November 12, 2014

The Honorable Rick Perry, Governor
The Honorable David Dewhurst, Lieutenant Governor
The Honorable Joseph R. Straus, III, Speaker of the House
Members of the 83rd Legislature

Ladies and Gentlemen:

Pursuant to Article I, Comptroller of Public Accounts, Rider 16 (Page I-23), of the General Appropriations Act for the 2014-15 biennium, I am providing the requested information regarding the reduced tax rate provisions for high-cost natural gas wells.

Sincerely,

Susan Combs

cc: The Honorable Jane Nelson, Chair, Senate Finance Committee
The Honorable James Pitts, Chair, House Appropriations Committee
The Honorable Harvey Hilderbran, Chair, House Ways and Means Committee
Ursula Parks, Director, Legislative Budget Board

High-Cost Natural Gas Tax Rate Incentive Study

Introduction:

The Texas Legislature's General Appropriations Act for the 2014-15 biennium[1] directed the Texas Comptroller of Public Accounts in a rider (No. 16 on Page I-23) to "conduct a study of the natural gas prices at which the high-cost gas rate reduction incentivizes natural gas production in Texas." According to Rider No. 16 the study should:

A. Provide criteria for evaluating the effectiveness of the high-cost natural gas tax rate reduction program.
B. Provide recommendations for increasing the effectiveness of the high-cost natural gas tax rate reduction program.
C. Detail the range of natural gas prices at which the rate reduction incentivizes natural gas production.
D. Consider the economic costs and benefits to the state of any increased production that is due to the rate reduction.
E. Consider the degree to which oil and condensate production encourage natural gas extraction.
F. Attempt to identify natural gas break-even prices in different shale plays throughout the state.

In January 2013, the Legislative Budget Board (LBB) presented to the Legislature its latest *Texas State Government Effectiveness and Efficiency Report* (GEER).[2] In that GEER report's section beginning on page 73, the LBB made two recommendations to statutorily modify the high-cost natural gas tax rate reduction program. The first recommendation was to amend the Tax Code to revise the formula used to determine the natural gas tax rate applicable to a specific high-cost well; the second recommendation was to amend the Government Code provisions for the Comptroller's *Tax Exemptions and Tax Incidence* report. To date, the Legislature has not adopted those two recommendations.

The GEER report made a third recommendation, which the Legislature accepted, to include in the General Appropriations Act:

> a rider to require the Comptroller to conduct a study to determine at what natural gas prices, if any, the high-cost gas-rate reduction incentivizes production.

[1] Senate Bill 1, Conference Committee Report, 83rd Legislature, Regular Session (2013).
[2] The GEER report can be accessed at this URL:
http://www.lbb.state.tx.us/Documents/Publications/GEER/Government%20Effectiveness%20and%20Efficiency%20Report%202012.pdf#ModifyTheHighCost.

Legal Citation and Language

The statutory high-cost natural gas tax rate reduction provisions can be found in Tax Code Section 201.057 (Temporary Exemption or Tax Reduction for Certain High-Cost Gas). This section is included as Appendix A. Texas has had two high-cost natural gas tax rate reduction programs. The first was for a 100 percent tax exemption that began in 1991 and ended 2001. The second program is the tax rate reduction program currently in law.

Section 201.057 provides the calculation procedure for the high-cost natural gas tax rate reduction, as follows:

> The amount of tax reduction shall be computed by subtracting from the tax rate imposed by Section 201.052 (*the natural gas production tax*) the product of that tax rate times the ratio of (the well's drilling and completion costs) to (twice the median drilling and completion costs for high-cost well during the previous state fiscal year), except that the effective rate of tax may not be reduced below zero.

That procedure is expressed in this formula:

> 0.075 – (0.075 * (the well's drilling & completion costs / (2 * the previous year's median drilling & completion costs)))

Examining the results produced by this formula for a new well drilled in 2014 and using the median drilling and completion cost from 2013 ($4,824,414), one may see that a well with a 2014 cost of $9,648,828 (twice the 2013 median) or more would result in a tax rate of zero. A 2014 cost equal to the 2013 median would produce a 3.75 percent tax rate. A 2014 well with a cost of $2 million would have a rate of 5.9 percent.

Historical data

The following table on page 3 presents historical high-cost natural gas data, including production, average tax rates, and the costs of the high-cost gas program. As the natural gas production tax is a tax on the value of production (generally, price times production) it should be noted that the high-cost gas program cost figures below respond to both changes in price and/or production. Note that in the period following the last recession and corresponding with the opening of the Eagle Ford Shale (a predominately oil play) the cost figures generally declined as prices dropped (never regaining their previous levels) and production followed a natural decline in existing high-cost wells and fewer new wells were being drilled. Also note that, as the program has a maximum time limit of 10 years per well, only wells first taking the rate reduction in 2005 or, thereafter, would be included in the 2014 cost figure.

HIGH-COST (H-C) NATURAL GAS TAX RATE REDUCTION PROGRAM

Fiscal Year	H-C Wells Submitted to Comptroller	H-C Average Tax Rate*	H-C Taxable Production (Mcf)	H-C Share of Total Taxable Production	Cost of H-C Rate Reduction
1997	559	1.45%	168,889,339	3%	$22,833,506
1998	1,714	1.16%	678,138,262	13%	$95,191,380
1999	1,413	1.06%	1,019,239,081	21%	$120,481,661
2000	1,150	1.31%	1,253,491,342	25%	$210,540,431
2001	1,888	1.45%	1,512,895,659	29%	$470,126,351
2002	2,943	1.36%	1,850,608,829	36%	$283,167,835
2003	2,966	1.64%	1,974,548,381	38%	$505,039,972
2004	3,467	1.90%	2,188,664,203	41%	$596,071,963
2005	4,297	1.79%	2,402,241,501	44%	$808,802,827
2006	4,392	1.42%	2,743,103,257	47%	$1,300,354,421
2007	7,406	1.18%	3,231,149,020	51%	$1,293,536,442
2008	6,253	1.32%	4,146,520,207	56%	$1,974,204,232
2009	9,774	1.48%	4,748,150,593	61%	$1,481,625,687
2010	6,111	1.65%	4,453,473,268	61%	$989,419,185
2011	3,350	1.63%	4,704,948,871	62%	$1,079,717,312
2012	3,516	1.44%	4,755,614,578	62%	$906,806,900
2013	3,092	1.32%	4,323,609,415	56%	$810,493,709
2014	2,670	1.44%	3,516,210,409	46%	$812,295,780

* These rates reflect, for each year, the average reduced tax rate associated with all high-cost wells and the aggregate value of production from those wells.

Review of the Literature

The provision of federal tax incentives for oil and natural gas exploration and production began almost immediately with the passage of the federal Revenue Act of 1913. The Act did not provide explicitly for "intangible drilling costs." Very soon, however, the Board of Tax Appeals determined that taxpayers could choose between capitalizing or expensing intangible drilling expenses. This was statutorily specified in 1916. This first incentive still exists today. "Intangible drilling costs" are the costs for such activities that are incurred in commencing drilling or preparing the development of a well. The purpose of expensing such costs, as opposed to capitalizing them was to attract capital to what was and still is a risky investment. Under current federal law, small independent producers are allowed to expense 100 percent of their "intangible drilling costs." Major integrated producers are allowed to expense 70 percent of the "intangible drilling costs' and to capitalize the remaining 30 percent over a 60-month period.

Over time, a number of federal tax incentives for the oil and natural gas industry have been implemented. The next major incentive (the oil depletion allowance) was instituted in 1926. Percentage depletion is the deduction from a producer's annual gross income of a legally specified percentage (currently 15 percent) of the total value of the oil deposit that was extracted in the tax year.

The following table indicates the major federal incentives and the estimated federal revenue implications of such incentives for federal fiscal 2013.

ESTIMATED FEDERAL TAX EXPENDITURES FOR
OIL AND NATURAL GAS ACTIVITIES
(In millions of dollars)

Tax Provision	Amount
Enhanced oil recovery credit	$0
Credits for oil and natural gas from marginal wells	0
Expensing of intangible drilling costs	3,490
Deduction for tertiary injectants	7
Passive loss exception for working interests in oil and natural gas properties	9
Percentage depletion for oil and natural gas wells	612
Domestic manufacturing deduction for oil and natural gas companies	574
Geological and geophysical amortization	61
Total	$4,753

Source: Congressional Research Service, "Oil and Natural Gas Industry Tax Issues in the FY 2013 Budget Proposal," March 12, 2012

Taxation of crude oil first began in Texas in 1907 when the state imposed a 0.5 percent tax on the market value of oil produced. Taxation of natural gas began in Texas in 1931, initially at a rate of 2.0 percent of the value of production. The state of Louisiana instituted the first natural gas tax in 1910 at a rate of 1/5th of one cent per 10,000 cubic feet of natural gas.

The decision to drill and to produce is primarily based on geological considerations, the current and predicted future price of oil and natural gas, the costs of drilling and production, and the estimates of the potential reserves. Tax rates and tax incentives may also be determinants of the level of activity, or whether drilling will occur or not.

In a 2003 article published in "International Tax and Public Finance," Mitch Kunce presented the following conclusion:

> *In general, results show that severance tax rate reductions result in a substantial loss of tax revenue, moderate increases in drilling, but little change in reserve additions and production. A key question regarding this general result is: Why does output of oil respond*

so grudgingly to changes in severance taxes? There appears to be four reasons why this is so.

- *First, a reduction in severance taxes offers no direct stimulus for reserve exploration.*
- *Second, operators do not see the full effect of state severance tax changes because of the many tax base and rate interactions at all levels.*
- *Third, and in a related vein, a reduction in severance tax rates by 2 percentage-points has only a small impact on the net-of-tax price received by operators.*
- *Fourth, and most importantly, production of (as contrasted with exploration for) oil is driven mainly by reserves, not by prices, severance tax rates, or tax discounts.*

The general conclusion that severance tax changes appear to be unimportant may be problematic to public officials in oil producing states hoping to stimulate local economic activity by lowering such rates. The prospect of modest increases in exploration and production comes at a considerable cost, the loss of substantial state tax revenue that must be offset. Rather, state officials may have the incentive to raise severance tax rates risking little in the way of loss to future oil field activity.[3]

A January 2014 report commissioned by the State Chamber of Oklahoma Research Foundation and undertaken by the firm RegionTrack, Inc. questioned the method and certain specific findings of the Kunce report. Specifically, RegionTrack analysis found the Kunce study treated well types and well costs as uniform over time and did not differentiate between the production potential and cost-differential of older conventional wells versus modern horizontally drilled wells and deep wells. In other words, the Kunce study was based on obsolete drilling techniques not current drilling practices. However, the RegionTrack report did *to some extent* agree with the Kunce report on the effects of tax incentives, as shown in this passage:

In the short-run, production changes driven by changes in tax incentives are always likely to be modest. However, only going forward will we be able to form better estimates of the long-run response of oil and gas production to incentives. Although existing research suggests that incentives will produce only marginal changes in future drilling and production activity above what would have taken place otherwise, prior estimates are highly likely to understate the potential effect in the current environment.[4]

---

[3] Mitch Kunce, "Effectiveness of Severance Tax Incentives in the U.S. Oil Industry", "*International Tax and Public Finance,*" 10 (2003): 583.

[4] http://www.okstatechamber.com/sites/www.okstatechamber.com/files/OklahomaOilGasTaxPolicy_Jan2014_0.pdf, page 20.

Rider Element A: Provide criteria for evaluating the effectiveness of the high-cost natural gas tax rate reduction program.

Many criteria could be used to evaluate the effectiveness of a tax or tax exemption provision, such as the high-cost natural gas tax rate reduction program. Such criteria could include, but are not limited to, the following: the manner of natural gas taxation in other states; the adequacy of natural gas production tax revenue with the high-cost natural gas tax rate reduction included and with the resulting revenue collection reductions; the equity of the high-cost rate reduction among all similarly-situated natural gas production taxpayers; and the economic efficiency of the high-cost tax rate reduction provision.

Taxation in other states: Currently, 35 states impose severance taxes on oil and natural gas production, of which three (Idaho, North Carolina and Wisconsin) have no production of those minerals. The states of California and Pennsylvania are major producers of oil and natural gas but tax neither type of production. New York and Virginia are major producers of natural gas, but have no state severance tax provisions. With respect to natural gas, the following table on page 7 shows states with some level of natural gas production in 2013 and the conventional tax rate for natural gas production.

The Texas high-cost tax rate incentive may not be perceived as favorably as the incentive granted by California and Pennsylvania in that neither has a state natural gas severance tax. Also, the Texas incentives for high-cost natural gas wells may not be as generous as those granted by three states surrounding Texas. In a study prepared for the Oklahoma Policy Institute, Headwaters Economics concluded that Texas' effective tax on an unconventional natural gas well was greater than the effective tax rate for Arkansas, Louisiana and Oklahoma. That study also found that Wyoming and New Mexico provided no incentives for the drilling of unconventional natural gas wells. [5]

[5] http://headwaterseconomics.org, "Unconventional Oil and Natural Gas Production Tax Rates: How Does Oklahoma Compare to Peers," page 3.

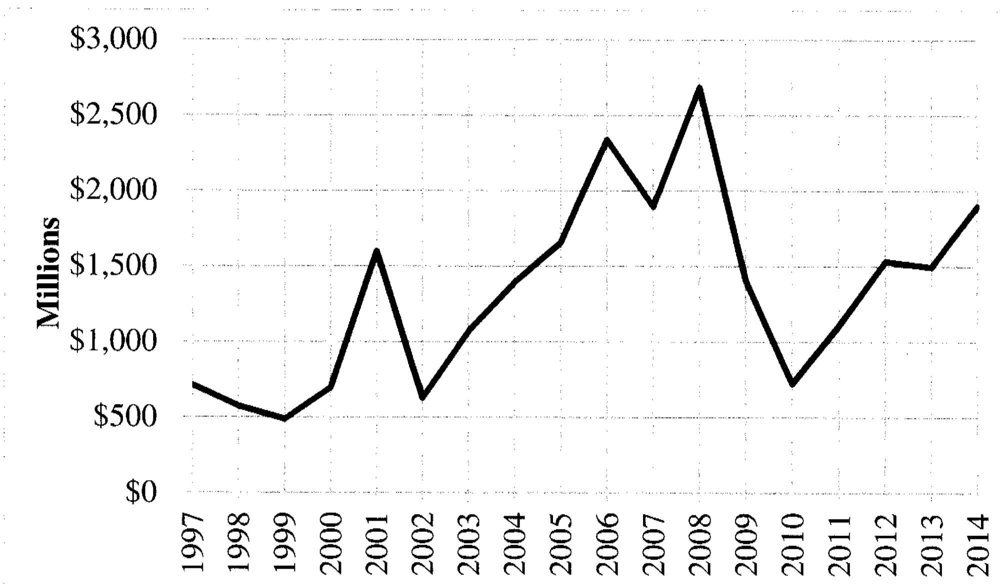
STATE NATURAL GAS PRODUCTION AND TAX RATES FOR PRODUCING STATES

State	Marketed Production in 2013 (MCF)	Share of U.S. Total	Current State Conventional Tax Rate
Texas	7,545,401,000	30.9%	7.5% of market value
Pennsylvania	3,259,042,000	13.4%	None
Louisiana	2,406,834,000	9.9%	1Jul2013 to 30Jun2014 - 11.8 cents/MCF; 1Jul2014 to 30Jun2015 - 16.3 cents/MCF
Oklahoma	2,143,999,000	8.8%	7.0% of gross market value. Wells spudded after 1Jul2015 taxed at 2% for 1st 36 production months.
Wyoming	1,858,207,000	7.6%	6.0% on value
Colorado	1,604,860,000	6.6%	2.0 to 5.0% based on gross income from production
New Mexico	1,195,431,000	4.9%	3.75% of value
Arkansas	1,139,654,000	4.7%	5% of market value
West Virginia	717,892,000	2.9%	5% of gross value
Utah	470,863,000	1.9%	3% for first $1.50/MCF and 5% for value in excess of $1.50/MCF
Alaska	338,182,000	1.4%	Current rate of 35% based on net value of oil and gas, which is the value at point of production less certain qualified expenditures
Kansas	292,467,000	1.2%	8.0% of gross value
California	252,310,000	1.0%	None
North Dakota	235,711,000	1.0%	For fiscal year 2013-2014, 8.33 cents per MCF
Alabama	196,326,000	0.8%	8% of gross value at point of production
Ohio	186,181,000	0.8%	2.5% of gross wellhead receipts
Virginia	139,382,000	0.6%	None
Michigan	123,622,000	0.5%	5.0% of gross cash market value
Kentucky	94,665,000	0.4%	4.5% of gross value
Montana	63,242,000	0.3%	Varies for different well types/over differing production horizons
Mississippi	59,272,000	0.2%	6.0% of value at point of production
New York	23,458,000	0.1%	None
South Dakota	16,205,000	0.1%	4.5% of gross value less royalties
Indiana	7,938,000	0.0%	1.0% of value
Tennessee	5,400,000	0.0%	3.0% of sales value
Illinois	2,887,000	0.0%	None
Nebraska	1,032,000	0.0%	3.0% of gross value
Oregon	770,000	0.0%	6% of gross value at wellhead
Florida	292,000	0.0%	30.4 cents per MCF, adjusted annually
Arizona	72,000	0.0%	3.125% of gross value of production
Maryland	32,000	0.0%	None
Nevada	3,000	0.0%	Sliding rate from 2 to 5% of net value of production

Source: U.S. Energy Information Administration

Adequacy: With the high-cost natural gas tax rate reduction provision in place, annual natural gas production tax revenue has risen from $712 million (accruing to all funds, General Revenue as well as the Economic Stabilization Fund) in fiscal 1997 to $1,900 million in fiscal 2014. Over those 18 years the trend has been, in general, consistently upward, although with a large degree of variation. While collections would have been greater without the high-cost provision, overall revenue figures do not generally display a long-term downward trend.

TEXAS NATURAL GAS PRODUCTION TAX
ANNUAL REVENUE COLLECTIONS



Source: Susan Combs, Texas Comptroller of Public Accounts.

Equity: All natural gas production taxpayers who are similarly-situated — that is, have a natural gas well meeting the high-cost standards of the Texas Railroad Commission — receive a reduced tax rate. The amount of that reduction varies with the relationship between the median drilling costs for all high-cost wells and the drilling costs of a particular well, such that the higher the relative total drilling cost for that particular well the more the tax rate is reduced. Further, a taxpayer receives the reduced tax rate for no more than 10 years, or until such time as the tax reduction realized becomes equal to one-half of the cost of drilling the well. A very high producing well might receive the rate reduction for less than 10 years while a low producing high-cost well might receive the rate reduction for the full 10 years allowable under statute.

Economic Efficiency and Incentives: The existence of the reduced tax rate for high-cost natural gas wells in Texas could have the effect, likely in concert with other economic and financial factors facing a producer, of increasing the number of such wells drilled in Texas by providing an incentive.

There appears to be a correlation between higher prices for natural gas and increased production. Natural gas prices averaged $2.42 per MCF in fiscal 1997, rising to $8.47 for 2008 prior to the last recession, then falling to $4.17 for 2014. During that period the high-cost natural gas share of total state natural gas production went from 3 percent in 1997, to 62 percent in both 2011 and 2012, then falling to 46 percent for 2014.

With lower prices seen in recent years, the stability in production could partially be attributed to gains in technology which seem to provide higher initial and overall production rates for newly drilled wells. Additionally, production has remained stable owing to rapid gains in associated gas (casinghead gas) coming from oil well activity.

Exploration activity in Texas moved away from the Barnett Shale (a natural gas play) toward the Eagle Ford Shale (primarily an oil play) concurrent with natural gas prices falling in late 2008, and remaining at lower levels. While oil prices also fell in 2008, they quickly rose into the $80 range and continued to rise. Observing this movement from predominately natural gas exploration to that for oil, one might infer from those changes that economic factors outweighed other possible considerations, including this incentive.

Rider Element B: Provide recommendations for increasing the effectiveness of the high-cost natural gas tax rate reduction program.

The high-cost natural gas tax rate reduction program, as mentioned earlier in this report, is established by statute as Tax Code Section 201.057. The structure and a number of specifics regarding the functioning of the rate reduction program are in this section of the Tax Code.

In terms of increased administrative effectiveness, below are two proposals intended for discussion by the Legislature and stakeholders, but not presented as recommendations by the Comptroller of Public Accounts:

1. <u>Streamline the exemption application process</u>. Under current law the natural gas producer submits an application to the Texas Railroad Commission (RRC) to obtain certification for a high-cost well. The RRC provides the producer with that certification if appropriate, then the producer provides the Comptroller with a copy of that certification along with the well's drilling and completion costs for determination of the natural gas production tax rate on natural gas produced from that well. After the producer is provided with the well's high-cost natural gas tax rate calculated by the Comptroller, the producer files an amended tax return to claim a tax refund from previous tax reports at the full tax rate. This proposal is to require producers, when applying for well certification by the RRC, to also include the well's drilling and completion costs. Implementing this proposal would:

- Eliminate the need for a Comptroller filing deadline.
- Eliminate the 10 percent penalty for not filing within 45 days of RRC certification. Since November 2010, a total of 1,121 leases have been assessed this penalty.
- Reduce taxpayer filing and correspondence costs.

In addition to the proposal's benefits above, Comptroller operations related to the natural gas production tax would be improved as these application and approval procedures would become more highly automated. A reduction in amended taxpayer reports (See Appendix B for a sample of reports and their instructions) could occur.

2. <u>Streamline taxpayer reporting requirements</u>. This proposal would require natural gas production taxpayers to prepare a single production volume report to be submitted to both the RRC and the Comptroller. Presently there are separate submissions, and Comptroller staff has noted that at times the two reports do not agree. This proposal would reduce paperwork and increase accuracy for the two agencies and for taxpayers.

As covered earlier in this report, the high-cost natural gas tax rate reduction program is statutorily established in Tax Code Section 201.057 (See Appendix A). The certification as to whether a natural gas well is high-cost, or not, is administered by the Texas Railroad Commission.

As provided by the statute and addressing workload, the program's 10-year time horizon (this is the maximum) for the early and peak years of the wells in the Barnett Shale development have either come to an end (those wells first receiving the tax rate reduction in fiscal 2005, or before) or will be ending in the next two to three years (those wells first receiving the tax rate reduction in fiscal 2006 through 2008). Therefore, and with respect to the Barnett Shale wells previously drilled and any possible new exploration, the administrative workload associated with this program should diminish as the older wells revert to full taxability status and fewer new applications for the high-cost provision are received.

Rider Element C: Detail the range of natural gas prices at which the rate reduction incentivizes natural gas production.

Higher market prices are clearly a factor in incentivizing the drilling of natural gas wells. While price is a factor there are other contributing factors such as geological formations, lease cost, contractual obligations to supply natural gas, type of natural gas (dry gas only, or with significant natural gas liquids), anticipated drilling and completion costs, anticipated initial/overall production, available pipeline infrastructure, and a host of other factors.

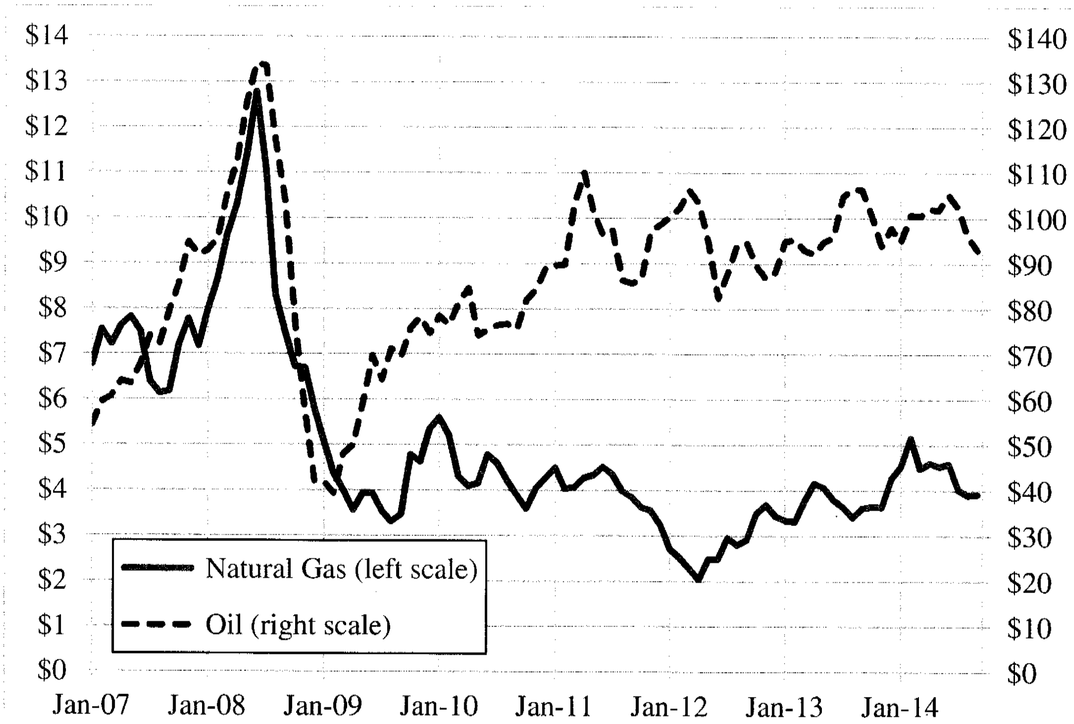
Among those cost considerations is the state's natural gas production tax. As a tax on value, the factor of greatest importance would ordinarily be the price of natural gas produced. And, as a tax on the value of production, it acts to reduce the producer's overall revenue from exploration efforts by 7.5 percent. A high-cost well with a tax rate of 1.5 percent, for example, would of course see lower taxes due. This holds true whether natural gas prices were to be $4, $6 or $8 per MCF. The incentive could be of greater importance when a producer's decision whether to drill, or not, is a close one and the incentive becomes a determining factor.

Another factor in considering price ranges and the degree to which these affect decision making is the alternative available to producers: drill for natural gas or drill for oil. Some producers are set up to explore for one of these hydrocarbons, utilizing their skill set, and they do not drill outside of those boundaries. However, many producers most likely can, and do, alternate between exploring for oil and exploring for natural gas based on prevailing conditions such as price and the attractiveness of a play.

In the early- to mid-2000s period, when the Barnett Shale was recognized as a gas-rich play, rapidly rising natural gas prices together with the improved hydraulic fracking technologies steered producers toward natural gas exploration. In contrast, just a few years later natural gas prices plummeted and did not significantly recover. However, oil prices did recover, the Eagle Ford Shale area opened, and the fracking technology was extended to apply to oil exploration. At that time, producers began to move away from natural gas to oil.

Historically, and in general terms, the market price for a barrel of oil was around 10 times the market price for a thousand cubic feet (MCF) of natural gas. But since the market prices for those products bottomed out in early 2009, that ratio has climbed, reaching a monthly average level of 50-to-1 in April 2012. Over the last two years the average ratio was above 20-to-1. The following chart demonstrates these recent changes in relative market prices.

FUTURES MARKET PRICES FOR
NATURAL GAS (PER MMBTU) AND CRUDE OIL (PER BARREL)
(MONTHLY AVERAGES FROM JANUARY 2007 TO SEPTEMBER 2014)



Source: CME Group/NYMEX. Prices are for the first forward month.

As shown in the following table on page 14, in 2009 on average there were 467 natural gas drilling rigs operating in Texas, compared to only 125 rigs drilling for oil. By 2014, the average number of natural gas rigs had fallen by 80 percent, to just 95; the number of oil rigs had increased by over 500 percent, to 765 (as noted later in this report, the natural gas drilling rig count during the week of October 31, 2014, stood at just 79).

TEXAS NATURAL GAS AND OIL PRICES, PRODUCTION AND DRILLING

	Natural Gas			Crude Oil		
Fiscal Year	Futures Market Price (per Mcf)*	Texas Total Production (Mcf)**	Texas Active Drilling Rigs***	Futures Market Price (per barrel)*	Texas Total Production (barrels)**	Texas Active Drilling Rigs***
1997	$2.42	5,899,222,683		$22.27	492,901,597	
1998	$2.47	5,846,253,232		$17.13	480,939,070	
1999	$2.06	5,700,889,620		$14.95	422,418,950	
2000	$2.86	5,676,785,089		$26.69	406,807,512	
2001	$5.41	5,797,502,307		$29.71	388,456,273	
2002	$2.84	5,798,759,652		$23.76	371,562,739	
2003	$4.79	5,735,382,403		$30.10	361,244,557	
2004	$5.55	5,946,025,377		$34.55	355,079,702	
2005	$6.53	5,995,180,877		$50.32	350,064,265	
2006	$9.28	6,174,730,073		$65.63	347,196,173	
2007	$7.07	6,553,346,102		$63.51	344,230,659	
2008	$8.47	7,389,655,552		$101.93	348,665,947	
2009	$5.96	7,864,960,645	467	$64.09	352,784,355	125
2010	$4.43	7,382,485,179	340	$76.32	354,296,272	215
2011	$4.20	7,656,342,683	350	$91.26	403,516,589	428
2012	$3.12	8,068,000,968	280	$94.37	539,431,656	636
2013	$3.47	8,193,179,261	152	$93.65	701,769,367	692
2014	$4.17	8,068,887,438	95	$101.07	833,630,140	765

* CME Group/NYMEX. Prices are annual averages, for the first forward month. Mcf = thousands of cubic feet.

** Texas Railroad Commission

*** Baker Hughes Incorporated (annual averages; state-specific figures for the years 1997 to 2008 are unavailable)

Rider Element D: Consider the economic costs and benefits to the state of any increased production that is due to the rate reduction.

The contribution of the mining industry (primarily related to oil and natural gas activity in Texas) to the state's economy has been significant for many decades. This can be examined in terms of employment, wages and salaries, and gross product. The following economic information is for the aggregate oil and natural gas industry in Texas, and does not distinguish between natural gas and oil activity.

Employment: Current (September 2014, seasonally-adjusted) employment in the mining sector in Texas stands at 323,900. Or approximately 2.8 percent of the state's total employment of 11,672,200. A year ago, September 2013, mining's employment stood at 295,400 — an increase over the year of 28,500 or 9.6 percent. Total Texas employment grew at 3.7 percent over that same period.

Within mining, subgroups include oil and gas extraction and support activities for mining. Together these two subsectors (not seasonally-adjusted) currently account for 309,400 jobs. Oil and gas extraction accounts for 113,000, an increase from 104,900 one year ago, or a 7.7 percent increase. Support activities, firms engaged in the support of drilling and extraction firms' efforts, currently employs 196,400, up from 179,000 last September and a 9.7 percent increase.

Wages and salaries: Wages and salaries earned by individuals in the oil and gas extraction and support subsectors tend to be higher than overall average Texas wages. For example, examining 2013 Quarter One statistics the oil and gas extraction subsector from the Texas Workforce Commission showed average employment those months of 100,752 and total wages that period of approximately $5.316 billion. Average weekly wages for this group during that time period was $4,058. Similarly, an average employment level of 170,539 was seen for support firms, total wages in 2013 Quarter One of $4.015 billion, for average weekly wages of $1,811. All Texas, all industry average weekly wages for that same time period was $1,015.

Gross state product: The contribution of the mining sector to the Texas economy has varied throughout the years, depending on conditions at the time. In 1997 (first year of new method of federal industrial classification, known as NAICS), the size of the mining sector — in billions of current dollars — was $36.088. Or 5.9 percent of the total Texas Gross State Product (GSP) of $612.658 billion. This proportion stayed almost constant in 2000, but by 2005 the effect of the Barnett Shale play activities can be seen. Industry gross product was $99.803 billion or 10.0 percent of total Texas gross product. By 2010, this has moved only slightly upward to 10.8 percent of the total. In 2013, the Eagle Ford Shale can be detected as total industry gross product rose to $206.220 billion or 13.5 percent of the total Texas GSP of slightly over $1.5 trillion.

According to a study by IHS Incorporated[6]:

> *By 2012, the unconventional natural gas and oil activity was already supporting more than 2.1 million (U.S.) jobs across a vast supply chain — a considerable accomplishment given the relative newness of the technology. About 60 percent of these jobs – 1.3 million – were from shale gas activity, the rest from tight oil. In 2012, this revolution added $74 billion to federal and state government revenues, a number we expect to rise to about $125 billion by 2020... also becoming clear is the lower costs of energy brought about by this abundant in natural gas supply is helping to stimulate a manufacturing renaissance and improving the competitive position of the U.S. in the global economy and further stimulating U.S. job creation. (Federal Reserve) Chairman Ben Bernanke described the unconventional revolution as 'one of the most beneficial developments if not the most beneficial development since 2008' in the economy. The unconventional revolution came along at the right time. One might well wonder how the U.S. economy would look today – much higher energy bills, higher unemployment, and lower growth.*

That report's section specifically relating to Texas is included as Appendix C. Briefly, it reports that "the economic activity associated with unconventional oil and gas directly and indirectly supported nearly 576,000 jobs in the state in 2012 (*and*) contributed value-added economic activity of $101 billion in Texas in 2012."

[6] America's New Energy Future: The Unconventional Oil and Gas Revolution and the U.S. Economy, 2012.

Rider Element E: Consider the degree to which oil and condensate production encourage natural gas extraction.

For natural gas wells being drilled, current price dynamics (i.e., lower natural gas prices) and evolving technology appear to have placed the drilling focus on liquids production. At the current time, drilling for oil is primary with natural gas exploration a secondary interest. According to Baker Hughes, Inc., during the week of October 31, 2014, 901 drilling rigs were operating in Texas. Of those, 79 were drilling for natural gas. Drilling for natural gas in Texas tends to be in areas which are heavy in natural gas liquids and/or with expected high condensate volumes taking advantage of the price differential between oil and natural gas.

The following table on page 18 illustrates the relationship between oil and natural gas well production, including casinghead gas and condensate. It appears to be not so much a situation of oil and condensate production encouraging natural gas production, but one where oil exploration (much of this in the Eagle Ford Shale) has resulted in wells producing — in addition to crude oil — other products, such as casinghead gas (or natural gas from an oil well).

The table clearly shows that as Texas oil production doubled between fiscal 2011 and 2014, the production of casinghead gas did as well going from approximately 0.8 billion MCF to almost 1.8 billion MCF. And the table also shows that, during this same time period, condensate (light oil) from natural gas wells ticked up considerably from about 67 million barrels statewide to over 136 million.

Appendix D includes a series of Texas Railroad Commission graphs for the major oil and natural gas fields in the state. In the period from 2008 to 2013 (annual totals) and 2014 through July, production from the Eagle Ford Shale exhibited extremely rapid growth; the Permian Basin showed steady growth. In the Barnett Shale play, from 2000 through 2013 (annual totals) and 2014 through July, the production levels for oil and natural gas showed growth and declines, while the growth of condensate production continued. In the Haynesville Shale play, from 2005 through 2013 (annual totals) and 2014 through June, there was no significant oil production. Natural gas production peaked in 2012 and declined in 2013, but may be rebounding in 2014. Condensate production in the Haynesville continued to grow.

TEXAS OIL AND NATURAL GAS PRODUCTION

	Oil Wells Statewide			Natural Gas Wells Statewide			Eagle Ford Shale Wells		
Fiscal Year	Oil Production (Barrels)	Casinghead Gas Production (MCF)	Ratio of Casing-head Gas to Oil	Natural Gas Production (MCF)	Condensate Production (BBL)	Ratio of Natural Gas to Condensate Production	Casinghead Gas Production (MCF)	Natural Gas Production (MCF)	Condensate Production (BBL)
1997	492,901,597	1,068,168,312	2.2	4,831,054,371	39,391,114	123	-	-	-
1998	480,939,070	1,013,664,150	2.1	4,832,589,082	39,511,390	122	-	-	-
1999	422,418,950	921,787,969	2.2	4,779,101,651	38,543,581	124	-	-	-
2000	406,807,512	882,859,887	2.2	4,793,925,202	36,667,257	131	-	-	-
2001	388,456,273	862,247,053	2.2	4,935,255,254	38,436,584	128	-	-	-
2002	371,562,739	848,695,055	2.3	4,950,064,597	39,911,324	124	-	-	-
2003	361,244,557	832,174,431	2.3	4,903,207,972	40,324,893	122	-	-	-
2004	355,079,702	868,976,105	2.4	5,077,049,272	41,678,426	122	-	-	-
2005	350,064,265	781,755,193	2.2	5,213,425,684	42,615,041	122	-	-	-
2006	347,196,173	637,532,406	1.8	5,537,197,667	43,895,804	126	-	-	-
2007	344,230,659	648,039,478	1.9	5,905,306,624	46,553,235	127	-	-	-
2008	348,665,947	669,710,666	1.9	6,719,944,886	50,957,261	132	21,945	13,610	989
2009	352,784,355	684,493,168	1.9	7,180,467,477	51,687,730	139	348,287	2,538,979	53,083
2010	354,296,272	712,218,408	2.0	6,670,266,771	51,080,427	131	339,255	47,033,000	1,952,340
2011	403,516,589	818,412,916	2.0	6,837,929,767	66,771,838	102	20,963,208	216,188,288	15,226,194
2012	539,431,656	1,078,951,888	2.0	6,989,049,080	95,795,609	73	133,569,667	557,041,358	44,187,176
2013	701,769,367	1,459,846,705	2.1	6,733,332,556	126,750,230	53	314,822,828	893,907,948	72,914,507
2014	833,630,140	1,786,159,844	2.1	6,282,727,594	136,471,329	46	503,603,890	1,047,154,458	90,267,717

Source: Texas Railroad Commission Production Data

Rider Element F: Attempt to identify natural gas break-even prices in different shale plays throughout the state

According to IHS, Inc.[7], a data and forecasting firm, the break-even price for natural gas plays within Texas (as of June 24, 2014) was estimated to be as follows:

Predominately Dry Natural Gas* Break-Even Price per MMBtu (million BTUs)

- Barnett Shale (core) $ 6.61
- Eagle Ford East Dry Gas $10.50
- Eagle Ford West Dry Gas $ 6.56
- Haynesville Tier Two $ 4.26
- Cotton Valley Horizontal $ 4.62

Predominately Wet Natural Gas** Break-Even Price per MMBtu

- Eagle Ford East Wet Gas $ -1.45[8]
- Eagle Ford West Wet Gas $ 1.46
- Granite Wash Wet Gas (Texas) $ 1.22

* natural gas (methane) possibly also containing, but not in significant amounts, natural gas liquids.
** natural gas (methane) and containing, in significant amounts, natural gas liquids such as butane, propane, and ethane, for example. Such liquids tend to enhance the profitability of a natural gas well as these liquids are priced more closely to crude oil than to dry (methane) natural gas.

A Massachusetts Institute of Technology interdisciplinary study on the future of natural gas (released in 2011, and based on data from 2009) included in its Appendix 2D an economic analysis of the break-even prices for natural gas in the major U.S. plays. For those natural gas plays within Texas the estimated break-even prices[9] were as follows:

Dry Natural Gas Break-Even Price per MMBtu

- Barnett Shale $ 5.84
- Haynesville Shale (TX and LA) $ 5.04

[7] Source: IHS Inc. The use of this content was authorized in advance by IHS. Any further use or redistribution of this content is strictly prohibited a without written permission by IHS. All rights reserved.

[8] This negative amount means that natural gas could be disposed of at a loss of this amount because revenue from condensate and natural gas liquids production alone would justify the drilling of a new well.

[9] Assuming mid-range well drilling/completion costs and average initial production rates.

APPENDIX A

TAX CODE

TITLE 2. STATE TAXATION

SUBTITLE I. SEVERANCE TAXES

CHAPTER 201. GAS PRODUCTION TAX

SUBCHAPTER B. TAX IMPOSED

Sec. 201.057. TEMPORARY EXEMPTION OR TAX REDUCTION FOR CERTAIN HIGH-COST GAS. (a) In this section:

(1) "Commission" means the Railroad Commission of Texas.

(2) "High-cost gas" means:

(A) high-cost natural gas as described by Section 107, Natural Gas Policy Act of 1978 (15 U.S.C. Section 3317), as that section exists on January 1, 1989, without regard to whether that section is in effect or whether a determination has been made that the gas is high-cost natural gas for purposes of that Act; or

(B) all gas produced from oil wells or gas wells within a commission approved co-production project.

(3) "Commission approved co-production project" means a reservoir development project in which the commission has recognized that water withdrawals from an oil or gas reservoir in excess of specified minimum volumes will result in recovery of additional oil and/or gas from the reservoir that would not be produced by conventional production methods and where operators of wells completed in the reservoir have begun to implement commission requirements to withdraw such volumes of water and dispose of such water outside the subject reservoir. Reservoirs potentially eligible for this designation shall be limited to those reservoirs in which oil and/or gas has been bypassed by water encroachment caused by production from the reservoir and such bypassed oil and/or gas may be produced as a result of reservoir-wide high-volume water withdrawals of natural formation water.

(4) "High-volume water withdrawals" means the withdrawal of water from a reservoir in an amount sufficient to dewater portions of the reservoir containing oil and/or gas previously bypassed by water encroachment.

(5) "Co-production" means the permanent removal of water from an oil and/or gas reservoir in an effort to lower the gas-water contact or oil-water contact in the reservoir or to

reduce reservoir pressure to recover entrained hydrocarbons from the reservoir that would not be produced by conventional primary or secondary production methods.

(6) "Operator" means the person responsible for the actual physical operation of an oil or gas well.

(7) "Consecutive months" means months in consecutive order, regardless of whether or not a well produces oil or gas during any or all such months.

(b) High-cost gas as defined in Subsection (a)(2)(A) of this section produced from a well that is spudded or completed between May 24, 1989, and September 1, 1996, is exempt from the tax imposed by this chapter during the period beginning September 1, 1991, and ending August 31, 2001. High-cost gas as defined in Subsection (a)(2)(B) of this section produced from any well regardless of spud date or completion date is eligible for refunds of tax paid and exemption from the tax imposed by this chapter for production occurring during the period beginning the first day of the month after commission approval of a co-production project and ending August 31, 2001; provided, however, in the event co-production ceases, the exemption shall also cease on the first day of the first calendar month that begins on or after the 91st day following the date of termination or co-production operations. Tax must be paid when due at the rate provided in Section 201.052 of this code for all high-cost gas, as defined in Subsection (a)(2)(B) of this section, produced on or before July 31, 1995. On or after September 1, 1995, the operator may apply to the comptroller for a refund and shall be entitled to receive a refund of all taxes paid on such high-cost gas produced on or after the first day of the calendar month after commission approval of the co-production project from which such gas was produced and that is otherwise eligible for the tax exemption.

(c) High-cost gas as defined in Subsection (a)(2)(A) produced from a well that is spudded or completed after August 31, 1996, is entitled to a reduction of the tax imposed by this chapter for the first 120 consecutive calendar months beginning on the first day of production, or until the cumulative value of the tax reduction equals 50 percent of the drilling and completion costs incurred for the well, whichever occurs first. The amount of tax reduction shall be computed by subtracting from the tax rate imposed by Section 201.052 the product of that tax rate times the ratio of drilling and completion costs incurred for the well to twice the median drilling and completion costs for high-cost wells as defined in Subsection (a)(2)(A) spudded or completed during the previous state fiscal year, except that the effective rate of tax may not be reduced below zero.

(d) Taxes must be paid when due at the rate provided in Section 201.052 of this code on all high-cost gas, as defined in Subsection (a)(2)(A) of this section, for wells spudded or completed between September 1, 1996, and August 31, 1997. On or after September 1, 1997, the operator of a well that was spudded or completed and that produced high-cost gas between September 1, 1996, and August 31, 1997, may apply to the comptroller for a refund and shall be entitled to receive a refund of taxes paid in excess of the taxes that would have been due if calculated under Subsection (c). Wells spudded or completed between September 1, 1996, and August 31, 1997, shall also be eligible for the reduced tax under this section for a 120-consecutive-calendar-month period as provided for other wells qualifying under this section. The time period for which an operator is entitled to a refund under this section shall be included for purposes of the calculation of this 120-month period. The period of entitlement for reduced taxation and refund for any qualifying well shall not exceed 120 consecutive calendar months.

(e) The operator of a proposed or existing gas well, including a gas well that has not been completed, or the operator of any proposed or existing oil or gas well within a commission approved co-production project, may apply to the commission for certification that the well produces or will produce high-cost gas. Such application, if seeking certification as high-cost gas according to Subsection (a)(2)(A), may be made at any time after the first day of production. The application may be made but is not required to be made concurrently with a request for a determination that gas produced from the well is high-cost natural gas for purposes of the Natural Gas Policy Act of 1978 (15 U.S.C. Section 3301 et seq.) or with a request for commission approval of a co-production project. The commission may require an applicant to provide the commission with any relevant information required to administer this section. For purposes of this section, a determination that gas is high-cost natural gas according to Subsection (a)(2)(A) or a determination that gas is produced from within a commission approved co-production project is a certification that the gas is high-cost gas for purposes of this section, and in that event additional certification is not required to qualify for the exemption or tax reduction provided by this section.

(f) To qualify for the exemption or tax reduction provided by this section, the person responsible for paying the tax must apply to the comptroller. The application must contain the certification of the commission that the well produces high-cost gas and, if the application is for a well spudded or completed after September 1, 1995, must contain a report of drilling and completion costs incurred for each well on a form and in the detail as determined by the comptroller. Drilling and completion costs for a recompletion shall only include current and contemporaneous costs associated with the recompletion. Notwithstanding any other provision of this section, to obtain the maximum tax exemption or tax deduction, an application to the comptroller for certification according to Subsection (a)(2)(A) must be filed with the comptroller at the later of the 180th day after the date of first production or the 45th day after the date of approval by the commission. If the application is not filed by the applicable deadline, the tax exemption or tax deduction is reduced by 10 percent for the period beginning on the 180th day after the first day of production and ending on the date on which the application is filed with the comptroller. An application to the comptroller for certification according to Subsection (a)(2)(B) may not be filed before January 1, 1990, or after December 31, 1998. The comptroller shall approve the application of a person who demonstrates that the gas is eligible for the exemption or tax reduction. The comptroller may require a person applying for the exemption or tax reduction to provide any relevant information in the person's monthly report that the comptroller considers necessary to administer this section. The commission shall notify the comptroller in writing immediately if it determines that an oil or gas well previously certified as producing high-cost gas does not produce high-cost gas or if it takes any action or discovers any information that affects the eligibility of gas for an exemption or tax reduction under this section.

(g) As soon as practicable after March 1 of each year, the comptroller shall determine from reports containing drilling and completion cost data as required on applications to the comptroller under Subsection (f), the median drilling and completion cost for all high-cost wells as defined in Subsection (a)(2)(A) for which application for exemption or reduced tax was made during the previous state fiscal year. Those median drilling and completion costs shall be used to compute the reduced tax under Subsection (c).

(h) Information regarding drilling and completion costs included on an application under Subsection (f) is confidential and may not be disclosed, except to the extent aggregated with other similar information to produce industry averages. Unauthorized disclosure is an offense subject to the same penalty as provided by Section 111.007 for unauthorized disclosure of federal tax return information.

(i) If, before the commission certifies that a well produces high-cost gas or before the comptroller approves an application for an exemption or tax reduction under this section, the tax imposed by this chapter is paid on high- cost gas that otherwise qualifies for the exemption or tax reduction provided by this section, the producer or producers of the gas are entitled to a credit against other taxes imposed by this chapter in an amount equal to the amount of the tax paid on the gas that otherwise qualified for the exemption or tax reduction on or after the first day of the next month after the month in which the application for certification under this section was filed with the commission. If the application for certification is submitted to the commission after January 1, 2004, the total allowable credit for taxes paid for reporting periods before the date the application is filed may not exceed the total tax paid on the gas that otherwise qualified for the exemption or tax reduction and that was produced during the 24 consecutive calendar months immediately preceding the month in which the application for certification under this section was filed with the commission. The credit is allocated to each producer according to the producer's proportionate share in the gas. To receive a credit, one or more of the producers must apply to the comptroller for the credit not later than the first anniversary after the date the comptroller approves the application for an exemption or tax reduction under this section. If a producer demonstrates that the producer does not have sufficient tax liability under this chapter to claim the credit within five years from the date the application for the credit is made, the producer is entitled to a refund in the amount of any credit the comptroller determines may not be claimed within that five years. Nothing in this subsection shall relieve the obligation imposed by Subsection (b) to pay tax when due on high-cost gas produced from co-production projects on or before July 31, 1995.

(j) An applicant for commission approval of a co-production project shall submit a written application for approval to the commission. Such application must be filed before January 1, 1994. The applicant shall provide the commission with any relevant information required to administer this section, including evidence demonstrating that the reservoir is eligible for the designation and demonstrating the minimum volumes of high-volume water withdrawal required to recover oil and/or gas from the reservoir that would not be produced by conventional production methods. A commission representative may administratively approve the application. If the commission representative denies administrative approval, the applicant shall have the right to a hearing upon the request.

Added by Acts 1989, 71st Leg., ch. 1197, Sec. 1, eff. Sept. 1, 1989. Amended by Acts 1993, 73rd Leg., ch. 958, Sec. 1, eff. Sept. 1, 1993; Acts 1995, 74th Leg., ch. 895, Sec. 1, eff. Sept. 1, 1995; Acts 1997, 75th Leg., ch. 1040, Sec. 52, 53, eff. Sept. 1, 1997; Acts 1999, 76th Leg., ch. 365, Sec. 1, eff. Aug. 30, 1999; Acts 2003, 78th Leg., ch. 209, Sec. 52, eff. Oct. 1, 2003; Acts 2003, 78th Leg., ch. 1310, Sec. 110, eff. Sept. 1, 2003.

APPENDIX B

10-157 (Rev.6-12/3) AAAA

b. ■

a. ■ 37180

You have certain rights under Chapters 552 and 559, Government Code, to review, request and correct information we have on file about you. Contact us at the address or phone number listed on this form.

Texas Comptroller of Public Accounts
PURCHASER REPORT OF NATURAL GAS TAX

c. Taxpayer number	d. Due date	e. Filing period	f.	h. ■ FM i. ■
■			■	

Taxpayer name and mailing address

g.

1 ■ Blacken this box if your address has changed. Show changes by the preprinted information.

2 ■ FINAL REPORT - Blacken this box if you are no longer in business and enter the last business date

j. *If you have nothing to report for ALL leases for this filing period, blacken this box, sign and date this report, and return it to the Comptroller's office.* ▶

REPORT TOTALS AND TAX COMPUTATION (See instructions)

A REPORT MUST BE FILED EVEN IF NO TAX IS DUE

1. **Total net taxable value of condensate** *(Enter dollars and cents.)* .... 1. ■ $
2. **Tax due on condensate** *(Multiply Item 1 by . Enter dollars and cents.)* .... 2. ■ $
3. **Total net taxable value of gas (Excluding leases with exemption Type 05 high cost gas)** *(Enter dollars and cents.)* .... 3. ■ $
4. **Tax due on gas (Excluding leases with exemption Type 05 high cost gas)** *(Multiply Item 3 by . Enter dollars and cents.)* .... 4. ■ $
5. **Taxable regulatory fee volume** *(See instructions. Round volume to whole numbers.)* .... 5. ■
6. **Regulatory fee due** *(Multiply Item 5 by . Enter dollars and cents.)* .... 6. ■ $
7. **Tax due on leases with exemption Type 05 high cost gas** *(Total of Item 22 from attached Lease Detail Supplements, Form 10-171. Enter dollars and cents.)* .... 7. ■ $
8. **Total tax and fee due** *(Add Items 2, 4, 6 and 7. Enter dollars and cents.)* .... 8. ■ $

NATURAL GAS TAX QUESTION?
CALL US
1-800-252-1384

10-157 (Rev.6-12/3)

**** * * DO NOT DETACH * * ****

9. **Credits** *(NOT valid without attached Credit Transfer Form for Natural Gas Tax, Form 10-147)* .... 9. $
10. **Net amount due** *(Item 8 minus Item 9)* .... 10. $
11. **Penalty & Interest** *(If report is filed or tax paid after the due date, see instructions.)* .... 11. $
12. **TOTAL AMOUNT DUE AND PAYABLE** *(Item 10 plus Item 11)* .... 12. ■ $

Taxpayer name

l.

■ T Code ■ Taxpayer number ■ Period

37020

Make the amount in Item 12 payable to: **State Comptroller**

I declare that the information in this document and any attachments is true and correct to the best of my knowledge and belief.		Mail to: Comptroller of Public Accounts P.O. Box 149358 Austin, TX 78714-9358
Print name	Business phone *(Area code and number)*	
sign here ▶ Taxpayer or duly authorized agent	Date	m. ■

777

Instructions for Completing
Texas Purchaser Report of Natural Gas Tax

Who Must File - Every first purchaser and/or processor of natural gas produced in Texas who takes delivery at the lease are required to file a Natural Gas Tax Purchaser Report. If the purchaser natural gas tax account is active, then this report must be filed even if no transactions occurred.

When to File - This report must be filed or postmarked on or before the 20th day of the second month following the month of production. If the due date falls on a Saturday, Sunday or legal holiday, the next business day will be the due date.

For Assistance - For assistance, please call 1-800-252-1384 or 512-463-4600. Forms and additional information are available online at **www.window.state.tx.us**.

General Information

- This report must be accompanied by all Lease Detail Supplement pages (Form 10-161). It is recommended that the supplement pages be completed prior to completing the Report Totals and Tax Computation page.
- Do NOT report corrections to previous filing periods on this report. The "Amended Natural Gas Tax - Purchaser Report" (Form 10-167) must be filed to correct previously reported data or to report data omitted from your original report.
- Do NOT write in shaded areas.

Specific Information

Item c. Taxpayer Number: Enter your 11-digit taxpayer number assigned by the Comptroller's office.

Item e. Filing Period: Enter the month and year for the filing period. Example: March 2007.

Item 1. Total Net Taxable Value of Condensate: Enter the total amount of all net taxable value of condensate from Item 20 of the Lease Detail Supplement page(s). Enter dollars and cents.

Item 2. Tax Due on Condensate: Enter the tax due amount on condensate by multiplying the value in Item 1 of this page by 0.046 (or 4.6%). Enter dollars and cents.

Item 3. Total Net Taxable Value of Gas: Enter the total net taxable value of gas for all commodities in Item 20 of the Lease Detail Supplement page(s), except for values that correspond with exemption "Type 5" leases and condensate values. Enter dollars and cents.

Item 4. Tax Due on Gas: Enter the tax due amount on gas by multiplying the net taxable value of gas in Item 3 of this page by 0.075 (or 7.5%). Enter dollars and cents.

Item 5. Taxable Regulatory Fee Volume: Enter the sum of your volume for all leases reported in Item 14 of the Lease Detail Supplement page(s) that includes the commodities of raw gas (RG), lease use (LU), and products (PR) less the total of all the governmental royalty volume reported in Item 17. Include volumes for residue gas (RS) unless the residue volume is included as part of the plant product or raw gas volume. Only include leases marked "Yes" as liable for tax due in Item 16. Leases with approved exemptions that report "Yes" as being liable for tax for the raw gas (RG), lease use (LU) and product (PR) commodities are subject to the regulatory fee. The exception is leases that are approved for the reactivated orphan well exemption are not subject to the regulatory fee. Enter whole numbers.

Item 6. Regulatory Fee Due: Enter the regulatory fee due amount by multiplying the volume in Item 5 of this page by 0.000667. Enter dollar and cents.

Item 7. Tax Due on Exemption Type 5: Enter the sum of all the reduced tax due amounts reported with exemption "Type 5" leases in Item 22 of the Lease Detail Supplement page(s). Enter dollar and cents.

Item 8. Total Tax and Fee Due: Enter the total tax and fee due amount by adding the amounts indicated in Items 2, 4, 6 and 7 of this page. Enter dollar and cents.

Item 9. Credits: Enter a credit amount if using a credit from another filing period to offset the liability in this filing period. In order to process the transfer of credit, the "Credit Transfer Form for Natural Gas Tax" (Form 10-147) must be signed and submitted.

Item 10. Net Amount Due: Enter the net amount due by subtracting Item 8 from Item 9 of this page. Enter dollar and cents.

Item 11. Penalty & Interest: If payment is 1-30 days late, a 5 percent penalty is assessed on the tax balance due. If a balance is remaining after 30 days, an additional 5 percent penalty is assessed on the tax balance due. Interest begins to accrue on the 61st day after the due date of a filing period. The interest rate varies annually. For current interest rate information, call the Comptroller at 1-877-447-2834 or visit our website at **www.window.state.tx.us/taxinfo/int_rate.html**.

Item 12. TOTAL AMOUNT DUE AND PAYABLE: Add the amounts in Item 10 and Item 11. Make the amount in Item 12 payable to **State Comptroller**.

10-161 (Rev.6-12/5)

BBBB

b. ■

a. ■ 37100

• *See instructions on back.*

Page ______ of ______

Texas Report of Natural Gas Tax
-- Purchaser Lease Detail Supplement --

c. Taxpayer number ■

NATURAL GAS TAX QUESTION? CALL US 1-800-252-1384

d. Filing period

e. Taxpayer name

f.

HP

1. Lease name (as recorded with the Railroad Commission)
2. County of production
3. Commodity *(Use the alpha codes listed in the instructions.)*
4. Commodity code *(Numeric)* ■
5. Lease type ■ OIL 1 GAS 2
6. County code ■
7. Lease number ■ Check digit
8. Is Item 7 a drilling permit number? ■ YES 1 NO 2
9. Exemption type ■
10. API number ■
11. Producer's name
12. Producer taxpayer number ■
13. Is tax reimbursement included in calculating the value on this lease? ■ YES 1 NO 2
14. Your volume ■
15. Value of your volume $ ■
16. Are you liable for the tax? ■ YES 1 NO 2

If "NO" in Item 16, do not complete Items 17 thru 22.

17. Governmental royalty volume ■
18. Governmental royalty value $ ■
19. Marketing cost $ ■
20. Net taxable value $ ■

Items 21 and 22 for Exemption Type 05 leases only.

21. Reduced tax rate for Type 05 ■
22. Tax due on Type 05 $ ■

1. Lease name (as recorded with the Railroad Commission)
2. County of production
3. Commodity *(Use the alpha codes listed in the instructions.)*
4. Commodity code *(Numeric)* ■
5. Lease type ■ OIL 1 GAS 2
6. County code ■
7. Lease number ■ Check digit
8. Is Item 7 a drilling permit number? ■ YES 1 NO 2
9. Exemption type ■
10. API number ■
11. Producer's name
12. Producer taxpayer number ■
13. Is tax reimbursement included in calculating the value on this lease? ■ YES 1 NO 2
14. Your volume ■
15. Value of your volume $ ■
16. Are you liable for the tax? ■ YES 1 NO 2

If "NO" in Item 16, do not complete Items 17 thru 22.

17. Governmental royalty volume ■
18. Governmental royalty value $ ■
19. Marketing cost $ ■
20. Net taxable value $ ■

Items 21 and 22 for Exemption Type 05 leases only.

21. Reduced tax rate for Type 05 ■
22. Tax due on Type 05 $ ■

Texas Report of Natural Gas Tax Purchaser Lease Detail Supplement

For assistance call 1-800-252-1384 or 512-463-4600. Information is also available online at www.window.state.tx.us.

Specific Instructions

Volumes: Report all gas volumes in "MCF" (1000 cubic feet at a pressure base of 14.4 pounds plus 4 ounces or 14.65 pounds absolute). For information on converting MCF to MMBTU or converting MMBTU to MCF, see the Natural Gas Tax Guide on the Comptroller's website. Do not report any volume amounts with decimals. Round the volume amount to the next whole number.

Items 1, 2, 5, 7 and 8.

- Enter the lease identification number assigned by the Texas Railroad Commission (RRC) in Item 7. For a gas lease, enter the 6-digit lease number. For an oil lease, add a leading zero (0) to the 5-digit lease number and enter as a 6-digit number. If the RRC has not assigned a lease number, then enter the 6-digit drilling permit number in Item 7.
- Items 7 and 8: Do not leave blank.
- If reporting a plant, then enter R3 and the last four digits of the plant identification number assigned by the RRC in Item 7.

Item 3. Commodity: Enter the 2-digit alpha code for the type of commodity reported on the lease identified in Item 7.

- **Raw Gas (RG)** - Sale or purchase of raw gas, unprocessed gas from an oil well or gas well gas.
- **Lease Use (LU)** - All gas produced and used to run equipment on the lease regardless of whether it is for oil well, gas well gas or residue gas. The lease use item will also include miscellaneous sales of gas to persons not normally engaged in purchasing gas for resale.
- **Condensate (CN)** - The taxable disposition and production of all condensate from a gas well, actual or theoretical. Condensate is the liquid hydrocarbon (a high gravity oil) that is or can be, removed from gas by a separator. It does not include absorption and separation by a fractionating process. Condensate volume should be rounded to the nearest barrel.
- **Residue (RS)** - Residue gas sold or purchased only when there is a distinct sale or purchase of residue gas. Example: If a processing plant takes title to both the products and residue commodities, do not report the products and residue commodities as separate items. Use the raw gas designation and enter the plant operator as the purchaser.
- **Products (PR)** - Report only when the purchasers of products and residue commodities are different parties. The volume associated with the product commodity will be the raw gas volume delivered to the gas processing plant (plant inlet volume).

Item 4. Commodity Code: Enter the numeric code for the type of commodity reported on the lease identified in Item 1 and Item 7. The numeric codes are: **1** - Raw Gas, **4** - Condensate, **5** - Residue, **6** - Products.

Item 6. County Code: Enter the 3-digit county code for the county of production indicated in Item 2. A list of county codes is available on the Comptroller's website at www.window.state.tx.us\taxinfo\taxforms\10-codes.html or in the Natural Gas Tax Guide.
Check Digit: If not known, the check digit is available at https://ecpa.cpa.state.tx.us/cong/checkDigitForward.do.

Item 9. Exemption Type: Enter the Comptroller approved numeric code for the legislative exemption type, if applicable.

- **03** - Two-year inactive well, effective Sept. 1, 1997
- **04** - Flared/released casinghead gas well, effective Sept. 1, 1997
- **05** - High cost gas lease with reduced tax rate, effective Sept. 1, 1996
- **07** - Three-year inactive well, effective Sept. 1, 1991
- **09** - Incremental production casinghead gas lease, effective Sept. 1, 1997
- **11** - Qualifying low-producing gas well, effective Sept. 1, 2005
- **12** - Reactivated orphaned well, effective Jan. 1, 2006
- **15** - Geothermal energy, effective Sept. 1, 2009

Item 10. API Number: Enter the last 8 digits of the America Petroleum Institute (API) number assigned by the RRC to each well that qualifies for a well-level exemption. The API number is only required for the two-year inactive well exemption (Type 3), three-year inactive well exemption (Type 7) and reactivated orphaned well exemption (Type 12).

Item 13. Tax Reimbursement: Mark the block indicating whether tax reimbursement is included in calculating the value in Item 15. For information on tax reimbursement, see Tax Rule 3.18, at www.window.state.tx.us.

Item 14. Your Volume: Enter the total volume of gas or condensate purchased. Do not use decimals.

Item 15. Value of Your Volume: Enter the entire value associated with the volume indicated in Item 14. This is usually referred to as the "contract price." Do not include tax reimbursement, if applicable. Round all volumes up to the nearest whole number.

Item 16. Are You Liable for Tax? Enter "YES" or "NO" for all lease types, even if you do not owe tax. Do not leave blank. Tax liability must be reported as "YES" by at least one party as stated in the contract between the operator and the purchaser, even if the lease qualifies for 100% exemption and taxes are not due because of the legislative exemption status.

Item 17. Governmental Royalty Volume: Enter the volume of gas not subject to tax due to governmental exempt status, such as a city, town or county government in Texas, a school district in Texas, public (state owned) colleges and universities in Texas or political subdivisions of the Federal government. See Rule 3.14.

Item 18. Governmental Royalty Value: Enter the value of the volume for the gas reported in Item 17. Do not enter volumes associated with lease types approved for a legislative tax exemption.

Item 19. Marketing Cost: Enter actual marketing cost incurred. The "market value at the mouth of the well" shall be determined by ascertaining the actual marketing costs incurred by the producer and subtracting these costs from the producer's gross cash receipts from the sale of the gas. For detailed information on allowable marketing costs, visit www.window.state.tx.us/taxinfo/nat_gas/ap56a.htm.

Item 20. Net Taxable Value: Enter the calculation of Item 15, less Items 18 and 19. If Items 18 and 19 exceed Item 20, enter the net taxable value as zero in Item 20. If reporting the following exemption types, then enter net taxable values indicated below:

Exempt Type	Enter the net taxable value as:
03, 04, 07, 12 or 15	zero
05	the sum of Item 15, less Items 18 and 19 and proceed to Items 21 and 22
09	50% of the sum of Item 15, less Items 18 and 19
for 25% exemption **11**	75% of the sum of Item 15, less Items 18 and 19 if the Comptroller certified price of gas ranges from \$3.01 to \$3.50/MCF
for 50% exemption **11**	50% of the sum of Item 15, less Items 18 and 19 if the Comptroller certified price of gas ranges from \$2.51 to \$3.00/MCF
for 100% exemption **11**	zero if the Comptroller certified price of gas is less than or equal to \$2.50/MCF

Item 21. Reduced Tax Rate for Type 05: Enter the 3-digit reduced tax rate for the approved exemption Type 5 lease indicated in Item 7.

Item 22. Tax Due on Type 05: Enter the tax due amount for the approved exemption Type 5 lease reported by multiplying Item 20 times the tax rate indicated in Item 21.

APPENDIX C

America's New Energy Future:
The Unconventional Oil and Gas Revolution and the US Economy

Volume 2 – State Economic Contributions

State Economic Contributions: Highlights

Prepared by:

IHS Inc.
1150 Connecticut Avenue NW, Suite 401
Washington, DC 20036

December 2012

TEXAS

OVERVIEW

The Texas economy is one of the country's main engines of growth. Post-recession payrolls in Texas have been expanding since 2010, and Texas, as of December 2011, was the second state in the nation to recoup all of its recessionary job losses (after Alaska). From peak to trough, Texas lost just over 430,000 jobs during the recession, or 4.1% of total payrolls. Oil and gas jobs have been a significant factor in the state's return to economic health. With oil prices falling from their recent highs, payroll expansion in the mining sector has slowed but continues to have a positive impact. The unemployment rate in Texas continues to gradually trend lower from its high of 8.7% in June 2010.

The Texas economy will expand at a moderate pace in the next few years, remaining one of the nation's top performers. The construction and professional-business services sectors will remain the main sources of new jobs. Payrolls in the state will gather momentum in 2013 and accelerate until 2015, averaging 2.2% annually between 2012 and 2017, placing Texas fifth in the country in terms of medium-term growth. But unlike Texas, other states in the top five – Florida and Arizona – were among the hardest hit by the recession and are posting high growth rates from a very low base. The fastest-growing sectors in Texas over the medium term are expected to be professional-business services and education-health services.

From 2012-17, the mining and manufacturing sectors, which are heavily dependent on the oil and gas industry, are projected to increase payrolls by 1.3% and 1.9%, respectively. Exploration in the Eagle Ford Shale will provide a large share of those jobs. Given San Antonio's proximity to the majority of shale play sites, Bexar County is likely to have a significant role in staging exploration, and the energy boom is expected to bring in new investment and generate thousands of jobs in San Antonio as well as other areas of south Texas. Energy companies such as EOG Resources and Chesapeake Energy have already opened satellite offices in the metro area, but the biggest announcement so far has come from oil-field services giant Halliburton. At the end of 2011, Halliburton began work on a $50-million base of operations in San Antonio, requiring 1,500 workers to support its operations in the Eagle Ford Shale. The company said it hopes to fill 75%, or more than 1,100, of these high-paying positions by hiring locally. Other oil-field services companies coming to San Antonio include Houston-based Baker Hughes, Inc., which announced plans to build a $30-million operations center and administrative headquarters employing 400 in southeastern Bexar County. Meanwhile, Schlumberger Ltd., the world's largest oil-field services company, has told local economic development officials that it wishes to establish a site in southern Bexar County as well.

CONTRIBUTION OF UNCONVENTIONAL OIL AND GAS

Texas is the country's leading provider of both conventional and unconventional crude oil and natural gas. Of the state's 254 counties, 223 are active in oil and gas production. Twenty of the nation's top 100 conventional oil fields are located in Texas' Permian Basin, and the state's crude oil reserves represent almost one-fourth of the US total. Texas natural gas reserves, meanwhile, account for almost 30% of total US reserves, and the state is the country's leading natural gas producer, accounting for nearly one-third of total domestic production at 22.4 bcf/day. The largest gas fields are heavily concentrated in the East Texas Basin in the northeastern part of the state.

Several of the nation's most important unconventional oil plays dot the Texas landscape. Production in the rapidly growing Eagle Ford play located in south Texas reached 500,000 barrels of liquids per day in June of this year, up from an average of 175,000 barrels per day during 2011. Some communities in south Texas have had difficulty absorbing the demand for infrastructure, housing and services due to the speed of the development. Historically, the Permian Basin has been the most prolific oil producing region in the country. Unconventional oil plays of interest from that basin include the Sprayberry and Bone Spring plays which are experiencing substantial production increases, and the emerging Wolfcamp Shale which may ultimately rival the Eagle Ford in production and drilling. Activity continues in the Barnett Shale Gas play, which was the first of its kind. Barnett production remains constant at 5 bcf/day. Another important play, the Granite Wash located in the Texas Panhandle, is an example of how horizontal drilling has transformed a dying tight sand play into one of the premier plays in North America. As development continues in this liquids-rich play, IHS anticipates that its production will exceed that of many of the noteworthy plays, such as the Barnett and Haynesville. Activity has dropped somewhat in the Cotton Valley and Bossier plays located in East Texas due to low gas prices, but these will remain important as gas prices firm and new technology is developed. Wet gas plays have a higher economic value as producers can garner additional revenues from associated condensate as well as natural gas liquids which can be extracted from the gas stream. As gas prices are expected to remain low, these plays, which include portions of the Eagle Ford, Barnett and Cotton Valley plays, will be preferentially developed.

The economic activity associated with unconventional oil and gas directly and indirectly supported nearly 576,000 jobs in the state in 2012.[12] This number represents 65% of the state's total manufacturing jobs. The state's unconventional oil and gas-related employment is expected to increase to 733,000 jobs by 2035. These jobs would employ 4.2% of the total state labor force by 2035, helping to reduce unemployment and creating a steady source of payroll growth for the next two decades.

Unconventional oil and gas activity contributed value-added economic activity of $101 billion in Texas in 2012. We forecast that this contribution will grow to $125 billion by 2035. As for labor income, the average annual wage in Texas in 2012 is $59,000, while the average wage of direct jobs in unconventional oil and gas activity is $155,000, so these jobs provide an enormous boost to quality of life and family income for state residents employed by the industry.

There is also the contribution of unconventional oil and gas employment to government revenues. In Texas in 2012, it will generate over $22 billion in taxes for state and federal coffers. This includes $10.2 billion in state and local taxes – or a whopping 24% of the state's total budget. We estimate that unconventional oil and gas activity generated $10.2 billion in state and local revenues, the equivalent of about 15% of the education and 18% of the state's healthcare budget.

[12] Direct jobs are those created by firms that comprise the oil and gas industry, or by the capital expenditures of related industries; indirect jobs are those created by suppliers of goods and services to industry. Induced jobs are those that meet the new demand for consumer goods created by the increased income generated by the direct and indirect jobs.

Texas Economic Contribution Summary: Total Unconventional Oil and Gas Activity

Employment

	Direct	Indirect	Induced	Total
2012	159,474	171,204	245,406	576,084
2020	236,976	282,538	409,968	929,482
2035	161,320	234,357	337,502	733,179

Value Added

	Direct	Indirect	Induced	Total
2012	56,729	24,318	20,585	101,633
2020	93,409	39,287	35,862	168,558
2035	62,970	32,728	30,003	125,701

Labor Income

	Direct	Indirect	Induced	Total
2012	24,674	12,892	11,317	48,883
2020	37,609	20,877	18,695	77,181
2035	27,916	17,591	15,783	61,291

NOTES: Numbers may not sum due to rounding.

Source: IHS Global Insight

Contribution of Total Unconventional Oil and Gas Activity to Government Revenue and Private Lease Payments: Texas

($M)

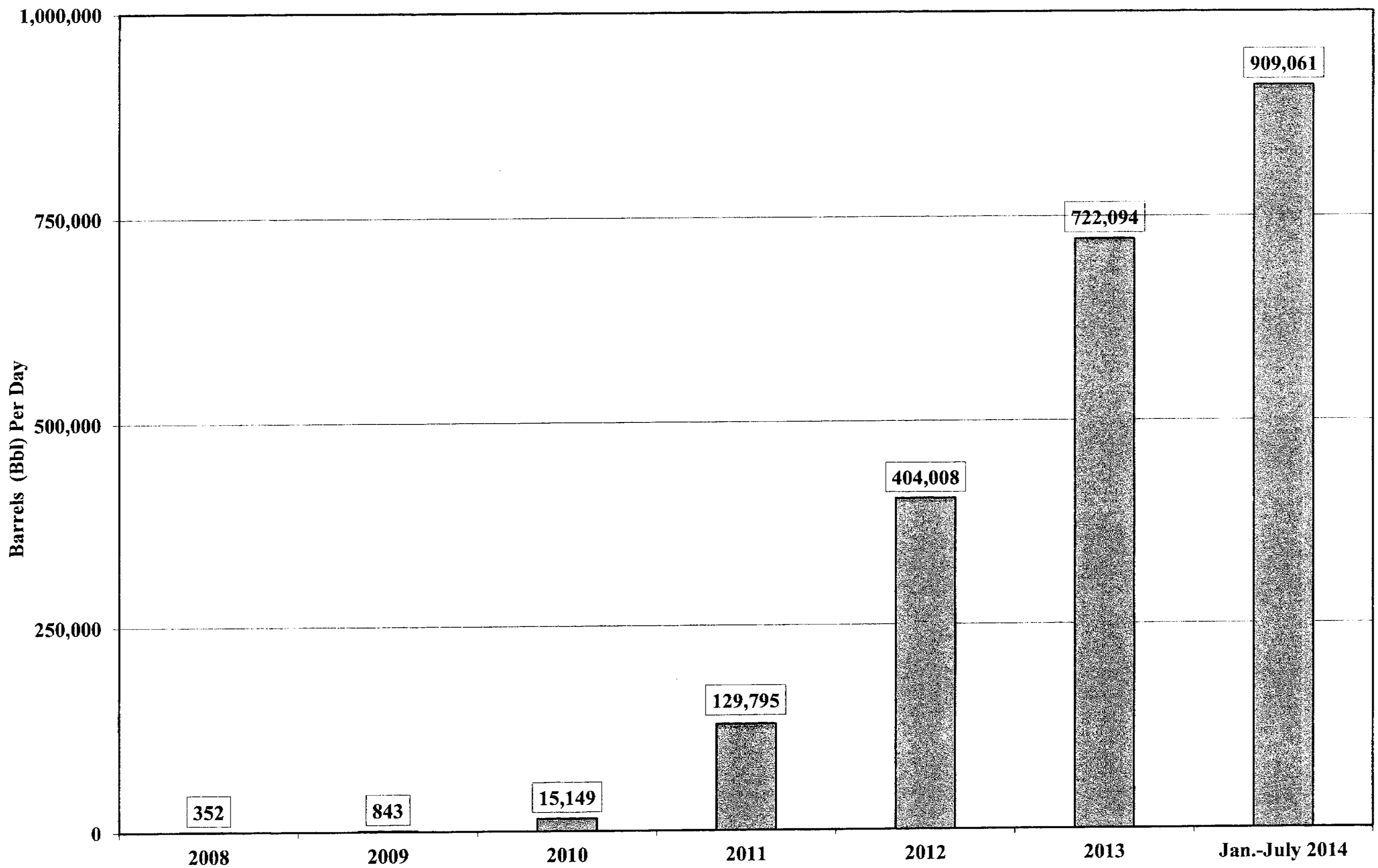
	2012	2020	2035	2012-2035*
Federal Taxes	**11,888**	**19,217**	**14,797**	**394,030**
Personal Taxes	8,668	13,644	10,871	282,554
Corporate Taxes	3,180	5,506	3,880	109,993
Federal Royalty Payments	23	50	40	1,145
Federal Bonus Payments	16	17	7	338
State and Local Taxes	**10,280**	**19,321**	**13,859**	**396,954**
Personal Taxes	0	0	0	0
Corporate Taxes	6,564	10,910	6,974	213,536
Severance Taxes	2,641	6,038	5,065	132,924
Ad Valorem Taxes	963	2,132	1,648	45,495
State Royalty Payments	110	239	170	4,955
State Bonus Payments	2	2	1	44
Total Government Revenue	**22,168**	**38,538**	**28,656**	**790,984**
Lease Payments to Private Landowners	**231**	**408**	**330**	**9,180**

NOTES: *2012-2035 represents the total for all years including those years not reported.

Source: IHS Global Insight

APPENDIX D

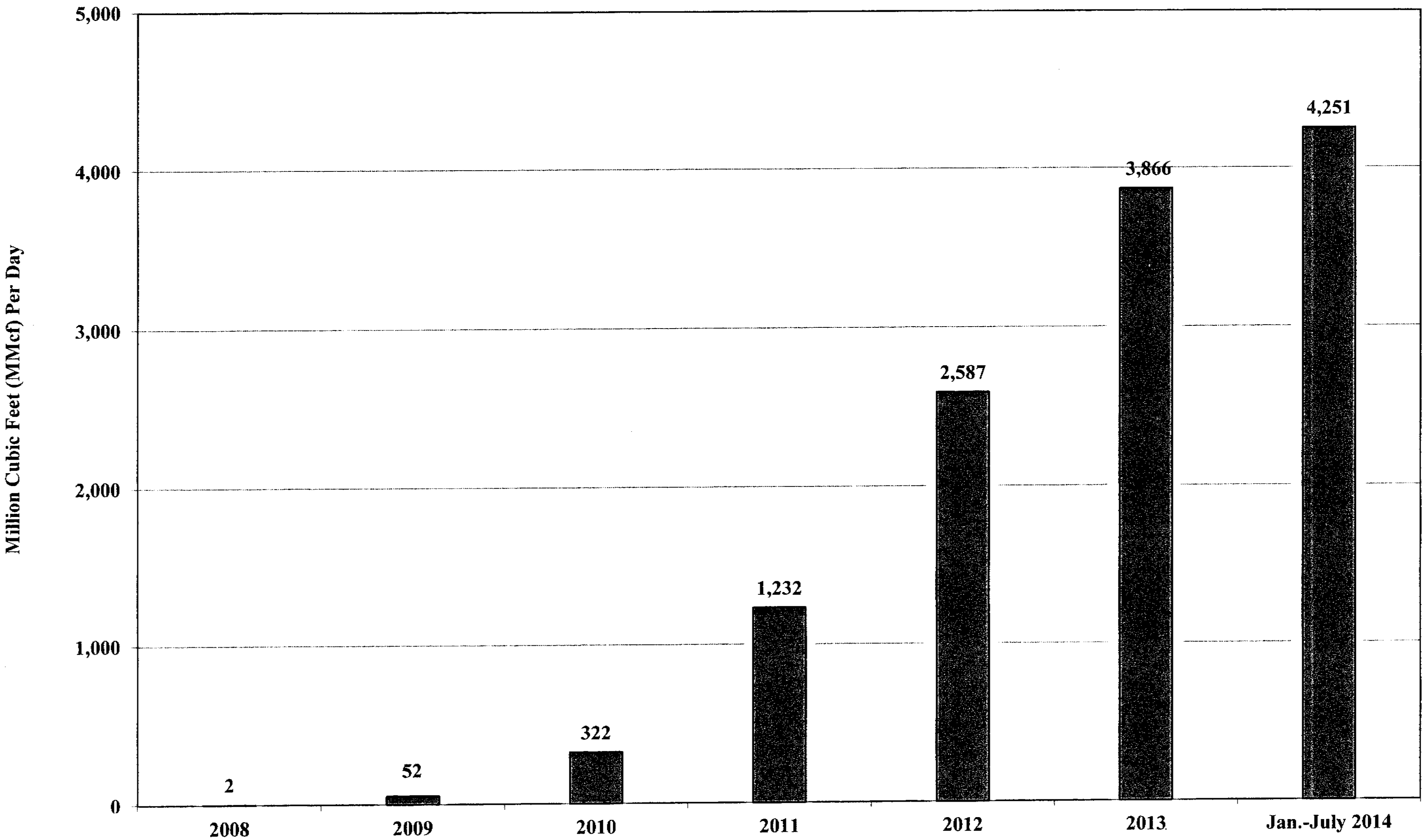
Texas Eagle Ford Shale
Oil Production
2008 through July 2014



09/24/2014

Source: Railroad Commission of Texas Production Data Query System (PDQ)

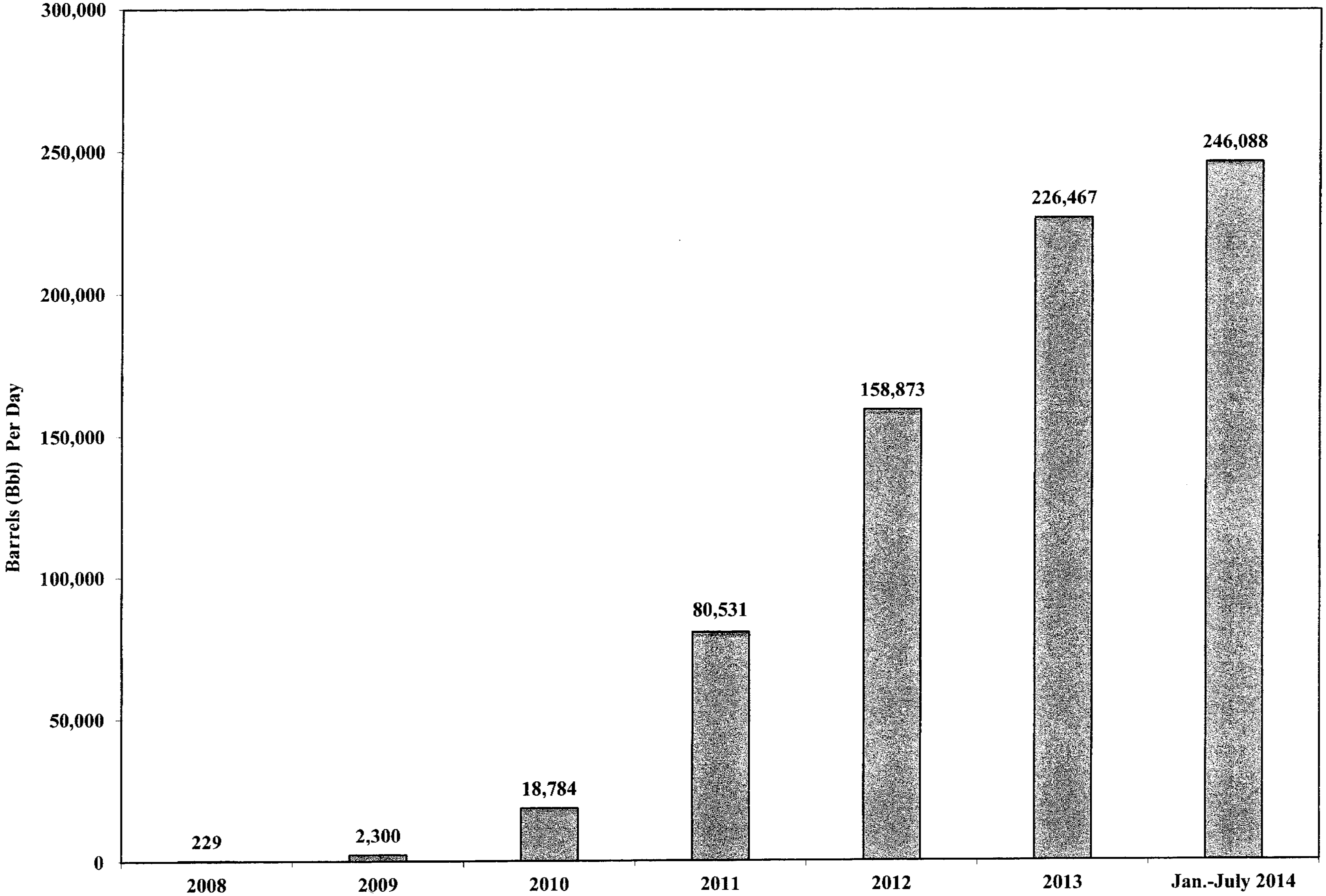
Texas Eagle Ford Shale
Total Natural Gas Production
2008 through July 2014



Source: Railroad Commission of Texas Production Data Query System (PDQ)

09/24/2014

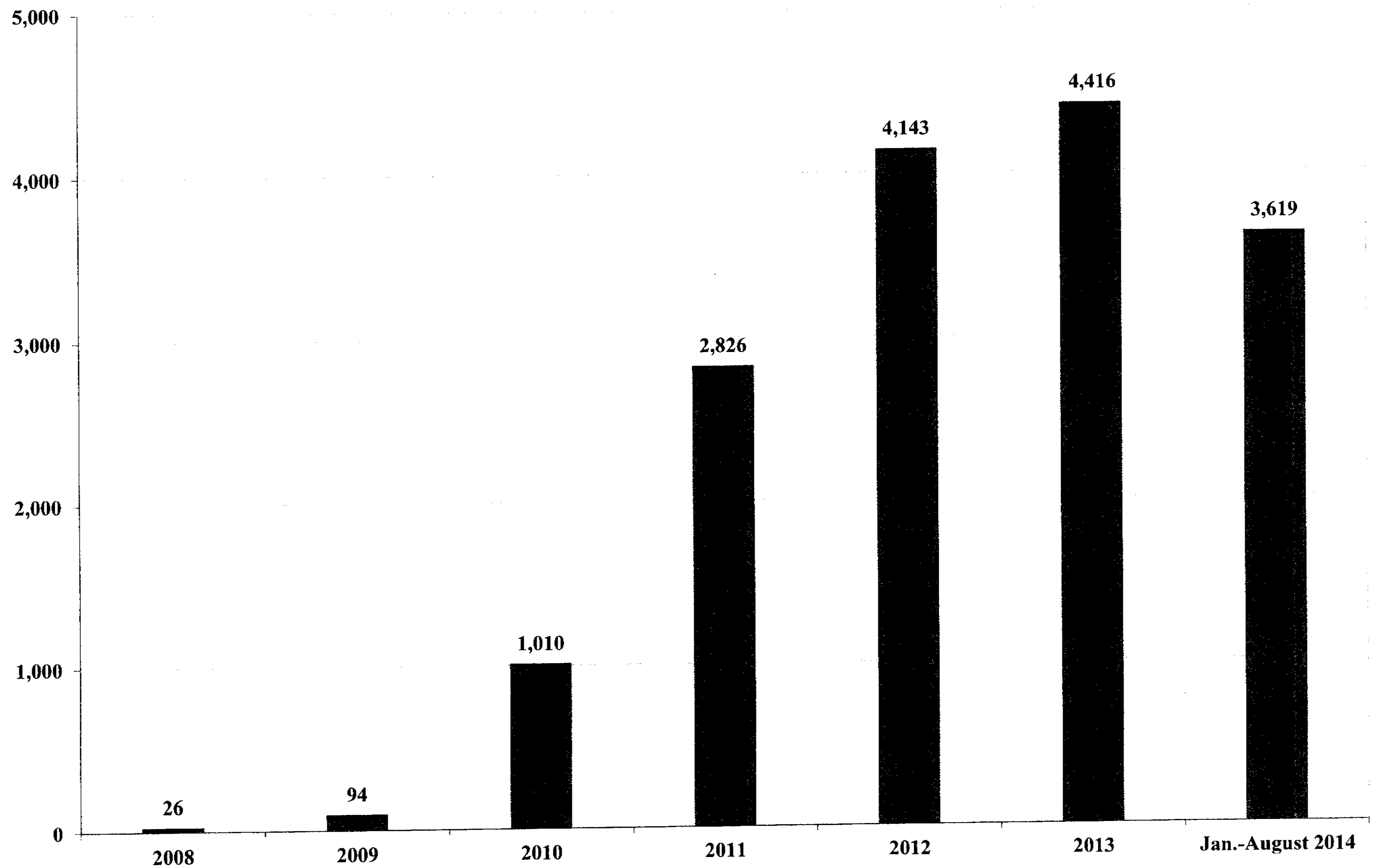
Texas Eagle Ford Shale Condensate Production 2008 through July 2014



09/24/2014

Source: Railroad Commission of Texas Production Data Query System (PDQ)

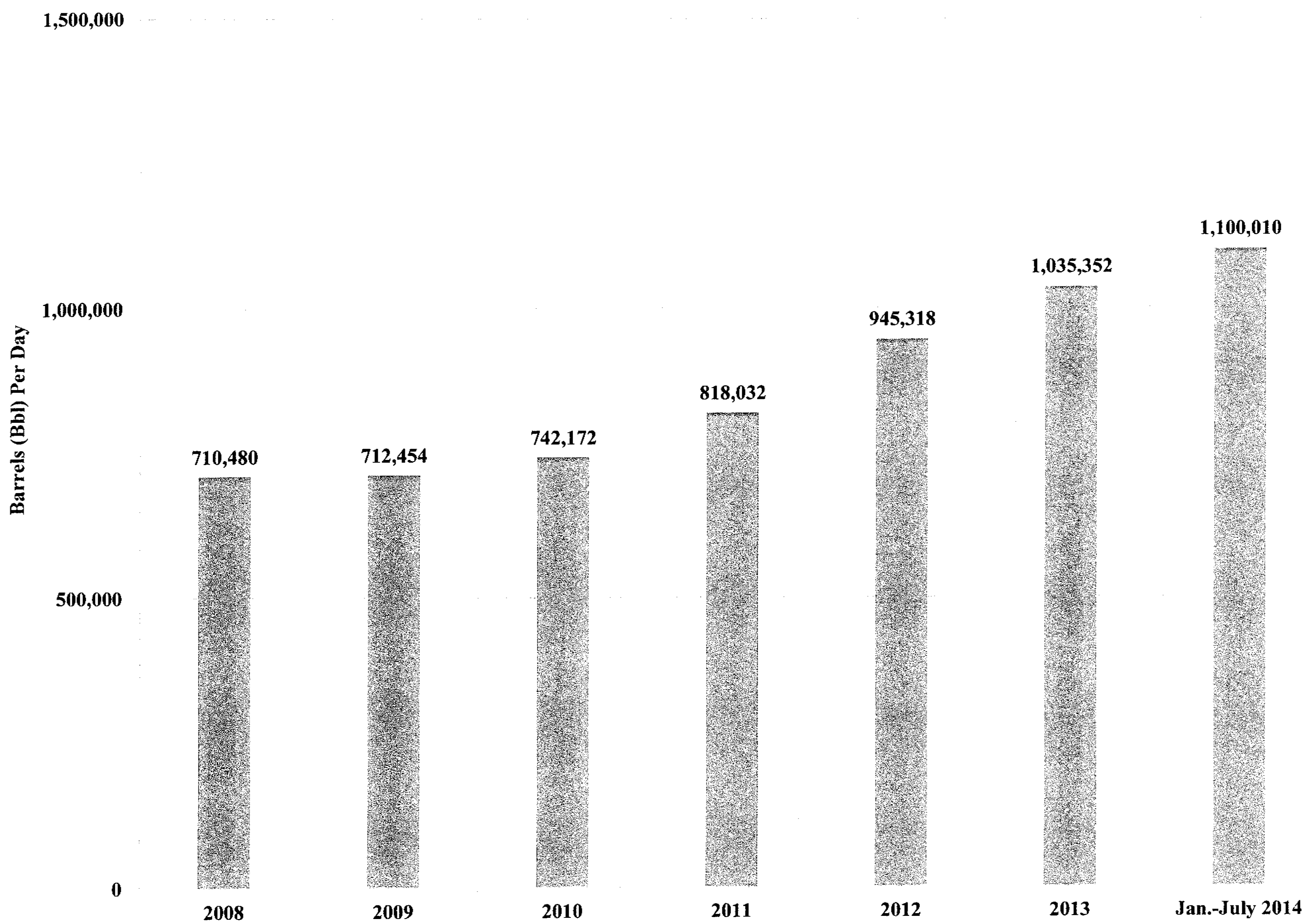
Texas Eagle Ford Shale Drilling Permits Issued 2008 through August 2014



Source: Texas Railroad Commission DrillingPermitQuery(Includes New Drill & ReEnter Permits)

09/09/2014

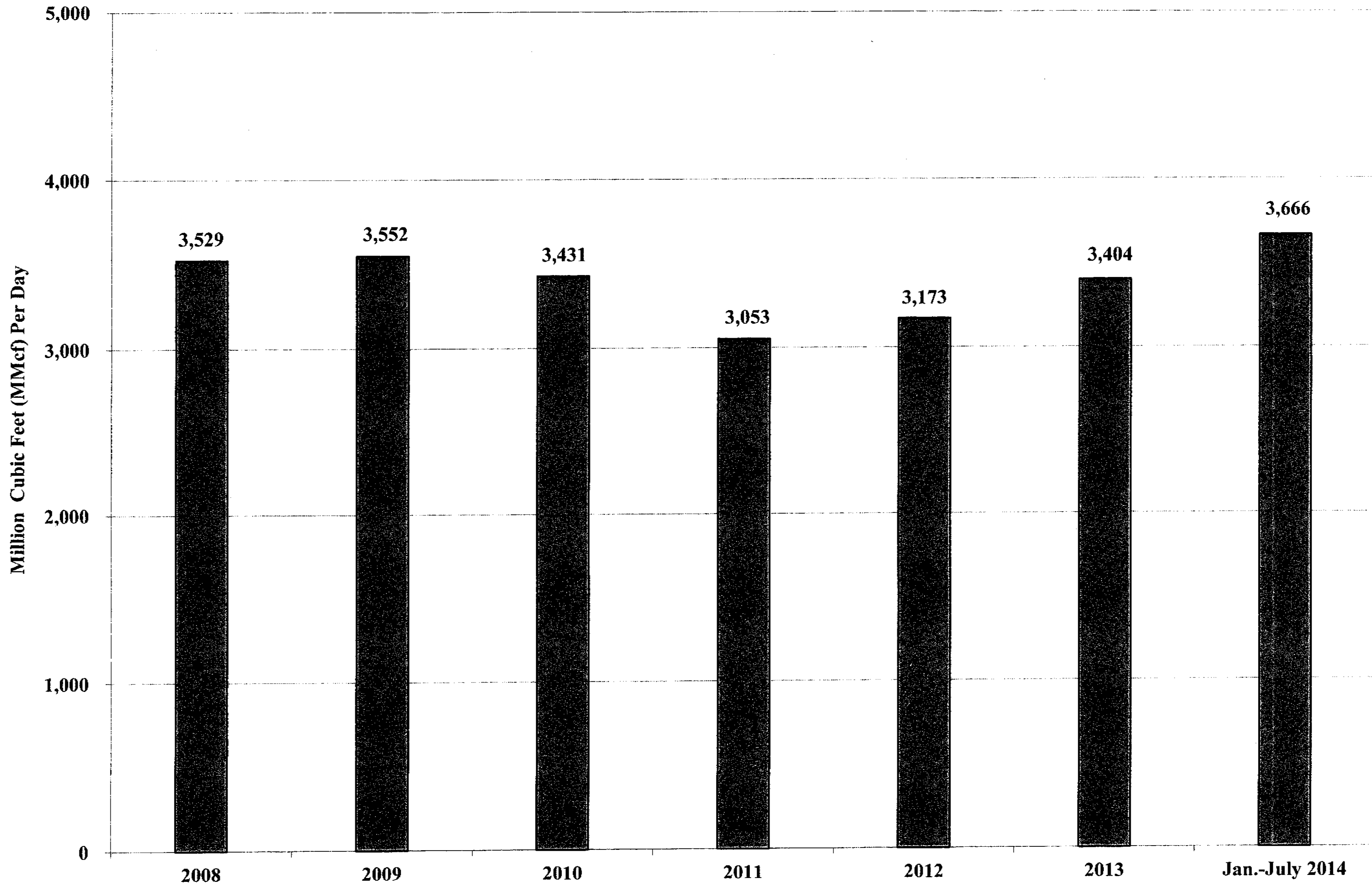
Texas Permian Basin
Oil Production
2008 through July 2014



09/24/2014

Source: Railroad Commission of Texas Production Data Query System (PDQ)

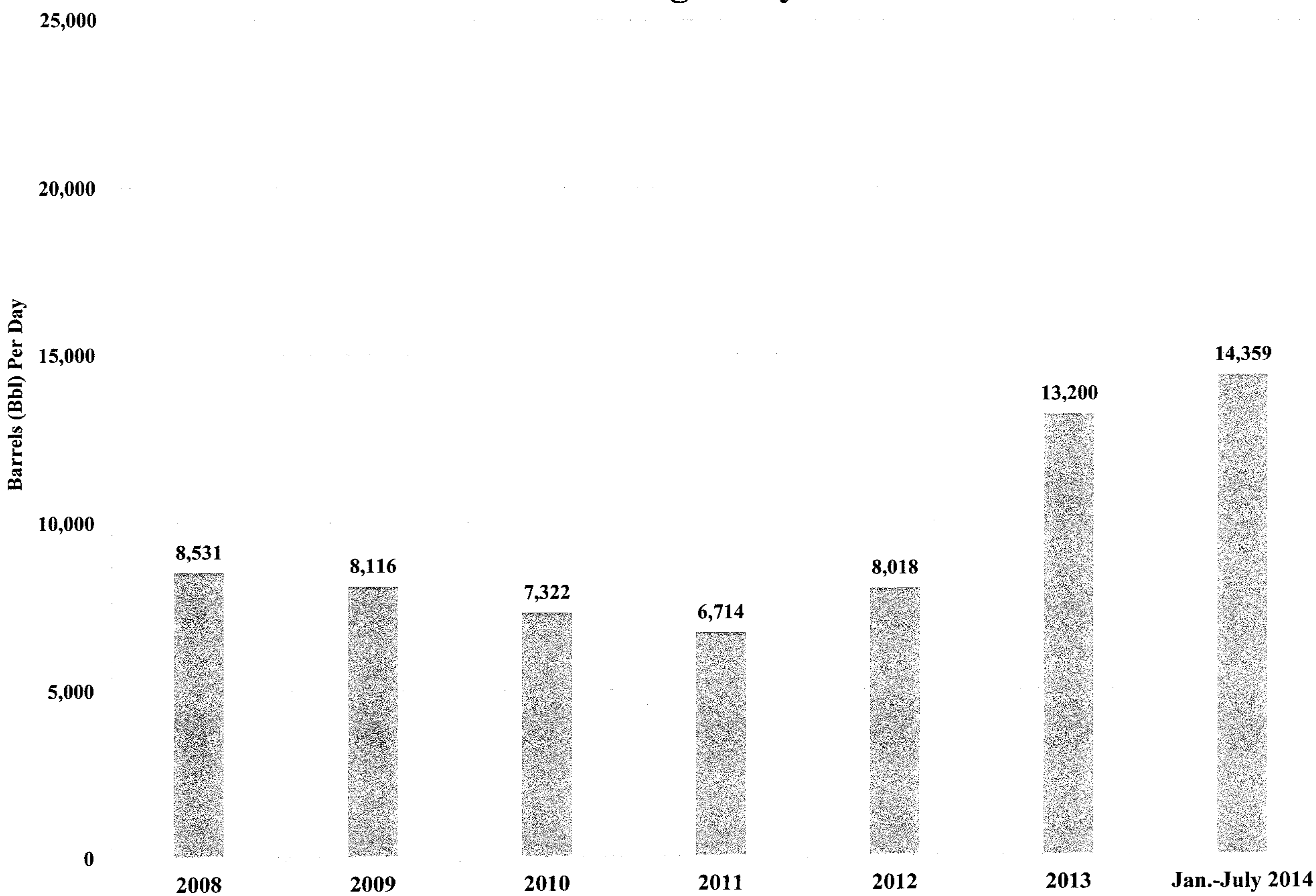
Texas Permian Basin
Total Natural Gas Production
2008 through July 2014



Source: Texas Railroad Commission Production Data Query System (PDQ)

09/24/2014

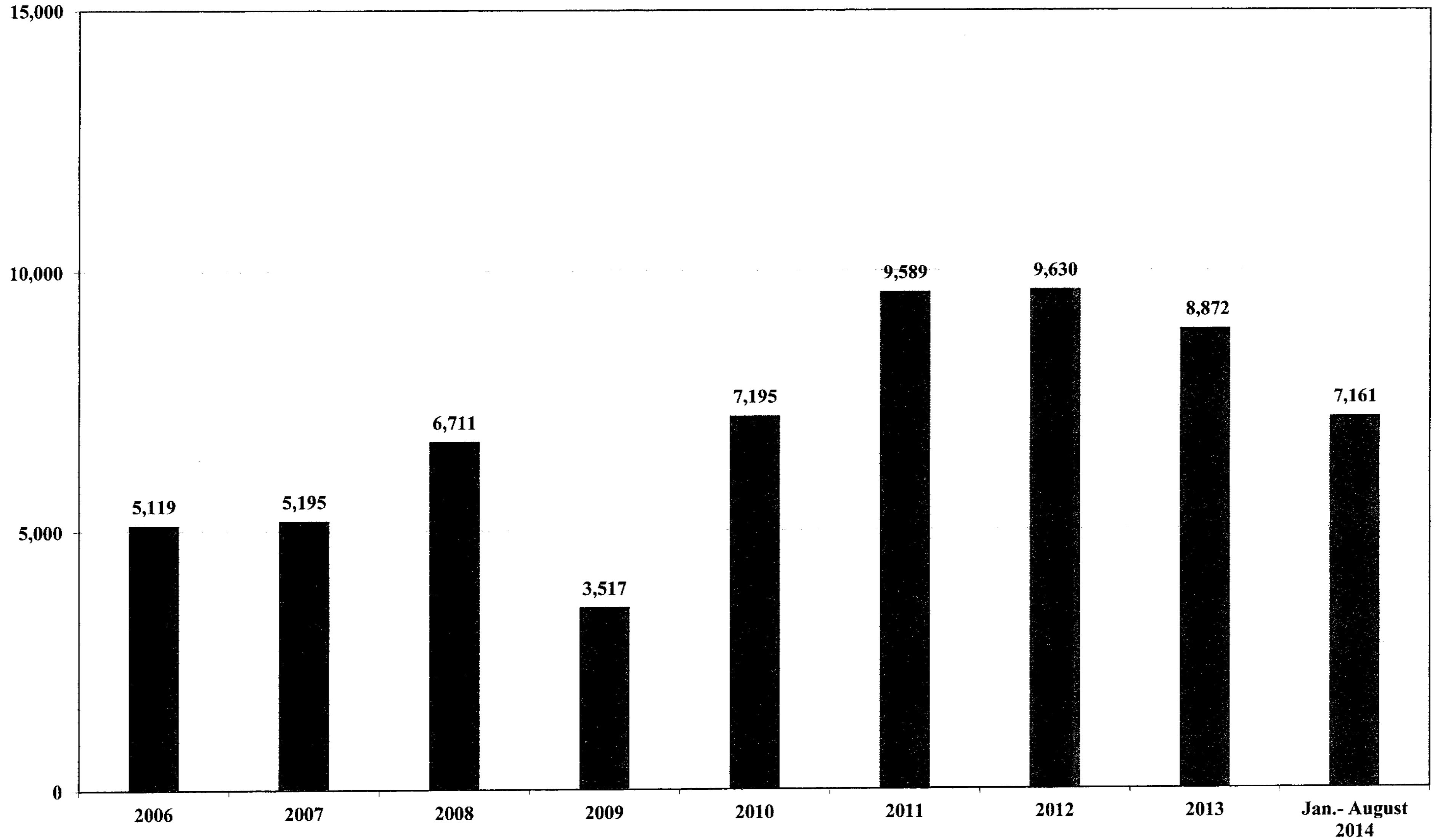
Texas Permian Basin
Condensate Production
2008 through July 2014



09/24/2014

Source: Railroad Commission of Texas Production Data Query System (PDQ)

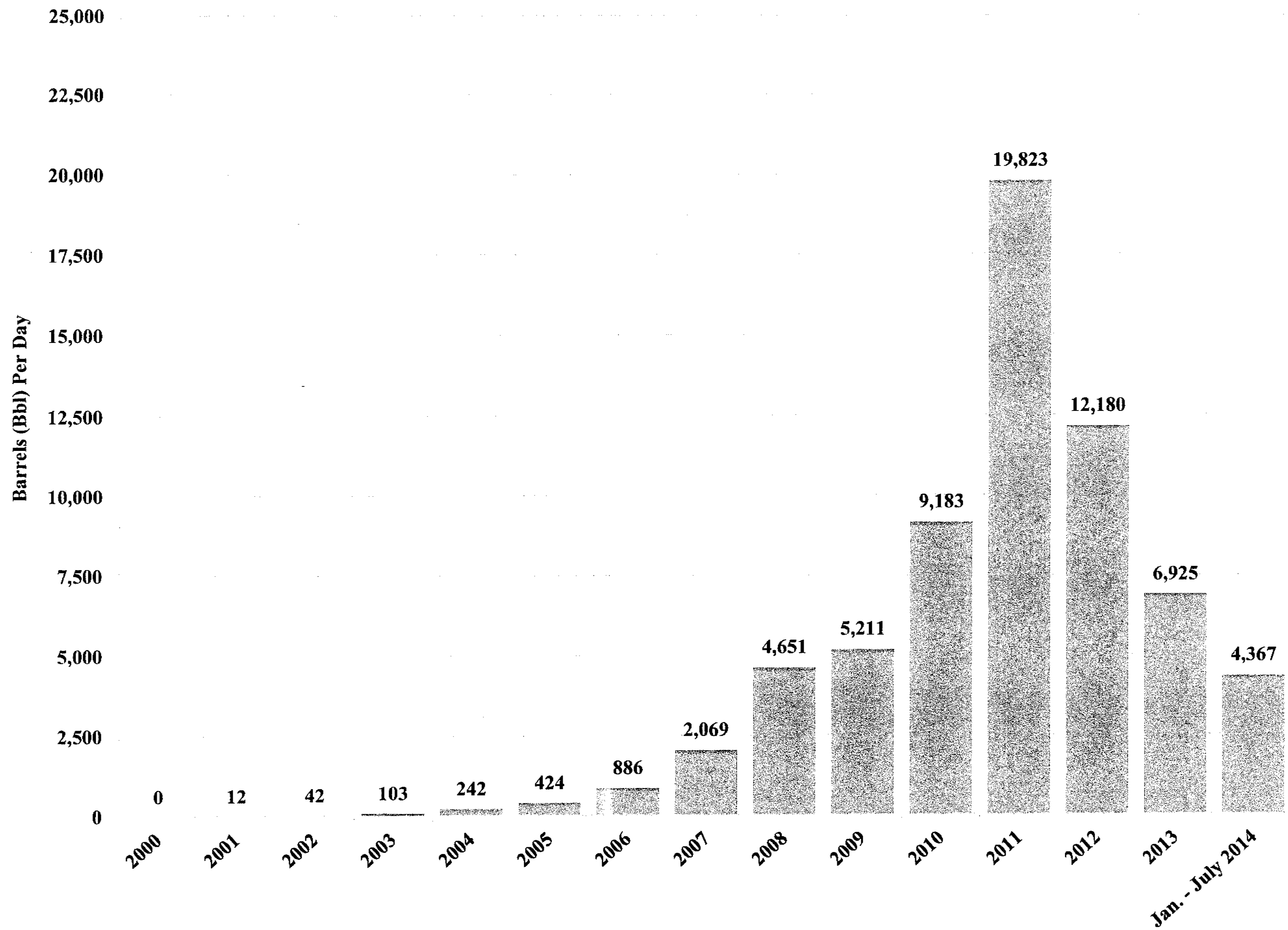
Texas Permian Basin
(District 7C, 08, & 8A)
Drilling Permits Issued
2006 Through August 2014



09/09/2014

Source: Railroad Commission of Texas Drilling Permit Online Query System (Includes New Drill & ReEnter Permits)

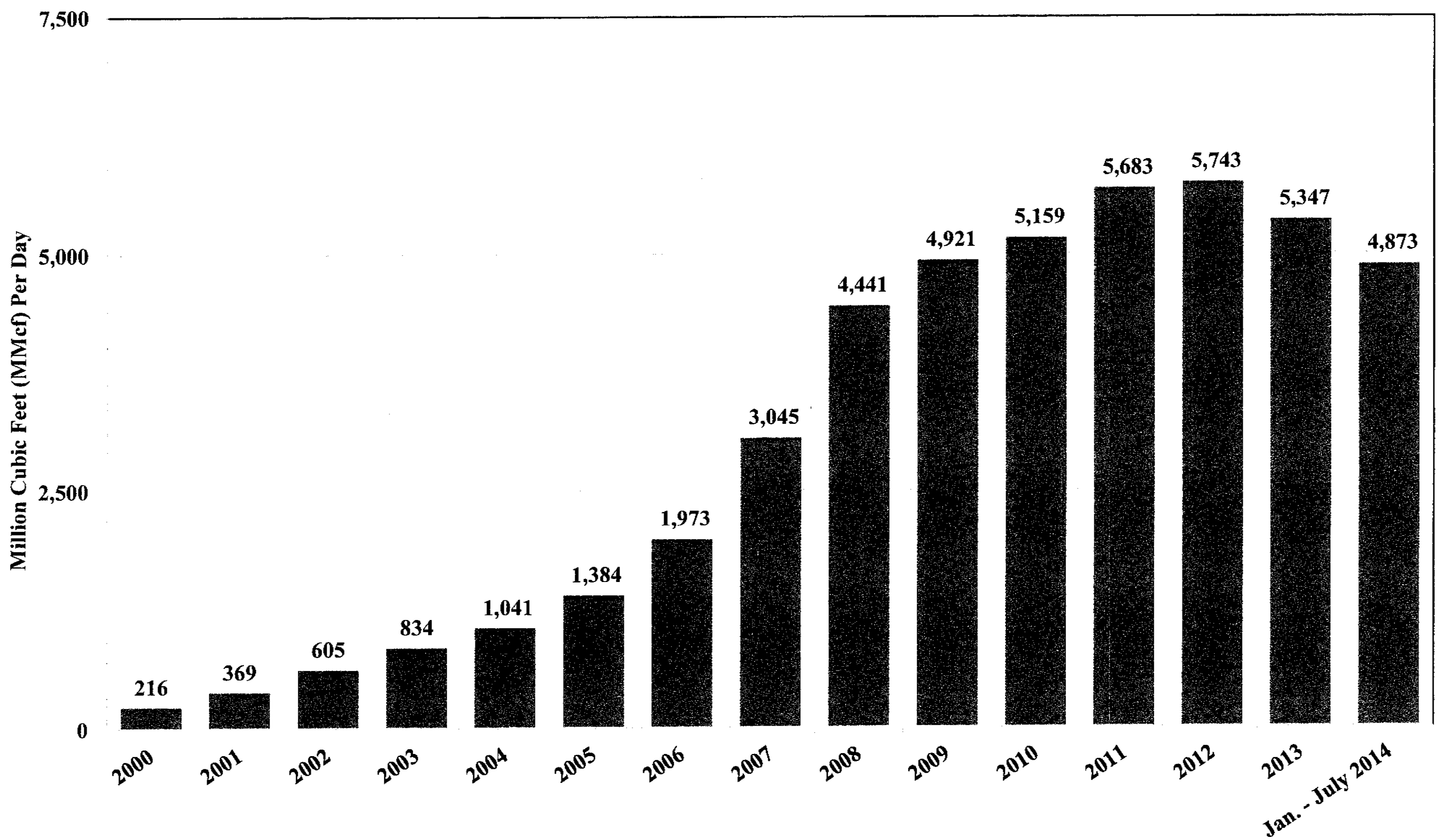
Texas Barnett Shale Oil Production 2000 through July 2014



Source: Railroad Commission of Texas Production Data Query System (PDQ)

09/23/2014

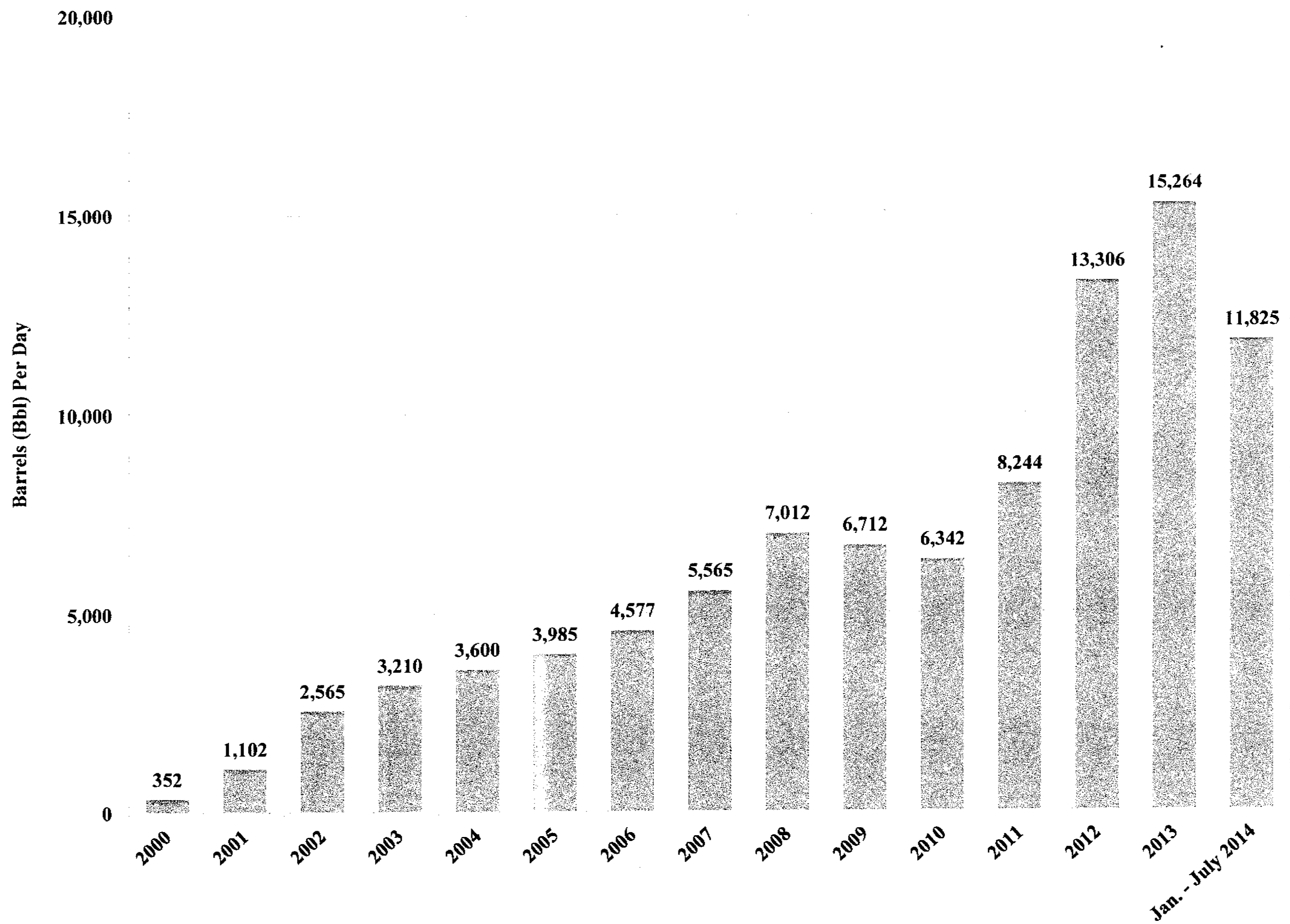
Texas Barnett Shale
Total Natural Gas Production
2000 through July 2014



09/24/2014

Source: Texas Railroad Commission Production Data Query System (PDQ)

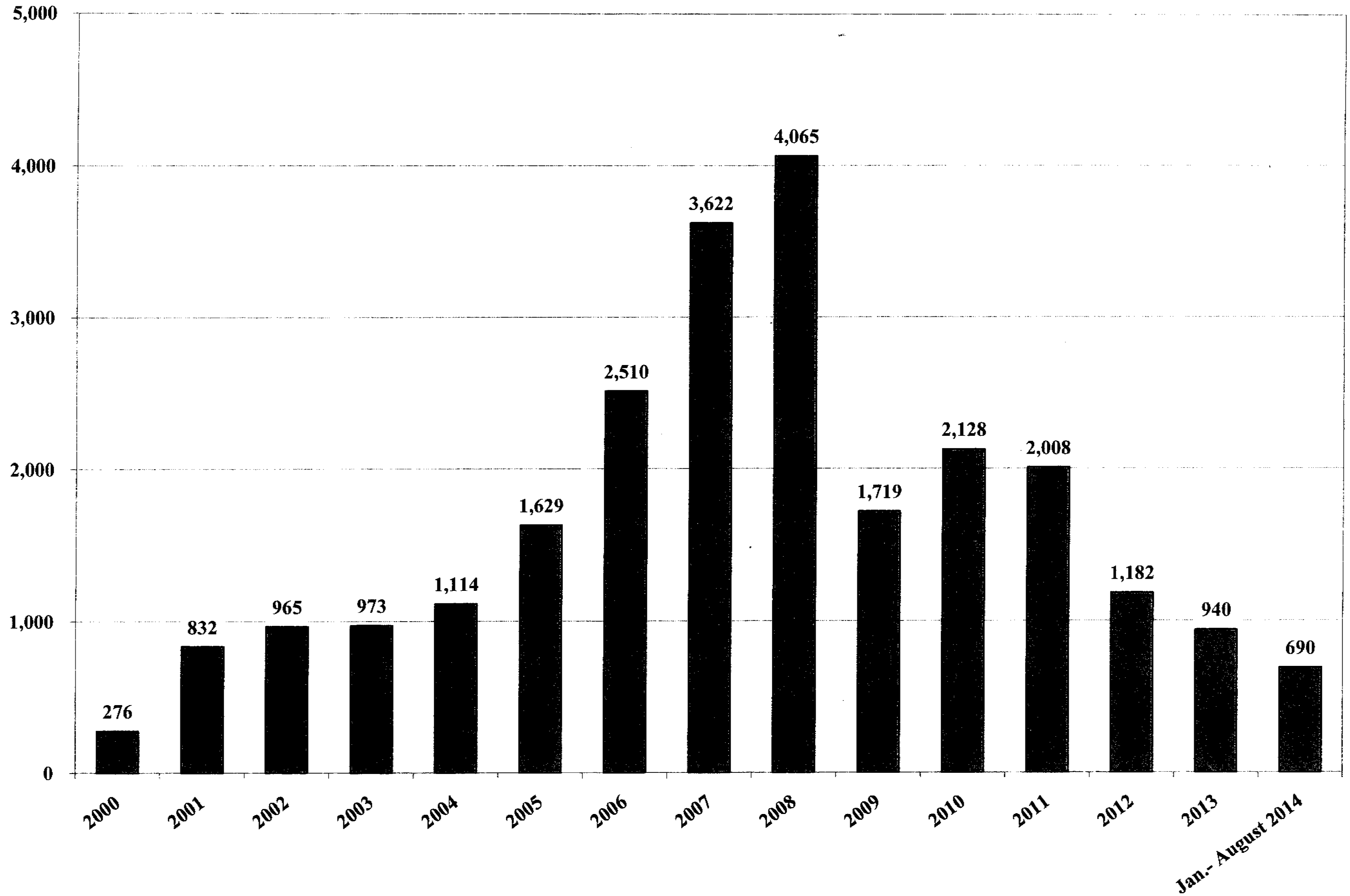
Texas Barnett Shale
Condensate Production
2000 through July 2014



09/24/2014

Source: Railroad Commission of Texas Production Data Query System (PDQ)

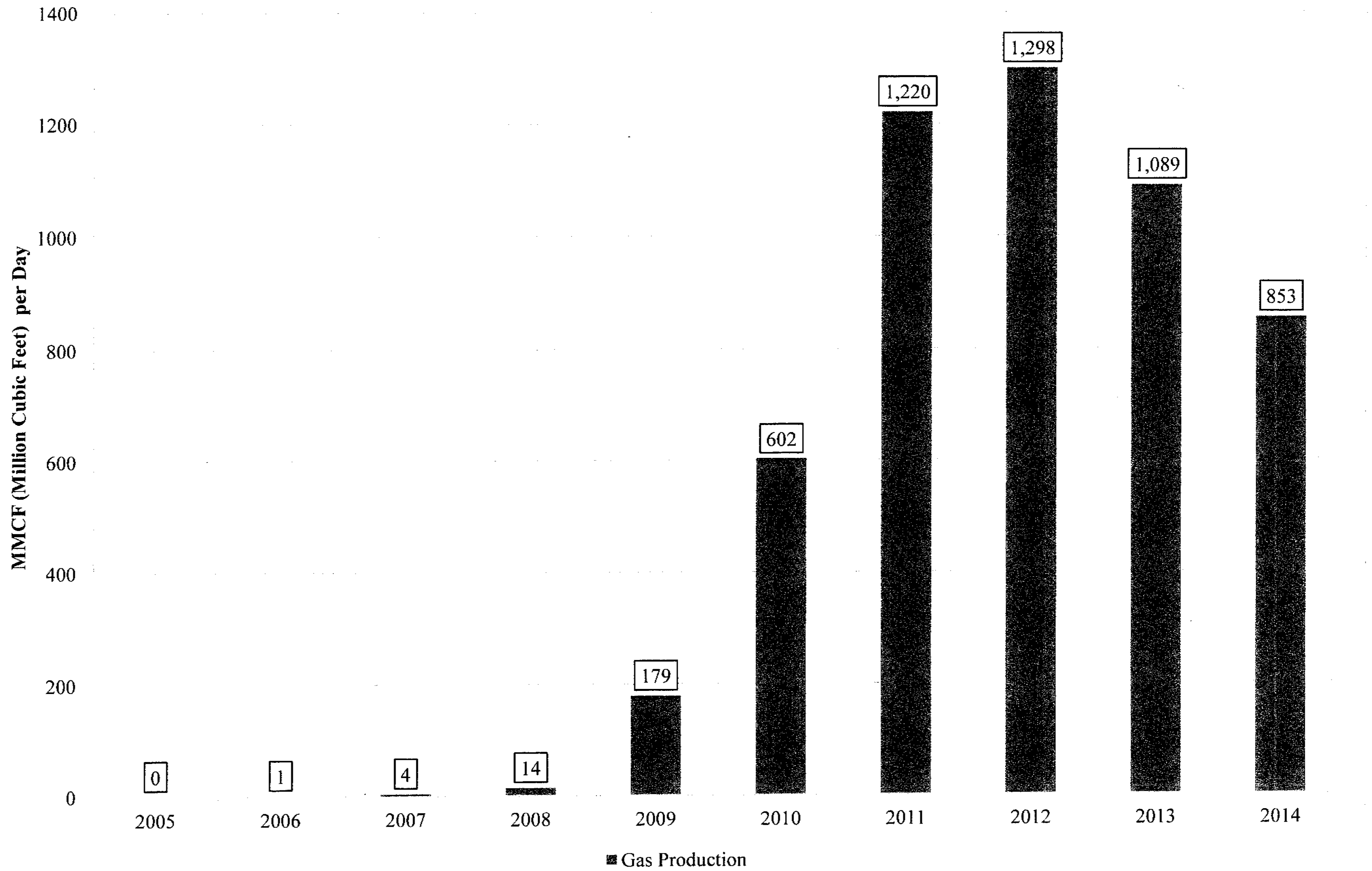
Texas Newark, East (Barnett Shale)
Drilling Permits Issued
2000 through August 2014



Source: Texas Railroad Commission Drilling Permit Query (Includes New Drill & ReEnter Permits)

09/09/2014

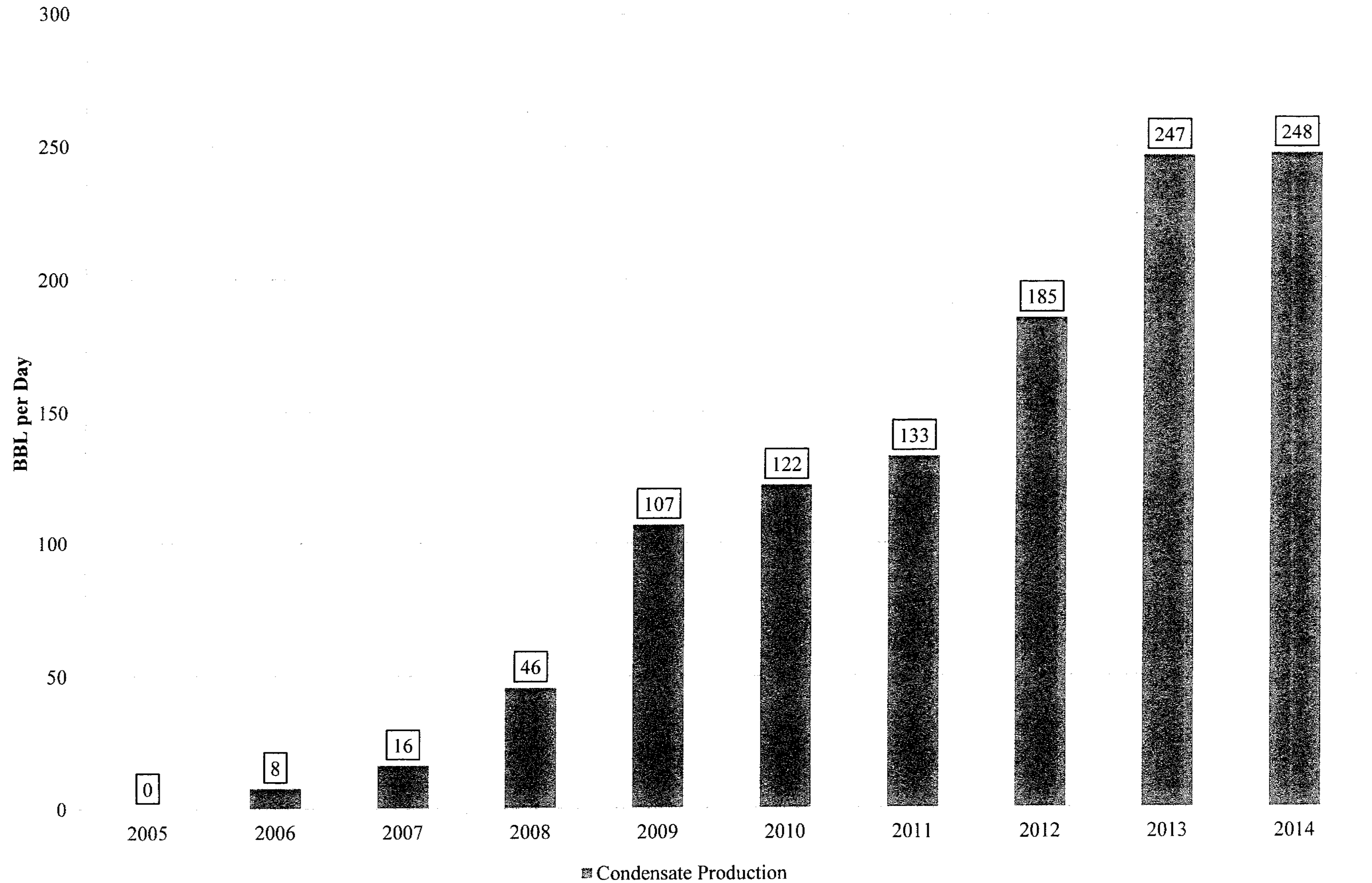
Texas Haynesville Shale Gas Production
2005 through June 2014



8/20/2014

Source: Railroad Commission of Texas Production Data Query System (PDQ)

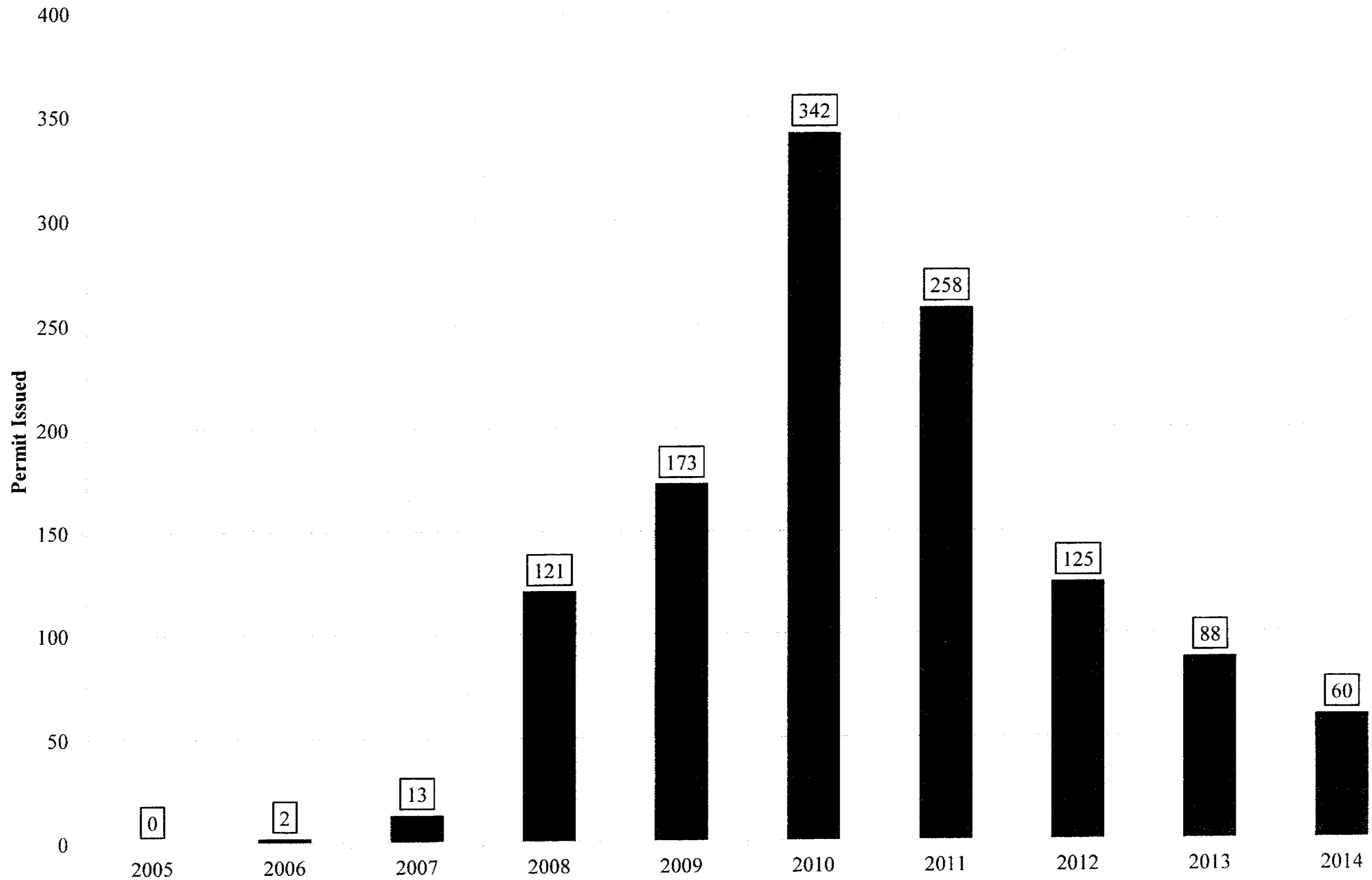
Texas Haynesville Shale Condensate Production
2005 through June 2014



8/20/2014

Source: Railroad Commission of Texas Production Data Query System (PDQ)

Texas Haynesville Shale Drilling Permits Issued 2005 through July 2014



8/20/2014

Source: Railroad Commission of Texas Drilling Permit Query (Includes New Drill & Re-Enter Permits)