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Shale impact fees hit a new low

Summary: Act 13 of 2012 imposed an impact fee on any unconventional well removing natural gas within Pennsylvania's shale formations (Marcellus and Utica). By design the impact fee benefits the counties and communities most affected by natural gas drilling, but all commonwealth counties receive some proceeds.

Since its inception, the impact fee has collected over $2 billion for the commonwealth, with collections averaging $207.8 million from 2012-2020. The revenue for 2021 hit a new low of just $146.3 million (the previous low was $173.3 million in 2017). But with wells aging and not being adequately replaced by new wells, the impact fee revenues that many levels of government rely on will continue to fall.

The impact fee is determined by the age of the well and the average annual price of natural gas (see *Policy Brief Vol. 12, No. 11*). According to the fee setting matrix, as a well gets older, it becomes less productive and thus is charged a lower fee. Likewise, the higher the traded price of natural gas, the higher the fee. The fee liability begins the year a well is drilled. However, if it is plugged or inactive the well becomes exempt. There are also discounts for low-performing wells.

Payments were first collected in 2012 with companies required by Act 13 to pay on all active unconventional wells drilled from 2007-2011. The 4,333 unconventional wells in the 2011 count paid $204.2 million in impact fees. 2021 collections were based on 10,466 active wells in 2020 paying the fee with total revenue of only $146.3 million. Thus, although the number of wells had increased since 2011, a rise of 141 percent, the impact fee revenue was 28 percent lower in 2021 than 2012.

As mentioned above the fee per well is based on two factors: the age of a well and the trading price of natural gas. The wells are grouped into age brackets—individually from year one through year three, then grouped in years 4-10 and again for years 11-15. After 15 years the wells are no longer subject to the fee. As they pass through each age bracket they become less productive as the pool of gas being tapped presumably diminishes; and the impact fee schedule is designed to take that into account.

The other determining fee factor is the average annual price of natural gas as traded on the New York Mercantile Exchange (NYMEX). Act 13 stipulates that for the year, the price for which the fee will be based is the average price per 1,000 cubic feet (Mcf) for the near-month contract, as reported on the last trading day of each month. The Act 13 fee calculation matrix is broken into five price ranges—not more than $2.25; between $2.25 and $2.99; between $3.00 and $4.99; between $5.00 and $5.99; and $6.00 and over.

For wells in their first year, the fee ranges from a minimum of $40,000 to a maximum of $60,000 depending upon the price of natural gas. For wells in the final grouping, years 11-15, the fee range is a minimum of $5,000 and a maximum of $10,000.

For example, consider the 4,333 wells that were active in 2011. The price of natural gas averaged $3.00 placing it in the range for an assessed impact fee of $50,000, potentially garnering $216.6 million. For the 2011 fee the state collected $204.2 million as some wells underproduced and were eligible for discounts.

For the 2020 assessment, these 4,333 wells would now be 10 years old. With the average annual trading price of natural gas at $2.08, the lowest annual average since the fee was instituted, the fee for a well in its tenth year is $10,000—80 percent less than the amount they paid in their first year of required fee payment. In 2022, these wells will move into the final age grouping (11-15) for the next five years, likely dropping the fee revenue even more. Note that through May of 2021 the trading price is averaging $2.73 which places the per well fee at $5,000. And that, of course, assumes that they are all still active and productive. The data on how many of these original wells are still active is not available.

Because wells age, impact fee collections will fall over time (assuming no sharp rise in gas prices) unless new wells with their higher fee structure come online to offset the revenue declines caused by the aging wells.

Data for new wells being drilled show that the busiest year for new rigs was 2011 when ground was broken for 1,956 unconventional wells. The next busiest years were 2014 (1,371), 2012 (1,351) and 2013 (1,218). No other year even approached 1,000 new wells. 2017 came closest with 811. 2020 recorded the lowest count of new drillings (476) since 2009 (332). As noted earlier, this has important implications for impact fee revenue because older wells pay much less than newer wells.

The incentive for producers to drill is driven in large part by the price and expected future price of natural gas. In 2010, the trading price of natural gas on the NYMEX was $ 4.24 per Mcf and remained at that high level throughout the first half of 2011, the year the most wells were drilled. That annual average price did not crest the $4.00 mark again until 2014 ($4.42). But the price fell quickly to reach $2.66 in 2015. The average annual price from 2015 to 2020 ranged from a low of $2.08 (2020) to a high of $3.11 (2017).

From 2015-20, fewer than 4,000 new wells were drilled. The boom period of drilling occurred from 2011-2014 when nearly 5,900 wells were drilled. Those wells are now in the 4-10-year age category and paid just $10,000 in impact fees each in 2020.

With the low gas price of $2.08 in 2020 the 476 wells drilled, assuming they are fully eligible, paid a per well fee of just $40,000 in their first year. The 614 drilled in 2019 would have paid a per well fee of just $30,000 in their second year.

The slowdown in drilling can be partially blamed on the trading price of natural gas. But some responsibility can also be laid at the feet of the producers who perhaps over-drilled in those beginning years and contributed to an over-supply that depressed the price of gas.

Then, too, some of the slowdown in activity can be attributed to policy makers in Harrisburg who insist on moving away from fossil fuels and toward solar and wind through policies such as the Regional Greenhouse Gas Initiative—a tax on fossil fuel energy generation facilities, including those powered by natural gas. Further adding to the reluctance to drill is the annual renewal of the threat to impose a severance tax on the industry.

In sum, it is very likely that impact fee revenues going forward will continue to decline. While the price of natural gas thus far in 2021 has been on the rise, it remains quite low compared to the levels of 10 years ago. Proposed regulatory pressures on the industry will keep producers wary of expanding and the counties and municipalities that have come to rely on impact fee money will face serious budget adjustments.

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