WP/17/254

IMF Working Paper

How Should Shale Gas Extraction Be Taxed?

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INTERNATIONAL MONETARY FUND

 WP/17/254

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Fiscal Affairs Department

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November 2017

Abstract

This paper suggests that the environmental and commercial features of shale gas extraction do not warrant a significantly different fiscal regime than recommended for conventional gas. Fiscal policies may have a role in addressing some environmental risks (e.g., greenhouse gases, scarce water, local air pollution) though in some cases their net benefits may be modest. Simulation analyses suggest, moreover, that special fiscal regimes are generally less important than other factors in determining shale gas investments (hence there appears little need for them), yet they forego significant revenues.

JEL Classification Numbers: H21, H23, Q38, Q48, Q58.

Keywords: shale gas; environmental risks; corrective taxes; liability; fiscal regime design; simulated projects; marginal effective tax rates.

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[1] We are grateful to Michael Keen for helpful comments and suggestions on earlier versions of the paper.

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I. INTRODUCTION

The boom in 'unconventional' natural gas (shale gas extracted by fracking processes) in the United States has encouraged numerous countries to begin developing their own reserves, though the contentiousness of fracking, including perceived environmental risks in densely populated or protected areas, has led some others to consider banning, or already ban, the activity.

An emerging literature discusses the transformational impacts of shale gas on energy markets (causing, for example, reduced gas imports and displacement of coal generation in the United States), and the associated environmental risks.[2] Little attention has been paid, however, to whether it also poses distinct new challenges for tax policy. Much thought has been given to this in context of conventional energy sources, both oil and gas and mining[3]—the question addressed here is whether different advice is needed for unconventional sources, taking the example of shale gas.

Specifically, this paper attempts to answer two important questions:

- Do the environmental issues associated with shale gas extraction warrant corrective taxes in fiscal regimes for the upstream production activity, or are they better addressed through other instruments?
- Do the commercial and technical features of shale gas development suggest that the principles of fiscal regime design for conventional oil and gas development need to be modified?

As regards the first issue, the paper suggests that many of the upstream environmental risks (e.g., water contamination) are generally best dealt with through regulation, though ex post liability for individual firms (and possibly, for large risks, compensation from industry-level funds collected through production fees), can play an important role. Moreover, novel tax schemes for leakages of methane emissions—a highly potent greenhouse gas (GHG)—are feasible despite limited metering capabilities, while levying charges for the downstream carbon dioxide (CO_2) emissions from gas combustion on fuel supply is appealing on administrative grounds (either at the point of fuel extraction, processing, or distribution). At the same time, research on the nature and magnitude of environmental risks from shale gas is needed to guide policy design.

As regards the second issue, simulations of how existing fiscal regimes in different (US and non-US) jurisdictions suggest that special fiscal regimes and incentives granted for shale gas development have, at best, only slight effects on investment, despite resulting in

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[2] See, for example, Hausman and Kellog (2015) and Mason and others (2015) for introductions to the literature. Impacts on energy markets are discussed in Brehm (2015), Brown and Krupnick (2010), Cullen and Mansur (2014), Krupnick and others (2013), and Linn and others (2014). Fitzgerald (2013) discusses technological aspects of fracking. Literature on environmental impacts is discussed below.

[3] For example, Daniel and others (2010), Daniel and others (2017), IMF (2012).

significant foregone government revenues. For the most part, there is little evident need to consider specific incentives for shale gas development, compared with conventional gas, provided that the overall fiscal regime responds substantially to realized profit or rent.

The rest of the paper is organized as follows. Section II provides a quick overview of shale gas development. Section III discusses the environmental risks from shale gas and the potential roles for fiscal versus other mitigation instruments. Section IV presents simulation results comparing fiscal regimes for conventional and unconventional gas in jurisdictions across North America and other countries. Section V offers concluding remarks.

II. Brief Overview of Shale Gas Industry

Shale gas exploitation targets gas deposits trapped in horizontal layers of organic-rich shale rock; by contrast, conventional gas reservoirs are formed by pockets of gas trapped in highly permeable reservoir rock by an overlying layer of impermeable rock. Extraction of shale gas is thus more challenging and requires the application of three technologies: hydraulic fracturing (injection of pressurized water and chemicals to enhance gas recovery); seismic imaging (to understand the geology and where the pay zones are best); and horizontal drilling. These technologies (invented for conventional gas and petroleum drilling) are generally used more intensively in shale exploitation, where the decline in well productivity is more rapid and a greater number of wells must be drilled to extract a given amount of gas. The capital intensity and operating costs of shale gas exploitation is thus generally higher than for conventional land-based drilling, as is water consumption and chemical use.

Large-scale shale gas production commenced in the United States around 2000 with the development of the Texas Barnett shale deposit, or “play”. Since then, production has ramped up from 300 billion of cubic feet (Bcf) to 15,213 Bcf by 2015, totaling about 40 percent of US natural gas production, while proven reserves stand at 175,000 Bcf (Figure 1), or 31 percent of total US gas reserves.[4]

Canada (with production of 765 Bcf in 2013) is the only other country that has invested substantially in shale gas production. However, numerous countries (e.g., Argentina, Australia, China, Mexico, Poland, the UK) are exploring shale production, and technically recoverable reserves totaling roughly 7.3 million Bcf have been identified across the globe (Figure 2), equal to about one third of total world gas resources.

Besides reserve quantity and accessibility, the viability of shale gas in other countries depend on several factors, which all happened to be favorable in the United States, including:

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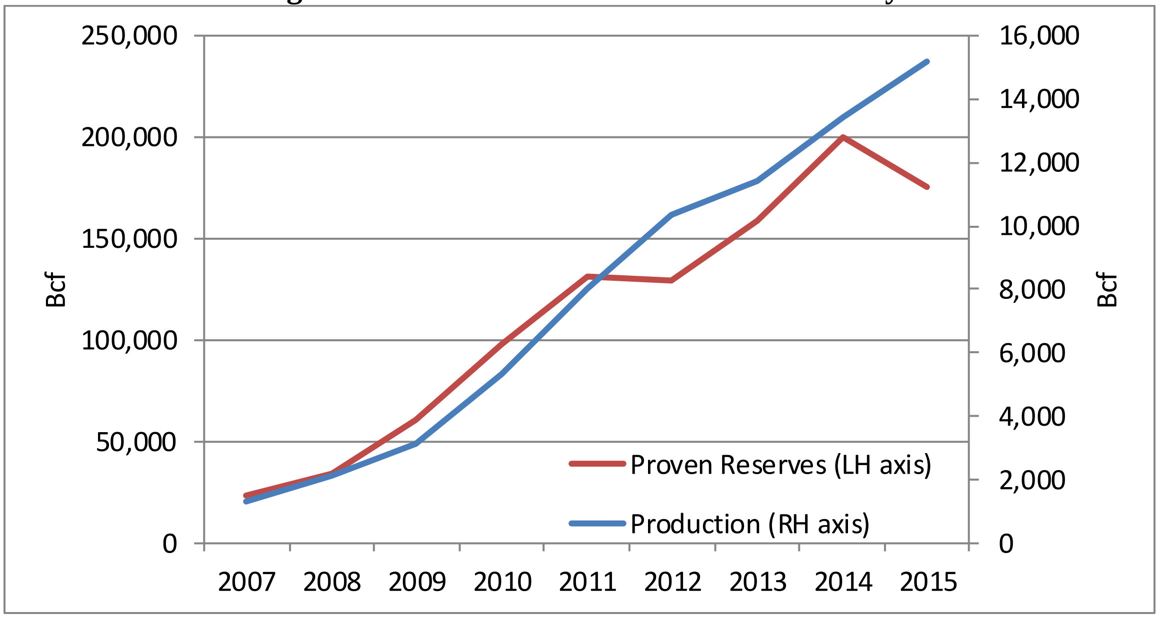
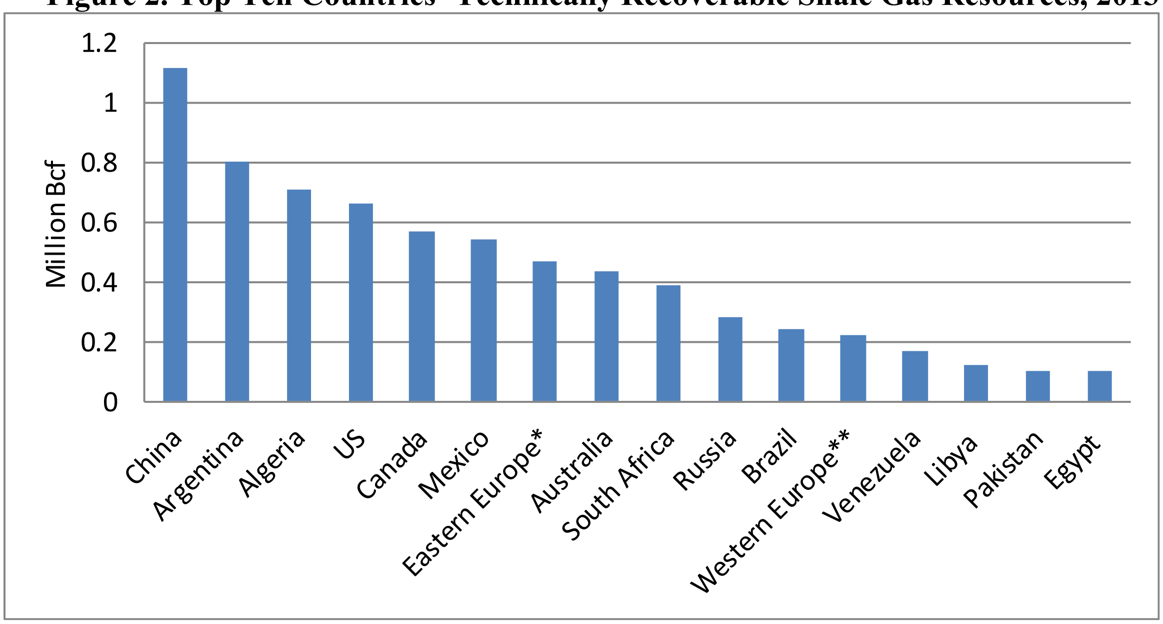
[4] Sieminski (2014), Hausman and Kellogg (2015), Figure 1. Hausman and Kellogg (2015) estimate that US shale gas production increased economic welfare (leaving aside environmental impacts) by $48 billion per year between 2007 and 2013.

Figure 1. Growth of the US Shale Gas Industry



Source: www.eia.gov/dnav/ng/ng_enr_shalegas_dcu_NUS_a.htm

Figure 2. Top Ten Countries' Technically Recoverable Shale Gas Resources, 2013



Source. www.eia.gov/analysis/studies/worldshalegas.
Notes. *Bulgaria, Lithuania, Poland, Romania, and Ukraine. **Denmark, France, Germany, Netherlands, Norway, Spain, Sweden and UK.

- private ownership of subsurface mineral rights (in other countries these rights are state-owned or may be ill defined, creating legal challenges to rapid development);

- an abundance of independent gas companies with the requisite technical knowledge or the incentive to develop it;

- pre-existing gas pipeline infrastructure and capacity;
- fairly abundant water resources;
- low population density (and hence public opposition);
- deep capital markets; and
- (not least) high natural gas prices in the early 2000s.

To varying degrees, these factors tend to be less favorable in other countries (Krupnick and Wang 2015) and the price remains a wildcard, though for the foreseeable future prices seem unlikely to return to their previous peaks (Box 1). In many cases however, the unquantified nature of many of the risks has led authorities in some jurisdictions to ban fracking altogether—these restrictions apply, for example, at a national level in Bulgaria, France, Germany, and South Africa and at a subnational level in Australia, Ireland, Italy, Spain, Switzerland, and the United States (including New York, Vermont, and cities and counties in California, Colorado, Texas, and Ohio). These restrictions are a judgment not questioned in this paper, nor are they a matter for fiscal policy (except to the extent any revenue loss can be estimated).

III. ENVIRONMENTAL RISKS AND POLICY RESPONSES

A. Risks

Differences in environmental impacts between conventional and shale gas are briefly introduced, followed by a closer look at the individual risks.[5]

(i) Differences with conventional gas

From an environmental perspective, there are many differences between a conventional (onshore) natural gas well drilled into reservoir rock and one drilled into shale rock, involving different pad footprint, water use, chemical use, and pressure below ground.

[5] For other overviews of environmental risks see Hausman and Kellogg (2015), Jackson and others (2014), Mason and others (2014), and Small and others (2014).

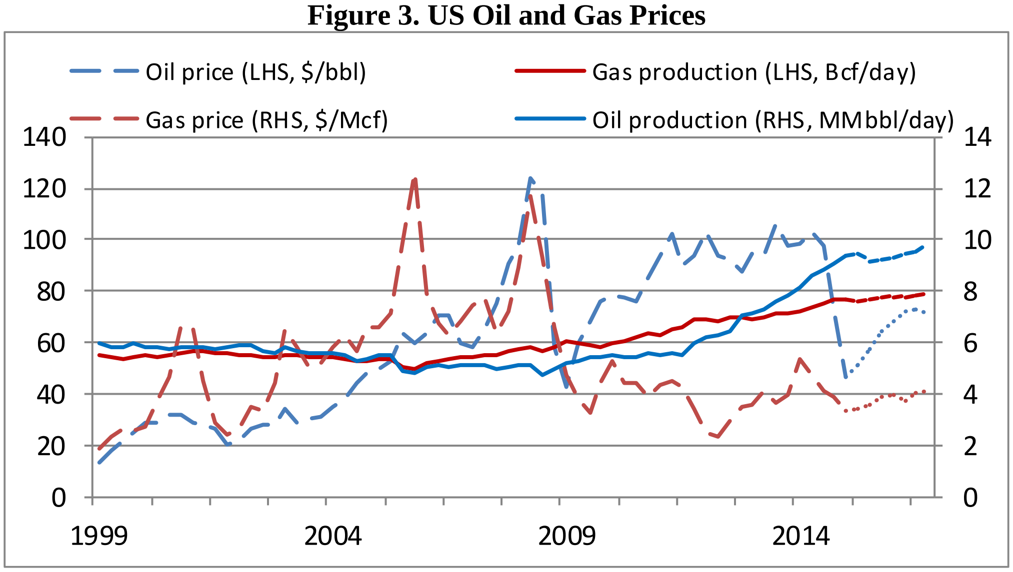
Box 1. Trends in Natural Gas Prices

Gas prices have fallen from their peak of over $12 per thousand cubic feet (Mcf) in 2005 to current levels of around $4 per Mcf, which may be about as low as they will go (pre-2000 prices were around $2.50 per Mcf). Lower prices deter drilling of marginal wells, though the effect on (conventional and unconventional) gas and oil production is being offset (Figure 3) by cost-cutting and productivity gains. Future demand growth could come from many sectors and raise prices, though supply curve elasticities are uncertain (Hausman and Kellogg 2015 put them at between about 0.4 and 1.6).

Although natural gas prices have loosely followed oil prices in the past, as in the 2002-2008 upswing (Figure 3), prices are becoming increasingly de-coupled (whereas oil prices are globally integrated, natural gas prices vary significantly across regional markets due to limited transportability). For example, after the sharp fall in energy prices at the onset of the Great Recession, oil prices quickly recouped much of their losses whereas gas prices lingered well below their earlier peaks, and oil prices declined far more sharply than gas prices at the end of 2014.

US oil and gas prices are not strongly linked on the demand side, as the energy sources are not close substitutes—gas is used primarily for electricity generation and household fuel, while oil products are used primarily in transportation. However, there is some substitution on the production side: when gas prices collapsed in 2008 many US drillers switched production to oil, though the relatively steep slide in oil prices, if sustained, could reverse some of this effect. On the other hand, the price of liquids produced in gas extraction is tied to oil prices, so the latter's fall could lower the return on gas production from some wells.

Figure 3. US Oil and Gas Prices



Source: www.eia.gov/petroleum/data.cfm, www.eia.gov/naturalgas/data.cfm
Notes. Gas price is Henry Hub and oil price is West Texas Intermediate. 2015-2016 data is projected.

Development of unconventional gas permits multiple wells on a single well pad. This could lead to a lower footprint per unit of gas extracted compared with conventional drilling (though many geological features would influence this comparison). However, the primary recipe for unconventional gas shale fracking involves the application of a mixture of water, sand and a variety of chemicals at high pressure—conventional drilling uses far less water and additives.

The greater concentration of wells on a pad, and the high pressures used for fracking, might create greater risks of groundwater contamination from casing and cementing failures and the return of some of the fracking fluid up the well creates additional concerns for liquid wastes handling, treatment, and disposal. Pumping liquid wastes into deep disposal wells might also affect risks of seismic activity. And generating the high pressures required by the fracturing operation itself requires powerful diesel engines, which contribute to local air pollution. Furthermore, the much higher water demands also imply more infrastructure (pipelines, roads, water storage facilities) and greater potential for habitat disruption, community impacts, roadway wear and tear, and (due to both water withdrawals and spills) damages to land and waterways.

There appear to be no environmental risks posed by conventional gas-only wells that are not also posed by shale gas wells.

(ii) Water quantity

Shale gas development requires large quantities of water[6] depending, for example, on maturity of the shale and formation thickness, and technologies used (e.g., horizontal versus vertical wells, and whether water is recycled). Per unit of energy content, shale gas uses a lot more water than conventional gas, similar amounts to coal (where water is used for coal cutting and dust suppression), and far less than enhanced oil recovery (Kuwayama and others 2013). And water consumption for shale gas is highly concentrated at a point in time (occurring over several days during fracking of the well), rather than spread out over the working life of the well. The opportunity costs of water use depend on usage *relative* to local water availability. For the United States, for example, areas of high shale gas activity sometimes overlap areas of high water stress, depending on seasonality and whether withdrawals are from small or large water bodies (e.g., Kuwayama and others 2013). Although, for regions with chronic water scarcity, shale gas development presents obvious challenges to aquatic life and even water users, water demands for energy extraction are generally trivial compared with other demands, such as agriculture.

(ii) Water Quality

Liquid and solid wastes from the toxic fluids used in fracking or naturally occurring chemicals released by fracking can affect surface and groundwater quality (Burton and others 2013). The liquid wastes can contain fracking fluids and highly salted water, radioactive materials, heavy metals and volatile organics from the formation itself, called ‘produced water’. Surface water quality can be affected by runoff, spills, and, when liquid wastes are treated and released, from waste stream discharges of treatment plants (e.g., Olmstead and others 2013), though impacts are highly site-specific, depending on environmental conditions and the care taken to treat and dispose of liquid wastes. Groundwater quality can be affected

[6] Around 3-5 million gallons for development of a well (Mielke and others 2010).

through leakages due to faulty casing and cementing around the well bore, though this is a standard problem in oil and gas drilling. More contentious is whether fracking itself can pollute groundwater by methane or substances in produced and flowback water—evidence on this is mixed (e.g., Osborn and others 2011, Schon 2011). Site-specific information on surface and ground water risks is needed, not least because public concerns over these risks have been a major impediment to shale gas development—current data gaps and uncertainties prevent a broad assessment of how often fracking harms water quality and how serious the effects are (US EPA 2016a).

(iii) Climate Change

Downstream combustion of (conventional and unconventional) natural gas is responsible for 27 percent of US fossil fuel CO_2 emissions[7] and these emissions should be priced at some point in the fossil fuel supply chain (see below). Shale gas development itself impacts climate change through two main mechanisms.

First is through altering downstream CO_2 emissions from fossil fuel combustion. Per unit of energy, combustion of natural gas (whether from shale or conventional) produces about 40 percent less CO_2 emissions than coal,[8] so to the extent gas displaces coal it reduces CO_2, but the opposite applies to the extent it displaces (zero-carbon) nuclear and renewables—Newell and Raimi (2104) and Brown and others (2009) find the net effect (for the United States) is a modest CO_2 reduction.

Second however, leakage or venting of natural gas itself—mostly methane, which is about 25 times more potent in trapping heat than CO_2[9]—can occur through the entire natural gas lifecycle (e.g., through faulty valves), including drilling, production, processing, distribution, and storage. These fugitive emissions have become a major concern and object of considerable research, though leakage rates are uncertain (a typical estimate is around 1.5 to 3.5 percent) and vary across firms (e.g., due to technologies used) and sites.[10] Most recent literature (e.g., Allen and others 2013) suggests that lifecycle GHGs are still significantly lower for natural gas than for coal. Shale gas development therefore makes more sense from a climate change perspective if it can displace coal[11] and if the fugitive methane can, at least

[7] US EPA (2016b), Table 3.5.

[8] EIA (2013).

[9] US EPA (2016b), Table ES 1.

[10] See, for example, Brandt and others (2014), EDF (2014), Moore and others (2014).

[11] And (from a global perspective) the displaced coal is not exported elsewhere, though Newell and Raimi (2014) suggest this effect is small.

(continued…)

in part, be addressed. Federal, state, and even voluntary industry initiatives in the United States are all attempting to do just that.[12]

(iv) Local Air Pollution

Combustion of diesel in engines used to pump fracking fluids and leaks of volatile organic compounds from storage and gas processing facilities contribute to local air pollution.[13] A voluminous literature documents an association between ambient air pollution and mortality risks (e.g., from heart and lung diseases).[14] Although these health damages have not been quantified in the context of shale extraction, some ballpark sense might be inferred from damage estimates for diesel used in road vehicles shown (for selected shale-endowed countries) in Figure 4. For illustration, if the average population exposure to emissions released in shale extraction (typically occurring in rural areas) is one-tenth of that for emissions from the average road vehicle, and (due to similar regulations) emission rates are comparable, pollution damages for the United States might be around 3 cents per liter (12 cents per gallon)—a significant, though not dramatic cost.

Downstream combustion of natural gas also causes local air pollution, though the damages are typically modest relative to global warming damages (Parry and others 2014) because, unlike for coal, natural gas combustion does not produce direct fine particulate or sulfur dioxide emissions, and nitrogen oxide emission rates are smaller than those for coal.

(v) Ecological and Seismic Risks

Land conversions for shale gas infrastructure (wells, roads, pipelines, rights of way) potentially disrupt ecosystems (e.g. deer habitat), particularly in areas of high well density, though there has been little documentation of these effects.[15] Seismic impacts have also received media attention and have caused the shutdown of several deep-injection disposal wells in Arkansas and Ohio. The quake magnitudes from fracturing *per se* are small to trivial, though wastewater disposal is nonetheless a contributing factor to earthquake risk—more evidence is needed on the probabilities of added wastes causing seismic events of different severities.[16] In short, the suitability of areas with endangered and highly-valued (e.g., for

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[12] Under the 2016 ‘Three Amigos Agreement’ the United States, Canada, and Mexico agreed to cut methane emissions by 45 percent by 2025, though the current US Administration is halting work on methane regulations. US methane emissions from all sources were estimated at 731 million tons in CO_2 equivalent in 2014 (12 percent of total greenhouse gases) with about a quarter of the emissions coming from (conventional and unconventional) gas systems (US EPA 2016, Table ES2).

[13] See, for example, Aldgate and others (2014), Moore and others (2014).

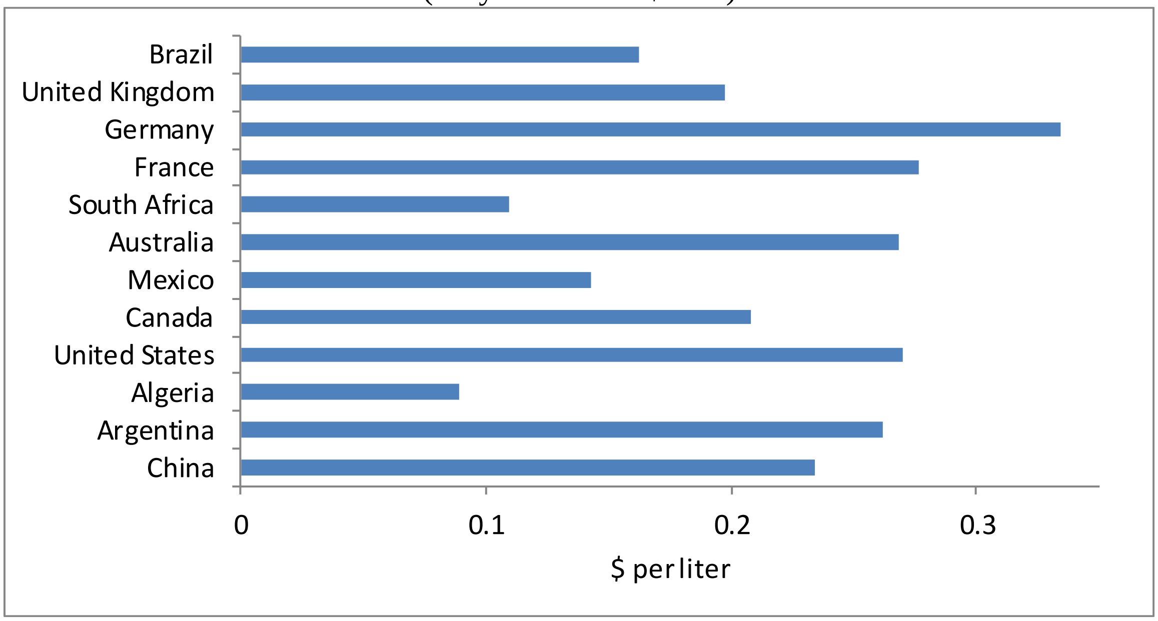
[14] For example, WHO (2014). Air pollution causes other damages (e.g., morbidity, impaired visibility, crop damage, building corrosion) but, even combined, these effects tend to be modest relative to mortality effects (e.g., NRC 2009, Ch 2).

[15] See, for example, Mason and others (2014), Slonecker and others (2012), and Small and others (2014).

[16] See, for example, Small and others (2014), US EPA (2014), US GS (2013).

recreational purposes) habitat, and where significant numbers of people are exposed to pre-existing seismic risks and lacking in viable means to dispose of liquid wastes, are probably not good candidates for shale gas development.

Figure 4. Estimated Air Pollution Damages from on-Road Diesel Vehicles
(for year 2010 in $2010)



Source. Parry and others (2014).
Note. These figures represent an average (across urban and rural areas) of damages from diesel combustion in on-road vehicles (cars, trucks, buses) accounting for existing emissions controls. The comparable damages for emissions from diesel engines used in shale gas extraction are likely a lot lower, at least if emissions regulations are similar and field operations are located away from urban population centers.

(vi) Community and Broader Impacts

Although local communities benefit economically from shale gas development, most likely they also bear the brunt of the environmental, health, and broader impacts like noise, visual degradation, traffic congestion and accidents,[17] property value changes,[18] overloaded schools (though the latter impacts may arise with any industrial development). More general impacts include damages to agricultural productivity (e.g., from increased water scarcity or pollution), tourism (e.g., from habitat destruction), other industries (e.g., breweries) needing high quality water inputs, and recreational activities (e.g., from habitat reduction, loss of hunted populations, loss of forested area available for hiking).

[17] For example, Muelenbachs and Krupnick (2013) estimate that extra truck traffic results in 9 extra road fatalities, and 12 extra (serious but non-fatal) injuries, in Pennsylvania counties with shale gas development.

[18] These can be significant: for example, Muelenbachs and Krupnick (2013) find that values for ground-water dependent properties fall by 16 percent as they become closer to shale wells, while values for properties with piped water access rise by 10 percent.

While these impacts are important in evaluating whether a given area is ripe for development, for policy there is a subtle distinction between 'direct' environmental impacts (which require corrective policies) and 'indirect' or 'pecuniary' effects (which should not). The former (e.g., health effects on exposed populations) are a cost on society, while the latter (e.g., reductions in housing values and hotel profits as residents and tourists re-locate away from a de-spoiled region), largely reflect transfers among regions, firms, or individuals, that approximately wash out in the aggregate. Pecuniary effects may, however, warrant compensation on equity (rather than efficiency) grounds.

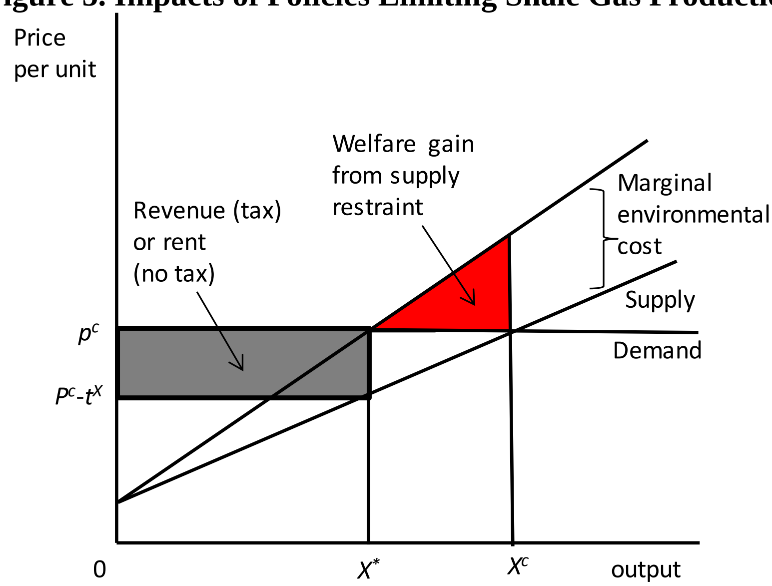
B. The Role of Fiscal Policy

This subsection discusses the possible use of fiscal policies to reduce the overall level of development, water use, air pollution, and GHGs.

(i) Controlling Development

Suppose the primary policy objective is to prevent shale gas development in regions with especially large environmental risks. Consider Figure 5, where the market price for natural gas is fixed at p^c and unit supply costs and environmental costs rise as reserves in progressively fragile areas are exploited. When environmental risks are ignored production is at the competitive level X^c. The efficient production level however is X^*, where supply and environmental costs equal p^c, and which could be induced by a unit production tax of t^X, resulting in an economic welfare gain (savings in supply/environmental costs less forgone consumer benefits) shown by the red triangle. However, when there is uncertainty over the tax rate needed for adequate protection, a ban in fragile areas preventing production beyond X^* may be more efficient. A ban alone leaves rents (the gray rectangle in Figure 5) in the hands of producers and these rents could be captured through combining the ban with a production tax, though rent taxation could be integrated in the broader fiscal regime (Section IV).

Figure 5. Impacts of Policies Limiting Shale Gas Production

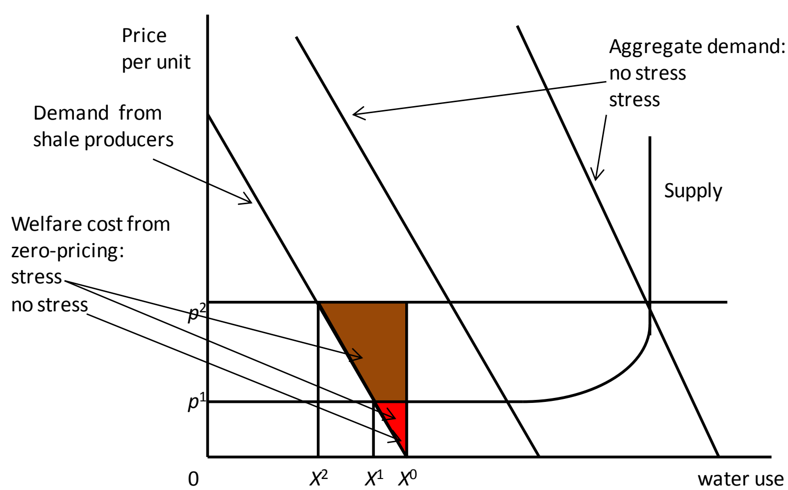


(ii) Pricing Water Use

Water (e.g., from rivers, lakes) for shale gas development is often controlled by regulation, but (even leaving aside fiscal benefits) a usage tax is potentially more efficient as it reflects (through tax payments) the opportunity cost of the water in firms' input costs, thereby promoting efficiency in the mix of developers' inputs and the extent of site development.

Prices would need to be set carefully depending, for example, on whether there is water stress. Consider Figure 6, where the local water supply curve is flat initially, but eventually becomes upward sloping and vertical as supply becomes exhausted. If total regional demand intersects the horizontal portion of the supply curve, then the efficient price is the unit supply cost p^1, and the economic welfare cost from failing to charge shale producers for water use would be the red triangle (costs to water suppliers less benefits to shale gas producers from extra consumption $X^0 - X^1$). However, if the regional demand curve instead intersects the upward sloping or vertical part of the supply curve the efficient price is higher at p^2, reflecting the high opportunity cost from alternative water uses. Failing to charge shale producers for water use now results in much larger extra welfare costs shown by the sum of the brown and red areas (associated with excess consumption of $X^0 - X^2$).

Figure 6. Economic Costs of Mispricing Water Supply



Again however, the practical relevance of this argument is questionable given the typically small share of water resources used by shale gas developers.

(iii) Pricing Air Pollution

Fiscal instruments might have a role, alongside regulations, in mitigating air pollution emissions. Ideally emissions from diesel engines would be taxed directly, thereby promoting use of emissions control technologies or cleaner diesel that reduce emissions per unit of diesel use, as well as reductions in diesel use (through more fuel-efficient engines and use of other fuels). Taxing diesel rather than emissions may be the more practical option, but does not promote the first set of responses. The best practical approach may be to combine a fuel tax with an emission rate standard, thereby approximately mimicking the effect of the emissions tax. To the extent that emission rates from diesel engines are tightly controlled through existing regulation, shale gas development is located away from urban centers, and engines are already relatively fuel efficient, the environmental gains from higher fuel taxes may however be limited.

Taxes for downstream local air pollution could also be imposed on gas supply at the point of extraction or processing/distribution (with rebates for any downstream users adopting mitigation technologies) which could make sense, in principle, where taxing at the point of combustion is impractical from an administrative perspective. The net benefits of these taxes however may be limited because of the relatively small size of air pollution damages.

(iv) Taxing GHGs

From an administrative perspective, charges for CO_2 emissions are generally best levied on fuel supply (in proportion to carbon content) as this covers all sources of emissions and minimizes administrative burdens. In contrast, levying charges downstream at the point of combustion on large industrial emitters (as typically occurs under emissions trading systems) misses a significant portion of emissions (e.g., from small firms, vehicles, and households) and administration is more complex (due to a greater number of taxpayers and the need to estimate emissions rather than infer them from already-observed fuel use and well-established emissions factors).[19] Whether charges are best levied on gas extractors, processors, or distributors will depend on national circumstances, such as where taxes are already applied (and could be readily modified to include carbon charges) and the number of potential collection points at different stages in the fuel supply chain.

If methane leakage from wells, pipes, processors and storage sites could be monitored on a continuous basis, an emissions tax would be the ideal instrument. Monitoring technologies are advancing though currently provide only discrete measurements at a limited number of sites.[20] One possibility for the interim might be to tax fuel suppliers based on a default leakage rate but allow rebates to firms that are able to demonstrate lower leakage rates through mitigation and installing their own continuous emission monitoring systems.[21]

C. Alternatives to Taxes

This subsection discusses the potential role of regulations and liabilities.

(i) Regulation

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[19] See Metcalf and Weisbach (2009), Calder (2015).

[20] Top down technologies include satellites, aircraft, and drones while bottom up technologies include remote sensing (e.g., from vehicles).

[21] For both CO_2 and methane, ideally the tax levels would be set in line with countries emissions mitigation pledges for the 2015 Paris Agreement. Parry and Mylonas (2017) develop a spreadsheet tool for roughly gauging these prices.

Regulatory approaches are attractive when the administration of environmental taxes is impractical and the government is mainly targeting one specific, observable behavior. Regulations encompass numerous instruments (e.g., technology requirements, case-by-case permitting for sites) available to national and sub-national governments. Box 2 discusses the role regulations (usually at the state-level) have played in shale gas development in the United States.

Box 2. The Regulation of Shale Gas Development in the United States

Extractive industries in the United States have traditionally been regulated primarily at the state level and this pattern has continued through the shale gas boom. States regulate the location and spacing of well sites, the methods of drilling, casing, fracking, plugging wells, the disposal of most oil and gas wastes, and site restoration. State common and public law governs the interpretation of lease provisions and disputes between surface and mineral owners and mineral lessees about payments and surface damage.

Federal authority is significant in some respects, however, including protection of air and surface water quality, endangered species, and regulating in its capacity as a landowner (many states with shale gas deposits include large areas of federally owned land). River basin commissions also issue relevant regulations to protect watersheds. And sometimes municipalities have a significant role: restricting the weight of equipment on roads; requiring operators to repair road damage; taxing oil and gas operations; and constraining well pad locations, drilling and fracking techniques, and waste disposal methods. Rapid expansion of shale gas has also created a dynamic regulatory environment which might help to explain the heterogeneity among state regulations of the same element (e.g., the required thickness of pit liners or distances between wells and water sources).

(ii) Liability

Litigation for shale drilling has increased rapidly since 2009 (Kurth and others 2011) and has a key role both in penalizing firms out of compliance with regulations and—which is discussed here—deterring one-off events like accidental leakage.[22] Firm-specific penalties for ex post damages is potentially more efficient than upfront regulations or taxes when producers have better information than regulators about environmental risks and the costs of mitigating them (see Box 3), but there are three notable obstacles to efficient liability policy.

First, firms are not always held accountable for their environmental impacts through lawsuit. For one thing, where pollution damages affect a large number of parties, lawsuit formation will face standard collective action problems and also legal and institutional hurdles (e.g., class action qualifications). For another, it may be difficult to establish clear causality between a pollution source and its negative effects, especially those (e.g., an increase in disease or mortality) occurring with a lag—indeed, by the time the long-term effects of pollution become manifest, the shale gas producer may no longer exist. Ideally, the penalty

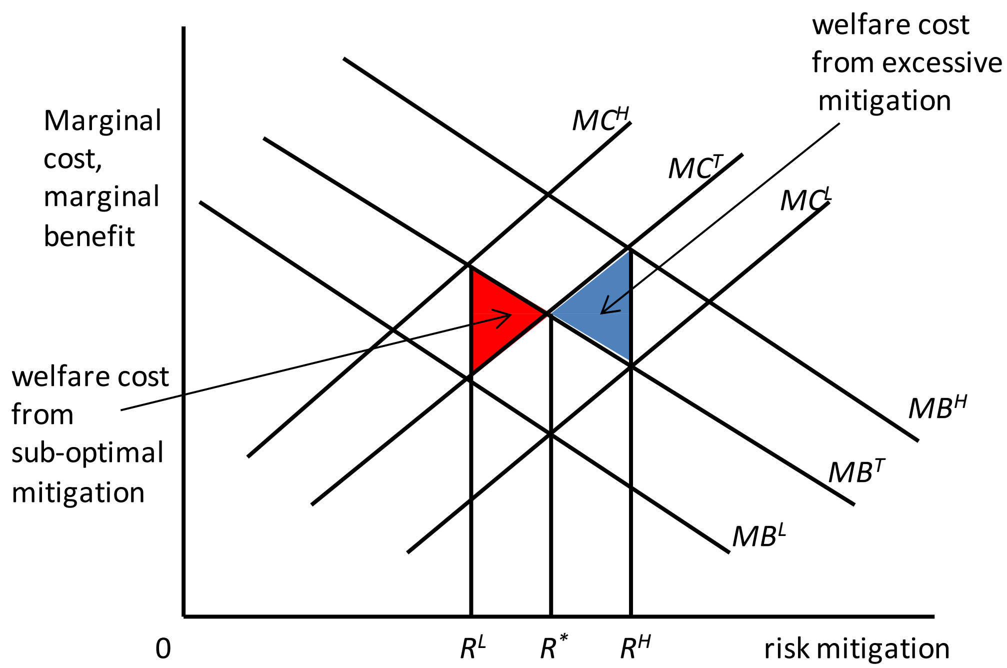
[22] The focus here is on 'strict' liability, where firms are responsible for damages, regardless of whether they tried to avoid them. Under 'negligence' liability firms are only responsible if it is found that they did not exercise an accepted standard of care, but this can be difficult to prove.

would equal the ex post environmental damages divided by the probability of the lawsuit (e.g., Becker 1968), though punitive penalties (in excess of actual damages) are rare.

Box 3. Private Information and the Relative Efficiency of Liability vs. Regulations/Taxes

Consider Figure 7 (adapted from White and Wittman 1983) where MC^T denotes the true marginal cost of mitigating an environmental risk (e.g. limiting contamination leakage), MB^T is the 'true' marginal environmental benefit in terms of reduced likelihood or scale of accidental damage, and R^* is the efficient level of risk mitigation. Suppose the regulatory agency is imperfectly informed about either these costs or benefits. If, for example, the regulator incorrectly perceives marginal costs to be MC^L (but knows environmental benefits) or incorrectly perceives marginal environmental benefits to be MB^H (but knows mitigation costs), and sets a standard (or the equivalent tax) to maximize expected welfare, risk mitigation will be too high at R^H, resulting in a welfare loss, indicated by the blue triangle. Conversely, suppose the regulator incorrectly perceives marginal costs to be MC^H, or marginal benefits to be MB^L, and again sets the standard (or tax) to maximize expected welfare, risk mitigation will be too low at R^L, resulting in a welfare loss indicated by the red triangle. By contrast, mitigation will be efficient if producers are subject to strict liability for environmental damages *and* they correctly perceive mitigation costs and environmental risks (in which case the private marginal benefit from risk mitigation coincides with the true marginal benefit).

Figure 7. Efficiency of Mitigation Policy Under Uncertainty



A second obstacle is that environmental damages may be difficult to quantify ex post—not least because the baseline level of environmental quality at different sites is frequently unavailable[23]—and some damages (e.g., to ecosystems) may extend beyond those suffered by victims of the lawsuit.

[23] See, for example, Adgate and McKenzie (2014), Moore and others (2014), and Small and others (2014).

Third is the existence of 'judgment-proof firms' declaring bankruptcy if liabilities exceed their net worth. In fact, businesses in hazardous industries may have some incentive to organize themselves to take advantage of this option by contracting out risky activities to small, undercapitalized firms.

There are nonetheless some possibilities for partly addressing these obstacles. The prospects for lawsuits might be enhanced by relaxing legal restrictions on class-action suits and requiring information disclosure by companies on environmental risks to enable third-party monitoring and reduce the cost of discovery for plaintiffs (Olmstead and Richardson 2014). Operating licenses can be conditional on minimum asset requirements, or liability insurance, and this is already a regular feature of many environmental protection laws.[24] 'Vicarious liability', which may hold principals accountable for harms committed by their agents when the latter's resources are insufficient to cover liabilities, can discourage contracting out of risky activities to undercapitalized firms.[25]

A further possibility would be to require a supplementary industry-level insurance fund, collected through production levies on individual shale gas developers, to pay out compensation for large environmental damages that are impractical to recover from individual firms. The industry would have some incentive to self-regulate, by monitoring member firm's efforts to limit environmental risks, thereby containing the needed production fees. This arrangement would be analogous to the International Oil Pollution Compensation Funds,[26] which provide financial compensation for persistent pollution damage from oil from tankers, financed by contributions paid on the amount of oil received (by large consuming entities) in the relevant calendar year.[27]

Developing and some emerging countries may have additional constraints on their ability to internalize environmental risks through legal liability—judicial capacity may be constrained or subject to capture; civil society organizations that might monitor petroleum companies are likely underdeveloped; and governments themselves could be capacity constrained, preventing public lawsuits and effective regulatory oversight. These countries may need to rely more heavily on ex-ante measures, particularly tax and/or insurance instruments that generate a revenue flow to help finance regulation, oversight, prosecution and/or remediation.

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[24] See, for example, Boyd (2001).

[25] For example, the US Oil Pollution Act of 1990, enacted in the wake of the Exxon Valdez spill, increased the likelihood of vicarious liability for oil companies, thereby reversing the trend toward contracting out shipping services seen over the previous two decades (e.g., Brooks 2002).

[26] See IOPC Funds (2016).

[27] See Viscusi and Zeckhauser (2011) for further discussion on two-tier liability and compulsory insurance regimes to deal with extreme damage risks.

(continued…)

D. Summary

Summing up Section III, there are numerous and diverse environmental risks associated with shale gas development, but their severity is highly site specific and there is scant quantitative evidence on the risks. Some combination of ex-ante (taxes, insurance and/or regulation) and ex-post (liability) controls seems most efficient response, given the diverse nature of the environmental risks and the varying strengths and weaknesses of different instruments in addressing each of them.[28] Table 1 provides a summary of appropriate instruments to address the identified risks.

IV. Fiscal Regimes

Tax incentives for shale gas tax began in the United States in the 1970s (Wang and Krupnick, 2013), and quickly spread. The same happened in other countries, especially in Europe where vast shale resources have been identified. The usual rationale for these incentives is that without them development would not occur due to high costs, or would be very limited due to low returns on capital. Because fiscal systems in North America have traditionally been front-loaded (i.e., relying on payment of taxes in early stages of a project, before capital cost is recovered through signature bonuses, royalties and/or severance taxes), these incentives may have been deemed necessary to overcome fiscal cost obstacles to development, but elsewhere, and with different fiscal systems, incentives may not have been needed. And even for the United States, the case for tax incentives is debatable, given that many projects in the shale sector have remained viable (due to cost cutting and, at least recently, declining costs of capital) despite the recent low commodity prices. Nonetheless, the impression has rapidly spread that shale gas "needs" special incentives and a differentiated fiscal regime.

This section discusses whether the commercial and technical features of shale gas development suggest principles of fiscal regime design—namely that the specifics of the regime can vary with local factors but there should be a balance among royalties, corporate income tax (CIT), and profit share (Box 4)—needs to be modified (e.g., in terms of favorable tax incentives) when applied to shale gas. A variety of fiscal regimes in different regions are tested to compare and contrast their implications for conventional and unconventional gas extraction. The focus of the discussion is on shale gas extraction which, by far, is the most common type of unconventional gas development.

[28] See for example Shavell (1984) for further discussion on instrument choice issues.

Table 1. Summary of Instruments to Address Environmental Risks of Shale Gas

Risk	Fiscal	Regulation	Liability
Overall development	Possibly (though to capture rents)	Yes (especially if uncertainty over tax needed to deter drilling in fragile areas)	No
Water use	Yes (especially if local water stress, though charging larger water users is more urgent)	Used in practice (but pricing policies could be more efficient)	No
Water pollution: surface	Limited practicality	Yes	Yes
underground	Limited practicality	Yes	Yes
Local air pollution	Yes (for diesel fuel used in drilling/pumping though environmental gains may be modest)	Yes (to encourage emissions control technologies)	No
GHGs	Yes (possibly for pricing carbon content and for methane leaks as metering technologies advance)	Yes (likely needed, in conjunction with taxes, to address methane releases)	No
Ecological, seismic, and other	Limited practicality	Yes (e.g., regulations for well density and pipeline location for biodiversity, or wastewater disposal wells for seismic)	Limited (given diffuse impacts, though environmental agencies and civil society organizations could be defendants)
Community and broader environmental	Limited (congestion and road damage might be addressed through fiscal instruments)	Limited (as many impacts reflect pecuniary externalities)	Some applicability (but perhaps more for compensation than efficiency)

Box 4. Common Advice on Extractive Industry Fiscal Regimes

Previous advice (e.g., Daniel and others 2010, Daniel and others 2017, IMF 2012) suggests that fiscal regimes for raising revenues from extractive industries can vary with political, institutional, and legal characteristics for particular jurisdictions. However, combining a royalty, an explicit rent tax, along with the standard CIT, with the economic substance of the instruments having similar properties (e.g., in terms of production sharing, risk service contracts, state participation, tax and royalty systems), has appeal in most cases. This regime ensures revenues are collected when production begins and that revenues increase with rents which, along with transparent rules and contracts, enhances the stability and credibility of the fiscal regime. Failure to address international tax issues (e.g., transfer pricing) however, can undermine revenue potential, and complex fiscal regimes and fragmented responsibilities among different government agencies can be major impediments to effective administration.

According to IMF (2012) simulations, the potential government share in rents for mining is around 40–60 percent and somewhat higher for petroleum at around 65–85 percent (reflecting international practice and the potential for higher economic rents in petroleum projects), though actual rent shares may be lower due to revenue erosion possibilities like shifting profits to lower taxed jurisdictions.

A. Fiscal Regimes

Fiscal regimes, where treatment differs between conventional and unconventional projects, are examined in a sample of ten jurisdictions—six in North America (Alberta, North Dakota, Oklahoma, Pennsylvania, Saskatchewan and Texas) and four elsewhere (Algeria, China, Poland and the United Kingdom). Incentives for shale gas generally take the form of lower royalties and/or lower profit tax (commonly used in the United States and outside of North America), or rates varying with well productivity or cost (commonly used in Canada)—the latter favoring unconventionals (due to the low productivity and high costs of wells).

North American regimes provide incentives for shale gas through a mix of direct and imbedded mechanisms (Appendix A, Table A1). Alberta, Oklahoma, North Dakota and Saskatchewan impose reduced royalty rates for horizontally drilled wells (which directly target shale hydrocarbon extraction), while Alberta and Saskatchewan also vary royalty rates with well productivity. Texas provides lower royalties for unconventionals through varying rates with well drilling and completion cost. Pennsylvania is the only jurisdiction that "penalizes" (through a special annual fee) unconventionals.[29]

The non-North American regimes (Appendix A, Table A2) provide incentives for shale gas through a variety of measures including lower royalty rates in Algeria and Poland, lower profit tax rate in Algeria and special deductions for development costs under the additional profit tax in the United Kingdom. China provides for a direct price subsidy along with a waiver or reduction of certain mineral resource fees.

[29] Even within jurisdictions multiple regimes co-exist (for example, Kepes and others 2011 found 188 different fiscal systems within ten Canadian Provinces and 25 US States), though these differences are beyond our scope.

(continued…)

Many jurisdictions also offer incentives for gas (over oil), horizontal drilling, "marginal" wells, "deep" wells, and "high cost" operations. While there seems to be a view in countries that petroleum that is costlier to extract receives tax relief, the definition for the specific criteria that qualifies petroleum extraction for this relief varies across jurisdictions. For example, North Dakota gives greater exemptions to wells that are "horizontally drilled"[30] whereas Poland charges reduced rates below a defined level of permeability.[31] There is little consistency among criteria for these concessions, possibly because there is no common view of relative costs across the industry. The greater the reliance of the overall regime upon levies related to gross production or proceeds, the more likely there will be arguments for reducing the levies for higher cost operations in general, and for shale gas in particular.

We do note that various indirect tax incentives, including reduced tariffs and VAT for imports of equipment, are also offered to shale gas development in some jurisdictions (e.g., China, Tian and others, 2014). Indirect taxes, however, are not part of our analysis.

B. Modeling Strategy

The modelling approach is used to explore: (1) whether there is justification for fiscal regimes favoring shale gas extraction (in terms of whether the incentives impact investments for marginal projects); and (2) potential revenues forgone from these incentives.

The analysis uses the Fiscal Analysis of Resource Industries (FARI) modeling tool[32] which takes a discounted cash flow approach to individual projects and, through fiscal calculations, allocates the project's pre-tax net cash flows to the investor and government according to the fiscal regime. Analysis can then be done using standard indicators defined in Box 5, namely the average effective tax rate (AETR), breakeven price, and marginal effective tax rate (METR), and comparisons of alternative fiscal regimes.

The project-based approach allows for conventional and unconventional projects and regimes to be better compared than in singe well studies,[33] given that fiscal regimes often have income taxes ring-fenced at the project level, meaning that the revenue and costs from each well are consolidated into a single flow of revenues and deductions for company income tax payments.[34] Therefore, the assumption of project-wide ring-fencing is more realistic and very

[30] Section 57-51 of North Dakota Tax Law and Regulations.

[31] Section 7a.6.1 of the Polish Act of March 2, 2012 on Certain Minerals Extraction Tax.

[32] See Luca and Puyo (2016).

[33] For example, Kepes and others (2011), Headwaters Economics (2013).

[34] Ring-fencing can also occur at the contract area, sector, or company level (e.g., Oklahoma has a reduced royalty rate applied to production from eligible wells in their first four years of production or until costs are recovered). For these cases, our analysis disaggregates projects into well production and costs by year and then applies the corresponding fiscal regime. Of the modeled jurisdictions, the United Kingdom has CIT and Supplementary Charge ring-fencing around the upstream sector, Algeria has CIT and APT ring-fencing around a contract area, and the United States, Canada, China and Poland have no ring-fencing provision, meaning that

(continued…)

relevant for shale gas projects that incur large capital expenses throughout the life of the project. In reality, ring-fencing occurs at the project, contract area, sector or company level but the fiscal modeling used here assumes project level.[35] However, the modeling approach was altered to account for fiscal regimes that use individual well life and productivity to determine royalty rates, which is common in North America (see Box 6). This was done by disaggregating projects into individual well production and costs by year of well life and then applying this information to applicable regimes.[36]

Box 5. Indicators used in Fiscal Regime Analysis[1]

AETR. The ratio of the net present value (NPV) of total government revenue to the pre-tax cash flows over the entire project life (exploration through decommissioning) received by the government.

$$\text{AETR} = \frac{\text{NPV (government revenue)}}{\text{NPV (revenue} - \text{all project costs)}}$$

Investor's post-tax IRR. The discount rate at which the NPV of the investor's stream of post-tax cash flows is zero. In general, a project is perceived to be profitable if the IRR exceeds the investor's required rate of return (assumed below to be 10 percent).

METR. The wedge driven by the tax system between the minimum after-tax return investors require and the pre-tax project return needed to realize it. It is calculated as the percentage difference between the pre- and post-tax IRR at the breakeven price. The METR reflects the burden placed by the fiscal regime on a project with marginal viability, thereby indicating the extent to which the regime affects investment decisions.

$$\text{METR} = \frac{\text{Pre tax IRR} - \text{Post tax IRR}}{\text{Pre tax IRR}}$$

Breakeven Price. The minimum constant real commodity price to yield a specific investor post-tax IRR. A breakeven price over the market price implies an unviable project.

1/ For a more detailed discussion of the above indicators see Luca and Puyo (2016).

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the CIT calculation considers all company activities generating income and deductions. The special hydrocarbon tax in Poland is however ring-fenced at a sector level, i.e. only hydrocarbon operations of a given company enter the tax account and other streams of revenue (and cost) are ignored.

[35] Of the modeled jurisdictions, the UK has CIT and Supplementary Charge ring-fencing around the upstream sector, Algeria has CIT and APT ring-fencing around a contract area, and the US, Canada, China and Poland have no ring-fencing provision, meaning that the CIT calculation considers all company activities that generate income and deductions.

[36] For example, until 2015 Oklahoma had a reduced royalty rate for wells in their first four years of production or until costs are recovered. The reduced rate is applied to production from eligible wells; not the first four years of the entire project's production.

Four representative gas projects are created for conventional versus shale development and North America, using a generic US project, versus non-North America, using a generic European project. Contrasting North America and Europe is interesting as they have significantly different natural gas prices, petroleum geology, and sector-wide systems (technical support, transportation systems, regulations). This approach does not recognize all the differences, which may be large among and within specific locations and even individual fields, but allows capturing the major ones to inform our analysis.

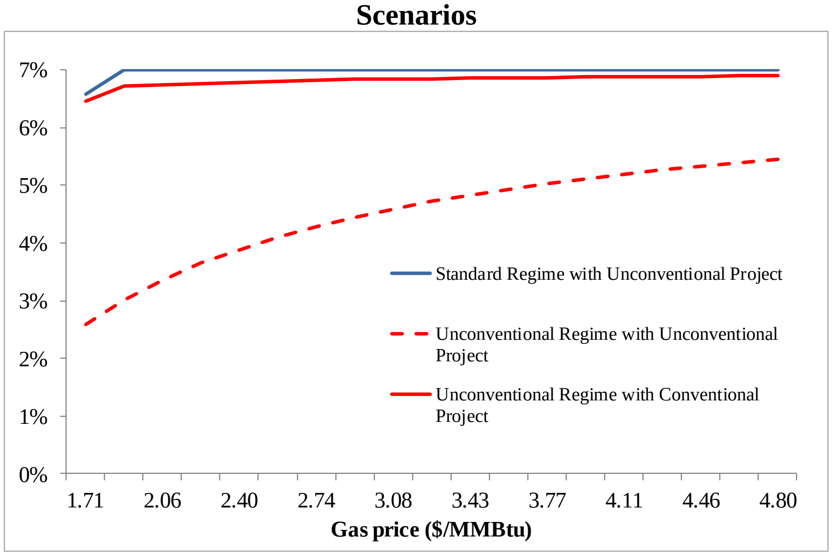
Box 6. A Closer Look at Shale Incentives in Oklahoma

More detailed analysis of the Oklahoma regime is given here to illustrate the intricacies of reduced royalty rates for shale and highlight mechanisms through which a regime can direct incentives at shale specific economics.

Oklahoma provides an interesting example of a regime that targets the differences in cost and production structures between shale and conventional gas. The state allows for a reduced royalty rate (1 percent) for production stemming from horizontal drilling up until all well development costs are recovered or the well's production reaches 4 years[1/]. Since shale, normally, has a much lower EUR, and thus production value per well than that of onshore gas, the incentive applies to a greater percentage of a shale gas well's total production. However, due to the well cost recovery limit, low-cost wells, which are less likely to be marginal and need an incentive, will not receive a full exemption.

Figure 8 shows the effective royalty rate on natural gas production and its progressive and targeted nature. Due to the mechanisms just described, the rate for an unconventional regime rate increases with price when it is imposed on a shale gas project. However, for a conventional gas project, the unconventional regime performs nearly identically to the rate under the conventional regime.

Figure 8. Oklahoma's Effective Royalty Tax on Natural Gas under Alternative Price Scenarios



[1/] Since 2015 the reduced royalty rate has been increased to 2 percent and applies for a maximum of 36 months.

Table 2 summarizes parameters assumptions for the four projects,[37] at the project and well level, with the general differences and similarities between each type of extraction and region summarized in Box 7. Appendix B provides further details on the modelling approach.

Box 7. Major Differences: Shale vs. Conventional Gas and US vs. Europe

Shale versus conventional:

- *Exploration cost*. Success factors for shale are lower in Europe (70 percent compared with 95 percent for conventional gas) and exploration costs are 50 percent higher. However, due to more favorable factors for the United States exploration costs for shale are 50 percent lower than for conventional gas and success rates are the same.
- *Well schedule and production profile*. Wells for conventional gas are mostly drilled as initial development, while those for shale gas are drilled throughout the project life—the latter have a much steeper decline and shorter production life (15 years compared with 40 for conventional gas).
- *Production per well*. Production is much higher for conventional gas—26.5 million barrels of oil equivalent (MMBOE) compared with less than 1 MMBOE for shale—therefore far more wells are drilled for shale gas (e.g., 403 in Europe per project compared with 8 for conventional).
- *Well drilling and completion cost*. Despite horizontal drilling and fracking, drilling and completion costs per well are lower for shale than conventional gas.
- *Operating expenditure*. About 60 percent higher per unit of gas recovered for shale due to the cost of chemicals, higher water usage, environmental protection, higher energy consumption, cost of land access and general and administrative costs, including higher social and community relations costs..
- *Decommissioning*. Progressive (“clean as you go”) for shale and lumped at the end of project life for conventional gas, however relative to well and non-drilling development costs decommissioning costs are taken to be the same for shale and conventional gas in the United States and somewhat higher for the former in Europe.

US versus Europe:

- *Well drilling cost*. Higher cost of drilling and well completion in Europe, partly also on account of a higher number of dry wells drilled (lower success factor).
- *Geology*. Less favorable for Europe, reflected in lower gas flow rates (2.5 Bcf per well compared with 3.5 Bcf for the United States).
- *Operating expenditure*. Higher for non-US; In Europe operating expenditures are moderately higher for shale, mostly on account of higher energy and chemical costs.
- *Natural gas price*. Lower for United States (around $3/MMBtu) than Europe ($5-10/MBtu).

[37] Parameters are based on IHS data, IMF’s TA experience in petroleum project evaluation, and judgement.

Table 2. Parameters for Simulated Projects

		Noth America		Europe	
Parameters	Unit	Shale	Conventional	Shale	Conventional
Project Level					
Project life	Years	44	40	44	40
Production	Years	37	32	37	32
Gas production	Tcf	1.0	1.0	1.0	1.0
Oil production	MMBbl	50	50	50	50
Total production[a]	MMBOE	222	222	222	222
Wells drilled	Wells	286	8	403	8
Success Rate	%	95	95	70	95
Gas price	$/MMBtu	2.86	2.86	4.79	4.79
Oil price	$/Bbl	50.0	50.0	60.0	60.0
Exploration	$bn	0.1	0.2	0.1	0.2
Capex	$bn	1.5	0.2	3.4	0.3
Opex	$bn	1.0	0.6	1.5	1.3
Total cost	$bn	2.7	1.0	5.1	1.8
Unit exploration	$/BOE	0.6	0.7	0.6	0.9
Unit capex	$/BOE	6.9	1.0	15.5	1.3
Unit opex	$/BOE	4.5	2.8	6.7	6.0
Total unit cost	$/BOE	11.9	4.5	22.8	8.2
Pre-tax cash flow	$bn	2.8	4.4	2.9	6.1
Pre-tax IRR	%	25.2	27.3	22.9	28.8
Well Level					
Well Life	Years	15	40	15	40
Gas production	Bcf	3.5	119.1	2.5	119.1
Oil production	MMBbl	0.2	6.0	0.1	6.0
Total production[a]	MMBOE	0.8	26.5	0.6	26.5
Production Decline	na	rapid[b]	slow	rapid[b]	slow
Gas revenue	$mm	10.3	440.7	12.2	738.0
Oil revenue	$mm	8.7	375.4	7.4	450.5
Drilling/Completion costs	$mm	5.0	6.0	8.0	14.1
Facilities	$mm	0.2	21.4	0.1	21.4
Opex	$mm	3.5	78.2	3.7	167.2
Total cost	$mm	8.8	107.9	11.8	205.2
Unit capex	$/BOE	6.6	1.0	14.7	1.3
Unit opex	$/BOE	4.5	3.0	6.7	6.3
Total unit cost	$/BOE	11.1	4.0	21.4	7.7
Pre-tax cash flow	$mm	10.2	695.3	7.4	953.2

Note. [a] Assumes 5.8 Mcf per barrels of oil equivalent (BOE). [b] Assumes 73 percent of production occurs in first three years.

C. Results

Figure 9 shows the METRs and breakeven gas prices, and Figure 10 the AETRs, for all modeled regimes when applied to the stylized shale and conventional gas projects in the respective jurisdictions. There are several noteworthy points.

For the North American shale gas project, from Figure 9 the actual fiscal regime for shale might appear to provide at best modest extra incentive for development compared with applying the fiscal regime for conventional gas. For example, breakeven prices in Oklahoma are $2.42 and $2.51 per MMBtu, and METRs are 49 and 52 percent, under the shale and conventional tax regimes respectively, and there is almost no difference between the fiscal regimes for shale and conventional gas in both Texas and North Dakota. Incentives for shale gas are somewhat more pronounced in the Canadian regimes—for example, the favorable regime for shale gas in Alberta reduces the breakeven price from $1.99 to $1.91 compared with the conventional regime. A look at the Figure 8 however, suggests that fiscal incentives have little effect on marginal investments under alternative gas price scenarios. The AETRs are upwards of 80 percent in half of the jurisdictions—projects are deemed to be marginal if AETRs exceed 90 percent—or put another way the breakeven prices in Figure 9 are not that different from the assumed gas price ($2.86/MMBtu). The Canadian shale gas regimes lower the government take by a few percentage points compared to (not so harsh) conventional fiscal regimes whereas the US shale gas regimes offer little relief, even though the overall level of taxation is much higher.

As regards the conventional US gas project breakeven prices, METRs, and AETRs are essentially the same under the fiscal regimes for shale and conventional gas, underscoring that the favorable tax provisions are specific to the unique features of shale gas extraction and would do nothing to help conventional gas. The one exception is Alberta, where petroleum by-products are subject to a lower royalty than by-products from conventional gas extraction, though at current gas prices these provisions would have minimal effect on incentives, given larger differences between actual and breakeven prices (compared with shale gas) and lower AETRs (typically in the range of 55 to 65 percent).

Fiscal regimes in Europe would provide stronger incentives for shale gas, for example, reducing the METR for the shale project in the United Kingdom from 28 to 8 percent (relative to the conventional fiscal regime), in Algeria from 59 to 42 percent, and in China from 59 to 36 percent. In the case of Algeria and China however, the breakeven prices are close the assumed gas price for Europe ($4.79 per MMBtu), suggesting incentives may not be sufficient to overcome currently unfavorable economics (put another way, the AETRs is only slightly below 100 percent in Figure 8). Although revenue differences between the fiscal regimes for shale and conventional gas are substantial—the AETRs for the United Kingdom, for example, are 30 and 62 percent respectively—marginal projects might not be developed without a favorable regime (in which case no revenues are raised).

As regards the conventional European gas project, unlike in the North American case, there are significant differences between treatment under the fiscal regimes for shale and conventional gas, most notably in China where the METRs are 49 and 21 percent respectively (incentives here take the form of lower royalty rates or subsidies which are not specific to the characteristics of shale extraction). In Poland, both METR and AETR are almost identical under the two analyzed fiscal regimes, implying that little incentive provided by the shale gas regime for economically viable projects. 50 percent reduction in already modest royalty rate (1.5 vs. 3.0 percent) accounts only for a small fraction of the total government take and does not influence incentives to undertake a project.

Differences in AETRs achieved under different regimes point to a substantial fiscal cost of incentivizing shale gas production, at least in non-American regimes. Revenue forgone due to applying a special shale gas regime rather than the one used for a conventional production is the largest in the UK—$145 million or 26 percent of pre-tax cash flow (in discounted terms) from the analyzed project is lost. The size of the fiscal subsidy in countries outside North America—at $33 million or 6 percent of pre-tax cash flow—is the smallest in Poland. Amongst Canadian regimes Alberta's tax expenditure—at $55 million or 13 percent of pre-tax cash flow—is double of that of Saskatchewan.

Figure 9. METRs and Breakeven Gas Prices

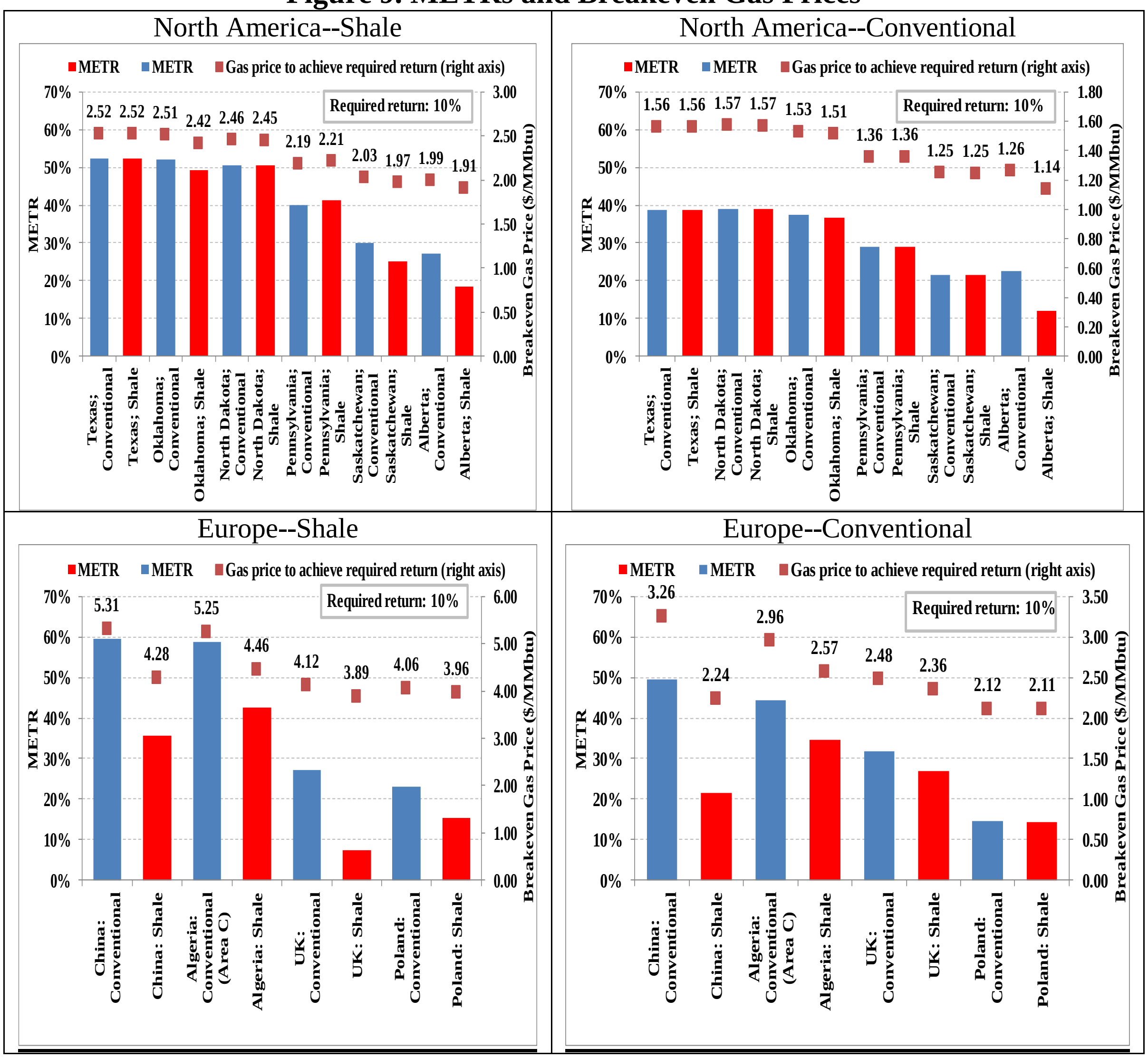
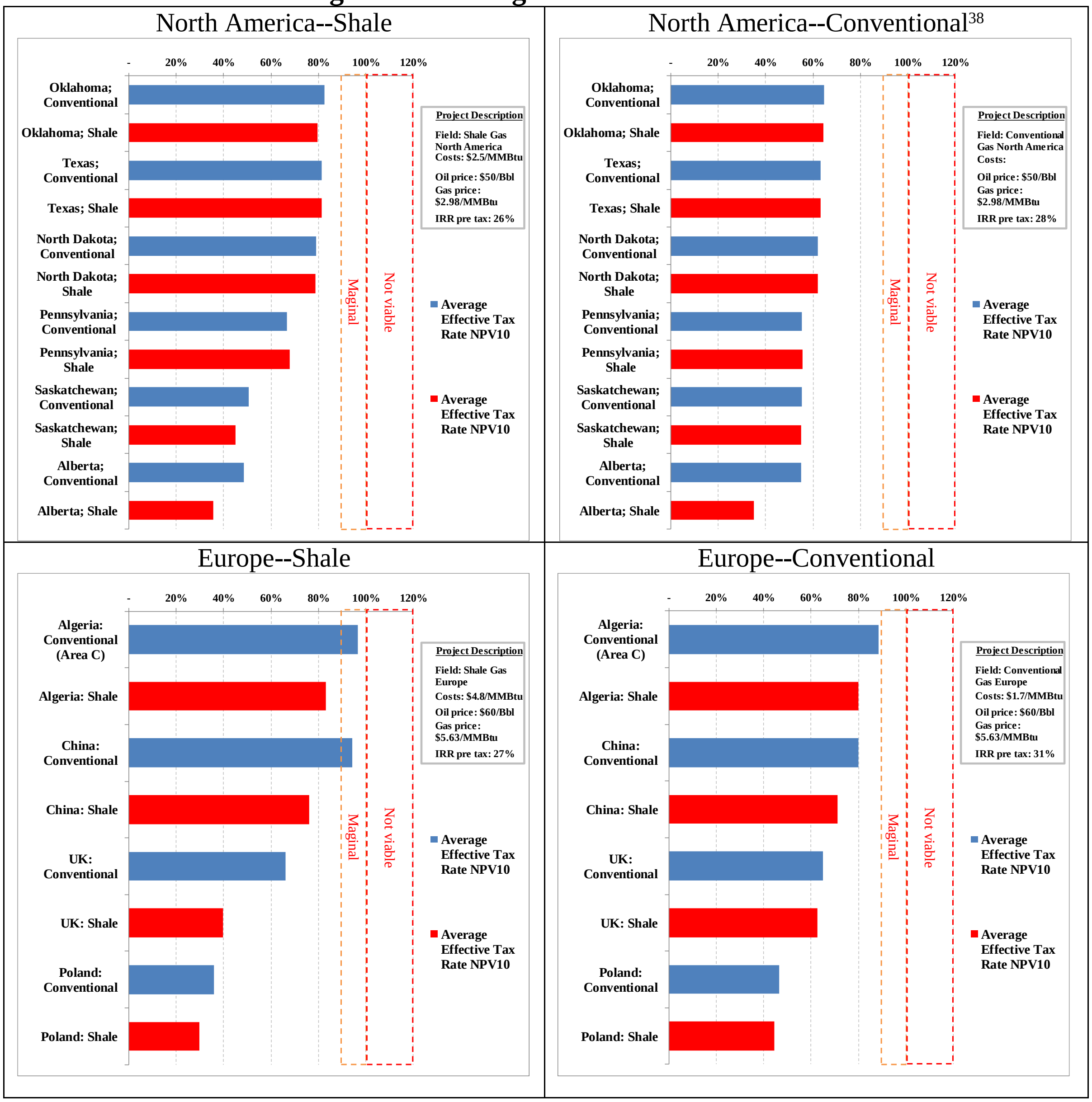


Figure 10. Average Effective Tax Rates



V. Conclusions

Although shale gas development poses a broader range of environmental risks than conventional gas, the implications for efficient fiscal regimes for extractives seem limited. For several risks (e.g., pricing water inputs, diesel fuel for pumping engines, greenhouse gas emissions) fiscal policies may have a role, though in some cases the net benefits from special tax provisions may be limited.

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[38] The discounted AETR is excluded from this graph as it does not provide meaningful results due to the slightly negative pre-tax net cash flow, which it the denominator in AETR.

The modeling results in this paper suggest that special fiscal regimes and incentives granted for shale gas development in some jurisdictions have, at most, only a slight impact on likely decisions to invest, whereas they may result in substantial cost to the government (tax expenditures). Other circumstances, such as private ownership of resource rights and availability of an extensive gathering and distribution infrastructure for gas, have probably played a much bigger role in promoting the rapid development of shale resources in the USA.

For the most part, there is little evident need to consider specific incentives for shale gas development, compared with conventional gas, provided that the overall fiscal regime responds substantially to realized profit or rent. The principal exception comes where authorities seek to promote shale gas development in a jurisdiction that relies heavily on gross royalties or on initial or continuing flat fees or bonuses.

In short, the case for providing relative fiscal incentives to unconventional over conventional natural gas is not especially compelling.

Appendix A. Details of Fiscal Systems in the Sample Jurisdictions

Table A1. North American Regimes

	North Dakota - Conv.	North Dakota - Unconv.	Oklahoma - Conv.	Oklahoma - Unconv.	Pennsylvania - Conv.	Pennsylvania - Unconv.	Texas - Conv.	Texas - Unconv.	Alberta - Conv.	Alberta - Unconv.	Saskatchewan - Conv.	Saskatchewan - Unconv.
Primary royalty gas	16%	16%	18.75%	18.75%	12.5%	12.5%	20%	20%	5%-36%[b]; limited reduced rate	5%-36%[b]; further limited reduced rate	0%-40%[b]; limited reduced rate	0%-40%[b]; limited reduced rate
Primary royalty oil	16%	16%	18.75%	18.75%	12.5%	12.5%	20%	20%	0%-40%; limited reduced rate	0%-5%	0%-40%[b]; limited reduced rate	0%-40%[b]; limited reduced rate
Additional royalty gas	US$ 0.0833/Mcf	US$ 0.0833/Mcf	1%-7%[a]	1%-7%[a]; limited reduced rate	No	$5k-$60k per well	0%-7.5%; varies with cost of well	0%-7.5%; varies with cost of well	No	No	No	No
Additional royalty oil	2%-6.5%[a] + 5% w/ limited exemption	2%-6.5%[a] + 5% w/ increased exemption	1%-7%[a]	1%-7%[a]; limited reduced rate	No	No	4.6%	4.6%	No	No	No	No
CIT - rate (%)	Federal: 35% State: 5%	Federal: 35% State: 5%	Federal: 35% State: 6%	Federal: 35% State: 6%	Federal: 35% State: 9.9%	Federal: 35% State: 9.9%	Federal: 35% State: 1%	Federal: 35% State: 1%	Federal: 15% State: 10%	Federal: 15% State: 10%	Federal: 15% State: 12%	Federal: 15% State: 12%
Depreciation (exploration)	7 years SL	7 years SL	7 years SL	7 years SL	7 years SL	7 years SL	7 years SL	7 years SL	Immediate	Immediate	Immediate	Immediate
Depreciation (capex)	IDC: 5 years SL Non-IDC: 200% accelerated w/ 7 year SL	IDC: 5 years SL Non-IDC: 200% accelerated w/ 7 year SL	IDC: 5 years SL Non-IDC: 200% accelerated w/ 7 year SL	IDC: 5 years SL Non-IDC: 200% accelerated w/ 7 year SL	IDC: 5 years SL Non-IDC: 200% accelerated w/ 7 year SL	IDC: 5 years SL Non-IDC: 200% accelerated w/ 7 year SL	IDC: 5 years SL Non-IDC: 200% accelerated w/ 7 year SL	IDC: 5 years SL Non-IDC: 200% accelerated w/ 7 year SL	25%-30% DB	25%-30% DB	25%-30% DB	25%-30% DB
LCF	20 years	20 years	20 years	20 years	20 years	20 years	20 years	20 years	Indefinite	Indefinite	Indefinite	Indefinite

Source. IMF FARI Database, EY 2016, countries' tax legislation;

Notes. SL: Straight line (depreciation); LCF: loss carryforward; IDC: intangible drilling costs; [a] rate varies with commodity price; [b] rate varies with commodity price and well productivity.

Table A2. Non-North American Regimes

	Algeria - Conv.	Algeria - Unconv.	China - Conv.	China - Unconv.	Poland - Conv.	Poland - Unconv.	United Kingdom - Conv.	United Kingdom - Unconv.
Royalty gas (%)	12.5%-23%[a]	5%	11%	11%	3%	1.5%	0%	0%
Royalty oil	12.5%-23%[a]	5%	11%	11%	6%	3%	0%	0%
Cost recovery limit	NA	NA	60% oil; 70% gas	60% oil; 70% gas	NA	NA	NA	NA
Production sharing method	NA	NA	Annual production	Annual production	NA	NA	NA	NA
Min government share	NA	NA	5%	5%	NA	NA	NA	NA
Max government share	NA	NA	55%	55%	NA	NA	NA	NA
CIT - rate	20%-70%[b]	10%-40%[b]	25%	25%	19%	19%	30%	30%
Depreciation (exploration)	Immediate	Immediate	3 years SL	3 years SL	Immediate	Immediate	Immediate	Immediate
Depreciation (capex)	8 years	8 years	Pre-production: 8 years SL Other: 10 years SL	Pre-production: 8 years SL Other: 10 years SL	5 years SL	5 years SL	Immediate	Immediate
Additional deductions	13% development costs	20% development costs	0%	0%	0%	0%	10% uplift on LCF for 10 years	10% uplift on LCF for 10 years
LCF	5 years	5 years	5 years once production begins	5 years once production begins	5 years; unused is creditable against royalty	5 years; unused is creditable against royalty	Indefinite	Indefinite
Additional Profit Tax rate	15%-30%[b]	15%-80%[b]	0%-40%; varies with oil price	0%-40%; varies with oil price	0%-25%; varies with R-factor	0%-25%; varies with R-factor	20%; limited uplift on capex	20%; uplift on capex
State participation	51% carried until development w/ repayment	51% carried until development w/ repayment	51% carried until development w/o repayment	51% carried until development w/o repayment	0%	0%	0%	0%
Other				Subsidy of CNY 0.4/cubic meter				

Source. IMF FARI Database; EY 2016, countries' tax legislation

Notes. LCF: loss carryforward; CNY: Chinese Yuan; [a] rate varies with production; [b] rate varies with profitability ratio.

Appendix B. Further Details on Representative Projects for Fiscal Regime Analysis

Production aims to maintain a plateau (though this may not necessarily be true for shale gas in the US). For Canadian regimes, where fiscal parameters depend on depth, reservoirs are taken to be at 3000 meters.[39] Associated liquids, so called "wet gas" (e.g., ethane, butane) are included in shale production.[40]

Several other assumptions deserve mention. Tax regimes are taken to apply throughout the project life with taxes paid by one entity, the "investor", and this entity receives all cash flows before paying taxes and interest.[41] 70 percent of development expenses are financed through debt, while the rest of project costs are paid from investor equity, reflecting an assumption that investors are not able to borrow to fund exploration and prefer to avoid excessive leverage (capitalization in line with prevailing debt-to-equity tax ratios). Inflation and interest rates are assumed to be constant throughout the project and, based on long-term forecasts published in the April 2016 World Economic Outlook, petroleum prices are in constant 2016 real dollars, meaning they annually adjust for inflation.[42]

[39] Additional simulations for Saskatchewan indicate that a well depth of 2,000 meters, rather than 1,500 meters, causes the pre-tax IRR to decrease by 0.4 percentage points due to the rise in costs. However, since a relatively large portion of oil becomes eligible for a lower royalty rate at the greater depth for the unconventional regime, the investor's post-tax return increases while the effective royalty rate sharply falls under the 2,000 meters scenario. A less significant impact is seen for the conventional regime due to the lower portion of petroleum eligible for the lower royalty rate.

[40] There is some substitutability between oil and gas flows which becomes important when gas prices decline sharply relative to those for oil. This feature is ignored in the analysis and a fixed ratio of 1 barrel of oil for every 20 Mcf of natural gas is assumed.

[41] An exception is when there is state participation, meaning that the national oil company (NOC) has an equity stake in the project. Specifically, in the case of state participation within the Algerian and Chinese regimes, the NOC has its share of exploration costs "carried", or paid for, by the investor and thereafter covers its share of costs, including the repayment of carried costs, with cash.

[42] Prices are US $2.86/MMBtu and $48.00/bbl for North American gas and oil, respectively, and $4.79/MMBtu and $51.01/bbl for non-US gas and oil, respectively.

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