Apocalypse Not: Severance Taxes and Industry Exit in the Marcellus Shale

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Replacing the current impact fee with a 5% severance tax is very unlikely to deter firms from drilling new wells in Pennsylvania.

A common argument against a severance tax on shale gas in Pennsylvania is that the additional economic burden will cause the industry to leave the state. In this paper, we analyze the economics of a typical unconventional gas well in the Marcellus Shale from the point of view of a driller. **We find that the replacement of the current impact fee with a 5% severance tax is very unlikely to deter firms from drilling new wells in the state, and it will certainly not inhibit the continued operation of existing wells**.

Beginning in 2012, companies that produce natural gas from unconventional (shale) wells in Pennsylvania have been required to pay an "impact fee"—an annual payment based on the age of the well and average price of natural gas during that year —no matter how much natural gas is produced. Yearly impact fee payments are made during the first 15 years after a well is drilled.

Critics of the impact fee have argued that it shortchanges the people of Pennsylvania, giving them too small a share of the wealth generated from the extraction of an irreplaceable resource. Instead many advocate a severance tax, which would require drillers to pay the State a small fraction of their gross revenues from the sale of unconventional natural gas.

Severance tax opponents counter that such a tax would make it unprofitable for shale gas producers to operate in Pennsylvania, driving them out and "killing the goose that lays the golden eggs."

Producers must raise capital to drill new wells, which must generate a large enough return to make it attractive for investors or lendors to provide that capital. For example, if a driller issues bonds, its wells must produce returns sufficient to pay its creditors a decent interest. Very large energy companies can borrow money as cheaply as the US government—at an interest rate of 2-3%—whereas smaller companies pay an interest rate of 5-6%. If the internal rate of return (IRR) of the well, which can be thought of as the maximum interest a company can afford to pay on the capital it borrows and still make money, is greater than the cost of borrowing, the driller will bring new wells online. Otherwise it will not.

We estimated the IRR of a "typical" shale gas well under two conditions: the current impact fee, and a 5% severence tax on gross revenue from the well's production. We used values for expenses, including capital expense, operating and gathering costs, lease payments and royalties, and taxes and fees characteristic of the industry.[1] We assume the current forward price curve, which reflect the present low prices and the fact that natural gas supply is expected to remain abundant in the United States even in the future.

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[1] In general, assumptions were conservative—that is, biased against the severance tax. In particular, we assume that the driller pays $3400 per acre for a 640-acre lease. Royalties are set at 12.5% of *gross* revenues and are treated as deductible for the purposes of state and federal taxes.

Switching from the impact fee to a 5% severance tax would result in a small reduction in the operator's IRR. A typical well drilled in 2014 and starting production in 2015 would generate a return of 13% with an impact fee and 12% with a severance tax. This is comfortably more than the interest drillers must pay in order to borrow the capital needed to drill new wells.

With the impact fee, we estimate that a well drilled in 2014 will earn the driller about $1.9 million and the State about $380,000 over 15 years.[2] With a severance tax, the driller would net $1.6 million and the State would earn $830,000. Proportionally, the loss to the driller—about 18% over the lifetime of the well—is much smaller than the gain to the State's coffers: about 120%.

Alternative scenarios. Drillers can legally reduce their tax liability well below the full federal income tax rate of 34-38%, and we assume an effective tax rate of 20%[3] in our base case, in addition to taking all the standard types of deductions (e.g., intangible drilling costs). If they paid the full rate instead, only taking the standard deductions, their return would be 10% with the impact fee, and 9% with the severance tax—still well above the driller's cost of borrowing.

The base case also assumes that the driller must acquire the acreage on which the well is drilled at the current market rate. However, there are a number of situations in which these costs might be treated as "sunk" and not included when calculating the IRR. For example, the driller may have acquired the acreage at well below the current market rate before the full potential of the Marcellus shale was widely known. If land acquisition is a sunk cost, the anticipated return from a well rises to a 31% with the impact fee and 30% with a severance tax.

For a producing well, the firm would earn up to $2.50 for every additional thousand cubic feet (mcf) of gas produced ($3.50 market price, less $1 operating and gathering costs). If a 5% severance tax were introduced, it would still earn $2.4 per mcf, making it very unlikely that reduction from current wells would be reduced in response to a severance tax.

Figure 1 shows the effect of the severance tax on a company's IRR for these scenarios. In all three scenarios, moving from an impact fee to a severance tax would increase the State's lifetime from the revenues from $380,000 to $830,000 if the severance tax is 5% of gross revenues and from $380,000 to $690,000 if it is 4%.

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[2] Net present value (NPV).

[3] A GAO report indicated that, in 2010, profitable US corporations paid federal income taxes amounting to 13% of pre-tax income.

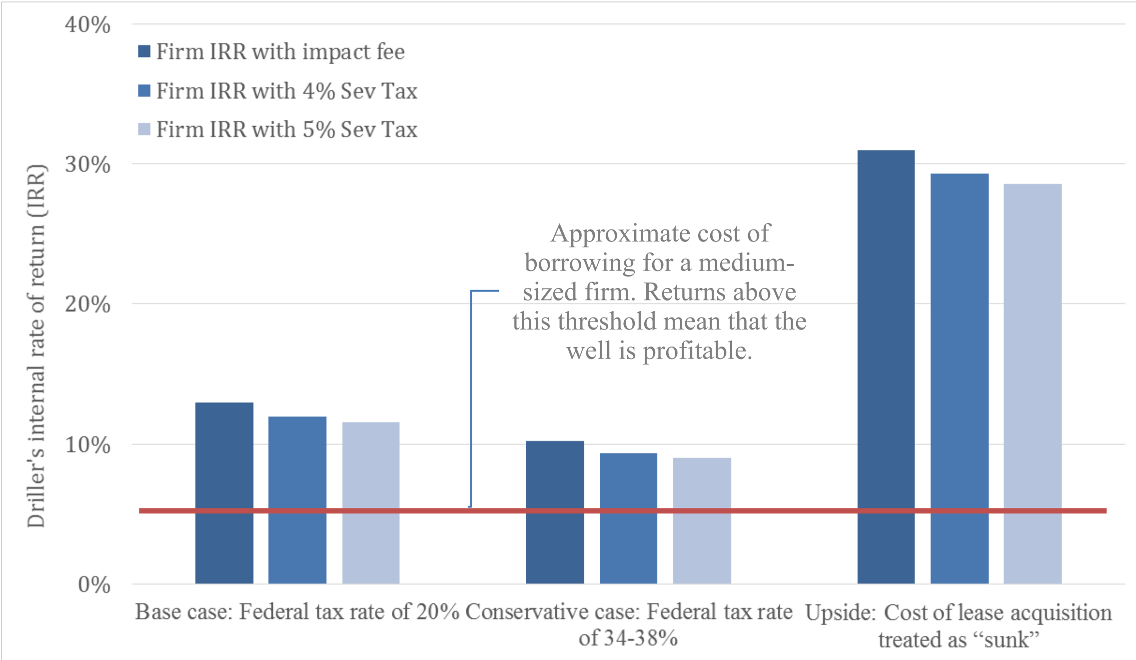

Figure 1: Under all three scenarios, going from an impact fee to a 4-5% severance tax changes the driller's internal rate of return only very slightly.

A sensitivity analysis, in which we varied our assumptions, showed that operators' returns were influenced most strongly by the upfront cost of drilling the well and its initial production. Indeed, our analysis indicates that increasing initial production of a well by about 15% would double the profit that the driller makes over its lifetime.

Data given to the Pennsylvania Department of Environmental Protection by natural gas producers indicate that the production of newly-drilled unconventional wells has risen steeply each year since production began. This is because the activity is relatively new—the first wells in Pennsylvania started producing commercially only in 2004—and producers are learning rapidly about both technology and geology. In 2004, the average new well had an initial output of only 44 thousand cubic feet (mcf) per day. By 2012, output had risen almost a hundred-fold to 3700 mcf per day. The average new well drilled in the first half of 2013 produced 4,900 mcf per day, or 33% better than in 2012.

In our analysis, we have assumed that the average new well produces 4,200[4] mcf per day in its first year. Given that new wells were already producing faster than this in 2013, this is a conservative assumption. Wells drilled in the future could easily produce even more, and as a consequence, their economics will be more attractive than we have described.

In summary, under our conservative base assumptions and in the current price environment, the returns from unconventional natural gas production from the Marcellus shale are significantly greater than the cost of capital. The salient point is that, even with the introduction of a severance tax, drilling in the Marcellus Shale will remain too attractive for drillers to ignore. The goose that lays the golden eggs will stay put.

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[4] This was the average actual production from new wells in the year to June 2013, the latest period for which data are available.