

Impact Fee Update and 2016 Outlook

INTRODUCTION

Pennsylvania collects an annual impact fee on unconventional (i.e., shale) natural gas wells that were drilled or operating in the previous calendar year. The impact fee for an unconventional natural gas well is determined according to a bracketed schedule based on the number of years since a well became subject to the impact fee (operating year), the type of well (horizontal or vertical) and the annual average price of natural gas.

Wells that produce less than 90 Mcf (thousand cubic feet) per day for the entire year are known as stripper wells. Horizontal stripper wells in operating years four or greater and all vertical wells that produce below the stripper well threshold, regardless of operating year, are exempt from the impact fee. Horizontal wells that have been plugged are exempt after their first operating year.

The Public Utility Commission (PUC) recently reported collections of \$187.7 million for calendar year (CY) 2015 (remitted in April 2016), bringing cumulative collections to \$1.04 billion.¹ Proceeds from the impact fee are distributed to local governments and state agencies to provide for infrastructure, emergency services, environmental initiatives and various other programs. (See Table 1.) Counties and municipalities receive funds based on the prevalence of drilling activity in each jurisdiction or their proximity to jurisdictions in which drilling activity takes place.

For CY 2015, impact fee collections were significantly lower than the prior year. This research brief (1) examines the reasons for that decline, (2) details the number of wells and fee schedule by operating year and (3) discusses three potential scenarios for CY 2016 collections. It also translates the impact fee into an annual average effective tax rate (ETR). This metric quantifies the implicit tax burden imposed by the impact fee in a given year.

2015 IMPACT FEE REVENUES

For CY 2015, impact fee revenues were \$187.7 million, which is \$35.8 million lower than the amount collected in the prior year. Table 2 (see next page) details the well count, fee schedule and actual collections by operating year. The decline in collections can be decomposed as follows:

- Lower fee schedule. The 2015 impact fee schedule decreased by \$5,000 per well for horizontal wells in operating years one, two, four and five. This adjustment is the result of the annual average price of natural gas on the New York Mercantile Exchange (NYMEX) falling to \$2.66, which is below the \$3.00 per MMBtu threshold that triggers a downward adjustment to the fee schedule.² Estimated impact: -\$33.0 million.
- Collections from new wells. There were 786 new wells (operating year 1) subject to the impact fee in 2015. Estimated impact: +\$35.5 million.

Table 1: Impact Fee Revenues and Distributions

	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>
Total Revenues	\$204,210	\$202,472	\$225,752	\$223,500	\$187,712
Counties, Municipalities and HARE Fund ¹	108,726	107,683	123,151	123,300	101,800
Marcellus Legacy Fund	82,484	79,289	84,601	82,200	67,867
Commonwealth Agencies	10,500	10,500	10,500	10,500	10,500
Conservation Districts/Commission	2,500	5,000	7,500	7,500	7,500

Notes: Dollar amounts in thousands. Fees are remitted in the following April and distributed in July.

Source: Pennsylvania Public Utility Commission.

¹ Housing Affordability and Rehabilitation Enhancement Fund.

Table 2: Well Count and Actual Collections for 2015

Operating Year ¹	Wells Subject to Fee		Fee Amount		Actual Collections
	Horizontal	Vertical	Horizontal	Vertical	
1	783	3	\$45,300	\$9,100	\$35,497,200
2	1,339	7	35,200	7,000	47,181,800
3	1,176	12	30,200	6,000	35,587,200
4	1,114	10	15,100	3,000	16,851,400
5	<u>3,335</u>	<u>95</u>	15,100	3,000	<u>50,643,500</u>
Subtotal	7,747	127			185,761,100
Other Payments ²					<u>1,950,600</u>
Total	7,747	127			187,711,700

Source: Pennsylvania Public Utility Commission.

¹ Refers to the number of years a well has been subject to the impact fee. Horizontal wells are subject to the fee for the first three years after being spud. Horizontal wells in other operating years and all vertical wells are subject to the fee if they produce above the stripper well threshold.

² Late payments or resolved disputed payments attributable to prior calendar years, remitted with 2015 collections. The wells remitting these payments are included in the well count above.

- Reduced collections from existing wells. Wells pay lower fees as they migrate down the fee schedule or become stripper wells. (See Table 2.) Estimated impact: -\$38.3 million, including late and prior year disputed payments.

The main driver of lower impact fee revenues was the price of natural gas. The dramatic decline in the average price (1) reduced the fee schedule for CY 2015 (the first such occurrence) and (2) motivated firms to reduce the drilling of new wells. The 783 horizontal wells spud in 2015 (operating year 1) were less than the 1,339 horizontal wells spud in 2014 (currently operating year 2). An additional \$25.2 million would have been collected for CY 2015 if the number of new wells had remained constant from 2014 to 2015.

EFFECTIVE TAX RATE

The impact fee does not directly respond to the price of natural gas or the volume of production, and it does not provide a measure of tax burden relative to natural gas sales. Therefore, this research brief computes an annual average effective tax rate (ETR) for all wells in operation during the year.³

The ETR is equal to annual impact fee revenues divided by the total market value of unconventional natural gas production. The market value is equal to the product of (1) the annual average regional price of natural gas net of post-production costs and (2) the total production from all unconventional wells.

The ETR computation for CY 2015 uses these data:

- Annual production of 4.6 trillion cubic feet. This figure is based on statewide well production data published by the Department of Environmental Protection (DEP).
- An annual average price of \$1.43 per Mcf, prior to the deduction of post-production costs.⁴ This price is a weighted average of spot prices at the Dominion South and Leidy trading hubs, converted to dollars per thousand cubic feet.⁵
- Post-production costs of \$0.84 per Mcf. This amount reflects costs for gathering, processing and transporting gas to markets. Such costs are deducted to approximate the value of gas at the wellhead, the point at which other states levy severance taxes.

For CY 2015, the ETR is 6.9 percent, an increase of 4.5 percentage points from 2014. The annual average ETR for 2011 to 2014 declined in each successive year. (See Table 3.) The main cause of that trend was the dramatic increase in production over the time period. The 2015 increase is predominantly motivated by the sharp decline of natural gas prices (54.3 percent prior to the deduction of post-production costs).

NON-PRODUCING WELLS

New production from formerly non-producing wells is a reason that unconventional gas production has increased despite a decline in the number of new wells drilled. There are two types of non-producing wells

Table 3: Impact Fee Annual Effective Tax Rates

<u>Calendar Year</u>	<u>Impact Fee Revenues</u>	<u>Unconventional Production (MMcf)</u>	<u>Price of Gas (\$/Mcf)¹</u>	<u>Market Value²</u>	<u>Annual ETR</u>
2011	\$204,210	1,064,000	\$3.40	\$3,612,700	5.7%
2012	202,472	2,042,900	1.93	3,937,600	5.1
2013	225,752	3,102,900	2.70	8,381,000	2.7
2014	223,500	4,070,400	2.33	9,493,100	2.4
2015	187,712	4,592,900	0.59	2,709,800	6.9

Notes: Dollar amounts in thousands. Mcf is thousand cubic feet. MMcf is million cubic feet.

Sources: Pennsylvania Public Utility Commission, Department of Environmental Protection and Bentek Energy.

¹ Weighted average spot price converted to dollars per Mcf using Pennsylvania heat content, net of post-production costs.

² Does not include natural gas liquids (NGLs).

that are relevant to this discussion: (1) “spud but not completed” wells that have been drilled but are not yet producing and (2) “shut in” wells that have produced natural gas but are currently dormant. These types of non-producing wells generally can be brought into production at a lower cost than new drilling. In the current low-price environment, operators have incentive to obtain production from non-producing wells in lieu of drilling new wells.

According to recent data released by DEP and analyzed by the IFO, the number of spud but not completed wells peaked at the end of 2014, and the number of shut-in wells peaked in the second quarter of 2015.⁶ These data indicate that a number of formerly non-producing wells recently have been placed into production. This trend corresponds with the decline in new wells spud over the same period.⁷

New production from non-producing wells affects impact fee collections differently than newly-drilled wells. Horizontal wells must pay the impact fee for the first three years after being spud, even if they do not produce. When brought into production, a formerly non-producing well continues to be subject to the statutory fee schedule from the point it left off, which will be less than the fee paid on a newly-drilled well.

If non-producing wells are placed into production instead of drilling new wells, impact fee collections will be constrained, even if production holds steady or increases. Due to the reduction in the inventory of non-producing wells, it is unclear how long producers can rely on those wells to supply further support for production.

2016 OUTLOOK

For CY 2016, two factors will have significant implications for impact fee revenues. They include:

(1) The statutory fee schedule. The schedule is based on the average price of natural gas on the NYMEX. If that price falls below \$2.25 per MMBtu for CY 2016, the impact fee schedule will decline by \$5,000 per well (horizontal) compared to CY 2015 levels. For the first six months of 2016, the NYMEX price ranged from \$1.71 to \$2.92, with an average of \$2.11. Bentek Energy forecasts that the price for the remainder of the year will average \$2.73, for a calendar year average of \$2.38. This level is close to the \$2.25 threshold for a schedule adjustment.

(2) The number of new wells. DEP spud data from January to June 2016 reveal an approximate 60 percent year-over-year decline in the number of new horizontal wells spud (no vertical wells have been spud in 2016 to date). Wells in their first year of operation pay the impact fee at the highest level. (See Table 2.) Revenues from new wells are important to total impact fee collections because they offset the decline in fees received from existing wells as they age. For example, a well spud in 2015 paid a fee of \$45,300. That same well will pay a fee of \$35,200 for CY 2016.⁸

Table 4 displays three potential scenarios for CY 2016 impact fee revenues. The scenarios differ based on the number of new wells spud in the second half of 2016 and whether or not a fee schedule reduction occurs. Each scenario contains the same assumptions for (1) the number of wells that attain stripper status for CY 2016 and become exempt and (2) the number of previously non-producing wells that did not pay an impact fee for CY 2015, but which will be brought into

production and begin paying the fee for CY 2016.

1. The Current Trends scenario assumes that the number of new wells spud in the second half of 2016 declines by 60 percent compared to the same period in the prior year, consistent with the trend observed in the first half. This yields a calendar year total of 329 new wells, and represents a \$15.2 million reduction in impact fee collections under the current fee schedule.
2. The Drilling Pick-Up scenario assumes that the number of new wells spud in the second half of 2016 is the same as the number spud in the second half of 2015. This yields a calendar year total of 547 new wells (a 30 percent reduction from the prior year), and represents a \$5.4 million reduction in impact fee collections under the current fee schedule.
3. The Fee Reduction scenario assumes (1) an average NYMEX price that is less than \$2.25 per MMBtu and the associated reduction in the fee schedule and (2) the number of new wells spud follows current trends. This scenario demonstrates that CY 2016 impact fee revenues will decline substantially if the fee schedule is further reduced due to the low NYMEX price. This scenario yields a \$56.5 million reduction in impact fee collections.

Impact fee collections decline under all three scenarios. The largest decline occurs under the scenario in which a fee schedule reduction takes place, and smaller declines occur in the other scenarios based on new well assumptions for 2016. An additional 120 new wells beyond those included in the Drilling Pick-Up scenario would need to be spud in the last six months of 2016 in order to maintain collections at the CY 2015 level.

In the long term, new pipeline capacity may be built to connect gas production to major demand markets in other states. This would allow regional prices and producers' revenues to rebound. As a result, the drilling of new wells could increase, and if so, impact fee collections would rise accordingly.

Industry analysts are unsure when this anticipated price inflation will occur. Analysts had expected that additional pipeline capacity would be completed by 2018. However, several large projects have been delayed or cancelled. Currently, the NYMEX futures market suggests that the price will reach \$3.00/MMBtu in 2017 and remain near that level until 2021. Forecasts from Bentek Energy show regional hub prices will maintain their significant differential below the NYMEX through that time, so the current low-price environment is likely to continue. If these conditions hold, then drilling activity will likely remain subdued through 2018, and impact fee revenues will have limited opportunity for growth.

Table 4: CY 2016 Impact Fee Revenue Scenarios

	Current Trends	Drilling Pick-Up	Fee Reduction
Total Revenues	\$170,600	\$180,400	\$129,300
<u>Difference from 2015</u>	<u>-15,200</u>	<u>-5,400</u>	<u>-56,500</u>
Lower Fee Schedule	0	0	-41,300
New and Existing Wells ¹	-15,200	-5,400	-15,200

Notes: Dollar amounts in thousands. Excludes late or disputed payments from prior years.

Source: Well counts estimated using data from the Public Utility Commission.

¹ Reflects change in revenues from (1) more wells subject to impact fee (new wells plus non-producing wells brought into production less new stripper wells) and (2) existing wells aging and migrating down the fee schedule.

Endnotes

1. The Pennsylvania Public Utility Commission administers the impact fee and provides data on impact fee assessments and actual collections. This was cross-referenced with unconventional well production data and spud data published monthly by the Department of Environmental Protection.
2. The fee schedule is adjusted downward if the price of gas falls below \$3.00 and downward again if it falls below \$2.25. See [58 Pa.C.S. § 2302\(b\)](#) for the statutory adjustments and [46 Pa.B. 632](#) for the current fee schedule. Pursuant to [58 Pa.C.S. § 2301](#), the price used is the annual average of the settled prices for near-month contracts on the New York Mercantile Exchange (NYMEX) in million British thermal units (MMBtu). This is the national benchmark price for the sale of natural gas. Other regional hubs exist in Pennsylvania, e.g., Dominion South and Leidy, which are used in Table 3 to approximate the prices received by producers.
3. An alternative to the annual average ETR is the lifetime ETR, which is the average rate over the lifetime of a single new well; this measure is best used to quantify the prospective tax burden on new wells across states. (See the IFO's previous publication, [Natural Gas Extraction: An Interstate Tax Comparison](#), for an analysis using the lifetime ETR.)
4. Conversion of units from dollars per MMBtu into dollars per thousand cubic feet (Mcf) was calculated using the Pennsylvania-specific heat content of natural gas, as published by the U.S. Energy Information Administration. Post-production cost estimates are from a Range Resources investor presentation, March 31, 2016. These costs were adjusted by the IFO based on the proportion of wet and dry gas produced in Pennsylvania in 2015. "Wet" gas from the southwestern portion of the state incurs higher processing costs to separate natural gas liquids. Therefore, the post-production costs deducted from the price are a weighted average of \$1.48 per Mcf for wet gas and \$0.78 per Mcf for dry gas.
5. This price is different from that used in prior research briefs on the impact fee, which relied exclusively on the Dominion South hub. Changes in the industry and availability of trading information have made this weighted price appropriate. In addition to spot trading, producers also hedge prices for a large share of their production, using futures contracts and other more complex instruments. These strategies may yield a higher average price than the daily spot price.
6. See the IFO's publication, [Natural Gas Production Report: First Quarter 2016](#) for a summary of DEP data on production and wells drilled. These data do not directly correlate to data published by the PUC. Both are submitted to the agencies by operators.
7. According to DEP data, the number of wells spud from January to June was 421 in 2015, and 183 in 2016.
8. Exclusive of any change in the fee schedule due to price.

Data Sources

- Statewide production data and spud well counts can be found at <https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Welcome.aspx>.
- Act 13 impact fee revenues and distributions can be found at http://www.puc.state.pa.us/filing_resources/issues_laws_regulations/act_13_impact_fee.aspx.
- Natural gas price forecast data are from BENTEK Energy and can be found at <http://www.bentekenergy.com/index.aspx>.

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