Outlook for Natural Gas Demand for the Summer of 2015

Overview

The combination of structural demand increases within both the industrial and electric sectors, along with higher levels of coal-to-gas fuel switching within the electric sector, will cause summer period gas demand to increase approximately 3.2 BCFD, or 5.2 percent.[1] Furthermore, while storage injections this year will be approximately 1.8 BCFD, or 14 percent, less than last summer, season ending (October 31, 2015) storage levels should be adequate (i.e., about 3,840 BCF).

As noted in Exhibit 1, slightly less than 70 percent of the expected increase in summer demand (i.e., primary demand) will occur within the electric sector. This increase in electric sector demand is due to the combination of (1) near record fuel switching and (2) the impact of coal-fired unit retirements as a result of the implementation of EPA's MATS[2] regulations, which will cause total electric demand to increase about 2.0 BCFD, or 8.3 percent. Additive to this is a 0.9 BCFD, or 4.5 percent, demand increase in industrial sector demand. The latter primarily occurs because of the series of capacity expansions scheduled to come online in 2015.

Exhibit 1. Projected Gas Demand for April Through October 2015[(1)]

	2015		2014		Change	
Sector	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**	**BCF**	**Average BCFD**
Residential	1,234	5.8	1,233	5.8	1	0.0
Commercial	1,194	5.6	1,192	5.6	2	0.0
Industrial	4,452	20.8	4,260	19.9	192	0.9
Electric	5,567	26.0	5,142	24.0	425	2.0
Lease, Plant & Pipeline Fuel	1,424	6.6	1,353	6.3	71	0.3
Subtotal	**13,871**	**64.8**	**13,180**	**61.6**	**691**	**3.2**
Net Storage Injections	2,365	11.1	2,753	12.9	(388)	(1.8)
Source: EIA and EVA.				(1) Figures may not add due to rounding.		

[1] For purposes of this report, summer refers to the period April through October, even though technically this period includes part of the spring and fall seasons. This terminology is used in order to simplify the discussion contained in this report.

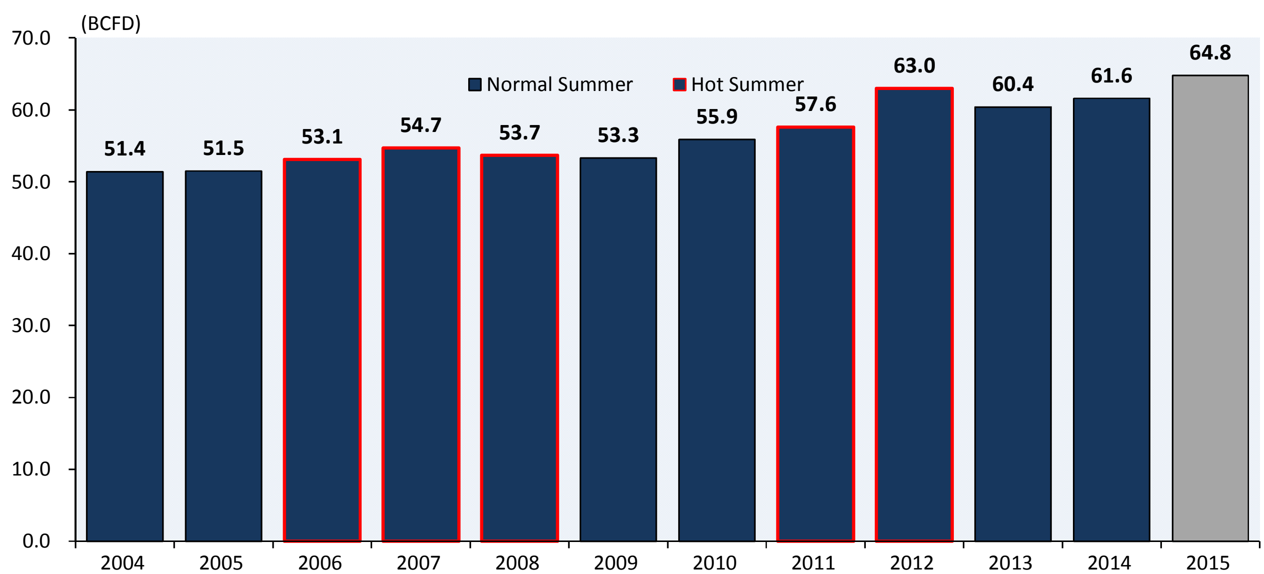
[2] Mercury Air Toxic Standards (MATS).

With respect to significant risk factors for this outlook, there are two noteworthy items, namely (1) the summer weather and (2) the potential for declining domestic production towards the end of the summer period. Concerning the former, the NOAA forecast is for a slightly warmer than normal summer (i.e., 3.5 percent warmer than normal), whereas last summer was very close to normal (i.e., 0.4 percent warmer than normal). The key concern is if this summer turns out to be a hot summer then electric gas demand could be significantly higher (e.g., 0.9 BCFD, which would increase consumption from 26.0 to 26.9 BCFD).[3]

With respect to domestic production, there is uncertainty over future production levels, as a result of the 38 percent decline in the gas-directed rig count since the recent October 2014 levels. While there will be year-over-year increases in production levels, the concern going forward is that month-over-month changes could be flat to slightly declining. The latter could impact, to a degree, the level of summer storage injections.

Exhibit 2 provides a longer term overview of historical trends for summer gas demand. As illustrated, 2015 summer gas demand will exceed the prior record set in 2012, when a combination of very hot weather and record fuel switching caused summer demand to soar. Lastly, several addendums are attached to this report, which cover some of these areas in greater depth.[4]

Exhibit 2. Summer Natural Gas Demand for All Sectors



Note: 2015 natural gas demand is forecasted.
2005, 2006, 2007, 2010, 2011, and 2012 denote hot summers.

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[3] Cooling degree days for periods noted are as follows: 30-yr average = 1,242; 2015 = 1,286; 2014 = 1,247; 2013 = 1,293; 2012 = 1,382; 2011 = 1,340; 2010 = 1,430; and 2009 = 1,174.

[4] Addendums for the following are attached (1) industrial sector expansions; (2) LNG exports; and (3) associated gas.

Outlook For Demand

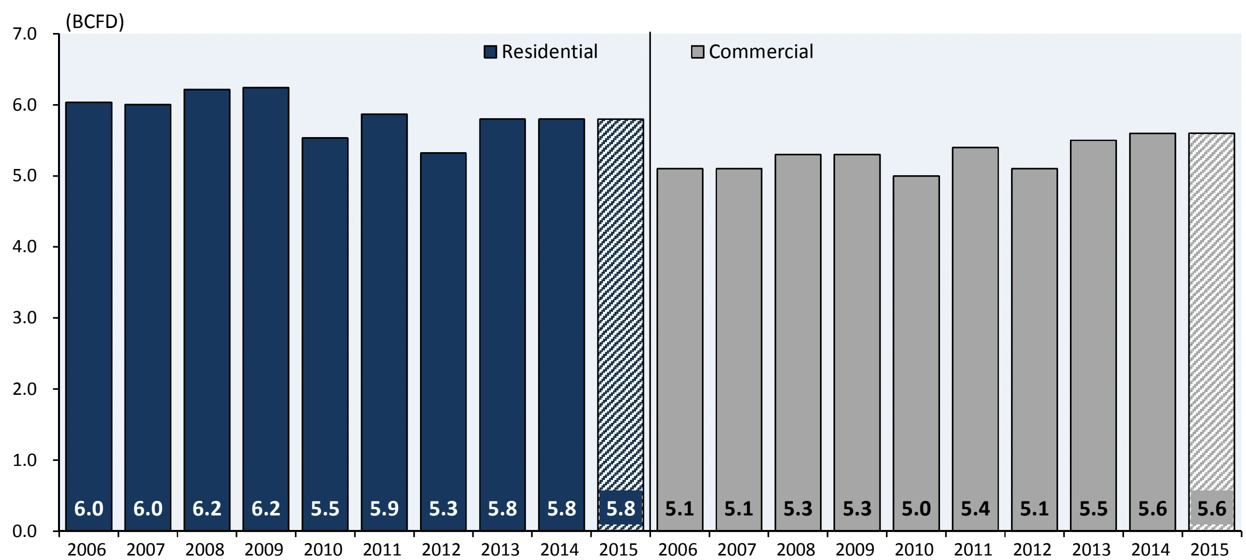
Overview

The following discussion provides an assessment of summer demand for each of the four major sectors. The impact of storage injections is addressed in a subsequent section.

Residential and Commercial

Residential and commercial sector gas demand for the forthcoming summer is, in essence, expected to be equivalent with the prior summer's demand levels. These two winter weather-sensitive sectors usually are not affected by changes in the summer weather. Finally, Exhibit 3 summarizes the longer term trends for summer gas demand within both sectors.

Exhibit 3. Summer Natural Gas Demand for the Residential and Commercial Sectors



Note: 2015 residential and commercial sector natural gas demand is forecasted.

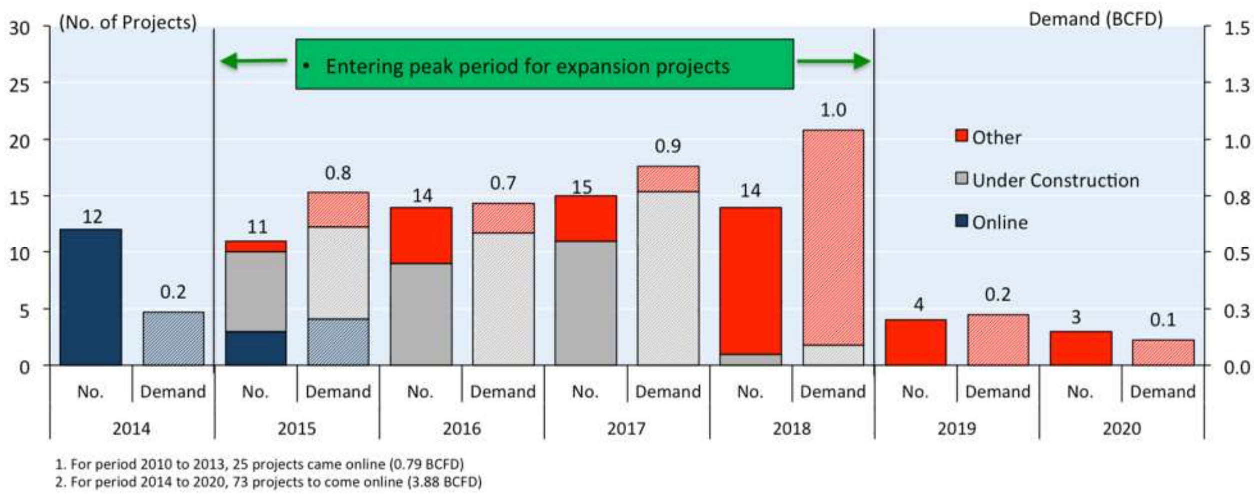
Industrial Sector

Currently the industrial sector is the fastest growing sector within the natural gas industry. Two factors are driving this growth, namely (1) a series of capacity expansions by a few key industries and (2) the impact of the slow recovery of economic growth for the U.S.

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 will be entering the peak period for the annual additions of these projects. This is illustrated in Exhibit 4. 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., petrochemical and fertilizer) that either increase U.S. exports or alternatively reduce U.S. imports.

Exhibit 4. Industrial Capacity Expansion Projects[(1),(2)]



While there have been some additions and deletions to the list of industrial capacity expansion projects, at present there are 98 likely capacity addition projects in the fertilizer, petrochemical, methanol, steel and paper and pulp industries. Of these 98 projects 25 came online in the 2010 to 2013 period and an additional 12 came online in 2014. The remaining 61 projects are projected to come online in the 2015 to 2020 timeframe.[5]

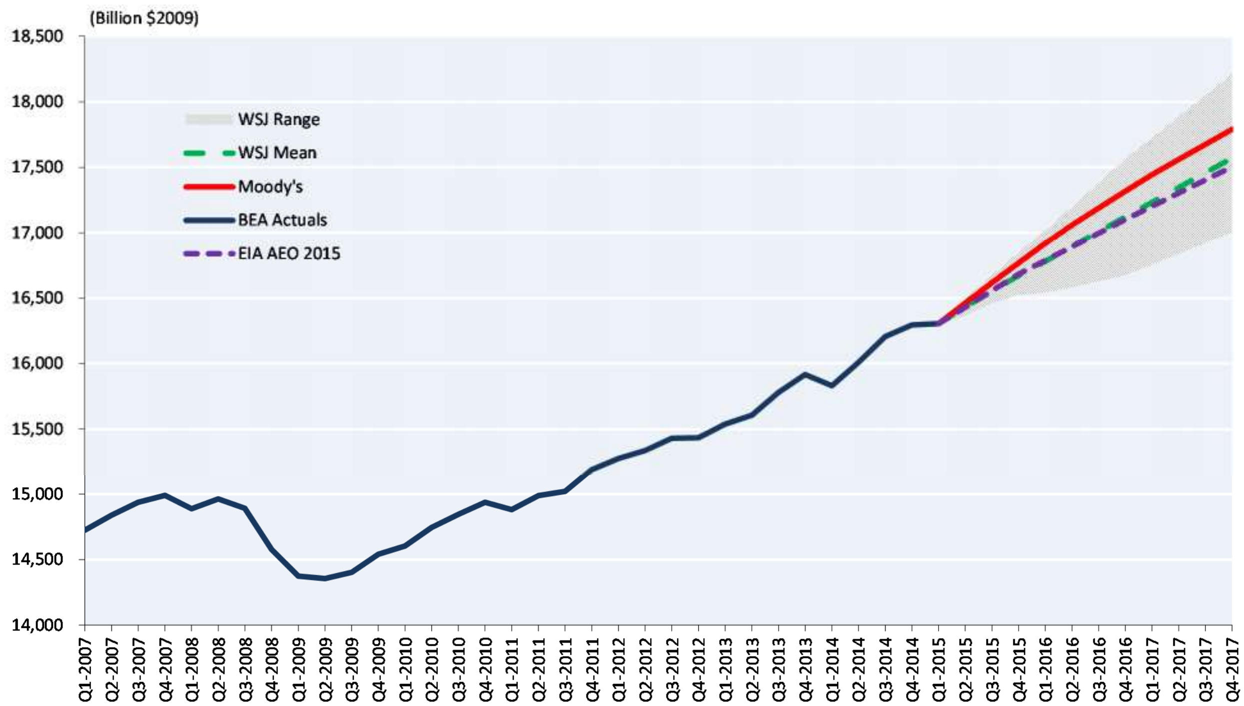
With respect to 2015, this year will receive the benefit of the full year impact of the 12 projects that came online in 2014, plus the partial year impact of 11 additional projects scheduled to come online in 2015. The net result is that summer gas demand within the industrial sector is expected to increase approximately 0.75 BCFD, as a result of these capacity expansion projects coming online.

Economic Growth

The remainder of the industrial sector is benefitting from the modest recovery in U.S. economic growth. Exhibit 5 summarizes the current range of views for U.S. economic growth, with the average expectation for the second and third quarters of the year being 3.0 percent per annum.

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

Exhibit 5. U.S. Real GDP Short-Term Forecast Comparison

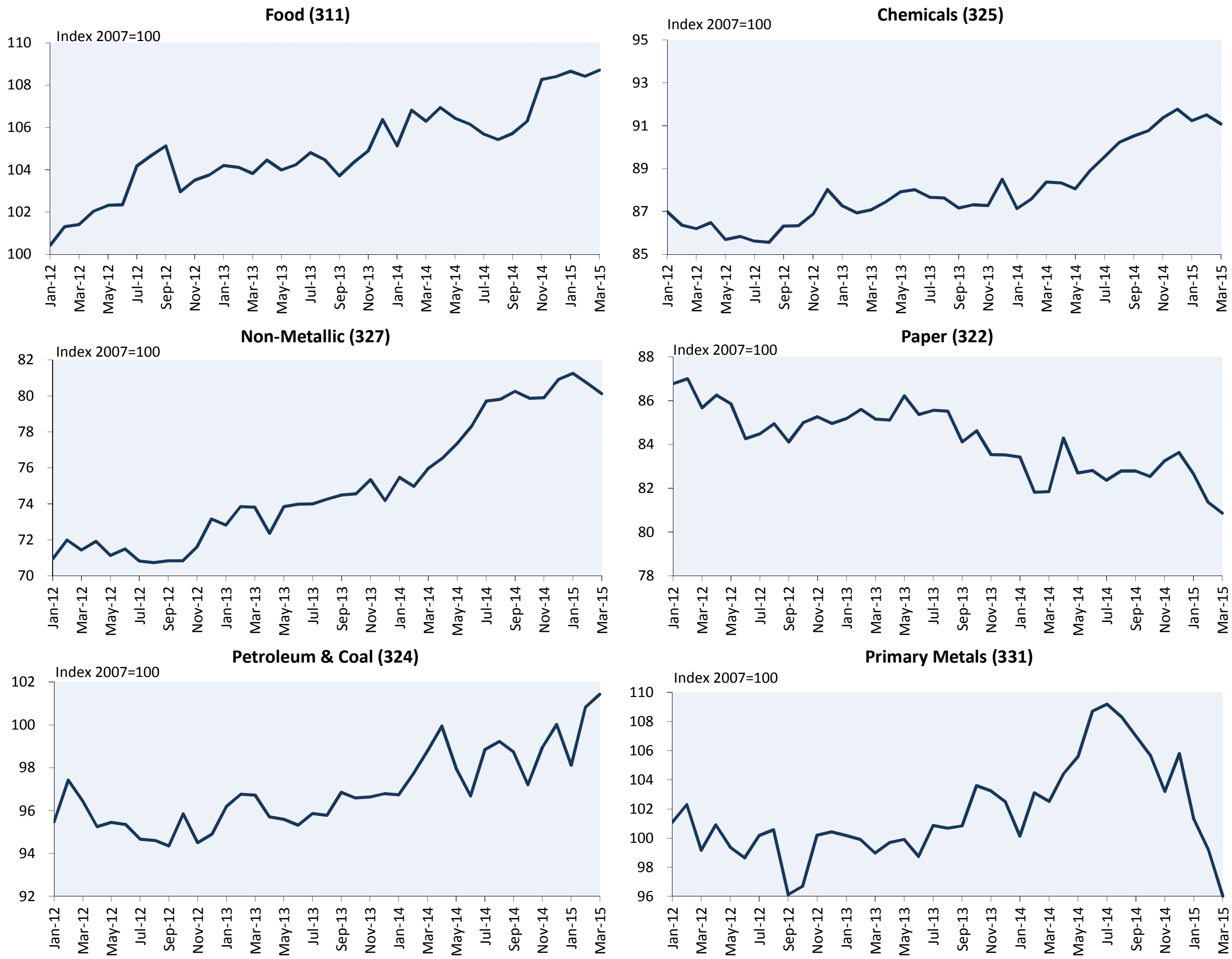


The impact of recent economic growth on the production indices for the six major energy intensive industries is summarized in Exhibit 6. There currently is a mixture of trends for these six key industries with the food and refining indices increasing, while the paper and primary metal indices are declining. Lastly, the chemical and non-metallic indices are relatively flat.

Summary

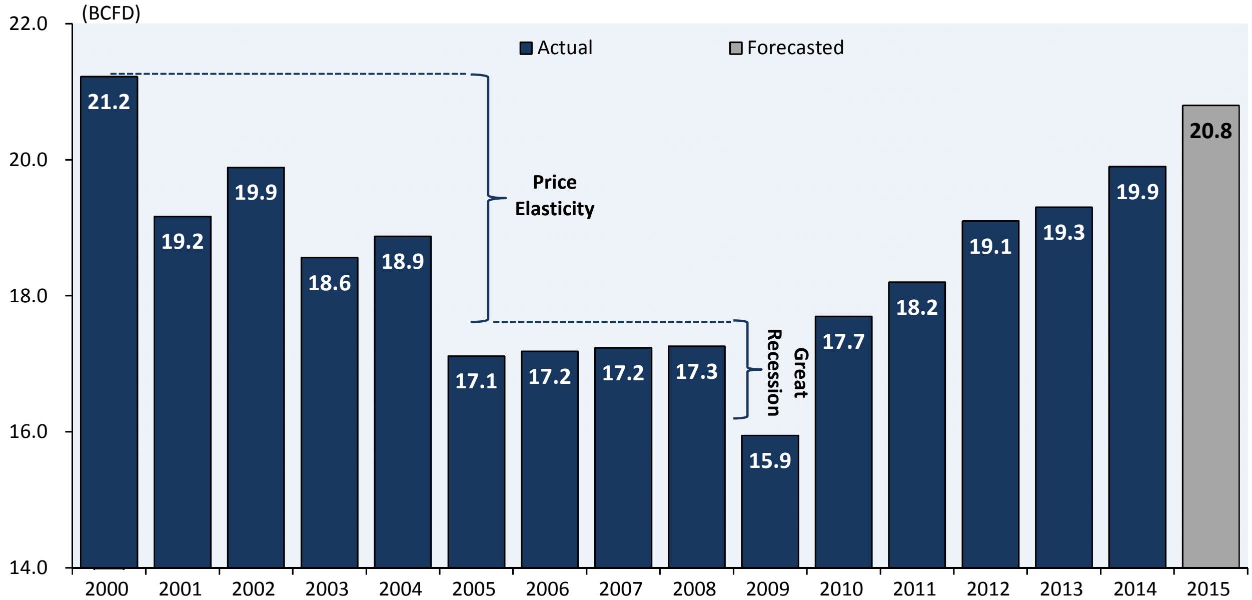
With respect to the integrated outlook for industrial sector gas demand this summer, it is expected to increase 0.9 BCFD, or 4.5 percent, over last year's level. As an added point of perspective, Exhibit 7 compares and contrasts, on an annual basis, the expected outlook for 2015 industrial sector gas demand with the consumption levels for the sector since 2000. As illustrated, during the prior decade the dominant trend for industrial sector gas demand was decline, as the sector initially experienced significant price elasticity during the era of high gas prices that occurred during the first half of the decade. This was compounded by the impact of the Great Recession during the second half of the decade. However, currently with the ratio of oil-to-gas prices at about 21:1 U.S. industrial gas demand is not nearly as sensitive to changes in gas prices as in the past, when the ratio of oil-to-gas prices was closer to 6:1.

Exhibit 6. Performance of the Six-Key Energy Intensive Industries



Source: Federal Reserve.

Exhibit 7. Summer Natural Gas Demand for the Industrial and Transportation Sectors



Source: EIA and EVA.

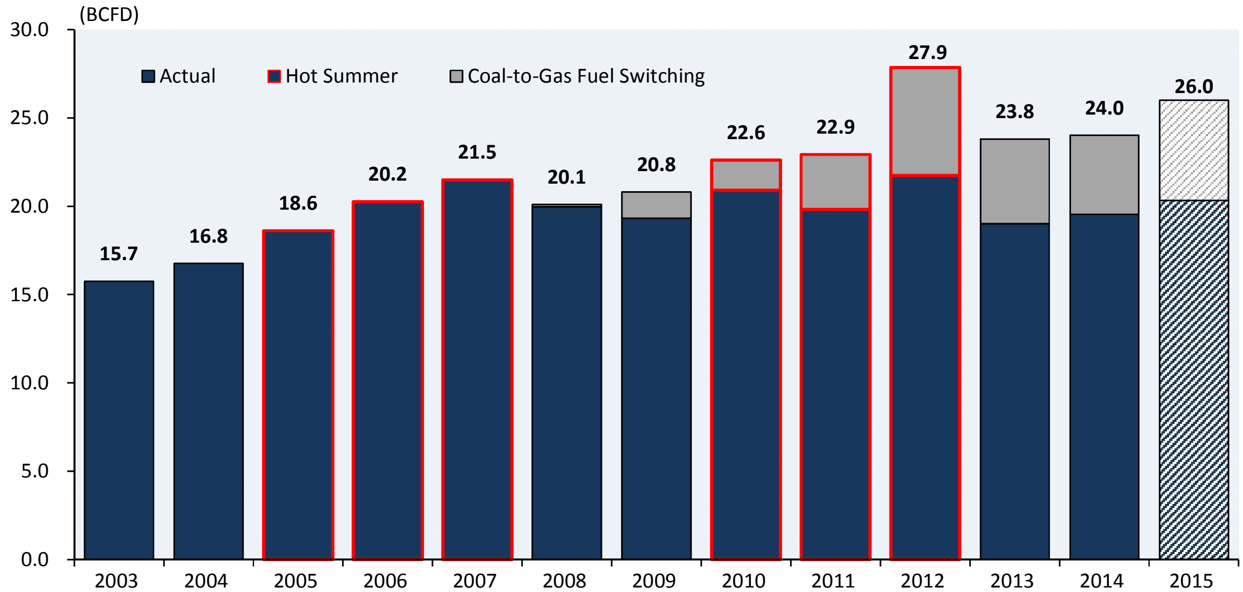
Starting in 2010, however, this basic downward trend for industrial sector gas demand reversed itself, as the country began to emerge from the Great Recession and the sector benefitted from the initial impact of the previously noted series of capacity additions.

Electric Sector

While historically a number of factors have influenced summer electric gas demand, for 2015 the dominant factor is the increase in coal-to-gas fuel switching, which is occurring because of the decline in gas prices in 2015. The latter accounts for approximately half of the projected 2.0 BCFD, or 8.3 percent, increase in this summer's electric sector gas demand. Additive to this is the estimated impact of the increase gas-fired generation because the retirement of coal-fired capacity as a result of the implementation of EPA's MATS regulations. The latter is estimated to account for about 25 percent of the increase in this summer's electric sector gas demand.

In addition to these two major factors both the overall increase in electricity demand and the drought conditions in California will have impacted the outlook for this summer's electric sector gas demand – albeit to a much smaller degree. The net effect of all these factors is summarized in Exhibit 8.

Exhibit 8. Summer Natural Gas Demand for the Electric Sector



Note: 2002, 2005, 2006, 2007, 2010, and 2011 denote hot summers.
Demand and coal-to-gas fuel switching for 2015 is forecasted.

MATS

Approximately 20 GW of coal-fired capacity is expected to retire in 2015.[6] The driving force behind these retirements is the implementation of EPA's MATS regulations in April 2015. While on the surface this appears to be a relatively large reduction in capacity, in actuality these retirements result in a much smaller reduction in generation. The latter occurs because about 50 percent of the units that are retiring operated in 2014 at a 20 percent or lower capacity factor (i.e., see Exhibit 9).[7] As a result, the gain in gas-fired generation to offset the decline in coal-fired generation is much lower than that opined by some industry observers. For just the summer period the net increase in gas-fired generation is estimated to increase electric sector gas demand about 0.5 BCFD.

Fuel Switching

Coal-to-gas fuel switching peaked at 6.1 BCFD in the summer of 2012, when gas prices averaged about $2.65 per MMBTU, but then declined about 22 percent last summer to approximately 4.75 BCFD, as average gas prices increased to about $4.20 per MMBTU. For the summer of 2015 fuel switching is expected to rebound to about 5.75 BCFD (i.e., 22 percent increase from 2014 levels (i.e., current NYMEX futures for the summer average $2.82 per MMBTU). As previously noted this increase in coal-to-gas fuel switching accounts for about half of the increase in this summer's electric sector gas demand versus last summer's results.

[6] These retirements represent approximately six percent of the capacity for the existing coal fleet.
[7] In Exhibit 9 the Category "N/A" (not available) refers to a series of relatively small units for which 2014 capacity factor data is not yet available. For the most part, the units in the Category N/A operated at low capacity factors.

Exhibit 9. Impact of MATS Regulations in 2015

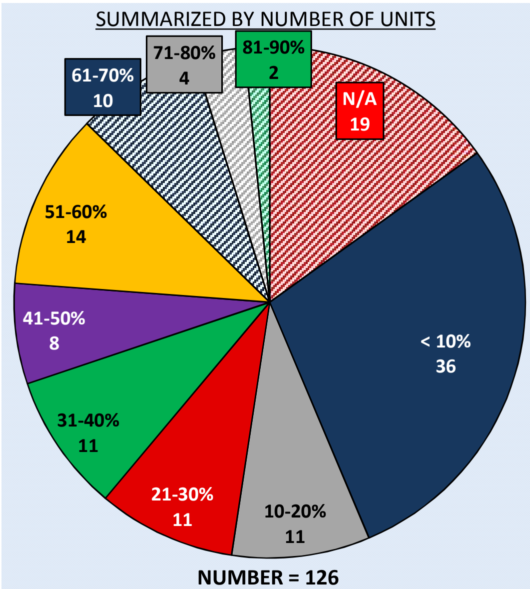
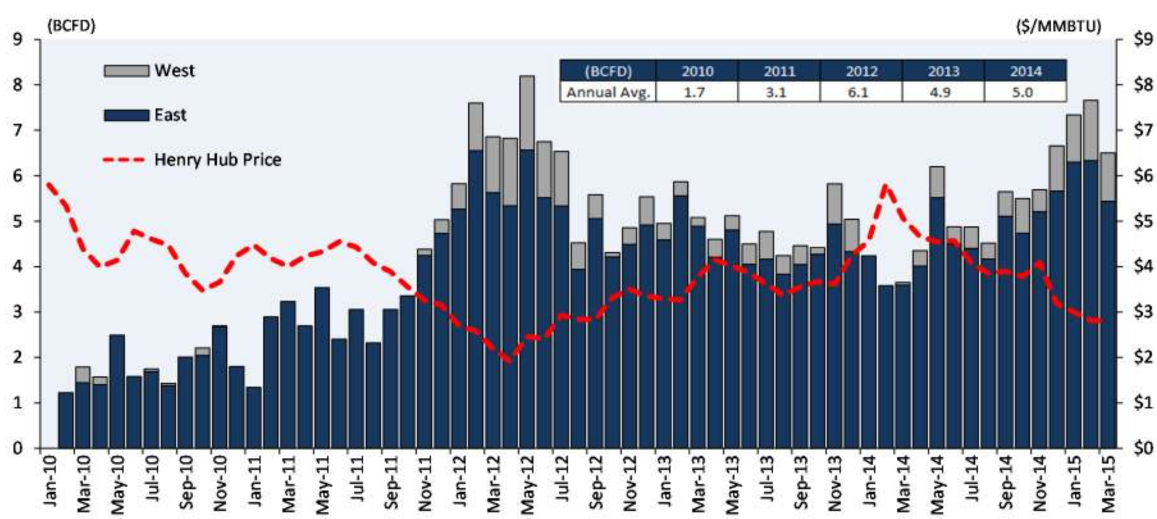


Exhibit 10 provides a monthly summary of the increase in gas demand due to fuel switching for the last four years, plus the initial months for 2015. The data presented in Exhibit 10 is segmented between the western U.S., where coal prices are lower (i.e., primarily Powder River Basin coal), and the eastern U.S., where coal prices are higher (i.e., primarily Northern Appalachia coal). While the correlation between gas prices and the level of fuel switching is not perfect, the trend of increasing levels of coal-to-gas fuel switching as gas prices decline is very evident.

Exhibit 10. Coal-to-Gas Fuel Switching



Electric Sales

Among the other factors that historically have influenced electric 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 electric sector gas demand, because gas-fired generation tends to be at the margin in most regions. Exhibit 11 summarizes the year-to-date growth in electricity sales. As illustrated, on a year-to-date basis electricity sales figures for 2015 are, in essence, flat with those for 2014. However, both years' results were impacted to different degrees by the severe winter weather. While it is only one month, April 2015 electricity sales are about 0.5 percent greater than the April 2014 figures, and this is more indicative of the modest electricity sales growth expected for the summer of 2015. The net result of this anticipated modest growth would be a small increase in gas-fired generation and, as a result, electric sector gas demand.

With respect to the influence of summer weather, Exhibit 12 compares and contrasts peak month electric sector gas demand for each of the last six years with the outlook for the peak month in 2015. Also, included in this graphic is the CDD for each month. The data in this exhibit presents the lowest to highest peak demand levels for the selected years. While there is not a perfect correlation between peak electric gas consumption levels and CDD,[8] the general trend is readily apparent. Also, readily apparent in Exhibit 12 is the uniqueness of July 2012 electric sector gas demand, which was driven by both record levels of hot weather and fuel switching. With respect to August 2015, it is more on a par with historical peak performances of the other years than the July 2012 record.

California Drought

California currently is in a period of critical drought conditions (i.e., approximately four years). In addition to adversely impacting a number of other industries, the low water conditions have reduced significantly the state's hydro generation. The primary alternative for replacing this lost hydro generation is increased renewable and gas-fired generation (i.e., another form of fuel switching). While California is only one piece of the West's total hydro generation output, it traditionally has represented about 23 percent of the total hydro generation in the West.

[8] In addition to differences in the warmth of the summer weather, gas-fired generation in a specific month can be affected by a number of factors (e.g., unplanned outages of nuclear and coal units, availability of renewable capacity, etc.).

Exhibit 11. Total Weekly Electric Output (48-States)

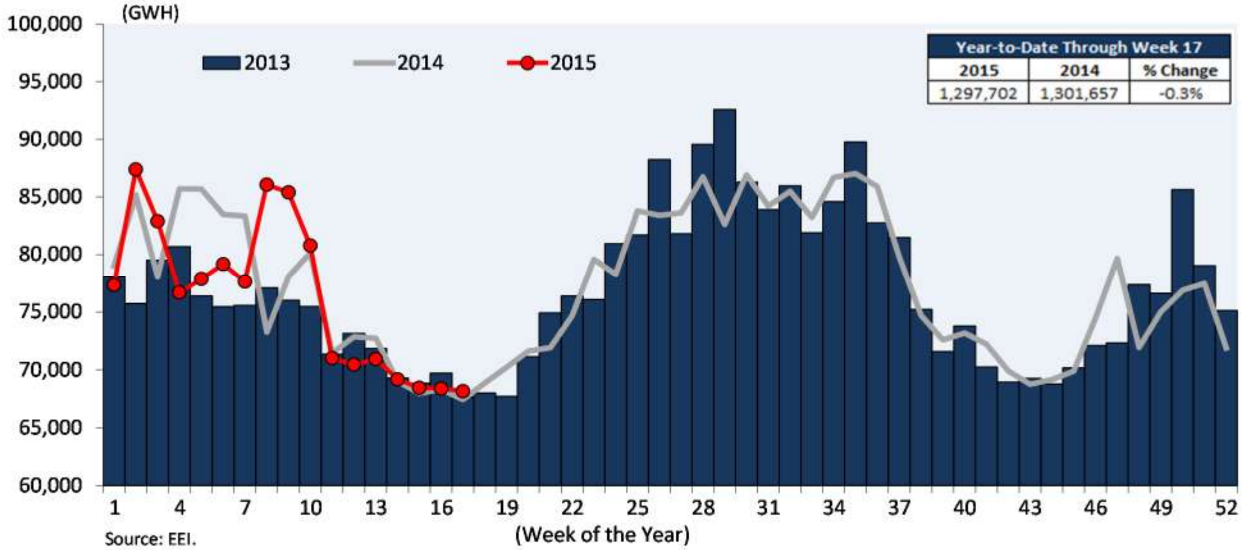
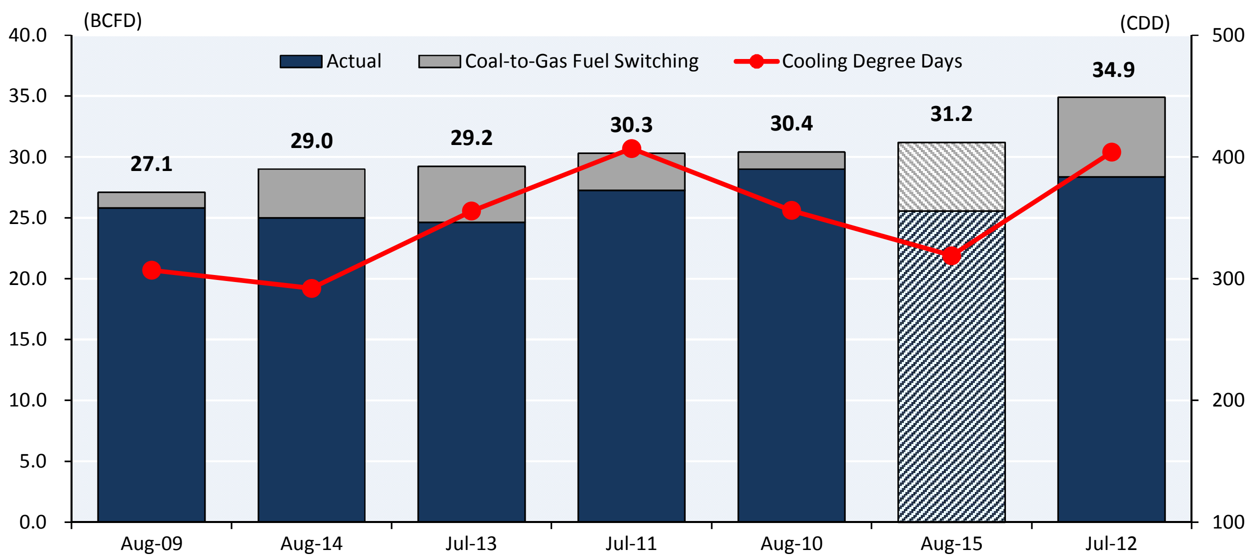


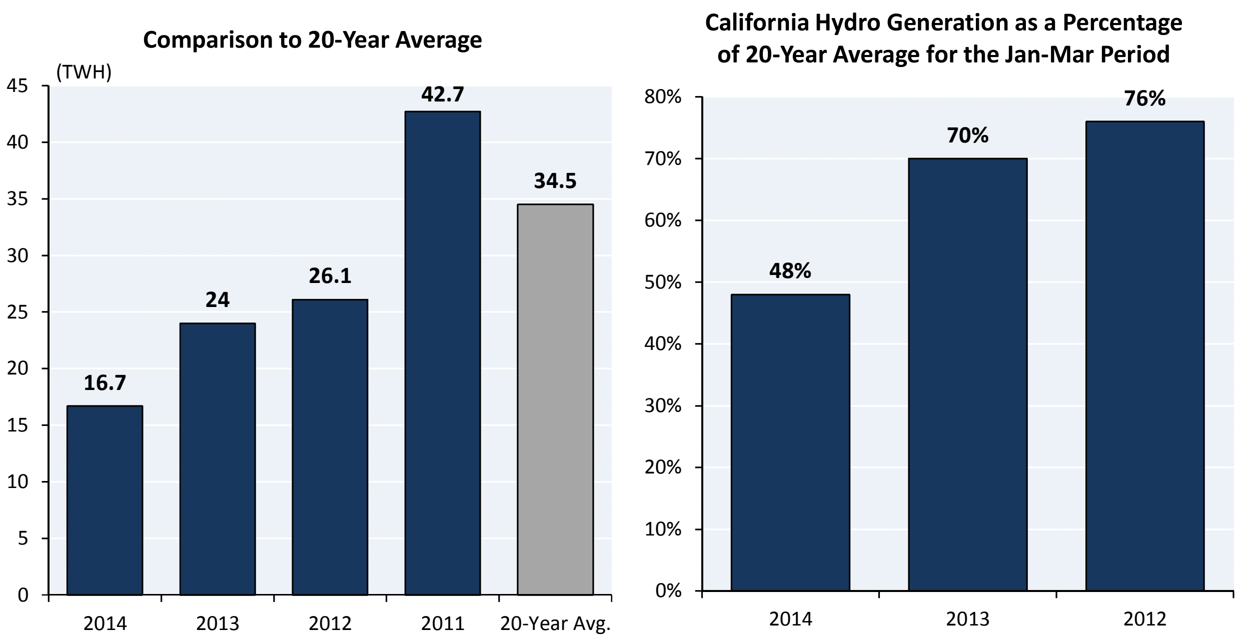
Exhibit 12. Comparison of Summer Peak Period Natural Gas Demand for the Electric Sector and Cooling Degree Days



Note: 2015 demand, fuel switching, and cooling degree days for are forecasted.
Source: EIA and NOAA.

Exhibit 13 illustrates how sharply hydro generation in California has declined during the last three years when compared to a 20-year average. With respect to the outlook for 2015 it is likely that hydro generation will be similar to the very low levels recorded in 2014 (i.e., 52 percent below the 20-year average).[9] As a result, while hydro generation will be low in 2015, the net impact on gas-fired generation and thus, electric sector gas demand when compared to 2014 likely will be minimal.

Exhibit 13. California Hydro Generation



With respect to the remaining portion of the Western hydro generation picture, it is in much better shape than the California portion and should not impact significantly either regional or U.S. gas demand.[10]

Capacity Additions

Finally, while it is unlikely that the addition of new gas-fired capacity will have a significant impact on this summer'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 14 summarizes recent historical capacity additions, as well as the current outlook for capacity additions for the next two years. In addition to gas-fired capacity additions,

[9] For just the first two months of the year California hydro generation was 13 percent above 2014 results for the same period.

[10] Hydro generation in the West, excluding California, in 2014 was about three percent above a 20-year average, while 2013 results were five percent below the 20-year metric. Data for the first two months indicates that 2015 hydro generation for the rest of the West is about 56 percent above 2014 results.

capacity additions for coal-fired units, wind and solar units, which are the three key competitors to gas-fired generation, are noted.

One of the most significant aspects of Exhibit 14 is how dominant gas-fired capacity additions were in 2014, as they represented about 60 percent of the total capacity additions for the industry. This is very different than 2012 when wind capacity additions dominated overall capacity additions for the industry.[11] While in 2015 wind and gas likely will add equivalent amounts of capacity, in 2016 it is expected gas-fired capacity additions will once again be the dominant form of new capacity.

Exhibit 14. New U.S. Generation Capacity

					Projected	
(MW)	**2011**	**2012**	**2013**	**2014**	**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	6,842	6,633	6,210	12,145
Grand Total	**19,010**	**27,394**	**12,340**	**10,965**	**14,940**	**20,602**
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.

With respect to future electric gas demand the most significant of the gas-fired capacity additions is the combined cycle (CCGT) additions noted in Exhibit 14. These units operate at much higher capacity factors (e.g., about 48 percent in 2014) and thus, consume much more gas than the simple cycle peaking units that typically operate at capacity factors of five percent, or less. As noted in Exhibit 14, while annual CCGT capacity additions in 2015 decline from the levels in 2014, in 2016 they are expected to be more than double the annual additions in 2015.

With respect to coal-fired capacity, no new coal plants are expected over the next two years. Probably more significant is the level of retirements of existing coal-fired facilities, which is occurring because of both the implementation of the EPA's MATS regulations and the inability to compete with gas-fired generation.

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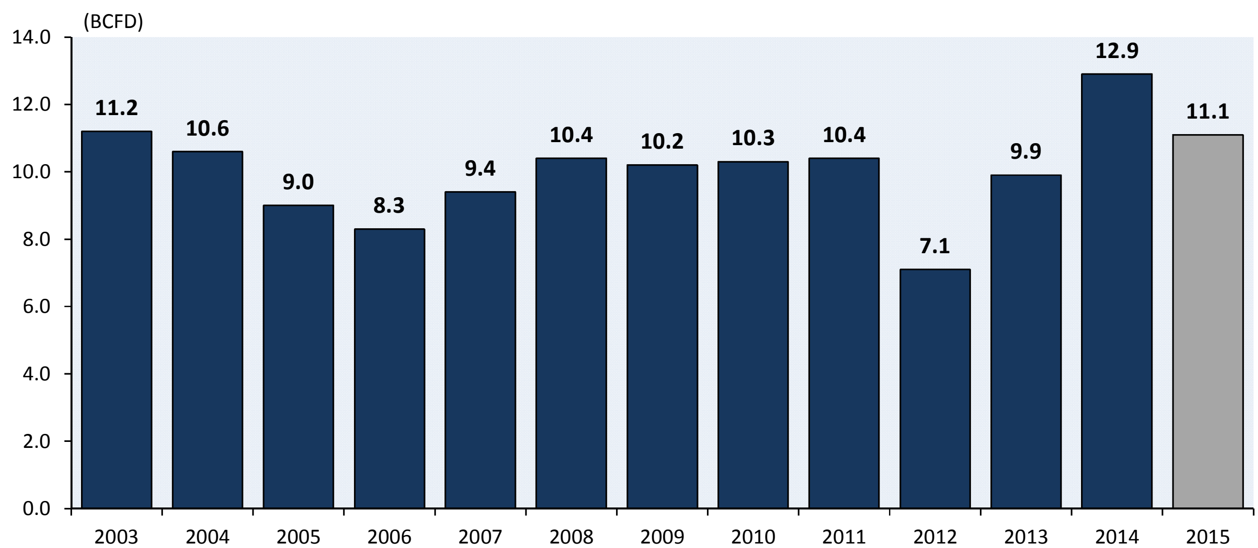
[11] In 2012 wind developers rushed to complete their projects in the fourth quarter in order to qualify for the Federal wind subsidies that were scheduled to expire in December 31, 2012. Subsequently, Congress has reinstated these Federal wind subsidies, but only for a two-year period.

Storage Injections

Probably the most difficult element to project in this assessment of 2015 summer gas demand is the final component of the demand picture, namely 2015 storage injections. While the current outlook is for storage injections this summer to be below last year's record injections for recent times, they still will be about 1.5 BCFD, or 16 percent, higher than the 10-year average prior to 2014 (i.e., see Exhibit 15). Furthermore, with this level of storage injections season-ending (October 31, 2015) storage levels should be approximately 3,840 BCF. That latter figure is, in essence, equal to the average storage level entering the winter season for the last four winters.

Exhibit 15. U.S. Storage Injections



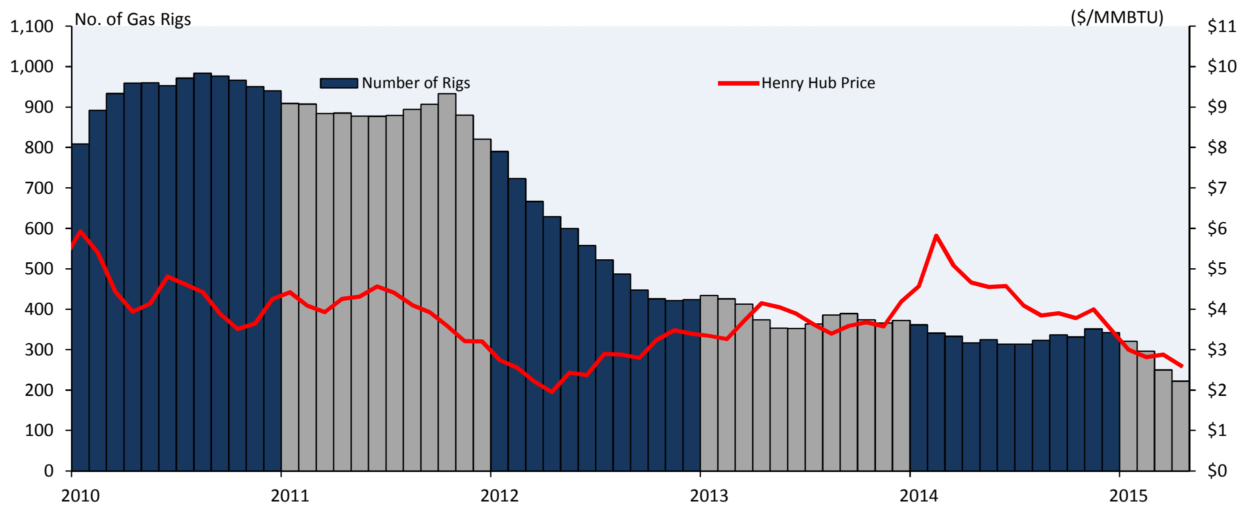
Note: 2015 is estimated.
Source: EIA.

However, there are several factors that could impact this outlook. Key among these is the summer weather and uncertainty over future domestic production levels – both of which are discussed below.

- **<u>Summer Weather</u>:** If the summer weather turns out to be very hot, gas demand within the electric sector could increase about 200 BCF. Thus, there would be less gas to inject into storage. However, if such an event were to occur, it is very likely that gas prices would be affected and this, in turn, would result in less fuel switching within the electric sector. Nevertheless, some portion of the increased peak summer electric sector gas demand likely would come from the projected storage injections for the entire summer.

- **<u>Domestic Production</u>:** There has been a 38 percent decline in gas-directed drilling activity since the recent October 2014 peak for the gas-directed rig count (i.e., see Exhibit 16). While the industry will achieve year-over-year increases in domestic production levels, there already are indications that this sharp decline in drilling activity is having an impact on U.S. production profile. For example, it appears that after recovering from the impact of winter well freeze-offs that domestic production levels have not recovered to their peak December levels.

Exhibit 16. Rig Count for Gas Wells



Note: Blue bars represent the number of gas rigs on even years while gray bars represent odd years.
Source: NGW.

Furthermore, this observation includes the impact of the offshore Keathley Canyon Connector coming online in late April, which to a degree represents a one-off event for the industry.[12] Absent the Keathley Canyon event the differences between current production levels and the prior December peak production levels would be more apparent. In addition, it appears that the associated gas component of domestic production is starting to decline, because of the reduction in U.S. oil drilling activity (i.e., the oil-directed rig count has declined 58 percent from its recent October 2014 peak levels).[13]

As a result there is a concern that on a month-over-month basis U.S. production levels are either flattening or modestly in decline. If this trend materializes during the second part of the summer season, there would be less gas for storage injections. However, as previously noted, the industry likely would compensate, to a degree, and reduce fuel switching within the electric sector.

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[12] The offshore platforms for South Hardin and Lucius are connected to onshore via the Keathley Canyon Connector, which came online in late April (i.e., approximately 0.4 BCFD).

[13] For a complete discussion on associated gas see the attached addendum on this topic.

Absent these uncertainties, Exhibit 17 compares and contrasts the current outlook for season ending (November 1) storage levels with those of prior years.

Exhibit 17. Comparison of Storage Capacity and Season-Ending (November 1) Storage Levels

	Actual									Est.
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Total Working Gas Capacity - Start of Injection Season(1)	3,546	3,593	3,665	3,754	3,925	4,049	4,103	4,265	4,363	4,336
Annual Capacity Additions	47	72	89	171	124	95	162	98	3	10
Total Working Gas Capacity - End of Injection Season	3,593	3,665	3,754	3,925	4,049	4,103	4,265	4,103	4,336	4,346
Storage Level at Start of Winter	3,452	3,567	3,399	3,810	3,847	3,804	3,929	3,804	3,590	3,840
Percent of Capacity	96%	97%	91%	97%	95%	93%	93%	87%	81%	88%

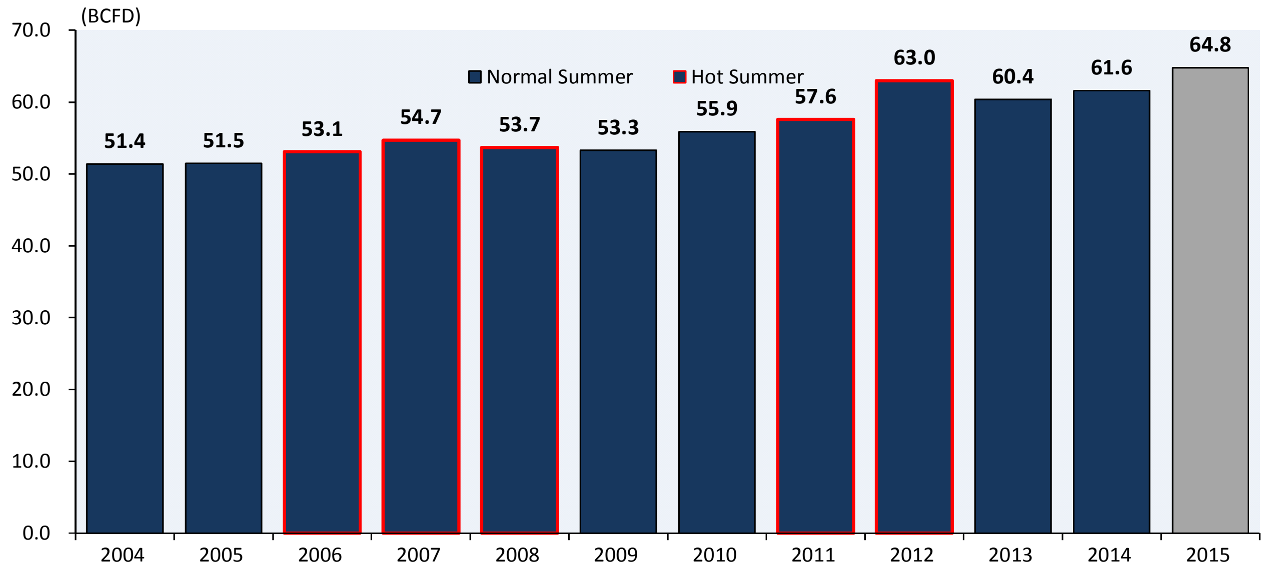
1. Effective maximum usable working capacity.

Conclusions

As illustrated in Exhibit 18 summer gas demand this year should be approximately 3.2 BCFD, or 5.2 percent, greater than demand last summer. Furthermore, gas demand this summer will set a new record, as it will exceed the prior record set in 2012. The key factor behind this new record is structural demand increases within the industrial and electric sectors plus relatively high levels of coal-to-gas fuel switching, whereas the high demand in 2012 primarily was due to high levels of fuel switching and seasonal factors (i.e., a hot summer).

Lastly, storage injections are projected to be about 1.5 BCFD, or 16 percent, higher than a 10-year average when 2014 is excluded. This should result in season ending (October 31, 2015) storage levels being close to the average for the prior four years at this point in time.

Exhibit 18. Summer Natural Gas Demand for All Sectors



Note: 2015 natural gas demand is forecasted.
2005, 2006, 2007, 2010, 2011, and 2012 denote hot summers.

ADDENDUM I:

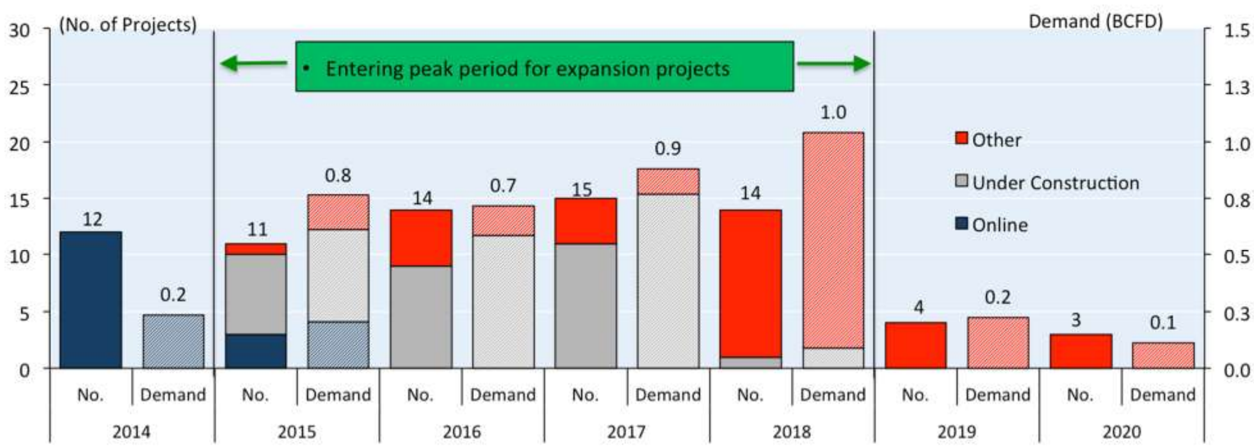
OUTLOOK FOR CAPACITY EXPANSIONS FOR THE INDUSTRIAL SECTOR

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, 13.5 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 0.83 BCFD per annum, or a total of 3.3 BCFD over the four year period, assuming a 100 percent capacity factor. Using a more realistic average 90 percent capacity factor for these projects yields slightly less than 3.0 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 1.0 BCFD at a 100 percent capacity factor, or 0.9 BCFD at a 90 percent capacity factor.

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



1. For period 2010 to 2013, 25 projects came online (0.79 BCFD)
2. For period 2014 to 2020, 73 projects to come online (3.88 BCFD)

Outlook for 2015

With respect to the outlook for 2015, the expected increase in natural gas demand for the industrial sector from the capacity expansion projects will be the combination of the full year impact of the 2014 projects plus mid-year timing of the 2015 projects. The net result is approximately a 0.4 BCFD increase, assuming a 90 percent capacity factor, which is about 65 percent higher than the annual increase that occurred in 2014 – using the same methodology.

With respect to the projects that will impact 2015, 15 projects already are online and an additional seven projects are under construction (i.e., including both 2014 and 2015 projects – see Exhibit Add I-1). With respect to the one project noted in Exhibit Add I-1 in the 'Other' category, there is not any publicly available data on the milestones for this project. As a result, it could be under construction. This lack of data on project milestones for some of the smaller projects or expansions, rather than new projects, is problematic for all the years which include projects in the 'Other' category, particularly in the near-term years.

Outlook by Sector

At present there are 98 industrial sector capacity projects that either already have come online or are projects in various stages of development. The cumulative effect of these projects is to increase industrial sector demand approximately 4.6 BCFD at a 100 percent capacity factor, or about 4.15 BCFD at a 90 percent capacity factor. In general these projects can be divided into three broad categories, namely:

- **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.

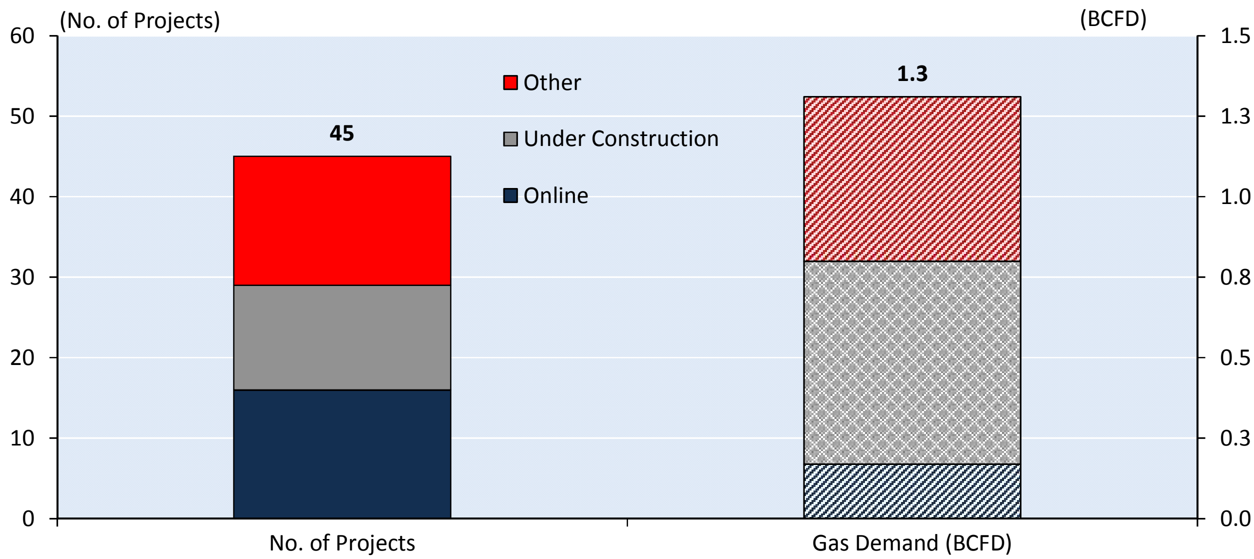
Petrochemical Projects

As illustrated in Exhibit Add I-2, there are 45 planned petrochemical projects, which on a cumulative basis would increase industrial sector gas demand about 1.3 BCFD. Of these projects 35 percent already are online and another 33 percent are under construction. With respect to the remaining 15, or 32 percent, of the petrochemical projects, five of them are expansion projects, while two of the new facilities either already have, or have filed for, an air permit. For the remaining eight projects there is some uncertainty, as a final investment decision (FID) has been made for some, but not all of these projects. Lastly, as might be expected, the vast majority (i.e., 87 percent) are located along the Gulf Coast in Texas and Louisiana.

Methanol and Fertilizer Projects

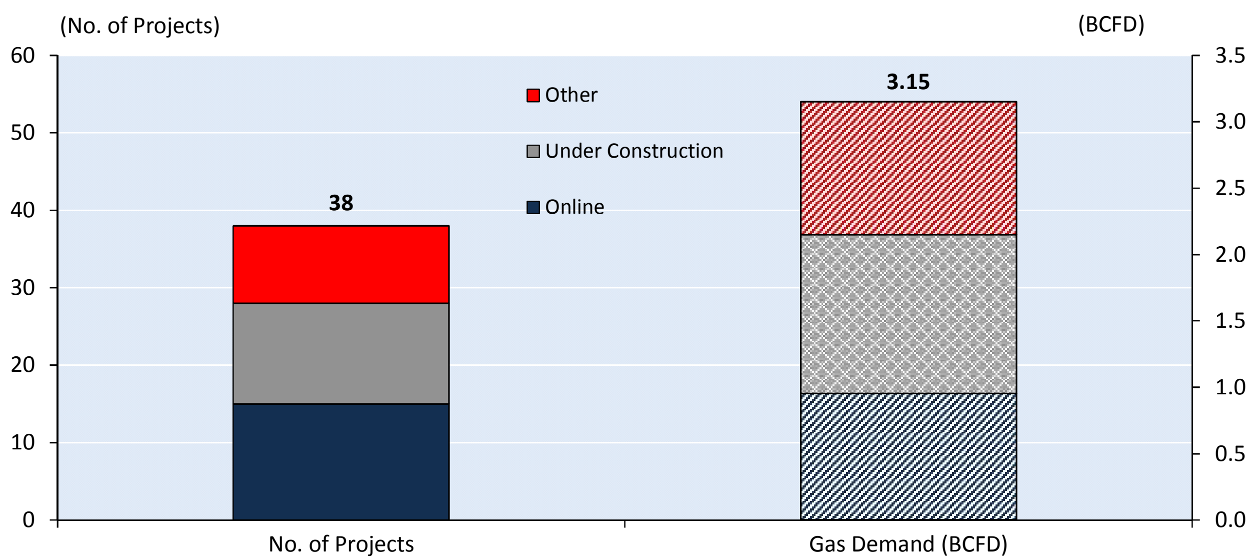
The category of projects that has the greatest impact in industrial sector gas demand – by far – is the methanol and fertilizer projects. As illustrated in Exhibit Add I-3, there are 38 projects in this category which would increase industrial sector demand about 3.15 BCFD at a 100 percent capacity factor. Of these 38 projects, 40 percent already are online,

Exhibit Add I-2. Petrochemical Projects



while another 34 percent are under construction. Of the remaining 10, or 26 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, 66 percent of them are still located in Texas and Louisiana.

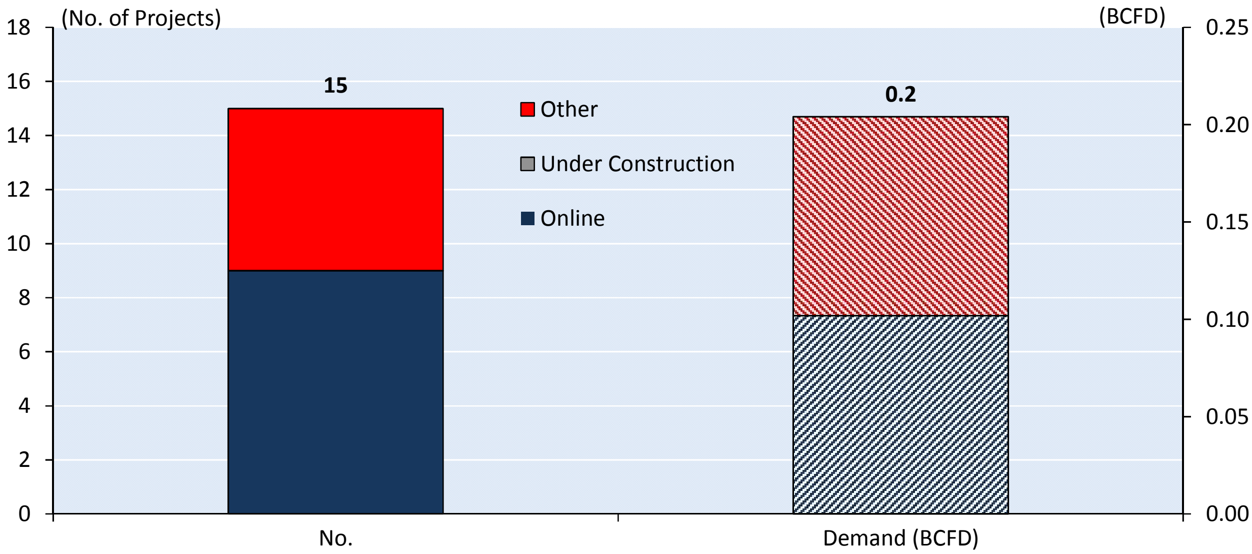
Exhibit Add I-3. Methanol and Fertilizer Projects



Other Projects

The category 'Other' projects consists primarily of steel and paper and pulp facilities converting to natural gas for energy. There are only 15 projects in this category and their cumulative impact on industrial sector gas demand is only 0.2 BCFD (i.e., see Exhibit Add I-4). Lastly, 60 percent of these projects already are online.

Exhibit Add I-4. Other Projects



Ownership

As a further point of perspective concerning these 98 projects, approximately 25 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.

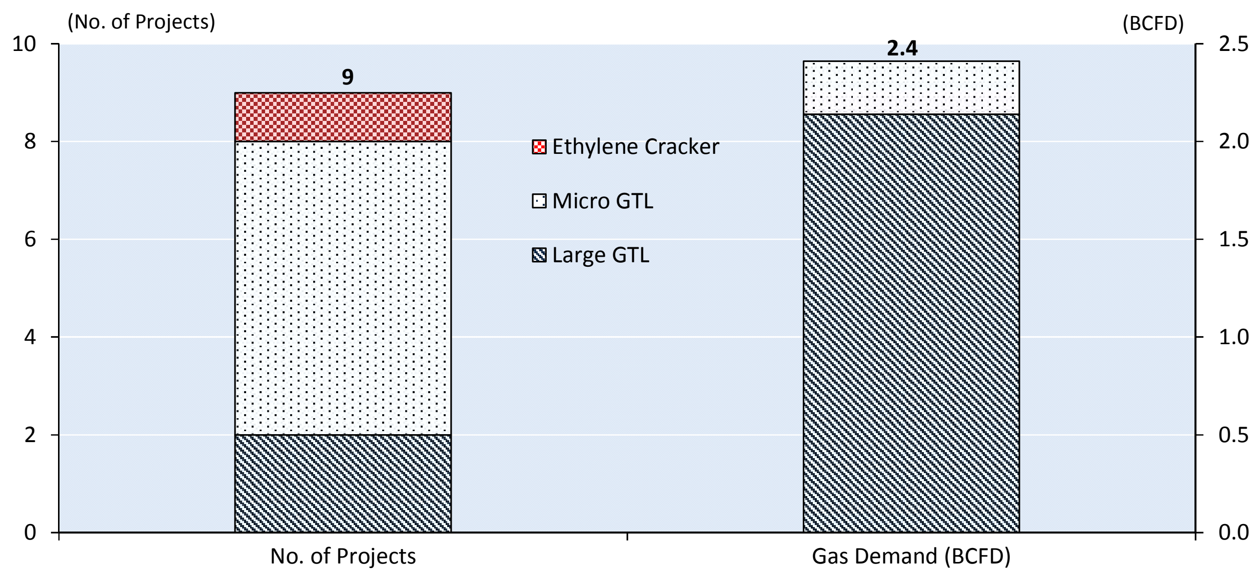
Project Cancellations

Every year there are both additions and deletions to this list of capacity expansion projects within the industrial sector. Typically additions occur because of new entrants, while deletions often occur because of competition between projects or the inability of smaller developers to secure financing. The fertilizer segment is a classic example of competition causing projects to be deleted, as initially a farmer cooperative will propose a local, small scale fertilizer project and then later a large urea/ammonia producer will propose a world scale facility to serve the same market. As a result, the smaller facility, which cannot provide the economies of scale, withdraws its proposed project.

More recently the approximate 50 percent decline in oil prices has caused the developers of the proposed gas-to-liquids (GTL) projects to either withdraw, or delay, their projects. As illustrated in Exhibit Add I-5, this phenomenon has impacted two very large GTL projects, as well as six micro-GTL projects.[14] In the case of the larger GTL projects they typically need at least a 20:1 oil-to-gas to be viable, whereas the smaller micro-GTL projects appear not to be able to secure financing.

In addition, the Appalachian Shale Cracker Enterprise in Parkersburg, WA, which was proposed by the Brazilian Obedrecht, has been delayed or potentially cancelled. There are two potential factors driving the change in the status of this project, namely the decline in oil prices, which has impaired margins, and the huge corruption scandal in Brazil. This elimination of the GTL projects and the ethylene cracker does have a significant impact on the potential increase in industrial sector demand (i.e., about 2.4 BCFD). However, because of the general uncertainty concerning GTL projects, not all of the identified projects noted in Exhibit I-5 were included in prior lists of industrial expansion projects.

Exhibit Add I-5. Cancelled Projects



[14] Excluded from this assessment are proposed micro-GTL projects that primarily rely on landfill gas, such as the Velocys project in Oklahoma City, and the proposed Primus Green Energy project to convert flared gas in North Dakota.

ADDENDUM II:

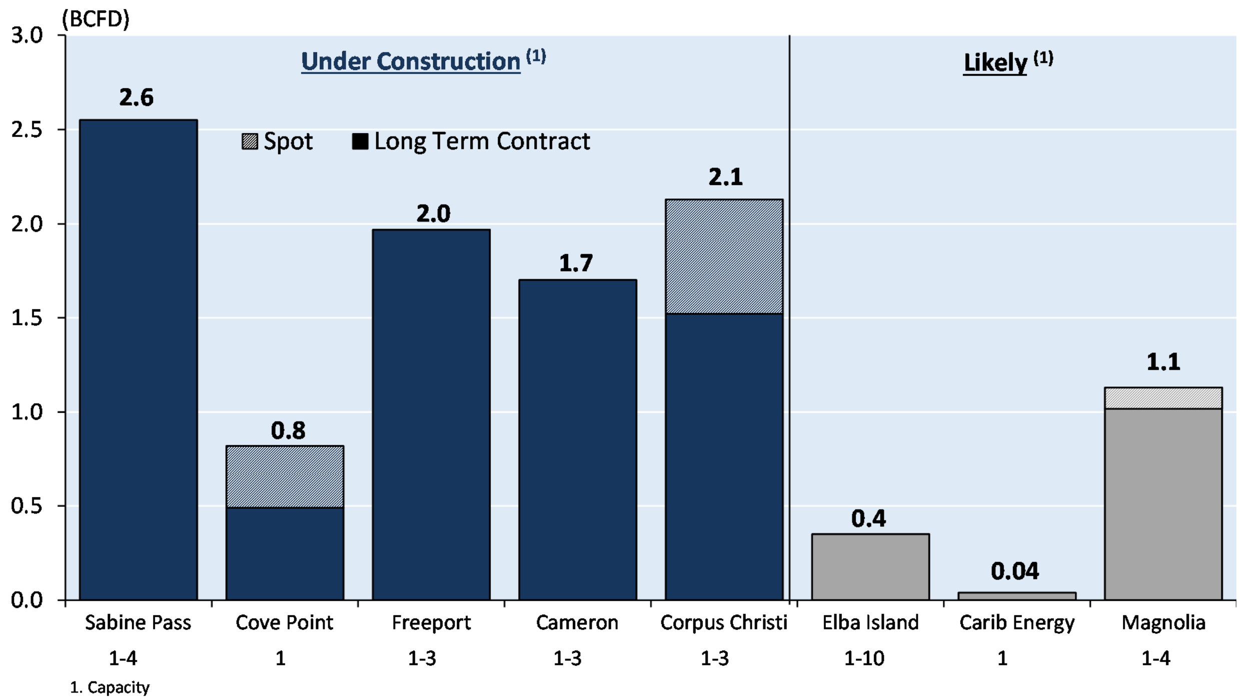
U.S. LNG EXPORTS

U.S. LNG Exports

Overview

The clarity concerning the outlook for U.S. LNG exports has increased significantly over the last year, although there is still some uncertainty and variation in views among industry observers. As noted below in Exhibit Add II-1, there currently are five large U.S. liquefaction terminals (i.e., 15 trains eventually) under construction, with a total capacity of 9.2 BCFD. In addition, there are three smaller projects that likely will proceed (i.e., 1.5 BCFD).[1] The construction of all the trains associated with these projects likely will take five years. As a result, U.S. LNG exports will ramp up steadily between year-end 2015 and 2020 to approximately 8.9 BCFD, assuming an average 85 percent capacity factor and the sale of uncommitted volumes in the spot LNG market.

Exhibit Add II-1. First Wave of U.S. LNG Projects



First Wave

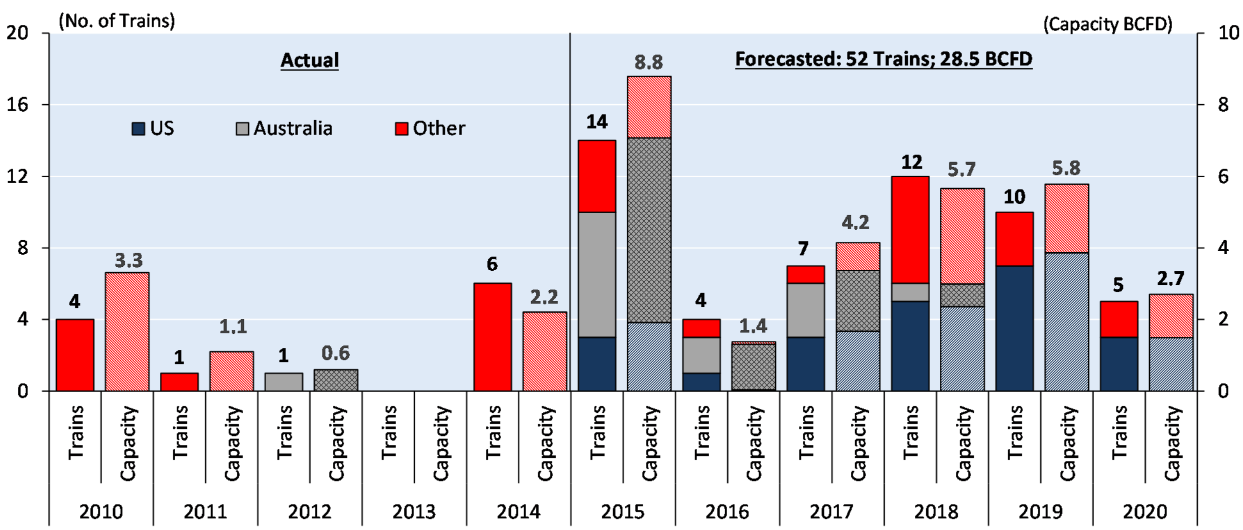
The U.S. liquefaction facilities identified in Exhibit Add II-1 represent the first wave of U.S. LNG projects that will enter the global market by 2020. These projects will be joined by other liquefaction projects (i.e., 30 trains; 17.1 BCFD) from other countries. This includes six projects (i.e., 13 trains; 8.8 BCFD) from Australia. The net effect of

[1] Most of these smaller projects can proceed with just FTA permits, as their primary customer base is the Caribbean and Latin American markets, as well as their own portfolios.

this surge in new liquefaction will be to add approximately 28.5 BCFD of new capacity which at an 85 percent capacity factor represents approximately a 70 percent increase in global supply from 2014 consumption levels (i.e., an average 9.1 percent per annum growth rate). As a result, the global LNG market going forward likely will be in an excess supply position, at least through 2020, which will inhibit significantly any other new entrants.

Exhibit Add II-2 both summarizes the new global LNG capacity to be added between now and 2020, and compares this outlook to the results over the last five years (i.e., 12 trains, 7.2 BCFD). Concerning the latter, the global capacity being added over the 2015 to 2020 period will be about four times that amount.

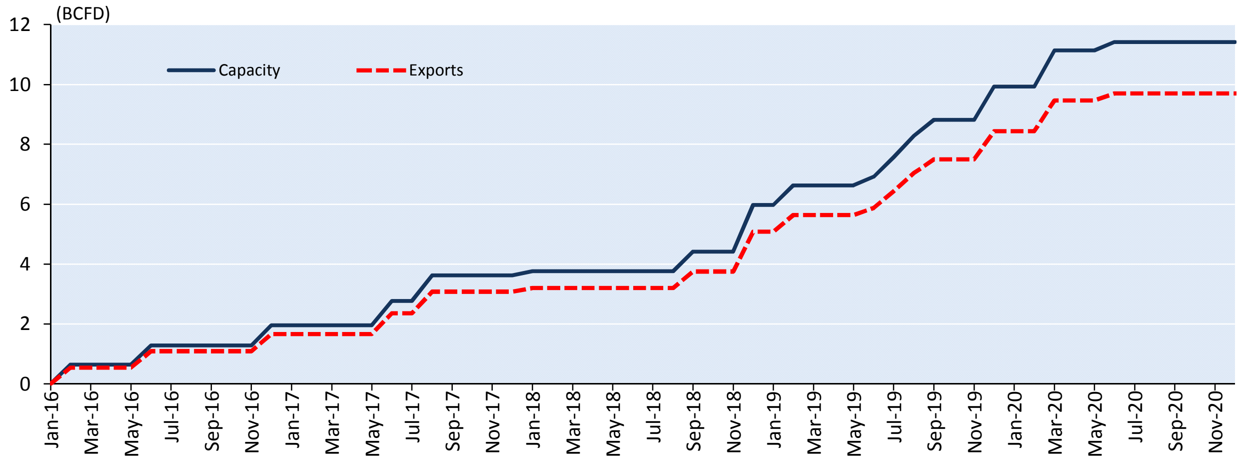
Exhibit Add II-2. Annual Additions of Liquefaction Capacity



Once this initial group, or first wave, of capacity is absorbed by the global LNG market, there will be an opportunity for a second wave of global LNG expansion, which likely will include some U.S. LNG projects. As a point of perspective, U.S. LNG projects represent approximately 40 percent of the total capacity being added in this first wave. This is a significant accomplishment that likely will not be repeated in the second wave of LNG capacity additions, because of the significant change in the competitive playing field, which has occurred because of the sharp decline in oil prices.

With respect to the outlook for U.S. LNG exports, Exhibit Add II-3 summarizes the current outlook through 2020, which has U.S. LNG exports reaching approximately 8.9 BCFD, assuming an average 85 percent capacity factor. With respect to the outlook post-2020 there is significantly more uncertainty.

Exhibit Add II-3. Timeline for U.S. LNG Capacity and Exports[(1),(2),(3)]



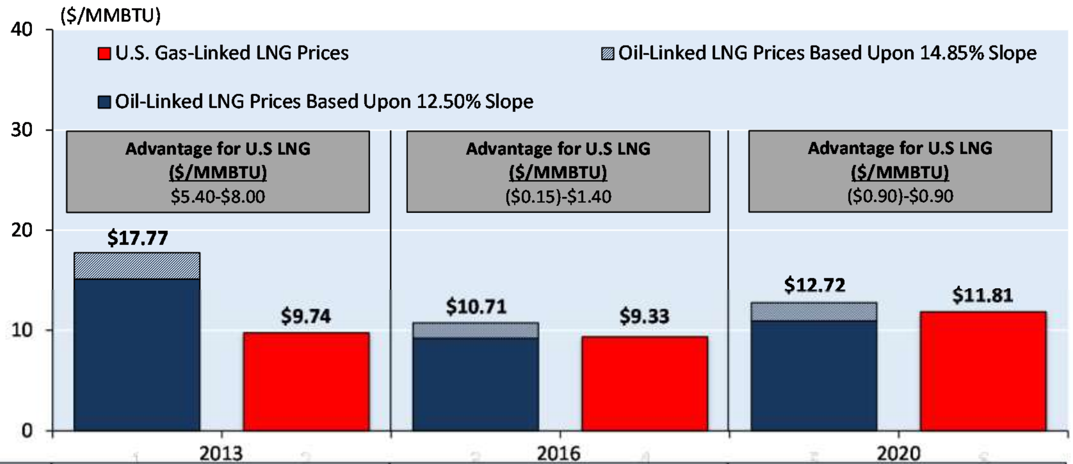
1. Use an 85% capacity factor for actual exports.
2. Expansion of Panama Canal occurs in early 2016.
3. Nicaragua Canal scheduled online 2020.

Second Wave

As noted above, post-2020 the competitive situation for U.S. LNG projects likely will be significantly different than that which existed prior to 2014. This phenomenon is illustrated in Exhibit Add II-4, which compares and contrasts the traditional oil-linked LNG contracts with the U.S. gas-linked contracts for deliveries to China, assuming the expanded Panama Canal, which is slated to be completed in early 2016. With respect to the oil-linked contracts, two alternatives are noted namely (1) the legacy contract terms that have used a slope of approximately 14.85 percent and (2) the more recent trend in the industry of using a slope of approximately 12.5 percent.

As noted in Exhibit Add II-4, in 2013 oil-linked contracts resulted in a delivered LNG price in the range of $15 to $18 per MMBTU, while U.S. deliveries at that time in theory would have been just under $10 per MMBTU. This resulted in approximately a $5.40 to $8.00 per MMBTU advantage for U.S. LNG projects. However, with the decline in oil prices this advantage has declined substantially. For example, in 2016 the advantage for U.S. LNG shipments will decline to between a loss of about $0.15 per MMBTU (i.e., a disadvantage) to an advantage of only $1.40 per MMBTU. Furthermore, based upon the current outlook for oil and gas prices in 2020 the competitive situation for U.S. LNG shipments likely will range from a loss, or disadvantage, of $0.90 per MMBTU to an advantage of only $0.90 per MMBTU.

Exhibit Add II-4. Oil-Linked vs. Gas-Linked LNG Prices (Delivered to China)



	2013	2016	2020
Brent Oil Prices ($/BBL)	$111.50	$64.00	$77.50
Henry Hub Gas Prices ($/MMBTU)	$3.70	$3.35	$5.50

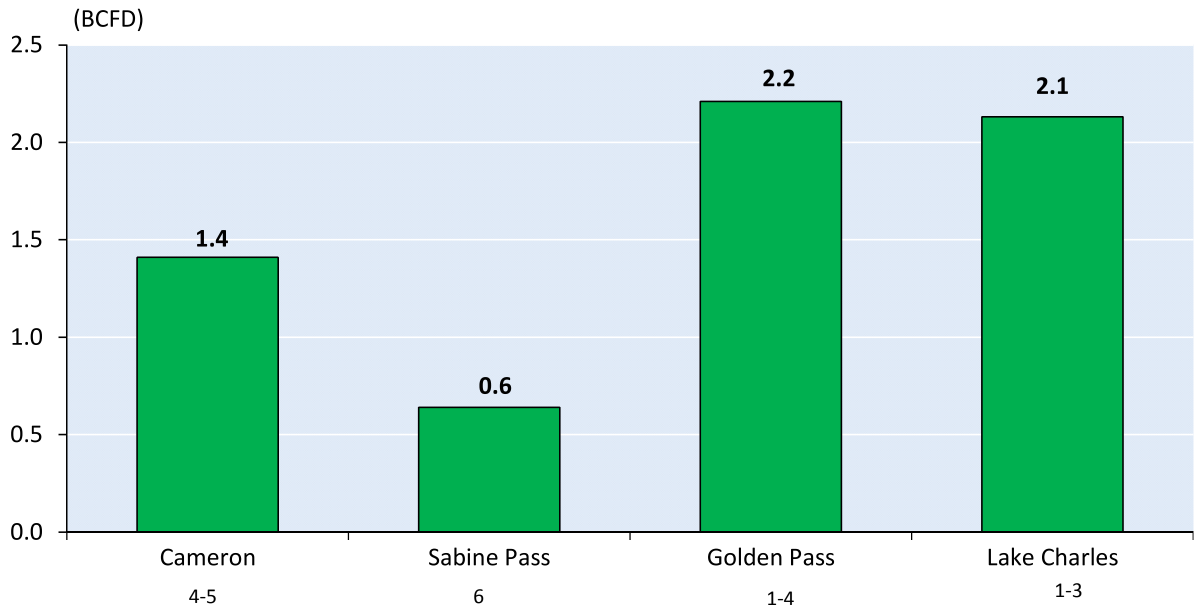
At present there is every indication that post-2020 world competition within the global LNG market for incremental demand will be very keen, as additional U.S. L-48 projects will have to compete on nearly equal pricing terms with (1) very viable projects in Mozambique and Tanzania; (2) expansions of existing projects in Australia; (3) new projects in Canada; (4) an almost certain project in Papua New Guinea; (5) several projects in Russia; and (6) the Alaskan project.

Exhibit Add II-5 highlights what appears to be the most likely U.S. LNG projects for the post-2020, or second wave, of capacity additions for the global LNG market. All the U.S. liquefaction projects noted in Exhibit Add II-5 are either expansions of existing L-48 projects or brownfield projects.

With respect to the remaining 25 proposed L-48 liquefaction projects, which are summarized in Exhibit Add II-6, the prospects of these projects being completed are not very promising. As an added point of perspective, most of these 25 projects are greenfield expansions, which means their per unit capital costs likely will be higher.

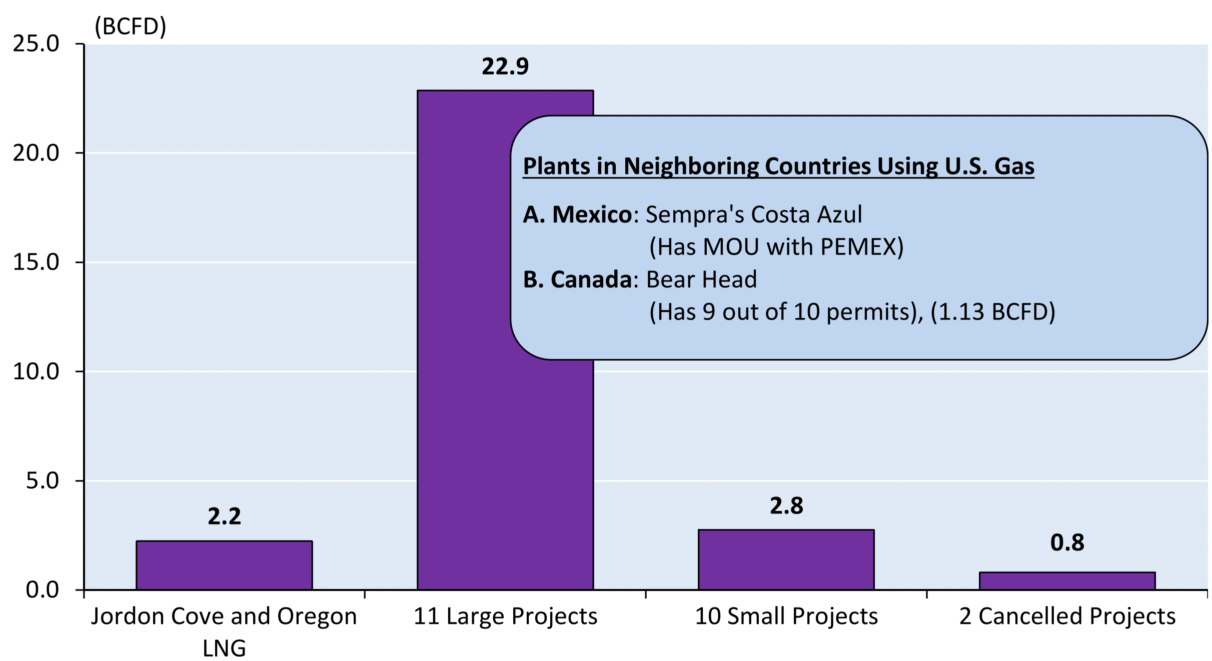
Lastly, there are two proposed liquefaction projects in Canada and Mexico that likely would rely on U.S. natural gas as feedstock. While both of these projects have the potential to be completed, Canada's Bear Head to date has accomplished the most project milestones.

Exhibit Add II-5. Potential Second Wave L-48 Liquefaction Projects (10 Trains; 6.3 BCFD)[(1)]



1. Excludes Jordon Cove (0.96 BCFD) and Oregon LNG (1.28 BCFD).

Exhibit II-6. Remaining Proposed L-48 Liquefaction Projects (28.7 BCFD)

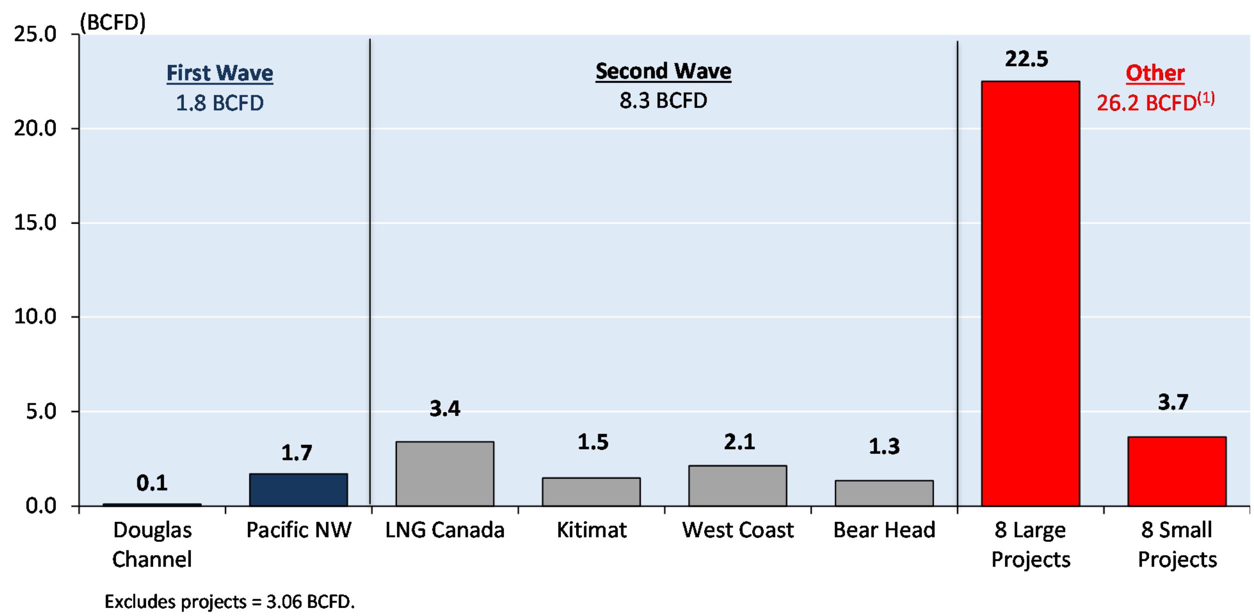


Canada

Prospects for Canadian liquefaction projects have declined, despite Canada finally revising its tax code for LNG projects to be on a par with most of the rest of the world.

Exhibit Add II-7 summarizes the current outlook for proposed Canadian liquefaction projects. As indicated in the first wave (i.e., pre-2020) it appears that only two Canadian projects will proceed and one of these is a very small barge-mounted project. For the second wave there are four Canadian LNG projects that appear to have an opportunity. With respect to the remaining 16 proposed Canadian projects the outlook at this time is not very positive.

Exhibit Add II-7. Proposed Canadian Liquefaction Projects



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’.

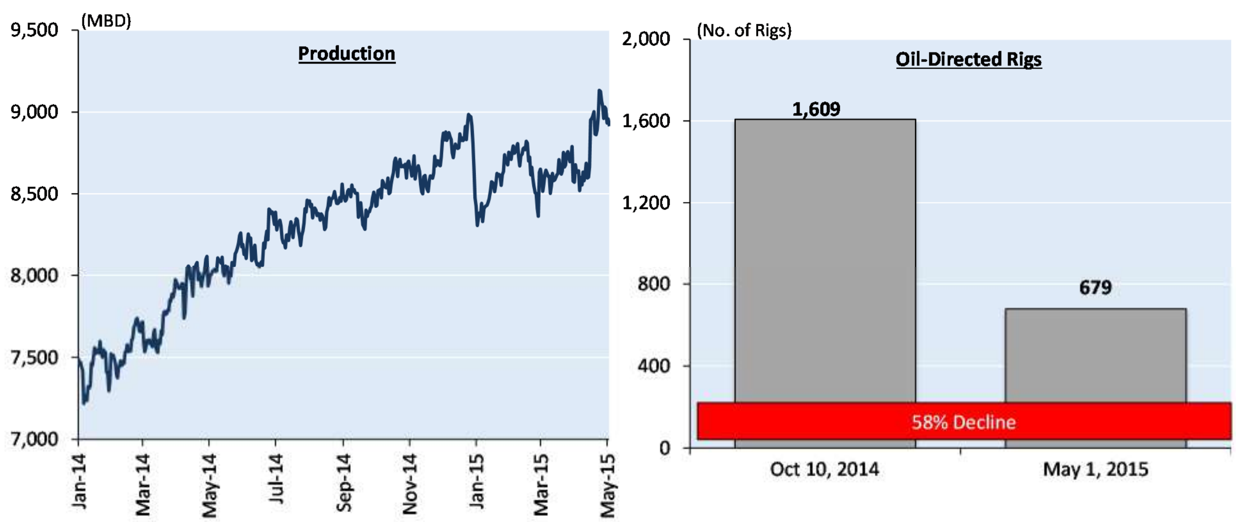
Realizing this lack of uniformity in the definition of associated gas, this addendum attempts to assess separately most of the major components of what might be included in the definition of associated gas. In this manner each reader can assemble the various components into the definition that is appropriate 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 10 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

Since associated gas production, for the most part, is directly connected to oil production, 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[16] 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

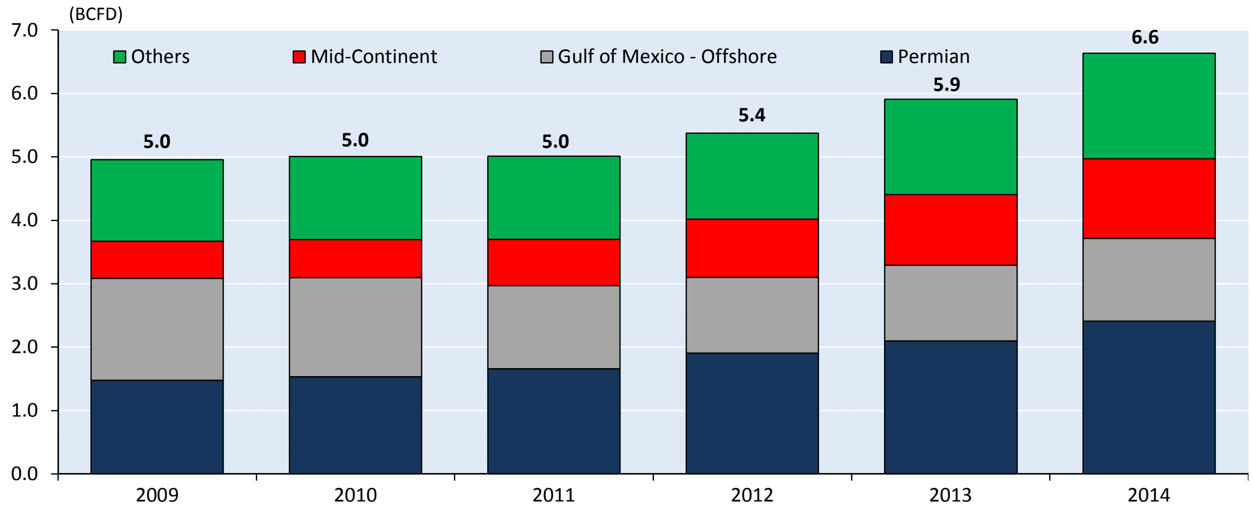


Associated Gas (Traditional Definition)

While there are some unique attributes for the assessment of associated gas production, this lack of growth 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.

[16] 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)



Prior to 2009, associated gas production had been in decline, while during the 2009 to 2011 period it was relatively flat. However, since 2011 associated gas production has increased 32 percent (i.e., a 7.3 percent per annum growth rate), as a result of the strong growth in oil production during this period.

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 20 and 19 percent, respectively.

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 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

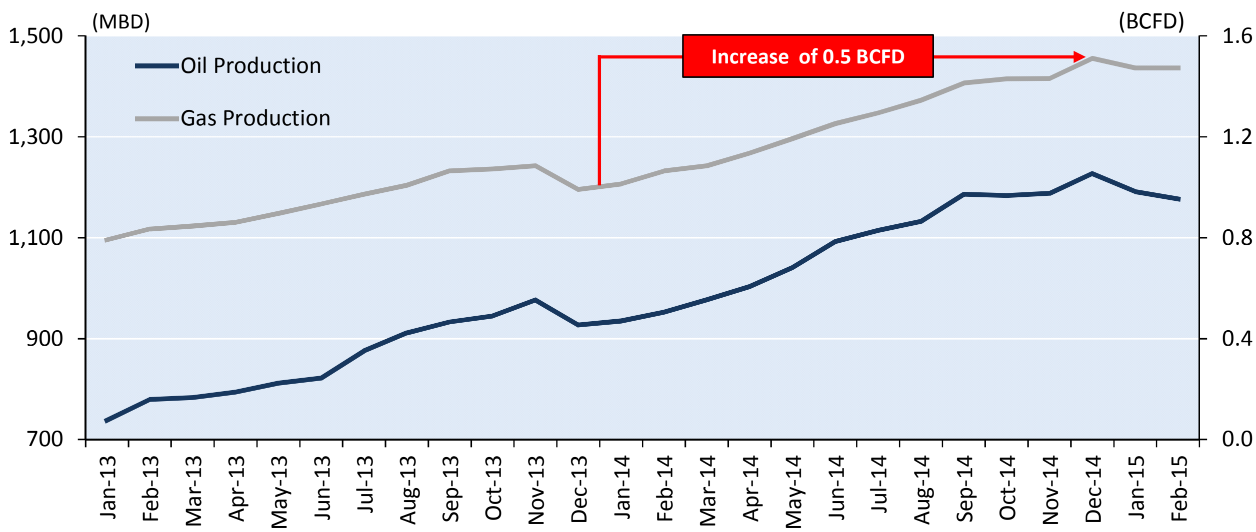
Among the most significant additional components that some observers include in the definition of associated gas, are (1) the Bakken shale/tight oil play; (2) the Eagle Ford shale play; and (3) the Permian basin. Each of these is discussed separately in the material below. The combination of the gas production for these three potential components currently represents about 15 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 17 percent of total production, when flared gas is included. Also, while for most plays there is a relatively close correlation between oil production and gas production, at the present time this is not the case for the Bakken play, because of the steady implementation of 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.[17] The enforcement of these regulations at the beginning of this year resulted in five producers shutting in 30 wells (i.e., approximately 3 MBD).[18]

Exhibit Add III-3 summarizes both monthly oil and gas production for North Dakota. As illustrated, while oil production declined in January and February (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 through about 2020.

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



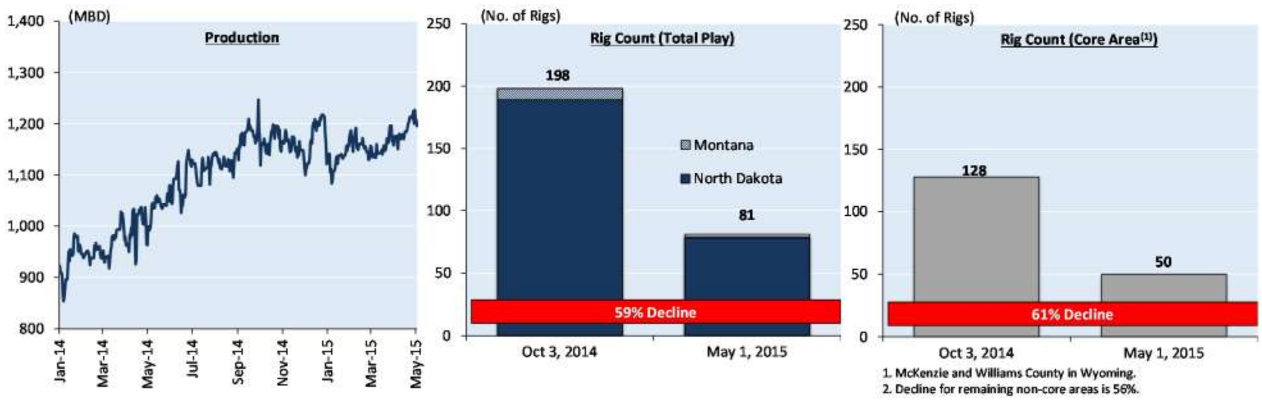
Note: February 2015 is preliminary.
Source: ND State Industrial Commission.

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

[17] 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.
[18] MBD is thousand barrels per day.

due to a 60 percent decline in drilling activity since October. Additive to this decline in drilling activity is the deferment of the completion of some wells that already have been drilled.

Exhibit Add III-4. Bakken Production and Rig Count



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. This means there will not be a direct correlation between the decline in drilling activity and the change in oil production. However, more recently there have been significant declines in both the core and non-core areas.[19]

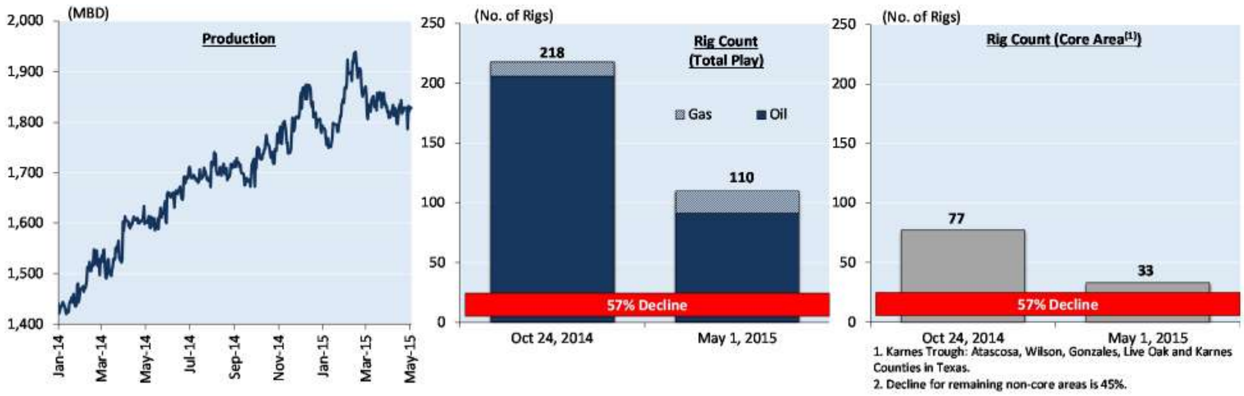
Finally, with respect to gas production for the Bakken play it likely will either increase or at least stay flat, as Bakken oil production starts to decline, because of the implementation of the anti-flaring regulations. For example, the full implementation of the current anti-flaring regulations would increase Bakken gas production approximately 0.25 BCFD (i.e., from 1.47 to 1.72 BCFD).

Eagle Ford

For the total Eagle Ford shale play dry natural gas represents about 30 percent of total 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 57 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).

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

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 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.[20] 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 two factors, namely (1) a significant decline in drilling activity, which by itself would lead to declines in associated gas and (2) 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.

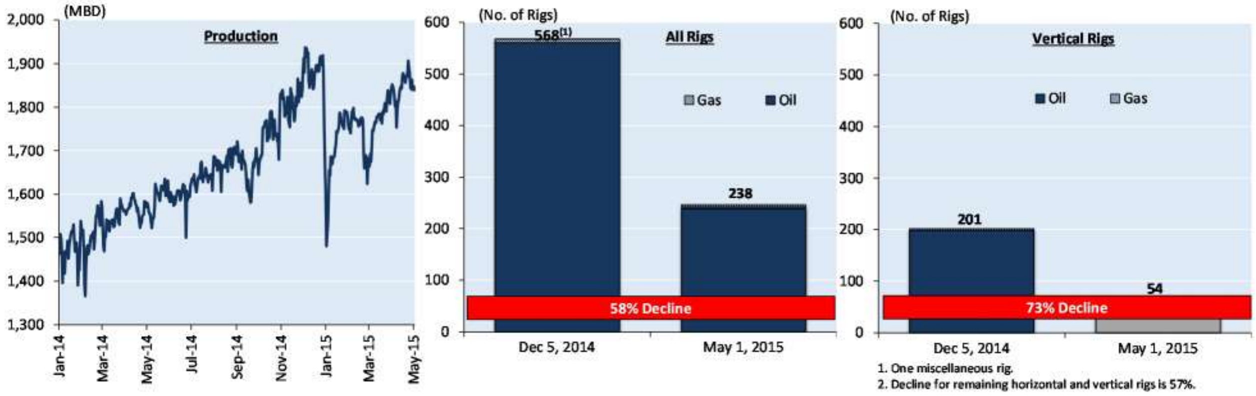
Permian Basin

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 58 percent since the December peak for the basin.

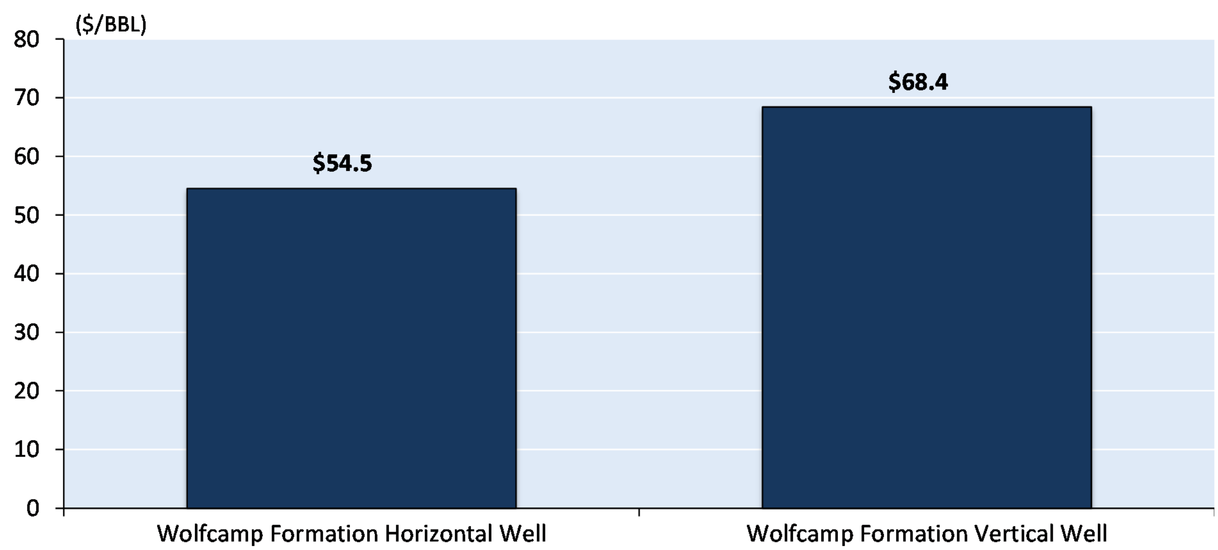
[20] "IHS: Eagle Ford completions pending", *Oil & Gas Journal*, April 20, 2015, p. 28.

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., 50 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. Exhibit Add III-7 provides a generalized summary of the difference in well economics for these two types of wells. 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.

Exhibit Add III-7. Comparison of Permian Basin Well Economics



1. Breakeven well economies for 10% B/T ROR.
Source: "Operators Just Scratching Surface in Assessing Permian's Tight Oil Bounty," *Natural Gas Week,* April 13, 2015, supplement.

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-8.

Exhibit Add III-8. Major Segments for the Permian Basins(1)

Segments or Plays	Oil Production (MBD) Dec 5, 2014 Peak	May, 2015 Peak	Difference	2014 Dry Gas Production Amount (BCFD)	Percent of Total
Wolfcamp/Bone Spring Shale Plays	0.470	0.468	(0.002)	1.35	28%
Sprayberry Trend	0.531	0.521	(0.010)	1.09	23%
Legacy Associated Gas	0.928	0.870	(0.058)	1.33	28%
Non-Associated Gas	0.008	0.007	(0.001)	1.08	21%
Total Permian Basin	**1.936**	**1.867**	**(0.069)**	**4.77**	**100%**

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

With respect to its Legacy Associated Gas and Sprayberry segments, which represent 51 percent of the Permian basin's gas production (i.e., 74 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 2.43 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. 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 approximately May 2015, primarily because of the overall decline in drilling activity. Exhibit Add III-9 provides an overview of this assessment by individual category. As noted in Exhibit Add III-9, 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 21 percent.

Exhibit Add III-9. Near-Term Outlook for Associated Gas (Broad Definition)

Category	2014 Production (BCFD)	Imponderable	Outlook for 2015
Traditional Associated Gas			
• Permian			
o Sprayberry	1.09	-	Flat to declining
o Other Associated	1.32	-	Declining.
• Offshore	1.30	-	Declining.[(1)]
• Mid-Continent	1.26	-	Declining.
• All Others	1.67	-	Declining.
Subtotal	6.64	-	Overall net decline.
Bakken	1.26	Implementation of anti-flaring regulations.	Increasing, modestly.
Eagle Ford	4.21	Timing for large inventory of uncompleted wells.	Modest decline to modest increase.
Permian Basin	2.35	-	Modest decline, with flat shales production offset by declines for non-associated gas.
Total	**14.46**		**Declining, albeit modestly.**

(1) Decline is from May production levels, which include the Keathley Canyon platforms coming online.

Appendix

Exhibit A-1. Natural Gas Consumption (BCF)

	Annual							
	2008	2009	2010	2011	2012	2013	2014	2015
Residential	4,890	4,777	4,783	4,715	4,149	4,913	5,073	4,993
Commercial	3,153	3,119	3,102	3,155	2,895	3,279	3,460	3,443
Industrial	6,662	6,168	6,825	6,995	7,227	7,414	7,655	7,791
Electric	6,668	6,871	7,388	7,574	9,112	8,152	8,150	8,955
Other	1,868	1,946	1,962	2,010	2,127	2,337	2,447	2,556
Transport	26	27	29	30	30	34	33	33
Total	**23,267**	**22,908**	**24,089**	**24,479**	**25,540**	**26,129**	**26,818**	**27,771**

	Summer (April-October)							
	2008	2009	2010	2011	2012	2013	2014	2015
Residential	1,327	1,333	1,182	1,254	1,138	1,251	1,233	1,234
Commercial	1,138	1,136	1,071	1,148	1,101	1,171	1,192	1,194
Industrial	3,679	3,396	3,770	3,884	4,062	4,108	4,241	4,432
Electric	4,303	4,454	4,844	4,911	5,964	5,097	5,142	5,567
Other	1,025	1,072	1,083	1,117	1,200	1,289	1,353	1,424
Transport	14	16	17	17	18	19	19	19
Total	**11,486**	**11,407**	**11,967**	**12,331**	**13,483**	**12,935**	**13,180**	**13,871**

Note: 2015 natural gas consumption is forecasted.

Source: EIA and EVA.

Exhibit A-2. Industrial Production Growth Rate

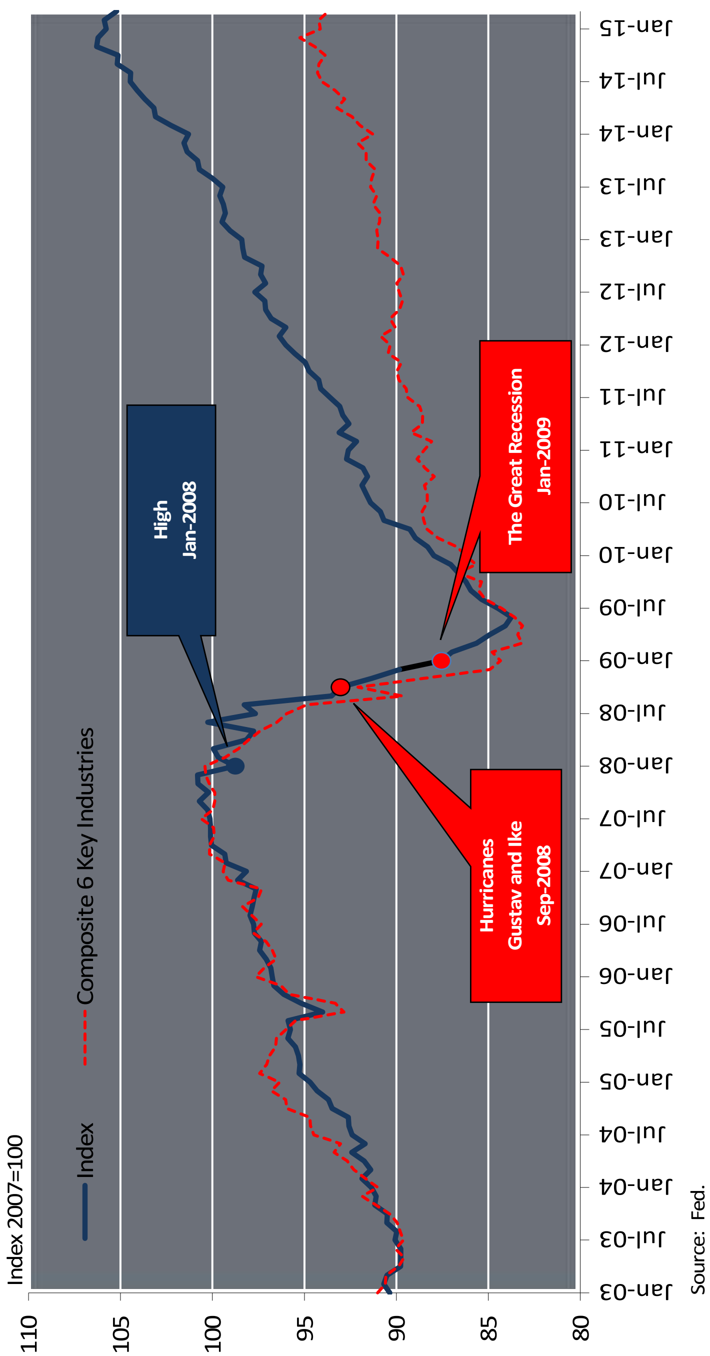
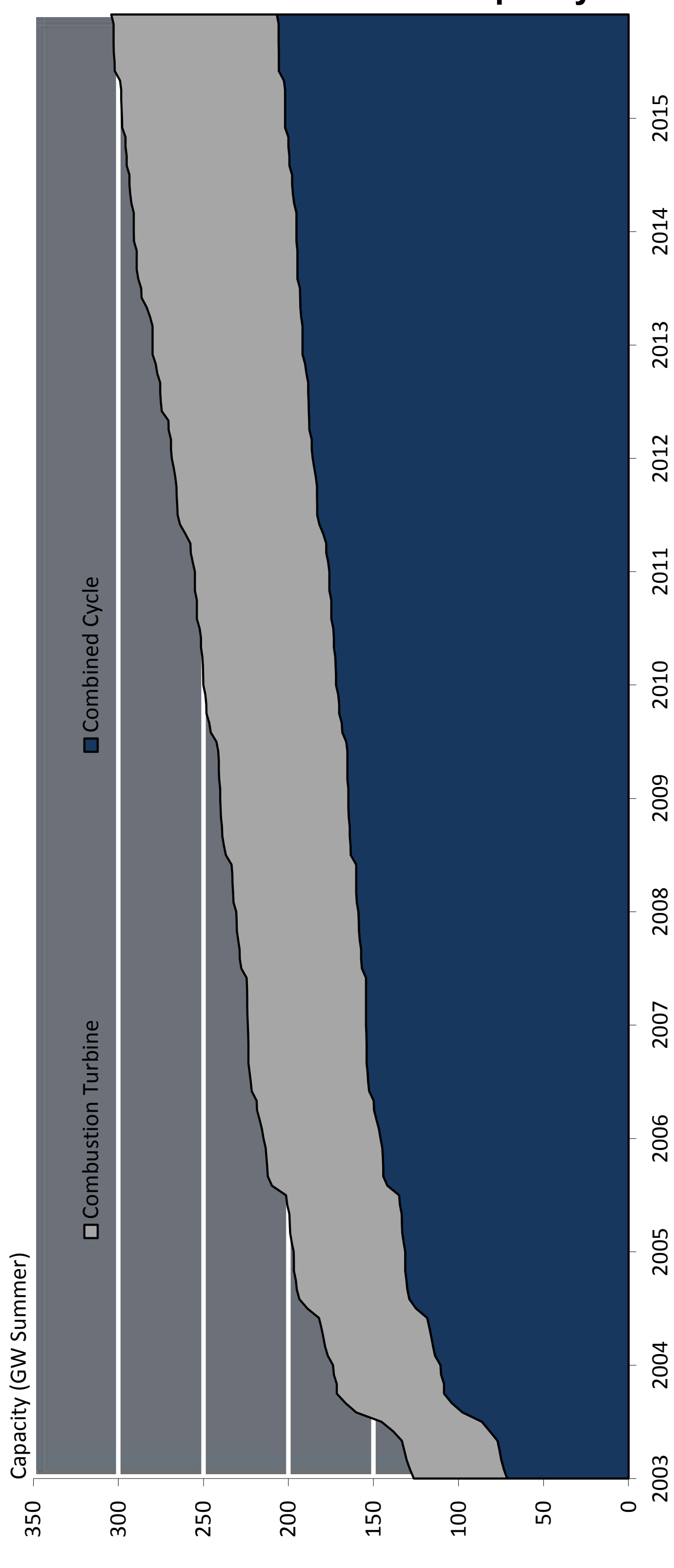


Exhibit A-3. New Gas-Fired Capacity



Source: EIA and EVA.

Exhibit A-4. Annual Additions of Gas-Fired Capacity (2003-2014)

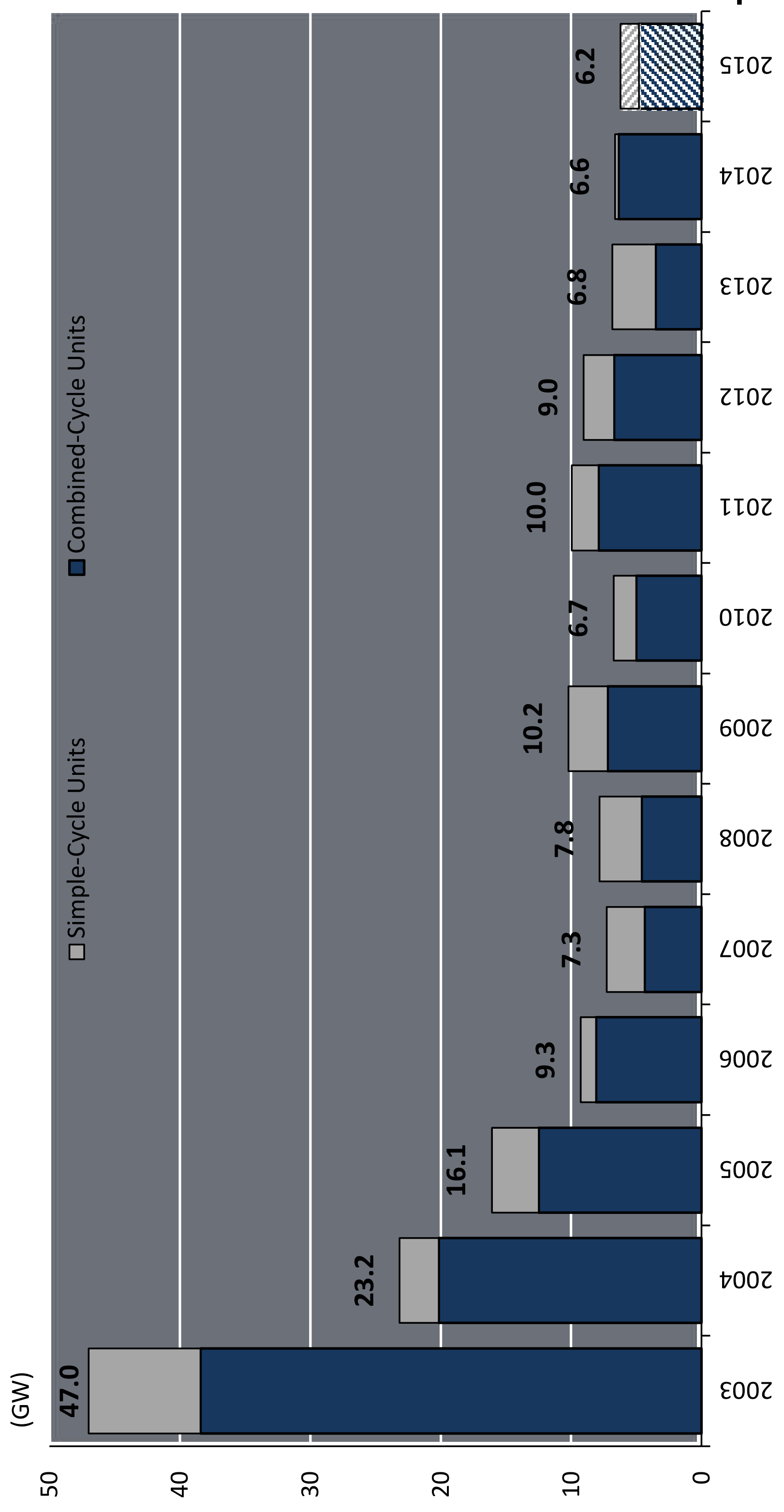


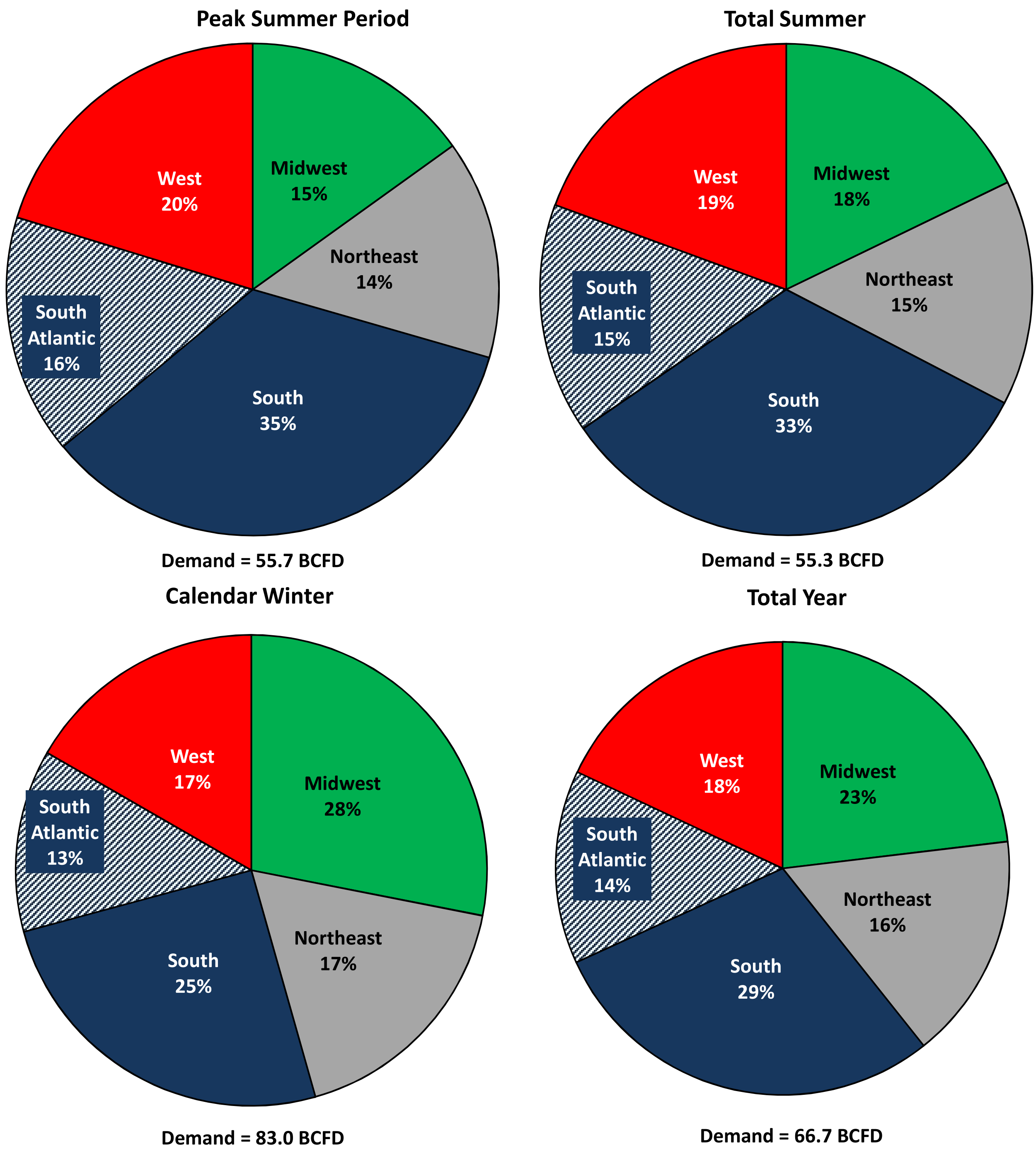
Exhibit A-5. Performance Characteristics Of Natural Gas Combined Cycle Units By Region

	Weighted Average Capacity Factor									
Census Region	**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%	45.8%	42.7%
Middle Atlantic	37.7%	42.0%	33.9%	34.1%	42.7%	46.0%	50.6%	59.7%	55.5%	57.8%
East North Central	27.3%	25.3%	20.0%	14.2%	16.3%	21.9%	30.7%	48.0%	33.6%	34.2%
West North Central	23.2%	19.6%	24.9%	20.2%	12.5%	17.5%	15.3%	26.5%	21.7%	16.8%
South Atlantic w/o Florida	30.0%	31.4%	26.6%	23.8%	36.1%	33.9%	44.3%	53.7%	58.4%	57.8%
Florida	65.6%	67.8%	54.0%	56.5%	54.3%	59.7%	59.5%	63.4%	61.6%	62.5%
South Atlantic	51.2%	53.5%	42.1%	42.4%	47.2%	48.6%	53.2%	59.0%	60.1%	60.4%
East South Central	31.0%	36.2%	30.7%	28.0%	38.1%	43.8%	49.7%	59.3%	49.1%	53.1%
West South Central w/o ERCOT	51.4%	57.5%	34.1%	34.5%	37.3%	36.6%	37.5%	48.0%	36.2%	36.6%
ERCOT	96.2%	96.3%	51.6%	49.5%	45.9%	45.1%	45.6%	50.0%	48.6%	50.7%
West South Central	75.5%	78.2%	43.8%	42.8%	42.1%	41.4%	42.1%	49.2%	43.3%	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%	49.1%	44.6%
California	64.8%	78.1%	61.4%	61.4%	52.3%	52.8%	40.0%	55.1%	56.1%	56.6%
Pacific Contiguous	67.9%	75.1%	58.3%	58.3%	52.5%	52.3%	36.1%	49.5%	54.3%	53.6%
TOTAL U.S.	**55.0%**	**58.0%**	**41.3%**	**40.0%**	**41.7%**	**43.2%**	**43.7%**	**51.8%**	**48.3%**	**48.8%**

	Weighted Average Heat Rate (Btu/kWh)									
Census Region	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
New England	7,416	7,410	7,467	7,458	7,462	7,489	7,438	7,492	7,518	7,556
Middle Atlantic	7,574	7,591	7,541	7,537	7,560	7,404	7,387	7,502	7,405	7,530
East North Central	7,488	7,540	7,439	7,509	7,437	7,473	7,371	7,315	7,069	7,557
West North Central	7,794	7,720	7,605	7,635	7,731	7,648	7,665	7,407	7,560	7,598
South Atlantic w/o Florida	7,770	7,654	7,701	7,642	7,439	7,484	7,410	7,306	6,437	7,288
Florida	7,417	7,416	7,476	7,409	7,479	7,431	7,381	7,320	7,080	7,326
South Atlantic	7,500	7,471	7,538	7,465	7,467	7,447	7,391	7,314	6,798	7,310
East South Central	7,713	7,643	7,633	7,629	7,437	7,409	7,377	7,296	7,022	7,356
West South Central w/o ERCOT	7,357	7,394	7,473	7,412	7,326	7,424	7,420	8,899	7,391	7,360
ERCOT	7,339	7,334	7,374	7,473	7,369	7,356	7,358	7,337	7,305	7,332
West South Central	7,345	7,355	7,408	7,451	7,353	7,382	7,381	7,987	7,336	7,342
Mountain	7,574	7,613	7,393	7,460	7,531	7,533	7,639	7,490	7,097	7,555
Pacific Contiguous w/o CA	7,217	7,288	7,303	7,183	7,129	7,194	7,210	7,222	7,310	7,431
California	7,345	7,504	7,453	7,285	7,291	7,255	7,358	7,305	6,895	7,359
Pacific Contiguous	7,307	7,458	7,422	7,261	7,247	7,239	7,331	7,291	6,989	7,374
TOTAL U.S.	**7,447**	**7,472**	**7,466**	**7,449**	**7,424**	**7,411**	**7,406**	**7,507**	**7,114**	**7,404**

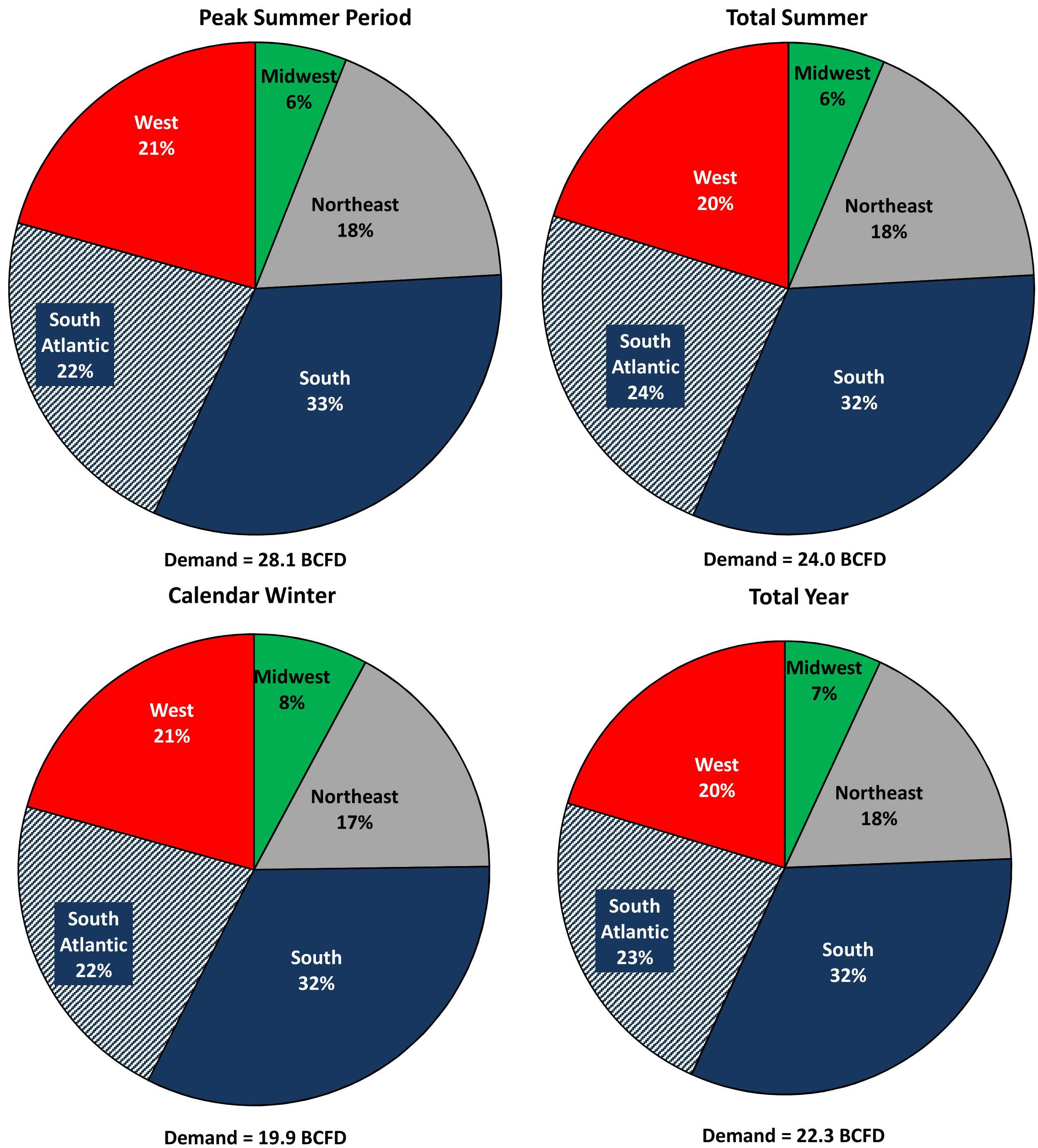
Note: 2014 is EIA-923 Preliminary Data.

Exhibit A-6. Total 2014 Primary Gas Demand By Region and Time Of Year



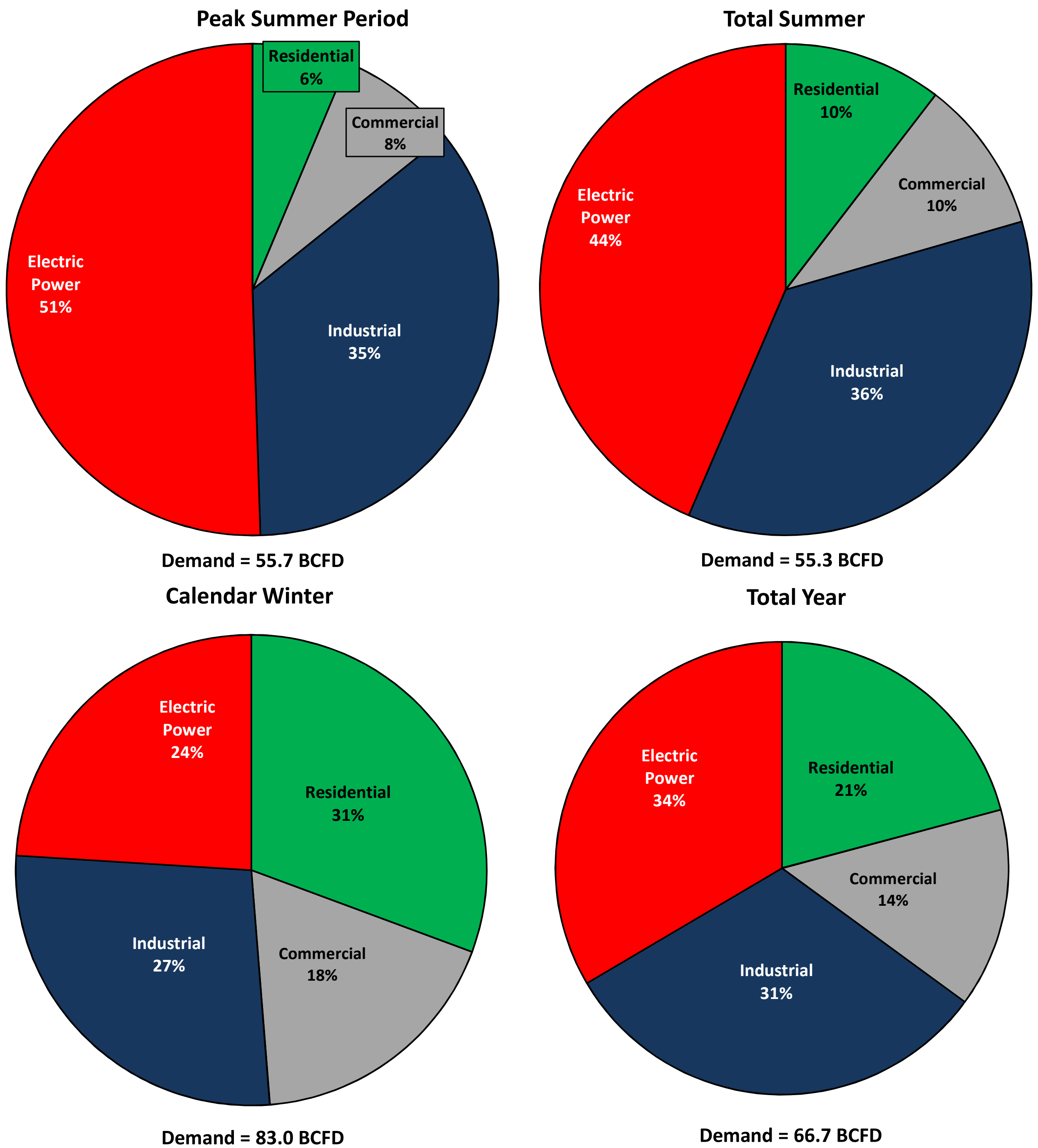
Note: Peak Summer = July & August; Total Summer = April through October; Calendar Winter = Jan, Feb, Mar, Nov, Dec.
Source: U.S. DOE, Energy Information Adminstration.

Exhibit A-7. Electric Power Sector 2014 Gas Demand by Region and Time of Year



Note: Peak Summer = July & August; Total Summer = April through October; Calendar Winter = Jan, Feb, Mar, Nov, Dec.
Source: U.S. DOE, Energy Information Adminstration.

Exhibit A-8. Total 2014 Primary Gas Demand By Sector and Time of Year



Note: Peak Summer = July & August; Total Summer = April through October; Calendar Winter = Jan, Feb, Mar, Nov, Dec.
Source: U.S. DOE, Energy Information Adminstration.

Exhibit A-9. Overview of Peak Summer Electric Sector Gas Demand

	Volume (BCFD)				Percent Change From Prior Year			
Year	Peak Summer Month (1)	Summer (2)	Winter (3)	Full Year	Peak Summer (1)	Summer (2)	Winter (3)	Full Year
2003	22.1	15.7	11.7	14.1	-9.5%	-11.9%	-4.4%	-9.4%
2004	20.2	16.8	12.3	14.9	-8.5%	6.5%	5.6%	6.1%
2005	25.5	18.6	12.4	16.1	26.4%	11.1%	1.0%	7.7%
2006	27.9	20.2	12.5	17.0	9.2%	8.7%	0.2%	6.0%
2007	31.3	21.5	14.8	18.7	12.2%	6.2%	18.8%	9.9%
2008	25.2	20.1	15.6	18.2	-19.3%	-6.5%	5.0%	-2.8%
2009	27.1	20.8	16.0	18.8	7.4%	3.5%	2.9%	3.3%
2010	30.4	22.6	16.9	20.2	12.3%	8.7%	5.3%	7.5%
2011	30.3	22.9	17.6	20.8	-0.4%	1.4%	4.6%	2.5%
2012	34.9	27.9	20.7	24.9	15.2%	21.5%	17.5%	20.0%
2013	29.2	23.8	20.2	22.3	-16.3%	-14.5%	-2.4%	-10.3%
2014	29.0	24.0	19.9	22.3	-0.8%	0.9%	-1.6%	0.0%
2015	31.2	26.0	22.5	24.5	7.6%	8.3%	12.8%	9.9%

1. Peak summer month is defined as the month with the highest demand (either July or August).
2. Summer consists of April through October.
3. Winter consists of January, February, March, November, and December.

Note: 2015 volumes are forecasted.
Source: EIA and EVA.

Exhibit A-10. U.S. Census Regions

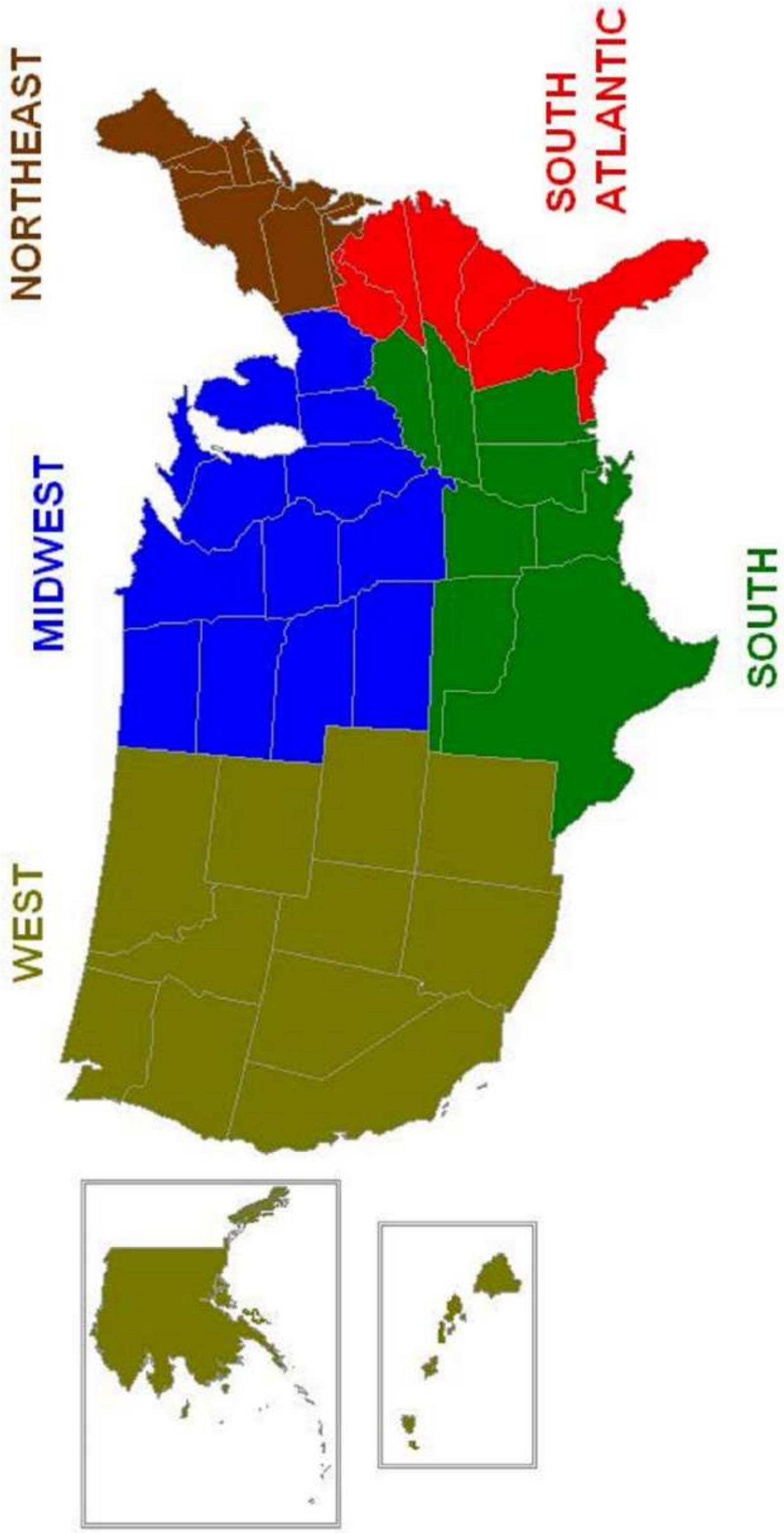


Exhibit A-11. Selected Relevant Data

		Annual							April-Oct							June - August						
		2010	2011	2012	2013	2014	2015	% Diff 15/14	2010	2011	2012	2013	2014	2015	% Diff 15/14	2010	2011	2012	2013	2014	2015	% Diff 15/14
Residential Housing Stock	(Thousands)	117,091	118,002	118,947	119,974	120,697	121,954	1.0%	117,139	118,033	119,004	120,039	120,704	122,015	1.1%	117,138	118,032	119,017	120,045	120,692	122,007	1.1%
Electric																						
Weather																						
Cooling Degree Days (CDD)	(Degree Days)	1,456	1,449	1,469	1,348	1,287	1,342	4.3%	1,430	1,390	1,382	1,293	1,247	1,286	3.1%	1,020	1,014	961	895	838	899	7.3%
Normal CDD[1]	(Degree Days)	1,299	1,299	1,299	1,299	1,299	1,299	-	1,242	1,242	1,242	1,242	1,242	1,242	-	877	877	877	877	877	877	-
% of Normal		112.1%	111.5%	113.1%	103.8%	99.1%	103.3%	-	115.1%	111.9%	111.3%	104.1%	100.4%	103.5%	-	116.3%	115.6%	109.5%	102.0%	95.5%	102.5%	-
New Gas-Fired Capacity[2]																						
CC	(MW)	5,205	8,862	6,899	3,618	6,676	4,848	-27.4%	2,642	5,401	3,115	2,993	4,697	3,755	-20.1%	1,613	3,602	619	1,671	2,036	3,031	48.9%
CT	(MW)	946	3,541	5,539	7,410	260	1,602	516.0%	870	2,920	4,966	6,460	125	656	424.8%	803	1,234	4,164	3,289	88	628	613.6%
Hydro and Nuclear Generation																						
Hydro Generation - Pacific	(GWh)	130,716	177,518	154,174	135,919	130,659	122,511	-6.2%	81,541	109,213	96,884	84,617	84,617	79,340	-6.2%	41,364	52,196	46,476	39,177	37,959	35,592	-6.2%
Nuclear Generation	(GWh)	793,504	790,204	769,331	789,017	796,048	797,172	0.1%	460,994	450,700	446,078	456,911	460,822	462,634	0.4%	208,053	208,954	203,872	208,313	211,748	210,448	-0.6%
Industrial (Index: 2007=100)																						
Food		98.6	98.5	102.8	104.5	106.5	128.1	20.3%	98.6	98.4	103.4	104.3	106.1	134.4	26.7%	98.5	98.2	103.7	104.5	105.8	134.6	27.3%
Paper		87.2	87.3	85.4	85.0	82.9	94.6	14.2%	87.2	87.0	85.0	85.2	82.9	98.8	19.2%	87.3	87.1	84.6	85.5	82.7	98.9	19.6%
Chemicals		86.3	86.3	86.4	87.5	89.4	112.6	26.0%	86.4	86.2	86.0	87.6	89.5	119.5	33.6%	86.6	86.1	85.7	87.8	89.6	119.5	33.5%
Petroleum		93.5	94.7	95.4	96.2	98.4	113.8	15.7%	94.2	95.1	95.1	96.0	98.4	118.2	20.2%	94.3	95.5	94.9	95.7	98.2	118.2	20.3%
Non-metallic Minerals		70.4	72.7	75.5	77.6	80.9	86.5	7.0%	70.5	72.4	75.2	77.3	80.7	87.6	8.5%	71.5	73.3	76.3	78.1	81.8	88.7	8.5%
Primary Metals		91.1	97.4	99.6	100.8	105.3	93.5	-11.2%	91.4	97.0	98.9	100.6	107.0	91.5	-14.5%	91.5	96.4	99.8	100.1	108.7	91.5	-15.9%
Total Industrial Production		90.6	93.6	97.1	99.9	104.1	111.4	7.0%	91.0	93.6	97.2	99.9	104.3	113.2	8.5%	91.3	93.6	97.3	99.7	104.3	113.2	8.5%
Composite 6-key Ind.		88.4	89.7	90.7	91.8	93.9	108.1	15.2%	88.6	89.6	90.5	91.8	94.1	112.5	19.6%	88.8	89.6	90.5	91.8	94.3	112.5	19.3%
Economy																						
Real GDP	(Bill. 2005$)	14,640	14,868	15,242	15,522	15,862	16,408	3.4%	14,670	14,867	15,256	15,546	15,903	16,436	3.4%	14,665	14,853	15,267	15,538	15,924	16,438	3.2%
Employment	(Thousands)	130,306	131,925	134,213	136,614	139,261	142,510	2.3%	130,463	132,013	134,247	136,670	139,380	142,638	2.3%	130,465	132,067	134,178	136,624	139,366	142,636	2.3%
GDP IPD	(2005=100)	101.5	103.8	105.9	107.6	109.2	110.5	1.2%	101.6	104.0	106.0	107.6	109.3	110.5	1.1%	101.6	104.1	106.1	107.6	109.4	110.5	1.0%

[1]Normal weather conditions are based upon the most recent 30 year average (i.e., 1983-2012).

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