pipeline projects spread across the U.S.

Outlook For The Fourth Quarter 2015

During the fourth quarter of 2015 there is a reasonable likelihood that an infrastructure event similar to those for the last two winter seasons will occur. However, like the event in 2014 the forthcoming infrastructure event will be spread across the months of November and December, plus the first few days in January 2016 when the Constitution Pipeline (0.65 BCFD) comes online.

With respect to the forthcoming infrastructure event, Exhibit Add IV-2 compares and contrasts the new pipeline projects for this winter with those for the last two winters. While the cumulative capacity figures in this exhibit are one metric for assessing the potential impact of the infrastructure event, they do not fully reflect the amount of gas supplies that could come online, as it often takes pipeline projects to form a single transmission path (e.g., a new gathering system and pipeline expansion project).

Exhibit Add IV-2. Comparison Of New Pipeline Projects For The Fourth Quarter of 2013, 2014 And 2015

	2013	2014	2015
Number of Pipeline Projects Online	13	15	14
Capacity of New Pipeline Projects (BCFD)	3.3	3.2	5.1
Number of Major Pipeline Projects Online	4	5	7
Capacity of Major Pipeline Projects (BCFD)	2.2	2.0	4.7

Finally, there is uncertainty over the magnitude of this winter's infrastructure event. The current estimate is 1.9 BCFD, which represents about the mid-point of the 2013 (1.55 BCFD) and 2014 (2.2 BCFD) infrastructure events.

ADDENDUM V

TRANSPORTATION SECTOR

Transportation Sector

Overview

While not a critical component to the outlook for gas demand for the forthcoming winter, over the last few years there has been considerable discussion concerning natural gas penetrating the transportation sector and capturing market share from oil, which dominates this particular sector. While some momentum developed for this phenomenon in 2013 and 2014 when oil prices where $100/BBL and the ratio of oil to gas prices was in the range of 20:1 to 25:1, this momentum appears to have declined sharply in 2015 with the decline in oil prices to $40/BBL and the ratio of oil to gas prices at approximately 15:1.

While this is a valid overview for the transportation sector, this assessment requires a more granular appraisal, because the transportation sector is not a homogenous entity. Instead there are approximately five major segments to the transportation sector that can be further divided into 11 subsegments, with each of the subsegments having their own unique attributes and drivers.

The material below briefly reviews the current outlook for these 11 subsegments of the transportation sector and the impact of the two key drivers, namely economics and environmental regulations, on each of these subsegments.

Outlook For Transportation Sector

There are two basic drivers for the penetration of CNG/LNG within the transportation sector, namely (1) economic and (2) environmental. Concerning the former, the recent 60 percent decline in oil prices has significantly reduced the economic incentive to use CNG/LNG as a replacement for diesel. This is illustrated in Exhibit Add V-1, which illustrates that the lifetime cost of a CNG truck was less than that to operate a diesel truck in June 2014, but that in August 2015 this relationship has changed, as it is now cheaper to run a truck on diesel. This is because of the relative fuel economics. More specifically, in June 2014 it was $11.53 per MMBTU less expensive to use CNG in heavy duty trucks than diesel, however by August 2015 this margin had declined to $3.50 per MMBTU. While the margin at lower oil prices is still positive, in most cases it either is not adequate to cover the additional capital costs or it is marginal at best. With respect to the environmental driver (i.e., the industry's response to changing regulations), it is still a significant factor for some segments of the transportation sector.

There are five major segments of the transportation sector and 11 subsegments within them. Each of these subsegments has its own unique characteristics, which makes developing a composite assessment of the penetration of CNG/LNG within the transportation sector rather complex. While there is significant momentum within certain subsegments, primarily because of commitments made in 2014, for many subsegments this momentum is declining because of the reduced economic incentives. Exhibit Add V-2 provides a simplified summary of CNG/LNG within most of the transportation subsegments.

Exhibit Add V-1. Lifetime Cost Of Heavy-Duty Trucks

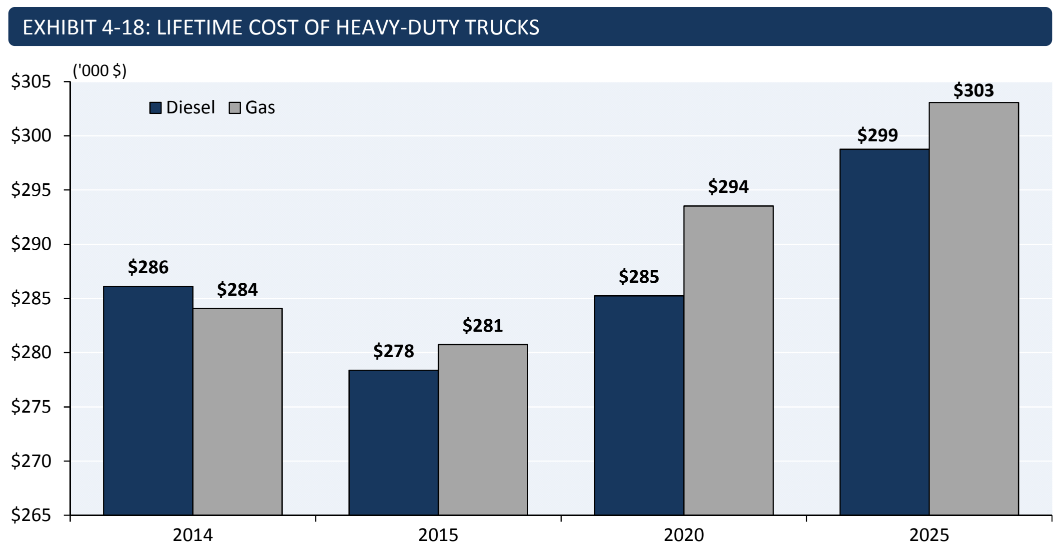


Exhibit Add V-2. Overview Of Emerging Transportation Markets

Transportation	Who's Hot: Economic	Who's Hot: Environmental	Who's Not
Maritime			
▪ Ocean Going Vessels		X(B)	
▪ Ferries		X(A)	
▪ Other			X
Trucks/Bus			
▪ Refuse Trucks	X(C)		
▪ Mining			X
▪ Fleet Vehicles			X(D)
▪ Transit Buses		X	
Field E&P			
▪ North Dakota		X	
▪ Other Areas			X
Railroads			X
Passenger Cars			X(E)

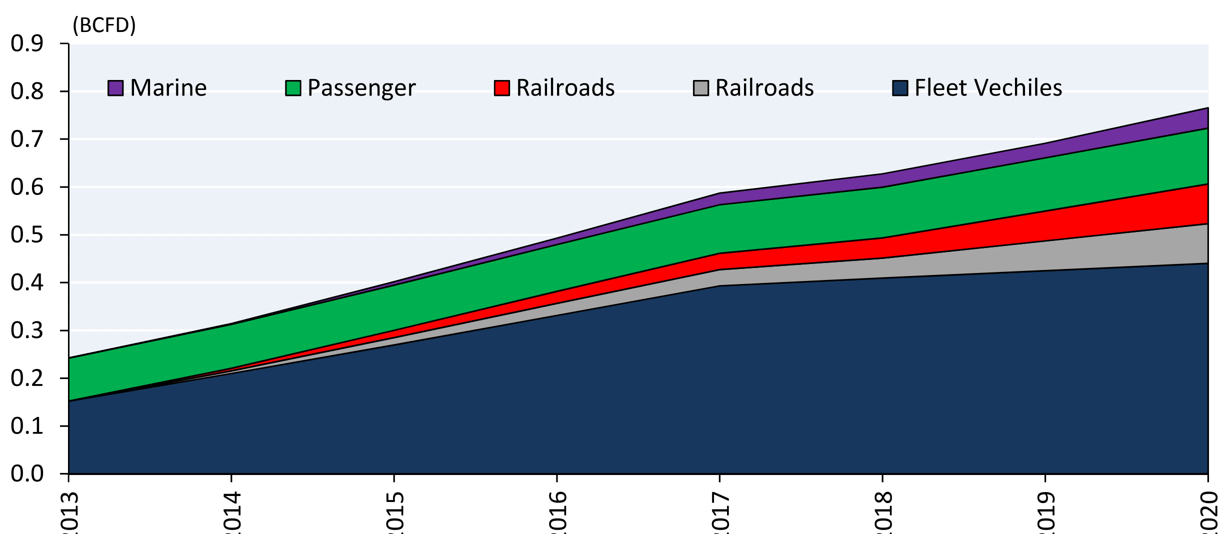
A. 17 LNG ferries in U.S. commissioned since 2013.
B. 59% of 27 major world ports have or plan to have LNG capability; 134 LNG vessels, of which most are in Norway.
C. Sales of heavy duty trucks in 2014 increased 30% to 8,300 trucks; CNG refuse trucks captured >50% of annual sales for refuse trucks; for all heavy duty trucks only 3% or 2.1 MM heavy duty trucks are CNG/LNG capable.
D. Sales of medium duty trucks in 2014 increased 24% to 2,700 trucks.
E. Light duty NGV sales in 2014 declined 34% to 3,500 cars.

As noted, only the refuse truck segment still has a significant economic incentive to convert to CNG/LNG. This occurs primarily because of the high mileage associated with waste management trucks (i.e., 150,000 mile/year versus the more typical 60,000 mile/year for heavy duty Class 8 trucks) and the fact that they are fleet vehicles that return to a common staging area each night (i.e., the need for a single CNG/LNG refueling location). In addition, the introduction in 2014 of the Cummins-Westport 15X-12G 11.9 liter engine represented a significant step forward for heavy duty trucks.

Furthermore, there are four other segments in which environmental factors are continuing to drive the industry to convert away from diesel consumption to CNG/LNG use. Other than these highlighted segments, there has been a significant loss in the momentum, because of the decline in the economic incentive, for an increased market share for CNG/LNG.

With respect to a composite view of the intermediate-term outlook for the increased penetration of CNG/LNG within the transportation sector, this is summarized in Exhibit Add V-3. Furthermore, according to the EIA the current gas consumption within the transportation sector is approximately 0.1 BCFD, however it is not clear that the EIA is capturing all of the natural gas use with the transportation sector, as there are now about 1,651 CNG/LNG fueling stations in the U.S. of which 57% are open to the public. It is assumed that any missing gas consumption levels for the transportation sector have been captured within the much larger industrial sector consumption data. Nevertheless, using the EIA metric the current outlook for the transportation sector represents a high percentage growth rate, but a relatively small overall increase in total gas demand by 2020 (i.e., about 0.5 BCFD).

Exhibit V-3. Outlook For Gas Demand Within The Transportation Sector



Marine Sector

Overview

As noted in Exhibit Add V-2, there is still significant momentum within the marine segment of the transportation sector for the use of CNG/LNG to replace fuel oil, with the primary driver being changing environmental regulations. However, while the above is, in general, true for the marine segment, there are unique attributes and differences within the four subsegments or categories of the marine segment. These are summarized briefly in Exhibit Add V-4 and then explored in more depth in the material below.

Exhibit Add V-4. Major Categories Of The Marine Transportation Segment

Categories	**Ferries**	**Harbor**	**Offshore O&G Field Services**	**Ocean**
Driver of Change	Emissions	Emissions	Regulations	Regulations
	Economics	Economics	Emissions	Regulations

Background

The marine segment of the U.S. transportation sector consumes about 645 MBD of oil-derived fuel per year, however roughly 80 to 85% of this is high-sulfur residual fuel oil with the remainder, or about 125 MBD, being diesel. Primarily because the cost of residual fuel oil is so low (i.e., less than $1.00 per gallon), the potential use of LNG as a substitute for most categories of the marine segment is unlikely on a purely economic basis. However, with the recent enactment of regulations to invoke more stringent emissions requirements the use of LNG as a substitute likely still will occur in many areas of the overall marine transportation segment.

In addition, there is a significant international perspective to use LNG within the shipping industry. More specifically, within certain segments of the international market the use of LNG has been growing rapidly and likely will continue to grow. The latter is particularly true of Europe and especially Norway. However, the same cannot be noted for the U.S., even though progress is being made.

Regulations

Approximately 10 to 15% of all marine fuel consumption for the international market occurs in areas that are now being designated as emission control areas (ECAs). To comply with both existing and pending regulations for ECAs, ship-owners can either: (1) install scrubbers; (2) use compliant low-sulfur fuel, such as marine diesel oil (MDO); or (3) switch to alternative fuels, with LNG being the leading candidate. In each case the primary objective is to reduce NOx and SOx emissions. With respect to the relative economics of these alternatives, installing exhaust gas-after-treatment, such as either scrubbers or urea catalysts, both add to capital costs and fuel costs, as overall fuel consumption can increase 2 to 3%. With respect to the alternative of burning cleaner oil-derived fuels, this will increase the overall cost of fuel and there is a risk that such fuel costs will increase if either demand increases or oil markets come under stress.

One of the major drivers for the adoption of natural gas in ocean-going vessels is the adoption of new stringent sulfur regulations throughout North America. These new regulations require ships to use higher-quality expensive fuels, which is going to increase the oil-to-gas price ratio. This in turn will increase the attractiveness of using natural gas. The timing of these regulations is indicated in Exhibit Add V-5, which highlights the initial transition to a 100 ppm sulfur limit by 2015/2016 and then subsequent regulations requiring better after treatment.

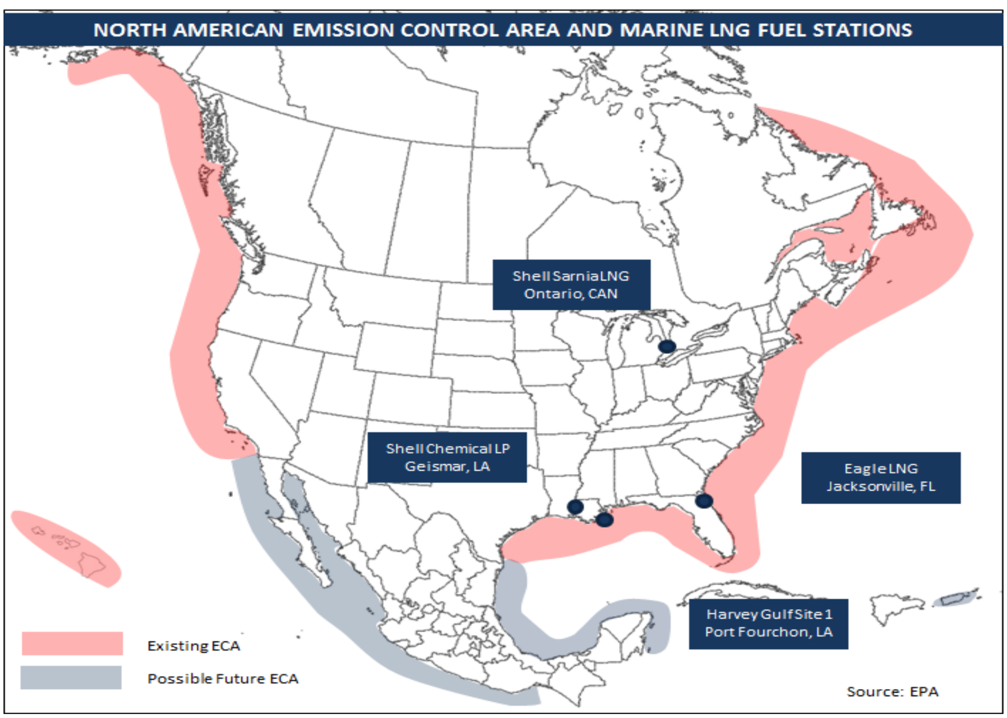
Exhibit Add V-5. MARPOL Regulations

	> Jan 1, 2010	< Jan 1, 2010	Jan 1, 2012	Jan 1, 2015	Jan 1, 2016	Jan 1, 2020
ECA Regulations	SOx <1.5%	SOx <1%		SOx <1%		
Other ECA Regulations				New after treatment regulation.		
Global Regulations	SOx <4.5%		SOx <3.5%			SOx <0.5%*

* Subject to review in 2018.

With respect to North America the existing and pending ECAs are illustrated in Exhibit Add V-6. To date the reaction to the ECA regulations has been mixed, particularly for the cruise ship industry. In the case of Sea Star Line and Tote they have ordered four LNG powered vessels in order to comply with forthcoming emission regulations.[1] However, the LNG tanks for these vessels are large, which reduces overall cargo space, and expensive (i.e., about a 19% premium to existing ships). This reduction in overall cargo space is a significant drawback for some firms. Carnival Cruise Ships, on the other hand, has chosen to pursue a bi-furcated strategy that involves (a) spending $180 MM to install sulfur scrubbers on 32 of its cruise ships and (b) ordering four new LNG powered cruise ships, which are scheduled to be delivered in 2019 and 2022.[2]

Exhibit Add V-6. North American Emission Control Areas And Marine LNG Fuel Stations



[1] The two Tote ships represent the first LNG powered container ships, with the first being delivered in the fourth quarter of 2015 for service between Jacksonville, Florida and Puerto Rico. The second is scheduled to be delivered in the first quarter of 2016.

[2] Two of the four new Carnival Cruise ships will be used for German-based cruises.

Four Categories

As noted above, there are four categories to the marine segment. The unique attributes for each of these categories is reviewed briefly below, along with a general assessment of the outlook for the use of CNG/LNG within each category.

Ferries

While the use of ferries within the U.S. is rather limited, ferries likely will be one of the first area of the U.S. marine segment to adopt the use of LNG as an alternative fuel. Ferries operate using a point-to-point system, which enables them to utilize a centralized refueling system that can be tailored to the specific needs of each fleet of ferries. This is a significant attribute that greatly enhances the economics of using LNG. In addition, ferries operate in urban environments, which in most instances have or are in the process of implementing stricter emission requirements.

Currently, the Washington State Ferries are retrofitting six ships to use LNG, while the Staten Island Ferries have undertaken a feasibility study for the use of LNG. A similar phenomenon is occurring in Canada, where the Quebec Ferries Company has ordered three LNG ferries, while BC Ferries in Vancouver has undertaken a feasibility study.

Harbor Vessels

While there are several different types of harbor vessels, the most significant, and primary focus of this assessment, is the tugboat. There are three significant attributes about tugboats, namely:

(1) Many tenders operate in major ports, which are densely populated areas that likely will enact more stringent emission requirements over time;

(2) The use of a centralized refueling station, which significantly enhances overall economics, is applicable for many of the tugboats; and,

(3) Tugboats, because of their powerful engines, are large consumers of fuel. The latter potentially results in significant annual fuel savings for those tugboats that convert to LNG. However, such savings are reduced at $40/BBL oil prices. With respect to the second attribute, namely centralized refueling, this is more applicable to tugboats serving major ports than it is to inland tugboats (e.g., tugboats in service along the Mississippi River). For inland tugboats the lack of refueling structure is problematic.

In addition, there could be a time delay in the rapid conversion of the U.S. tugboat fleet, because historically the manufacturing of new tugboats within the U.S. tends to occur in waves, with approximately a 20 year gap between peak building periods (i.e., the typical life of many tugboats). At present the U.S. is close to one of these peak building periods, which would imply some delay before rapid conversion occurs.

With respect to the economics for converting a tugboat to using LNG, they can be very attractive. This occurs because the typical tugboat uses about 7,000 gallons/day of diesel. Even at only $0.40 per gallon (DEQ) savings this would result in annual fuel savings of about $1.0MM, which in turn results in a payback period of about two or three years. In addition, this annual fuel savings likely will increase over time, as the trend in the shipping industry towards larger container ships (i.e., more dead weight tons (DWT)) is requiring that new tugboats have even higher horsepower engines.

Offshore O&G Supply Vessels

With respect to the current international LNG shipping fleet, a significant percentage are the various supply and transport ships used for the offshore O&G industry. At present most of these offshore field service ships are located in the North Sea and, in particular, Norway. However, it is expected over time that the U.S. offshore field service industry will follow suit. More specifically, Harvey Gulf has ordered six Marine 302' x 64' dual-fuel Offshore Supply Vessels, and the first of these launched in January 2014. Furthermore, Shell already has chartered three of these six vessels.

Ocean-Going Ships

Currently there are over 80 LNG-powered ships in the world and this number is projected to increase over the next several years. Most of these LNG-powered ships will be concentrated in Europe and, in particular, Norway, because of the strict EU regulations concerning emissions within European ports, which goes beyond the MARPOL standards.[3] With respect to the U.S., where progress towards an LNG shipping fleet has been slow, Exhibit Add V-7 identifies 16 LNG ships that are currently on order. In addition, VanEnkevart Tug and Barge has plans to convert some of its vessels on the Great Lakes. While economics are important, the key driver behind this initial fleet of U.S. LNG ships are the 2015 emission regulations for the shipping industry that operate within U.S. waters (i.e., 200-mile limit).

Exhibit Add V-7. U.S. LNG Ships Currently On Order

Company	No.	Type	Areas of Operations	New/Retrofit	Delivery Date
Crowley Maritime	2	RoRo	Caribbean, FL-PR	New	2017
Interlake	10	General Cargo	Great Lakes	Retrofit	2016
TOTE Inc.	2	Container	Caribbean, FL-PR	New	2015/2016
Navigation Co.	2	Container	West Coast-Hawaii	New	2018

Refueling Stations

A key component for the conversion to LNG vessels for each of the above segments is the building of LNG fueling infrastructure tailored to the needs of the marine sector. At present there are four planned U.S. marine LNG fueling stations that will be capable of serving the marine sector, as well as other sectors (i.e., see Exhibit Add V-8 for a tabulation of these facilities and Exhibit Add V-8 for a map of their locations)). Two of these four planned LNG fueling stations have received their final investment decision (FID) by their developers (i.e., the

[3] With respect to the international use of LNG for vessels, it is becoming rather widespread, and includes the following: (1) a medium range CNG ship in Indonesia; (2) a LNG bunkering vessel in the Baltic Sea (2016); (3) numerous ferries in Norway; (4) a unique CNG/Solar ferry in the Netherlands; (5) harbor patrol craft in Norway; and (6) a ferry in Argentina/Uruguay. Offsetting, to a degree, these advances are the cancellation of plans in the U.K. and France to use LNG powered ferries by Brittany Ferries.

Harvey Gulf and Eagle facilities), while Shell has announced that it is proceeding with its two facilities. With respect to the Sarnia facility, it will service ships operating in the Great Lakes.

Exhibit Add V-8. U.S. LNG Fuel Stations For The Marine Sector

Company	Location	MMCFD	Gallons
Shell Geismar	Geismar, LA	35	276,243
Shell Sarnia	Sarnia, Ontario	34	270,000
Harvey Gulf Site 1	Port Fourchon, LA	34	270,000
Eagle LNG	Jacksonville, FL	38	300,000
Total		**141**	**1,116,243**

Outlook

The movement towards the use of CNG/LNG within the marine segment in the U.S. is much slower than that elsewhere in the world, particularly for Europe. As a result, the outlook is that by 2020 use of CNG/LNG in U.S. marine segment, while increasing, likely will be 0.1 BCFD or slightly less.

Jones Act:

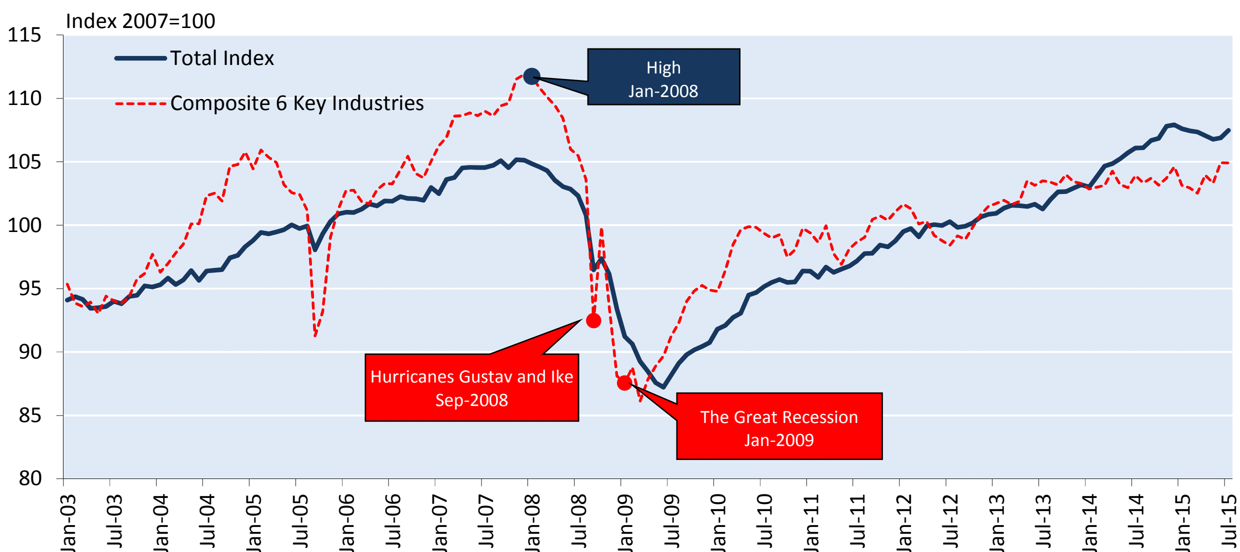
The international nature of the shipping industry means American ship-owners use international registries (also known as flag states or flags of convenience) to register their vessels. There are four major flag states: Panama, Liberia, Malta and the Marshall Islands. American ship-owners primarily use the Marshall Island registry. However, if a ship only uses American ports, or if it goes from one U.S. port to another, it needs to comply with the Jones Act. The Jones Act requires that a ship be (1) built in the U.S.; (2) registered in the U.S.; (3) owned by an American; and (4) operated by an American crew. This significantly raises the price of a ship and could be a major impediment to the adoption of LNG fueling in the U.S. For example, Valero Energy estimates that it costs $5.00 to $6.00 per barrel to ship oil from the Gulf to the East Coast in a Jones Act vessel, while it only costs $2.00 per barrel to ship oil from the Gulf to Canada's East Coast in a non-Jones Act vessel.

Appendix

Exhibit A-1. Natural Gas Consumption (BCF)

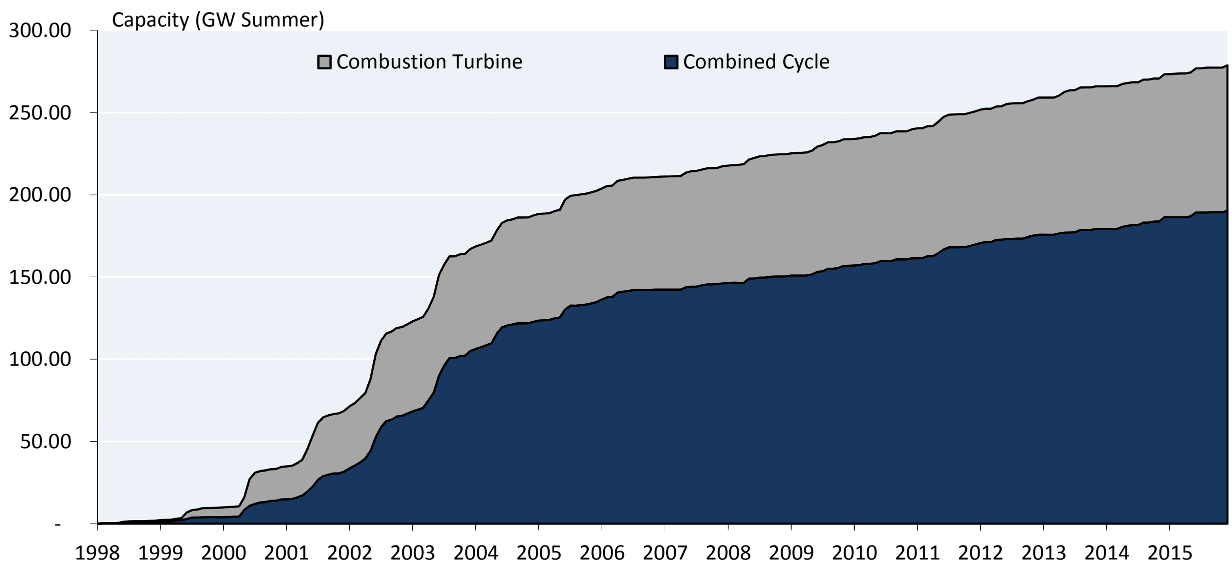
	Annual						Winter (November-March)					
	2010	2011	2012	2013	2014	2015	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016
Residential	4,783	4,715	4,149	4,913	5,072	4,963	3,627	2,987	3,444	3,953	3,731	3,511
Commercial	3,102	3,155	2,895	3,279	3,461	3,381	2,075	1,781	1,993	2,296	2,224	2,098
Industrial	6,825	6,995	7,227	7,414	7,655	7,594	3,093	3,134	3,216	3,420	3,395	3,455
Electric	7,388	7,574	9,112	8,152	8,150	9,387	2,567	3,125	2,975	3,031	3,317	3,509
Other	1,962	2,010	2,127	2,337	2,447	2,595	887	920	993	1,077	1,133	1,126
Transportation	29	30	30	34	33	33	12	12	13	15	14	14
Total	**24,089**	**24,479**	**25,540**	**26,129**	**26,818**	**27,953**	**12,261**	**11,959**	**12,634**	**13,792**	**13,814**	**13,713**

Exhibit A-2. Industrial Production Growth Rates



Source: Fed.

Exhibit A-3. Cumulative U.S. Capacity By Technology, 1998-2015



Source: EVA CCGT Database.

Exhibit A-4. Annual Additions Of Gas-Fired Capacity 2000-2016

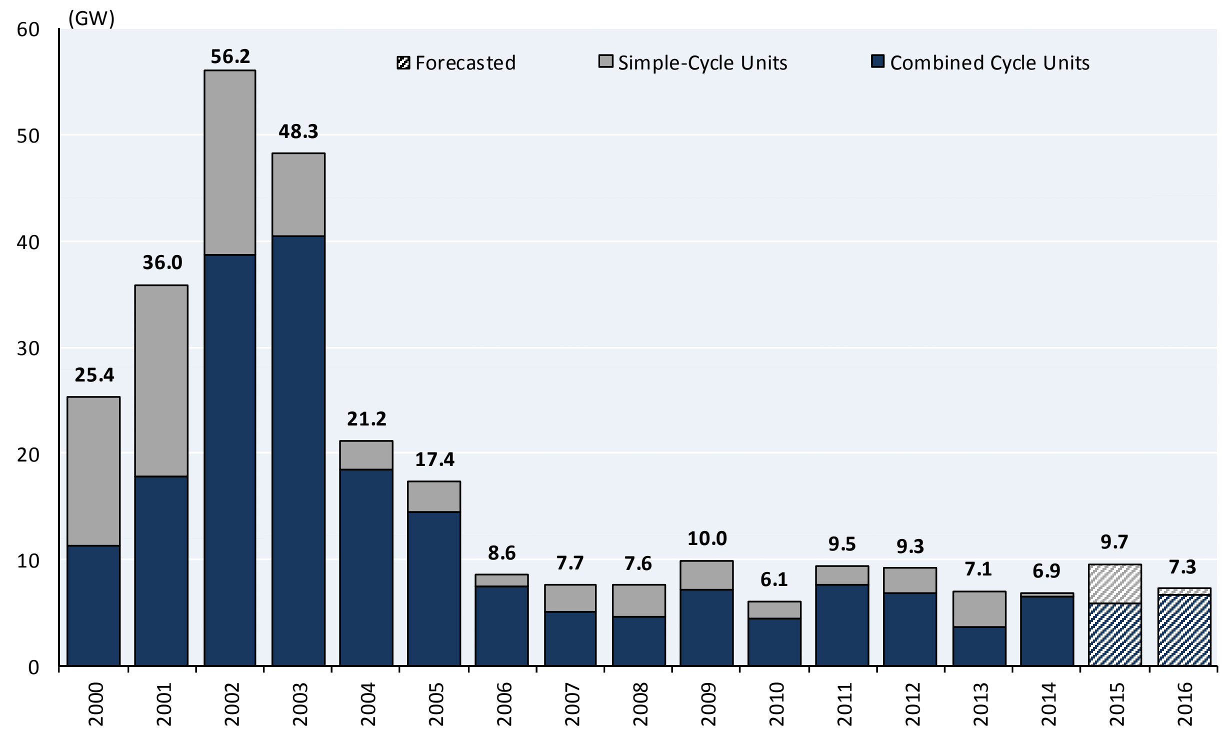


Exhibit A-5. Performance Characteristics Of Natural Gas Combined Cycle Units By Region

Capacity Factor %

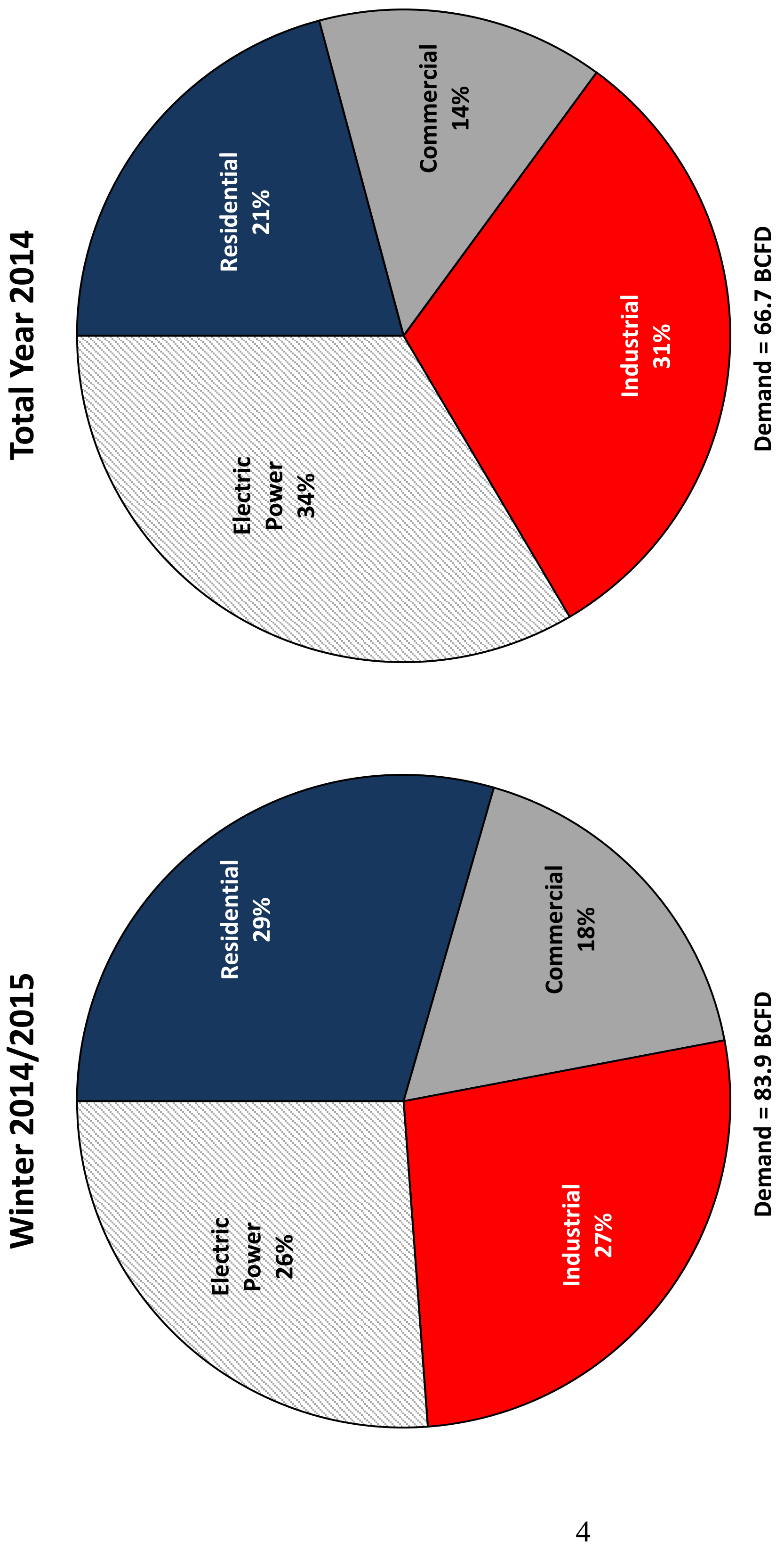
Census Region	Weighted Average Capacity Factor									
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
New England		77.3%	50.8%	48.2%	48.2%	55.1%	56.4%	52.8%	45.4%	42.7%
Middle Atlantic	38.6%	42.0%	33.9%	34.1%	42.7%	46.0%	50.4%	59.8%	55.6%	58.3%
East North Central	27.3%	25.3%	20.0%	14.2%	16.3%	21.9%	30.7%	48.0%	34.8%	33.2%
West North Central	23.2%	19.6%	24.9%	20.2%	12.5%	17.5%	15.3%	26.5%	21.6%	16.8%
South Atlantic w/o Florida	30.0%	31.4%	26.6%	23.8%	36.1%	33.9%	44.3%	53.7%	56.6%	54.3%
Florida	65.6%	67.8%	54.0%	56.5%	54.3%	59.7%	59.5%	63.4%	59.7%	62.0%
South Atlantic	51.2%	53.5%	42.1%	42.4%	47.2%	48.6%	53.2%	59.0%	58.3%	58.4%
East South Central	31.0%	36.2%	30.7%	28.0%	38.1%	43.8%	49.7%	59.3%	49.4%	53.2%
West South Central w/o ERCOT	47.5%	55.0%	32.2%	32.5%	35.3%	35.4%	35.9%	45.6%	36.1%	36.6%
ERCOT	96.3%	97.4%	52.0%	50.0%	46.7%	44.6%	45.2%	50.1%	47.9%	49.3%
West South Central	75.6%	78.4%	43.6%	42.6%	41.9%	41.1%	41.8%	48.5%	43.7%	44.6%
Mountain	65.1%	70.0%	48.2%	48.0%	45.7%	40.9%	34.7%	40.4%	40.4%	39.4%
Pacific Contiguous w/o CA	76.9%	66.0%	48.8%	49.7%	53.1%	51.1%	25.2%	32.9%	51.9%	45.2%
California	65.3%	78.1%	61.4%	61.4%	52.3%	52.8%	40.0%	55.1%	52.8%	57.3%
Pacific Contiguous	68.3%	75.1%	58.3%	58.3%	52.5%	52.3%	36.1%	49.5%	52.6%	54.3%
TOTAL U.S.	**55.1%**	**57.9%**	**41.2%**	**39.9%**	**41.6%**	**43.2%**	**43.6%**	**51.7%**	**48.1%**	**48.4%**

Heat Rate (BTU/kW)

Census Region	Weighted Average Heat Rate (Btu/kWh)									
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
New England	7,471	7,502	7,587	7,561	7,553	7,606	7,538	7,613	7,638	7,678
Middle Atlantic	7,389	7,591	7,541	7,537	7,560	7,404	7,355	7,426	7,358	7,396
East North Central	7,488	7,540	7,439	7,509	7,437	7,473	7,371	7,315	7,069	7,496
West North Central	7,794	7,720	7,605	7,635	7,731	7,648	7,665	7,407	7,560	7,613
South Atlantic w/o Florida	7,770	7,654	7,701	7,642	7,439	7,484	7,410	7,306	6,437	7,270
Florida	7,417	7,416	7,476	7,409	7,479	7,431	7,381	7,320	7,080	7,380
South Atlantic	7,500	7,471	7,538	7,465	7,467	7,447	7,391	7,314	6,798	7,332
East South Central	7,713	7,643	7,633	7,629	7,437	7,409	7,377	7,296	7,022	7,344
West South Central w/o ERCOT	8,664	8,446	8,549	8,414	8,005	8,420	8,333	9,730	8,198	7,947
ERCOT	7,342	7,331	7,369	7,462	7,349	7,347	7,350	7,328	7,304	7,382
West South Central	7,697	7,675	7,733	7,767	7,572	7,726	7,689	8,249	7,596	7,569
Mountain	7,574	7,613	7,393	7,460	7,531	7,533	7,639	7,490	7,097	7,526
Pacific Contiguous w/o CA	7,217	7,288	7,303	7,183	7,129	7,194	7,210	7,222	7,310	7,334
California	7,291	7,504	7,453	7,285	7,291	7,255	7,358	7,305	6,895	7,258
Pacific Contiguous	7,270	7,458	7,422	7,261	7,247	7,239	7,331	7,291	6,989	7,274
TOTAL U.S.	**7,537**	**7,571**	**7,561**	**7,539**	**7,484**	**7,497**	**7,481**	**7,561**	**7,169**	**7,429**

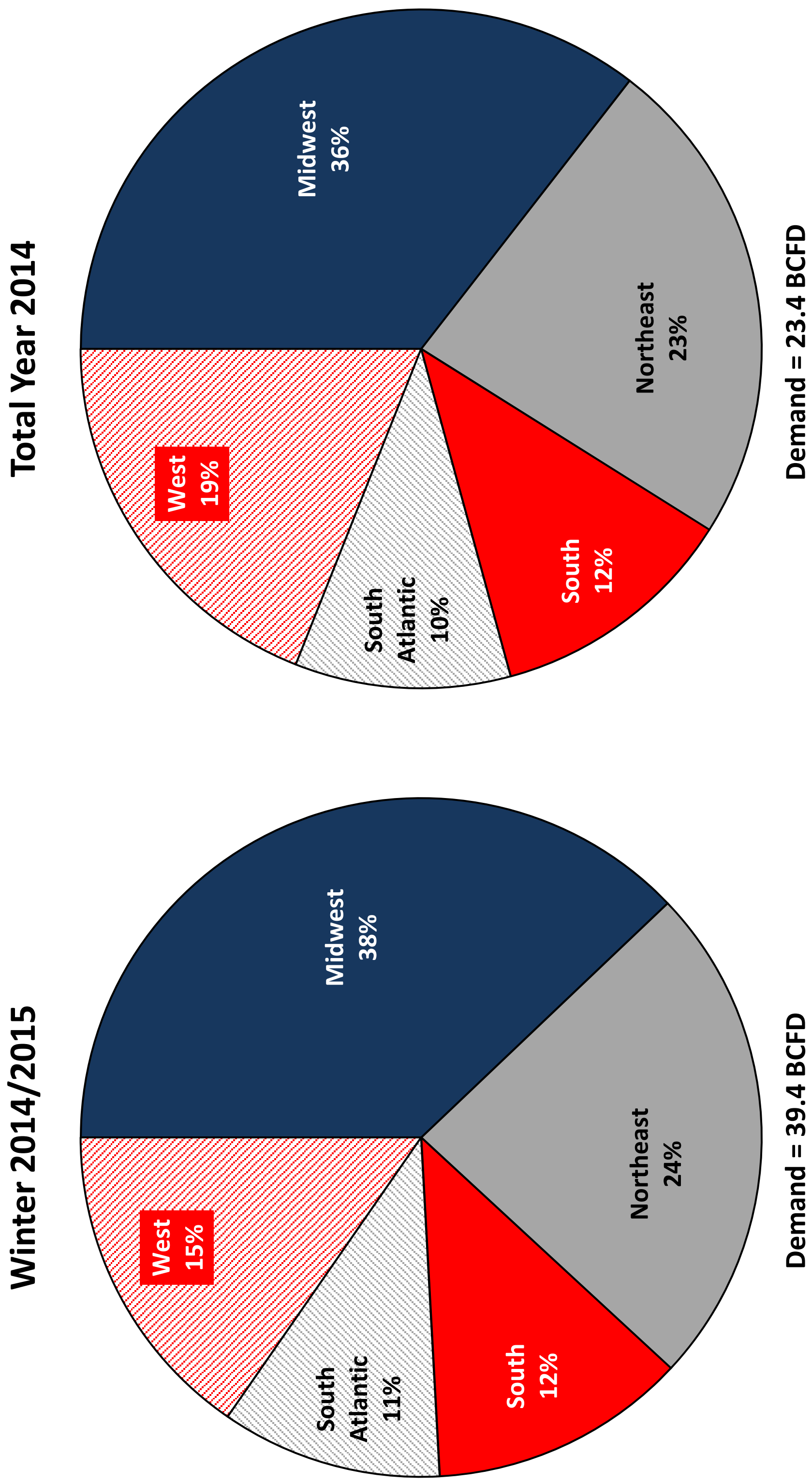
Note: 2014 is EIA-923 Preliminary Data.

Exhibit A-6. Total Primary Gas Demand By Sector And Time Of Year



1. Winter consists of November through March.
2. Excludes lease, plant, and pipeline fuel.
Source: EIA.

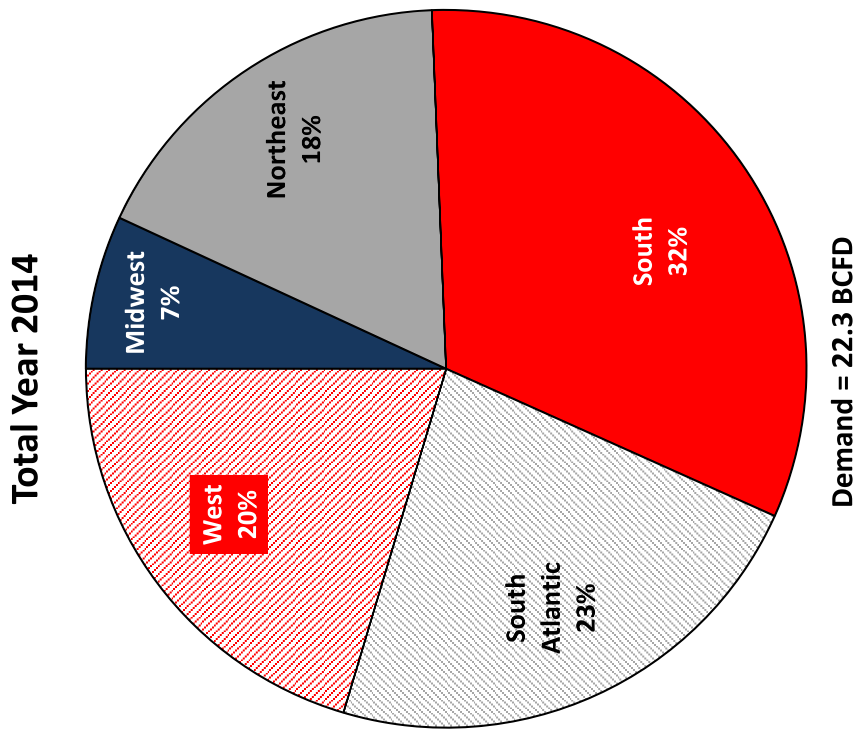
Exhibit A-7. Residential And Commercial Gas Demand By Region And Time Of Year

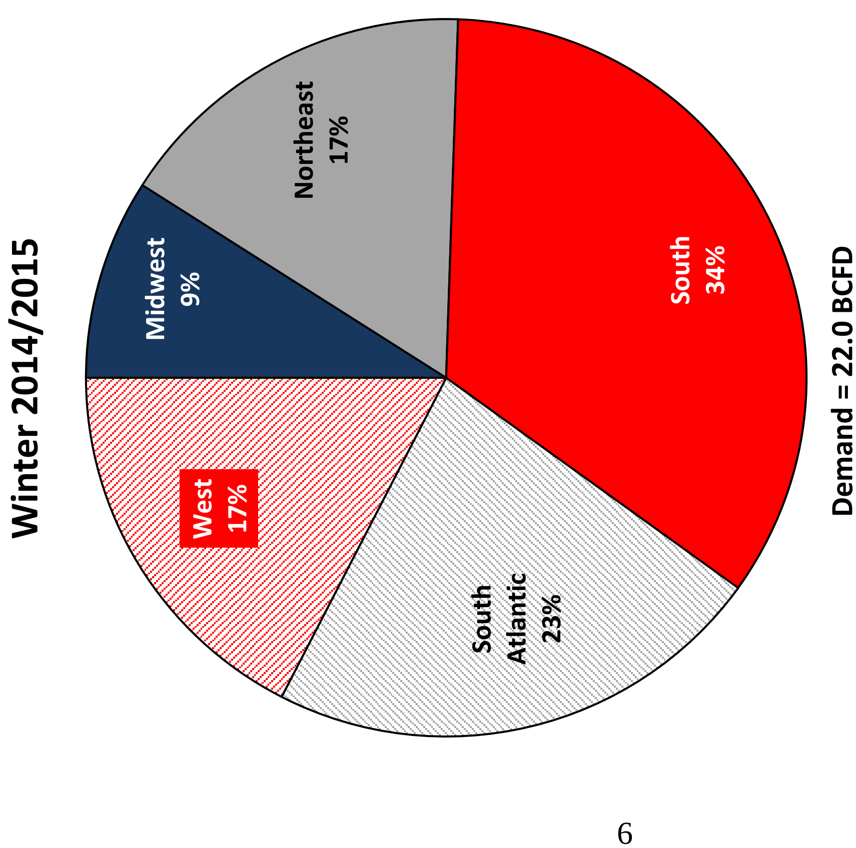


Note: Winter consists of November through March.

Source: EIA.

Exhibit A-8   Electric Power Sector Gas Demand By Region And Time Of Year





Note: Winter consists of November through March.

Source: EIA.

Exhibit A-9. U.S. Census Regions

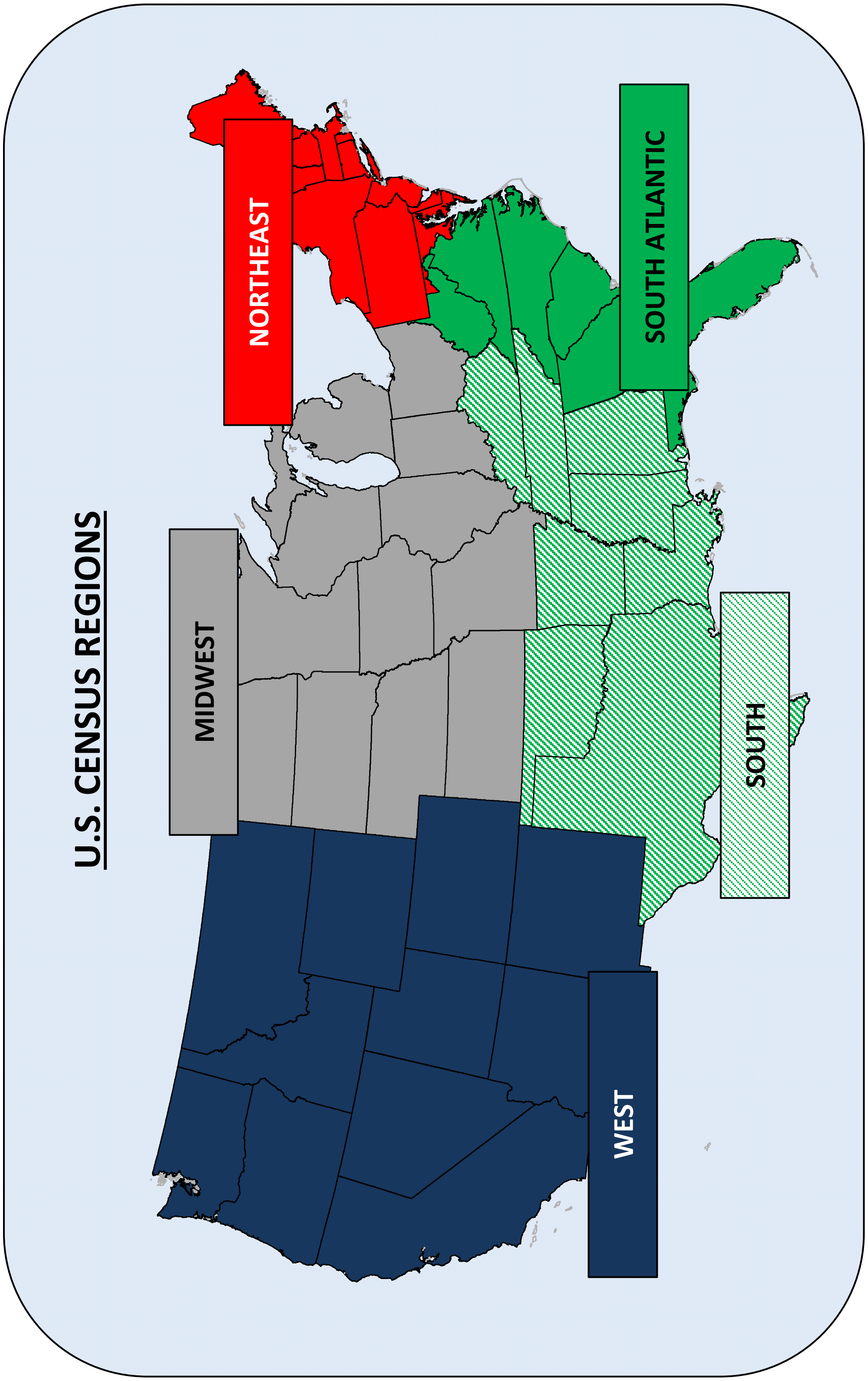


Exhibit A-10. Relevant Data

		Annual					Nov-Mar					
						% Diff						% Diff
		2012	2013	2014	2015	15/14	2011/12	2012/13	2013/14	2014/15	2015/16	15/16-14/15
Residential Housing Stock	(Thousands)	118,945	119,972	120,696	121,936	1.0%	118,470	119,462	120,438	121,144	123,019	1.5%
Electric												
Weather												
Heating Degree Days (HDD)	(Degree Days)	3,792	4,496	4,572	4,432	-3.1%	2,964	3,462	3,865	3,685	3,432	-6.9%
Normal HDD[1]	(Degree Days)	4,373	4,373	4,373	4,373	-	3,531	3,531	3,531	3,531	3,531	-
% of Normal		86.7%	102.8%	104.6%	101.4%	-	84.0%	98.1%	109.5%	104.4%	97.2%	-
New Gas-Fired Capacity[2]												
CC	(MW)	6,868	3,760	7,121	3,918	-45.0%	2,901	2,319	625	2,628	2,572	-2.1%
CT	(MW)	2,383	3,371	250	1,453	481.2%	180	815	125	458	400	-12.7%
Hydro and Nuclear Generation												
Hydro Generation - Pacific	(GWh)	189,803	166,395	159,973	148,543	-7.1%	67,380	67,382	59,577	58,770	61,455	4.6%
Nuclear Generation	(GWh)	769,331	789,016	797,067	793,193	-0.5%	334,268	321,133	325,022	342,472	341,555	-0.3%
Industrial (Index: 2007=100)												
Food		100.0	101.7	103.0	117.3	14.0%	99.3	100.4	102.7	104.6	135.7	29.8%
Paper		100.0	100.4	96.5	97.1	0.6%	100.9	100.8	97.3	95.5	99.7	4.4%
Chemicals		100.0	101.6	101.5	110.7	9.1%	100.3	101.9	101.2	102.5	120.5	17.5%
Petroleum		100.0	106.9	109.0	114.1	4.7%	100.2	102.9	109.0	110.0	119.4	8.6%
Non-metallic Minerals		110.6	112.7	116.9	121.4	3.9%	100.9	103.0	106.8	107.8	92.8	-13.8%
Primary Metals		100.0	101.9	104.6	93.0	-11.1%	105.3	99.1	102.5	97.7	113.7	16.3%
Total Industrial Production		100.0	101.9	105.7	109.8	3.9%	99.1	101.1	103.5	107.6	-	-
Composite 6-key Ind.		101.0	103.5	104.4	109.6	4.9%	100.9	101.5	103.1	103.4	-	-
Economy												
Real GDP	(Bill. 2009$)	15,369	15,711	16,086	16,417	2.1%	15,253	15,499	15,865	16,277	16,581	1.9%
Employment	(Thousands)	134,210	136,541	138,809	141,928	2.2%	129,842	131,349	133,641	135,930	138,368	1.8%
GDP IPD	(2005=100)	105.2	106.7	108.3	108.9	0.6%	104.3	106.1	107.5	108.6	109.7	1.0%

[1] Normal weather conditions are based upon the most recent 30 year average (i.e., 1985-2014).

[2] Amount of capacity brought online in the period.

Exhibit A-11. Regional Dry Natural Gas Production (BCFD)

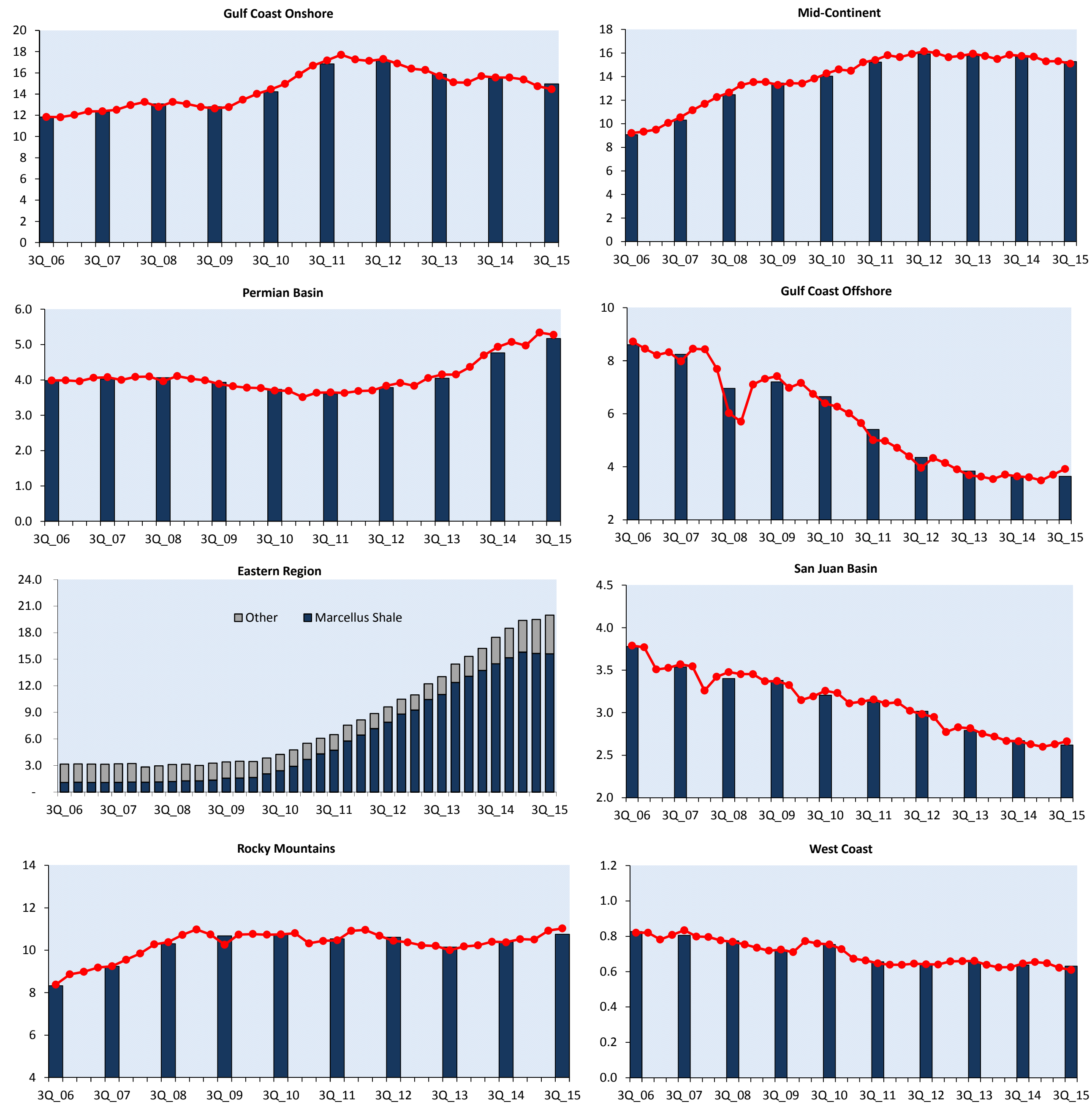


Exhibit A-12. Milestones For Proposed North American Liquefaction Projects

This chart excluded from this report because it contains Energy Ventures Analysis proprietary data.

Contact EVA for more information:
Steve Thumb – Tel: 703-276-8900

Exhibit A-13. Natural Gas Supply

Supply Component	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016
I. US Production						
Shale	2,757	3,726	4,336	4,882	5,814	6,180
Tight Sands	2,174	2,108	1,989	1,886	1,832	1,773
CBM	684	644	577	535	499	447
Associated(ex offshore)	543	599	671	745	834	900
Offshore	908	741	602	538	508	477
Other Conventional	1,924	2,019	1,662	1,536	1,533	1,538
Subtotal Lower-48	**8,990**	**9,837**	**9,836**	**10,122**	**11,021**	**11,314**
Footnote:						
Alaska	143	139	134	131	132	138
Total US	9,132	9,976	9,971	10,253	11,153	11,452
II. Imports						
Net Canada	1,018	832	715	855	861	851
Net Mexico	(180)	(208)	(262)	(257)	(329)	(479)
Net LNG	121	75	59	15	41	(17)
Total Net Imports	**959**	**699**	**512**	**613**	**572**	**356**
III. Storage Withdrawals	**2,268**	**1,327**	**2,253**	**2,993**	**2,106**	**1,956**
IV. Total Lower-48 Supply	**12,217**	**11,863**	**12,601**	**13,728**	**13,699**	**13,626**

Supply Component	2010	2011	2012	2013	2014	2015	2016
I. US Production							
Shale	5,355	7,972	9,948	11,041	12,561	13,983	15,695
Tight Sands	5,358	5,150	4,989	4,639	4,479	4,380	4,135
CBM	1,705	1,602	1,493	1,299	1,287	1,128	1,018
Associated(ex offshore)	1,274	1,351	1,530	1,719	1,881	2,150	2,172
Offshore	2,420	1,971	1,592	1,321	1,281	1,175	1,113
Other Conventional	4,902	4,518	4,148	3,997	3,915	3,833	2,975
Subtotal Lower-48	**21,013**	**22,564**	**23,700**	**24,017**	**25,404**	**26,649**	**27,109**
Footnote:							
Alaska	354	337	332	318	314	325	336
Total US	21,367	22,900	24,032	24,335	25,718	26,974	27,444
II. Imports							
Net Canada	2,541	2,180	1,992	1,876	1,865	1,997	1,989
Net Mexico	(303)	(500)	(619)	(657)	(726)	(1,066)	(1,263)
Net LNG	366	278	146	95	44	69	(314)
Total Net Imports	**2,604**	**1,958**	**1,519**	**1,314**	**1,183**	**1,000**	**412**
III. Net Storage Change	**4**	**(350)**	**(7)**	**548**	**(252)**	**(314)**	**365**
IV. Total Lower-48 Supply	**23,621**	**24,172**	**25,212**	**25,879**	**26,335**	**27,335**	**27,886**

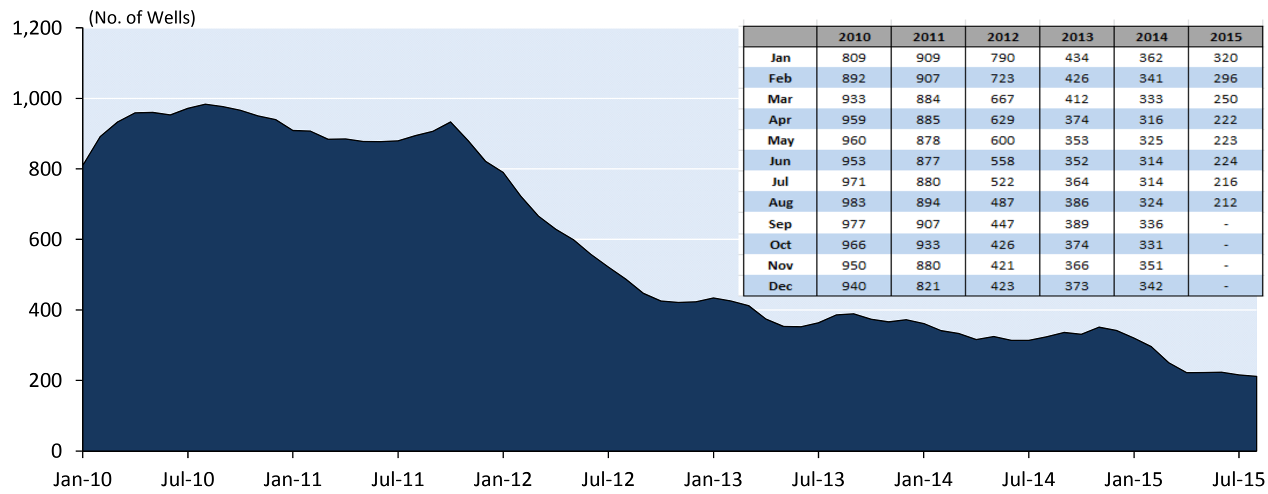
Exhibit A-13. Natural Gas Supply (Continued)

Supply Component	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016
I. US Production						
Shale	18.26	24.51	28.72	32.33	38.50	40.66
Tight Sands	14.40	13.87	13.17	12.49	12.14	11.67
CBM	4.53	4.24	3.82	3.54	3.31	2.94
Associated(ex offshore)	3.60	3.94	4.45	4.93	5.52	5.92
Offshore	6.02	4.88	3.99	3.57	3.37	3.14
Other Conventional	12.74	13.29	11.01	10.17	10.15	10.12
Subtotal Lower-48	**59.53**	**64.72**	**65.14**	**67.04**	**72.99**	**74.44**
Footnote:						
Alaska	0.95	0.91	0.89	0.87	0.88	0.91
Total US	60.48	65.63	66.03	67.90	73.86	75.34
II. Imports						
Net Canada	6.74	5.47	4.74	5.66	5.70	5.60
Net Mexico	-1.19	-1.37	-1.74	-1.70	-2.18	-3.15
Net LNG	0.80	0.49	0.39	0.10	0.27	-0.11
Total Net Imports	**6.35**	**4.60**	**3.39**	**4.06**	**3.79**	**2.34**
III. Storage Withdrawals	**15.02**	**8.73**	**14.92**	**19.82**	**13.95**	**12.87**
IV. Total Lower-48 Supply	**80.90**	**78.05**	**83.45**	**90.91**	**90.73**	**89.65**

Supply Component	2010	2011	2012	2013	2014	2015	2016
I. US Production							
Shale	14.67	21.84	27.18	30.25	34.42	38.31	43.00
Tight Sands	14.68	14.11	13.63	12.71	12.27	12.00	11.33
CBM	4.67	4.39	4.08	3.56	3.53	3.09	2.79
Associated(ex offshore)	3.49	3.70	4.18	4.71	5.15	5.89	5.95
Offshore	6.63	5.40	4.35	3.62	3.51	3.22	3.05
Other Conventional	13.43	12.38	11.33	10.95	10.73	10.50	8.15
Subtotal Lower-48	**57.57**	**61.82**	**64.75**	**65.80**	**69.60**	**73.01**	**74.27**
Footnote:							
Alaska	0.97	0.92	0.91	0.87	0.86	0.89	0.92
Total US	58.54	62.74	65.66	66.67	70.46	73.90	75.19
II. Imports							
Net Canada	6.96	5.97	5.44	5.14	5.11	5.47	5.45
Net Mexico	-0.83	-1.37	-1.69	-1.80	-1.99	-2.92	-3.46
Net LNG	1.00	0.76	0.40	0.26	0.12	0.19	-0.86
Total Net Imports	**7.13**	**5.37**	**4.15**	**3.60**	**3.24**	**2.74**	**1.13**
III. Net Storage Change	**0.01**	**-0.96**	**-0.02**	**1.50**	**-0.69**	**-0.86**	**1.00**
IV. Total Lower-48 Supply	**64.71**	**66.22**	**68.89**	**70.90**	**72.15**	**74.89**	**76.40**

Exhibit A-14. Gas Well Completions

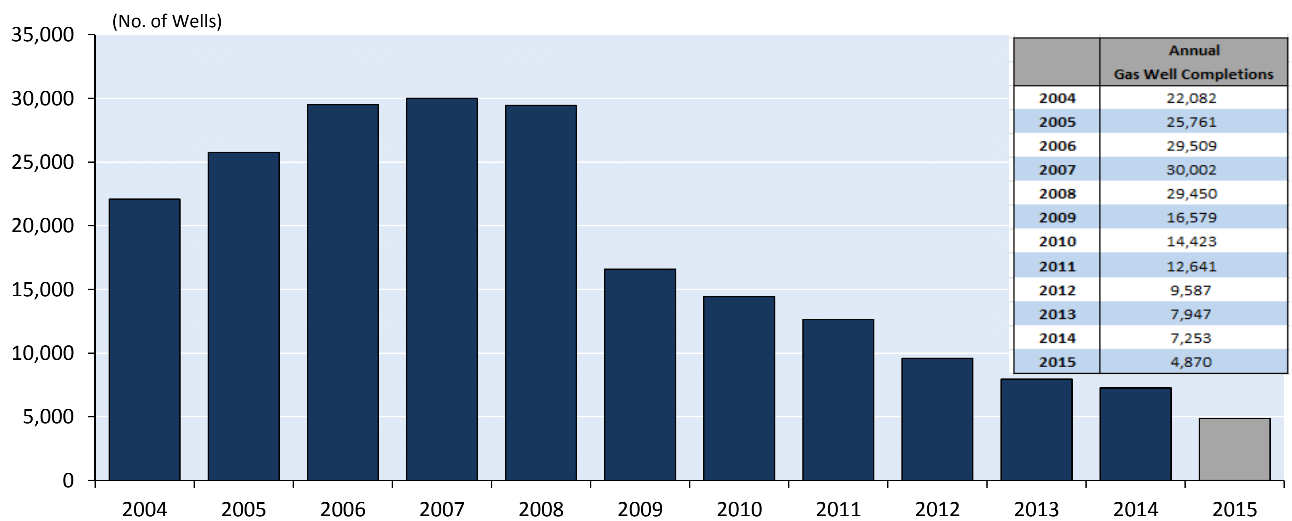
Monthly Well Completions



	2010	2011	2012	2013	2014	2015
Jan	809	909	790	434	362	320
Feb	892	907	723	426	341	296
Mar	933	884	667	412	333	250
Apr	959	885	629	374	316	222
May	960	878	600	353	325	223
Jun	953	877	558	352	314	224
Jul	971	880	522	364	314	216
Aug	983	894	487	386	324	212
Sep	977	907	447	389	336	-
Oct	966	933	426	374	331	-
Nov	950	880	421	366	351	-
Dec	940	821	423	373	342	-

Source: API.

Annual Well Completions



	Annual Gas Well Completions
2004	22,082
2005	25,761
2006	29,509
2007	30,002
2008	29,450
2009	16,579
2010	14,423
2011	12,641
2012	9,587
2013	7,947
2014	7,253
2015	4,870

Source: API.