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Highlights

- The particular mix of tax and royalty policies applying to an oil or gas property varies according to whether the landowner is a tribe, the state or federal government, or a private entity.
- In Utah, the federal government owns about two-thirds of the land surface area, and in recent times about half of Utah's oil and gas production has taken place on federal lands.
- Oil and gas reserves are as much an economic concept as a geological one. Oil and natural gas reserves are that amount of the resource in the ground that it is currently commercially viable to produce. Oil and gas reserves may therefore increase or decrease depending on the going price for oil and gas. A large part of the recent increase in Utah's oil and gas reserves was due to high oil and natural gas prices.
- Oil and gas production in Utah is subject to a fiscal system consisting of payments associated with gaining access to and producing from oil and gas deposits as well as a variety of federal, state, and local taxes. The particular treatment a property receives under a tax policy often varies with characteristics of the property or operator. For example, operators with no refining operations and who produce fewer than 1,000 barrels per day—and only those operators—are entitled to the lucrative federal percentage depletion allowance.
- Fiscal systems that extract only the economic rent of an oil or gas deposit do not alter an operator's production decisions, though they may alter the attractiveness of similar investments not yet made. Though such "rent taxes" are widely recommended by economists, their implementation involves a number of significant challenges for policymakers.
- Over half of the nearly 3,000 Utah oil wells in production during 2008 were low-production oil wells, often called "stripper" wells. These wells produced an average of 4.5 barrels of oil per day and collectively accounted for 12 percent of the total oil produced in Utah during 2008. Low-production natural gas wells counted for about one-third of all natural gas wells during 2008, with the total production from these wells equaling 4 percent of Utah's total natural gas production. This does not, however, include the considerable amount of natural gas produced from low-production oil wells ("associated gas" production). Utah exempts all such production from the state oil and gas severance tax. Low-production wells located on federal leases had been entitled to reduced royalty rates, but this program was terminated in October 2010.

Fiscal Policy and Utah's Oil and Gas Industry

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Introduction

Payments directed at tax obligations and the purchase of extraction rights are a major business expense for oil and gas extraction firms. A recent review by the Government Accountability Office indicates that such payments may amount to between 50 and 60 percent of cash flows for a typical onshore oil extraction project located on federal leases, and between 37 and 50 percent for extraction on leases in the Gulf of Mexico or Outer Continental Shelf. This article is based on work carried out by the Bureau of Economic and Business Research on the nature of the fiscal system applying to oil extraction in Utah. The original purpose of the research was to provide a client with: (1) a general discussion of the scope of fiscal policy, and (2) appropriate fiscal parameters for the client's model of production costs associated with various novel methods of producing crude oil. As the work neared completion it became clear that some of the findings might also prove useful to a broader audience of those interested in fiscal policy and the oil and gas industry. For completeness and perspective, we begin with a summary of the particularly important features of Utah's oil and gas industry.

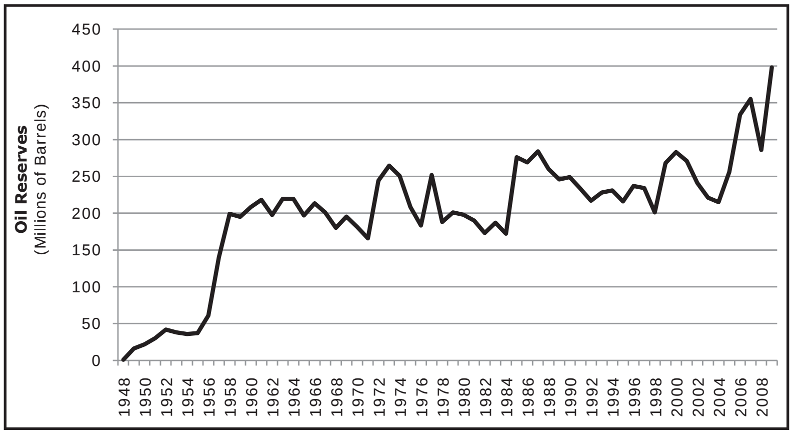
The Oil and Gas Industry in Utah

Reserves and Production

Oil and gas reserves are amounts of the resource for which extraction is commercially viable, or is expected to be so in the near future. Because commercial production occurs only from reserves, in the absence of other factors that influence the level of reserves production decreases reserves by the amount of production. New discoveries of oil and gas, as well as extensions of known oil and gas fields, increase reserves. Reserves may change, however, even without production, new discoveries, or extensions. This is possible because the level of reserves of a resource is linked to its market price. Generally, as the price of the resource increases, deposits become commercially viable which would not have been viable otherwise. Such deposits become part of reserves. When prices fall, deposits that were commercially viable under the higher prices are no longer so, and therefore drop out of reserves.

The Securities and Exchange Commission has recently devised new rules concerning the reporting of reserves. Three are of particular interest. First, the standard market price that is used to ascertain economic viability is now the average of the first-day-of-the-month prices during the year. Before the rule change, the market price used was the price on the final trading day of the year, which could easily be quite different from the year's average prices. Everything else being equal, this new rule should stabilize official reserve estimates. The second change concerns disclosure of oil and gas holdings. Companies must disclose both proved developed reserves and proved undeveloped reserves, while it is optional to also disclose (the increasingly uncertain) probable developed, probable undeveloped, and possible undeveloped reserves. Lastly, it is now possible for firms to include among reserves oil from unconventional sources, such as oil sands and oil shale.

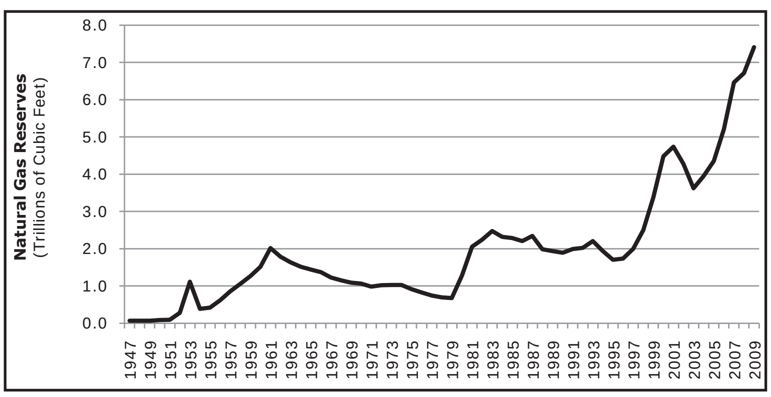
Figure 1
Proven Oil Reserves in Utah, 1948–2009



Source: Utah Geological Survey, Utah Energy and Mineral Statistics.

It is important to note that overall reserve figures, such as world, U.S., or Utah reserves, involve a summation across deposits that may vary greatly in extraction costs, refining costs, or access to markets (even though by definition they are all "economic"). As of the end of 2009, the U.S. Energy Information Agency (EIA) and Canadian Energy Resources Conservation Board credit Canada with 178 billion barrels of oil reserves, more than 99 percent of which is based on oil sands deposits. Among other countries, this number is second only to the 267 billion barrels the EIA credits to Saudi Arabia. But whereas oil sands crude is among the most expensive to extract and refine among official reserves, Saudi reserves are among the least expensive. Likewise, U.S. reserves located offshore are less valuable per barrel than typical reserves located onshore.

Figure 2
Natural Gas Reserves in Utah, 1947–2009



Source: Utah Geological Survey, Utah Energy and Mineral Statistics.

Figure 1 shows Utah's proven oil reserves over time. The recent sharp changes in Utah's reserves are largely the result of sharp changes in the price of oil. At the end of 2009, Utah held 398 million barrels of oil reserves, equaling 1.9 percent of the 20.7 billion barrels of U.S. reserves and 0.03 percent of the 1.34 trillion barrels of world reserves.

Figure 2 shows Utah's natural gas reserves since 1947. Utah's 7.4 trillion cubic feet of natural gas reserves represent 2.6 percent of the 273 trillion cubic feet of U.S. reserves and 0.12 percent of the 6,261 trillion cubic feet of world reserves as of 2009. Like oil, natural gas reserves depend not only on discoveries of new fields and extensions of known fields, but also on the price of natural gas.

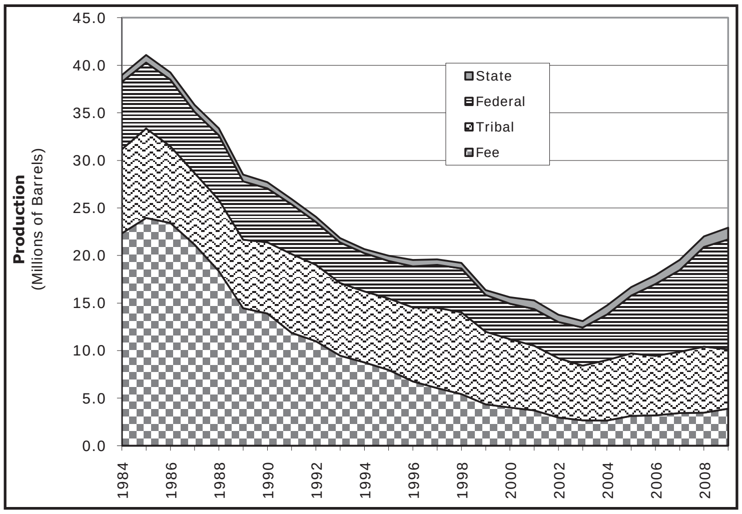
The significance of a barrel of oil is more intuitive than is that of a thousand cubic feet of natural gas. One way to compare quantities of oil and natural gas is by their energy content—the amount of energy released when the fuels undergo combustion. In terms of energy content, one barrel of oil equals about 5,800 cubic feet of natural gas. Another way to put natural gas quantities into a useful perspective is to indicate amounts used in typical applications. In recent years, a typical home in the Rocky Mountain region using natural gas as its primary heat source consumed about 66,000 cubic feet of natural gas per year.

During 2009, Utah produced 23 million barrels of oil (1.1 percent of the 1.96 billion barrels produced in the U.S. in 2009) and 430 billion cubic feet of natural gas (2.1 percent of the 20.3 trillion cubic feet produced in the U.S.). Figures 3 and 4 show oil and gas production, respectively, in Utah since 1984 by landowner.

For the purpose of this article, two particularly significant classifications of production are by the type of resource owner and by well productivity. These classifications are important because they segregate production into groups that differ substantially in their fiscal treatment.

There are four basic categories of land and mineral (e.g. oil and gas) owners in Utah: private, state, federal, and tribal ("Indian"). Usually, though not always, the type of mineral rights owner for a given deposit is the same as the type of owner for the surface

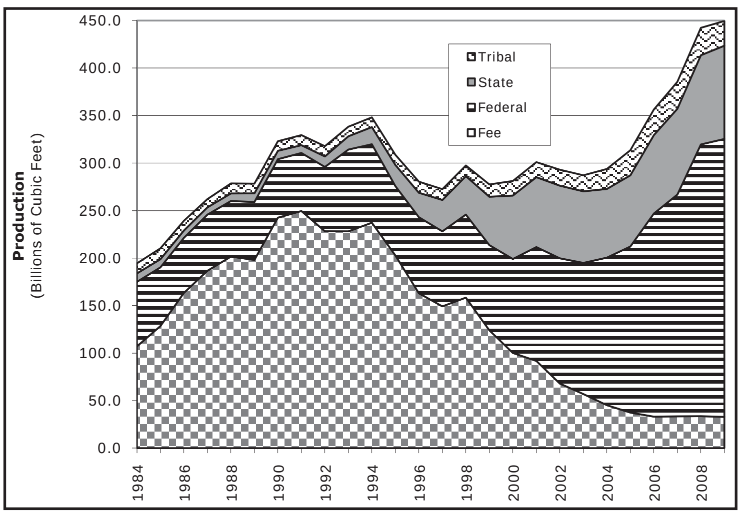
Figure 3
Utah Crude Oil Production by Landowner, 1984–2009



Source: Utah Geological Survey, Utah Energy and Mineral Statistics.

rights above the deposit. Table 1 shows the distribution of Utah's surface area by category of surface owner. Almost two-thirds of Utah's surface area is owned by the federal government, with the Bureau of Land Management having responsibility for the largest share of federal land.

Figure 4
Utah Natural Gas Production by Landowner, 1984–2009



Source: Utah Geological Survey, Utah Energy and Mineral Statistics.

Another important category of oil and gas production in Utah is that from low-productivity ("stripper" or "marginal") wells. These are usually wells that produced at much higher levels earlier in their life, when pressure in the reservoir was greater. But as production continues, oil reservoir pressure drops and, consequently, so does the rate of production. Eventually, the rate of production slows to such a level that it is no longer worthwhile to continue operating the well and the well will be shut in. Stripper wells often receive lenient tax or royalty treatment, justified on the belief that a more usual treatment would induce shut-ins to occur at substantially higher rates of production, leaving significant amounts of oil or gas in the ground that would have been produced otherwise.

For the purpose of special tax and royalty treatment, the definition of "low-production" varies somewhat. The Interstate Oil and Gas Compact Commission (IOGCC) defines an oil well as "marginal" if it produces on average 10 barrels or less per day. For the purpose of qualifying for severance tax exemption (see below), Utah defines a stripper oil well as one that produces on average 20 barrels or less per day. The federal government, for the purpose of classifying wells for royalty discounts, considers a stripper well as one that produces on average 15 barrels or less per day. These three entities do, however, agree on the definition of a stripper gas well: a stripper gas well produces no more than 60,000 cubic feet per day.

The share of Utah oil and gas production coming from stripper wells has generally increased over time as Utah's large oil and gas fields have matured. For oil, the share averaged 5.6 percent for the period 1983–1995, but 9.2 percent for the period 1995– 2008. For natural gas, the share rose from 1.3 percent for the period 1993–2000 to 4.0 percent during the period 2000–2008. Figure 5 shows production over time from stripper oil and gas wells. The production numbers are based on the IOGCC definition of a stripper oil well (10 or fewer barrels of oil per day).

Fiscal Systems

The constellation of policies that determines the size of the government's share in an oil project's cash flow is called a "fiscal system."

The policies that make up a fiscal system may be

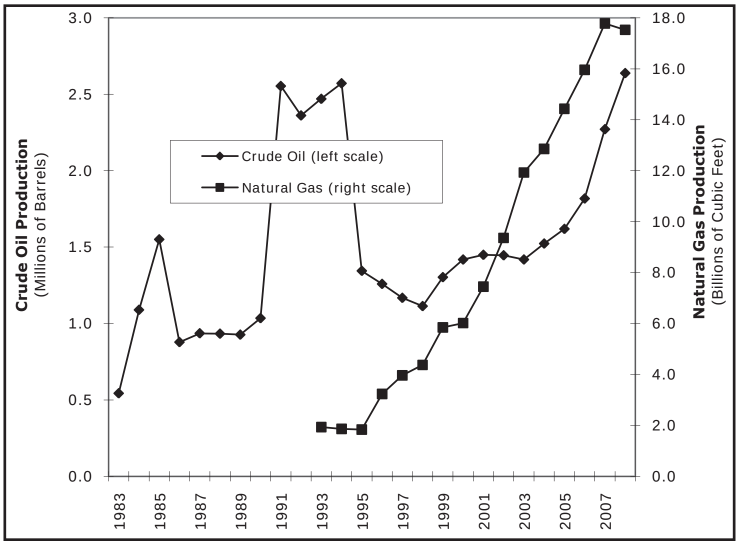
Table 1
Landownership by Entity in Utah

Landowner	Land Manager	Acres	Share
Federal		34,997,013	64.4%
	Bureau of Land Management	22,805,462	42.0%
	Bureau of Reclamation	1,363	0%
	Department of Defense	1,812,849	3.3%
	Department of Energy	42	0.0%
	National Park Service	2,095,730	3.9%
	Forest Service	8,171,024	15.0%
	Fish and Wildlife Service	110,542	0.2%
Private		11,446,078	21.1%
State		5,426,897	10.0%
	Department of Natural Resources	2,016,919	3.7%
	School and Institutional Trust Lands Administration	3,408,225	6.3%
	Department of Transportation	1,750	0.0%
	Other	2	0.0%
Tribal		2,446,000	4.5%

Source: Utah School and Institutional Trust Lands Administration, U.S. Bureau of Land Management.

motivated by a number of considerations, among them the presence of positive or negative side effects of oil and gas production, and the need to generate government revenue. There is ample potential for conflict: the goals of tax policy may receive different consideration under different taxing authorities; tax policies implemented by one taxing authority may undermine the effectiveness of policies implemented by another authority; and policies that perform well with regard to one factor may not perform well with regard to another.

Figure 5
Utah Oil and Gas Production from Stripper Wells, 1983–2008



Source: Utah Geological Survey, Utah Energy and Mineral Statistics.

Particularly when the main concern of oil and gas fiscal policy is revenue generation (which may include revenue collection for current or future use, as in the case of oil and gas trust funds), the concept of economic rent—the value of the oil or gas as it is situated in the ground—has long held a prominent role in both theory and practice.

Economic rent is defined as the difference between the price a factor of production actually receives in the market and the minimum price that would be necessary to bring the factor into use. In the case of oil, the production process combines varying amounts of capital (e.g., drills and pipes) and labor with a fixed ultimate amount of oil in the ground, to produce extracted oil. Although higher rental prices for drills and higher wages for labor would bring forth more drills and labor, the ultimately recoverable oil in a given deposit is fixed by nature: a high price for extracted oil will not bring forth more ultimately recoverable oil from this deposit. A high price for extracted oil, does, however, increase the accounting profit of oil production. A tax levied on drilling equipment increases its cost and decreases its use in oil production. Not so with the oil deposit itself. This has led many commentators to conclude that taxing oil in the ground can be done without the concerns associated with taxation of factors of production whose availability is sensitive to the price they could receive.

The connection between economic rent and fiscal system design is that because economic rent is income beyond what is needed to provide sufficient incentive to undertake production, it can be entirely taxed away without adversely affecting production. This is in contrast to the more usual case in which taxation leads to lower levels of production.

In practice, numerous complications arise that make the successful implementation of a complete economic rent tax difficult. In principal, the tax would be levied on the difference between the market price for the oil or gas and its extraction costs. But extraction costs are only known to a coarse approximation. As extraction takes place over time, economic rent depends on future oil and gas prices, which are clearly difficult to predict precisely. Even so, numerous fiscal regimes are based on the idea that some, however crude, measure of economic rent is the proper basis on which to levy taxes.

Taxes

Oil and natural gas extraction in Utah is subject to taxation at the federal, state, and local levels of government. Taxes generated from the oil and gas industry form an important but diminishing portion of total state government revenue. Some taxes, such as the property tax, sales and use tax, and the state and federal corporate income tax, apply broadly to businesses operating in Utah, while others, particularly the severance tax and conservation fee, are unique to the extractive industries.

Particularly in recent times, tax policy has been suggested as a tool for shaping patterns of consumption and production when decisions among private parties give rise to large costs borne by third parties ("negative externalities").

Although both taxes and royalties can reduce the price a producer receives and increase total "government take," they are motivated by different purposes. A royalty, unlike a tax, is a return to the owner of the resource. Severance taxes in Utah, by contrast, are levied on all conventional oil and gas production within the state's geographical boundaries, not just production occurring on state lands.

Although state and local levels of government may not directly tax the federal government, they may, according to the Mineral Leasing Act of 1920 and confirmed by the Supreme Court in *Commonwealth Edison Co.* v. *Montana*, tax the production of lessees on federal lands. That states can impose the severance tax on the production of lessees on tribal land is provided by the Indian Oil Act of 1927 and confirmed by another Supreme Court case, *Cotton Petroleum* v. *New Mexico*.

Rather than purchase all of the attributes of a property, oil and gas operators typically purchase only certain subsurface rights—those to extract oil or gas—rather than also acquire surface use, water rights, or the rights to extract other minerals, for example. The right to extract oil or gas is a "lease." A very common type of payment received by the seller of the lease is a percentage of the value of the extracted oil or gas. This share of the value of extraction is called the "royalty interest," and the remainder is the "working interest." The severance tax is applied to one's share in the total interest.

Severance Taxes

A severance tax, also known as a production tax, is a levy on the commercial extraction of natural resources. Except for the exemptions noted below, the tax applies to all oil and gas production in the state, regardless of landowner. The tax may be based on either the amount or the value of the resource extracted. The Utah oil and gas severance tax is value-based and, like the tax systems of other major oil-and-gas–producing states, incorporates a number of features meant to provide incentives for the exploration of new fields, further development of known fields, and production from methods that are novel, costly, or that come with unusually high financial risks.

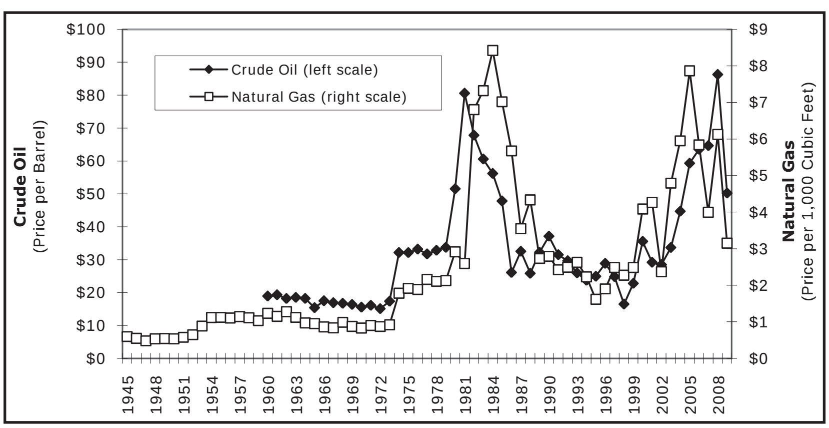
Table 2
Utah Oil and Gas Severance Taxes and Conservation Fees, 2001–2009
(Current Dollars)

Year	Severance Tax	Conservation Fee
2001	$39,357,798	$2,748,318
2002	$18,893,082	$1,710,219
2003	$26,745,279	$1,943,755
2004	$36,659,808	$2,696,250
2005	$53,484,320	$3,631,963
2006	$71,513,869	$5,560,449
2007	$65,429,873	$4,747,883
2008	$65,510,506	$5,408,934
2009	$70,995,789	$6,835,191

Note: Years are state fiscal years.
Source: Utah State Tax Commission.

The tax has a graduated structure that varies the burden of the levy, measured as a percentage of taxable value, with the price of the resource. For oil, the tax is 3 percent of the first $13 dollars of taxable value and 5 percent of the remaining taxable value. For example, if the taxable value for oil is $80 per barrel, then the severance tax due is $3.74 (3 percent of $13 plus 5 percent of $67), for an effective rate of 4.7 percent. For natural gas, the severance tax rate is 3 percent of the first $1.50 of taxable value per thousand cubic feet and 5 percent for the remaining taxable value. Operators pay severance taxes only on their working interest share. In other words, operators do not pay severance taxes on the royalty share of taxable value. Table 2 shows Utah oil and gas severance taxes and conservation fees collected since 2001.

Figure 6
Utah Wellhead Prices of Crude Oil and Natural Gas, 1945–2009
(Constant 2009 Dollars)



Source: Utah Geological Survey, Utah Energy and Mineral Statistics.

For the purpose of the state severance tax, "taxable value" means the value of the oil or gas at the point where it has undergone only minimal processing after exiting the top of the wellhead, rather than at the point of first sale. If actual sales take place, as they often do, after further processing and transportation, then the cost of that portion of the additional processing and transportation beyond the minimum is deductible from the actual sales price.[1] Thus, in this "netback" approach, the taxable value of oil may be substantially less than posted prices or market prices of oil as measured by the "first-purchase price" (Figure 6).

Oil or gas production taking place during the first 12 months of production from wells drilled outside of known fields ("wildcat" wells), and the first six months of production from wells drilled inside known fields ("development" wells), is exempt from the severance tax.

Additional breaks are given to certain operations aimed at increasing production from existing wells or reservoirs. The owner of a well that receives a "workover," which includes operations to increase the productivity of the well (deepening the well, for example), or "recompletion," which involves a conversion in the purpose of the well (from a well that produced oil to a water injection well, for example), is entitled to a tax credit of 20 percent of the expense of the operation.

Production made possible through an "enhanced oil recovery" (EOR) project[2] is exempt from 50 percent of the severance tax to which it would otherwise be subject. EOR operations have been in place since 1985 at the Aneth field, located in the Paradox Basin of southwestern Utah, with those efforts having intensified recently. Currently, the carbon dioxide needed for EOR at the Aneth field is supplied by the McElmo Dome in Colorado. Research is underway to assess the viability of EOR methods that incorporate permanent sequestration of the carbon dioxide. Rather than using natural sources of carbon dioxide, such as the McElmo Dome, the potential exists to use carbon dioxide generated by industrial processes which would have otherwise emitted the gas into the atmosphere.

The application of EOR techniques has the potential to greatly increase oil production from several existing reservoirs in Utah. The future of EOR depends on the future price of oil and carbon dioxide emissions. A serious concern regarding EOR is the extent

1. In the past, the Utah State Tax Commission levied the severance tax on the actual sales price, even if the sale took place after significant value-added processing or transportation. Exxon-Mobil challenged this practice to the Tax Commission and, eventually, the Utah Supreme Court, arguing that the appropriate stage of production at which to value the oil is the wellhead. The Utah Supreme Court ruled that future assessments of taxable value would have to reflect the value as near to the wellhead as at which sales could feasibly take place.

2. An "enhanced recovery project" involves the injection of gas into an oil or natural gas reservoir for the purpose of increasing the oil or natural gas recovered from the reservoir.

to which carbon dioxide injected into an oil reservoir increases the carbonization of the produced oil. Depending on how emissions would be accounted for under a potential carbon dioxide regulatory regime, EOR-sequestration methods that lose significant amounts of carbon dioxide to produced oil may be economically disadvantaged.

All oil produced from stripper oil wells is exempt from the severance tax. Natural gas that is produced along with the oil from a stripper well ("associated gas") is also exempt, even if the well would not qualify for severance tax exemption solely on the basis of its natural gas production. If an oil well does not qualify as a stripper oil well, then all natural gas produced from the well—even in amounts that would otherwise qualify a well as a stripper gas well—is subject to the severance tax. Until recently, operators of stripper oil wells located on federal leases were entitled to reduced royalty rates on oil production. The rates started at 0.5 percent and increased according to the average daily production of the well to a maximum of 12.5 percent. This provision was terminated in October of 2010.

Although Utah contains large deposits of oil shale and oil sands, both of which can be processed to yield a synthetic crude oil, these remain at a pre-commercial stage of development. At least until 2016, production from oil shale and oil sands is exempt from the state oil and gas severance tax.

Utah also levies a conservation fee equal to 0.2 percent of the taxable value, where taxable value is defined the same as for the severance tax. The conservation fee has the form of a severance tax, but is collected for a specific purpose. The conservation fee funds the Oil and Gas Conservation Account, which is used to pay for the "plugging and reclamation of abandoned oil or gas wells or bore, core, or exploratory holes for which: (i) there is no reclamation surety; or (ii) the forfeited surety is insufficient for plugging and reclamation."

In November 2008, Utah voters approved a ballot measure (Amendment B) that proposed to amend the state constitution to allow diversion of severance tax revenue into the state permanent trust fund. As of fiscal year 2009, the first $71,000,000 of oil and gas severance tax collections and $27,600,000 of mining severance tax[3] collections remain destined for the state General Fund, while any collections exceeding these amounts are deposited in the permanent fund. Oil and gas severance tax collections were $70,995,789 and mineral severance tax collections were $14,573,697 for fiscal year 2009. Removal of funds from the trust requires approval from the governor and three-fourths of both legislative houses.

The unsustainable nature of mineral extraction is the basis of the rationale for a program of saving a portion of the revenues from mineral extraction. Oil and gas extracted in the present permanently decrease the amount available to extract in the future. Saving a certain fraction of mineral revenue provides the funds necessary to build up wealth, the interest and dividends on which can be spent in perpetuity. In this way the monetary benefits from mineral extraction may persist well beyond the exhaustion of the mineral. Appeal to these considerations was explicit in the language of the Amendment B ballot measure and its supporters.

Table 3
Utah Oil and Gas Property Taxes, 2000–2009
(Current Dollars)

Year	Oil and Gas Property Tax	Share of Total	Total Property Taxes
2000	$11,977,061	0.83%	$1,437,329,779
2001	$18,255,394	1.18%	$1,541,928,607
2002	$16,869,293	1.05%	$1,608,884,900
2003	$16,653,638	0.99%	$1,686,765,323
2004	$22,901,842	1.27%	$1,796,354,030
2005	$26,519,307	1.40%	$1,888,716,549
2006	$34,511,673	1.68%	$2,058,326,860
2007	$34,522,793	1.54%	$2,237,691,058
2008	$34,522,793	1.54%	$2,237,691,058
2009	$42,582,114	1.70%	$2,502,414,690

Source: Utah State Tax Commission, Property Tax Division.

Property Taxes

Property tax systems can be distinguished according to the types of property subject to taxation, the methodology for arriving at the taxable value of these properties, and the tax rates that are applied to the taxable value to determine the total property tax owed. In some states (Alaska, for example), only the value of tangible property on the land surface, such as facilities and equipment used to explore for, produce, or process oil or gas, is subject to the property tax. In other states, including Utah, the value of the oil or gas as it is situated in the ground is subject to the property tax, in addition to the value of equipment and facilities.

The value of oil and gas properties is centrally assessed by the Utah State Tax Commission. The Tax Commission's method of valuing the oil and gas is based on the net present value of expected future operating profits from extraction. This method requires estimates of future oil and gas prices. For this purpose, the Tax Commission obtains oil and gas prices from a number of sources, including the U.S. Department of Energy's Energy Information Administration, and averages them along with its in-house forecast. The averaged forecast is used as the estimate of future prices. The Tax Commission applies to future operating profits a fixed discount rate, though the particular rate is revised each year to reflect changes in the industry and financial markets. For 2010, the Tax Commission applied a discount rate of 12.36 percent.

The levy on the value determined by the Tax Commission may vary by county, and even within a county, but generally the property tax rate is around 1 percent. Table 3 shows oil and gas property taxes paid to the State of Utah from 2000 through 2009. Although Utah applies the property tax to underground oil and gas deposits, whereas Alaska, for example, does not, it is worth noting that the property tax rate applied to taxable oil and gas property in Alaska is twice as high as in Utah.

3. The mining severance tax is a 2.7 percent levy on the "taxable value" of metalliferous minerals. Such minerals include gold, iron, lead, and uranium, but not coal. Utah coal is not subject to a severance tax. For the mining severance tax, taxable value is 30 percent of gross sales proceeds (except for beryllium, whose taxable value is 125 percent of mining costs), unless the mineral is sold out of state, in which case the taxable value is 80 percent of gross sales proceeds.

Corporate Income Taxes

Federal corporate income taxes are levied on taxable income. Taxable income for an operator of a single holding begins with gross revenue from oil or gas sales, which is then reduced by a number of deductions. An operator's federal corporate income tax bill is then the product of taxable income and the standard federal corporate tax rates given in Table 4. The state of Utah also levies a corporate income tax at a flat rate of 5 percent of taxable income, where taxable income is based on federal taxable income.

To arrive at taxable income, an operator subtracts from gross revenue "owner payments," including royalties, land rent, and that portion of the total cost of acquiring the oil or gas property—the "bonus payment" (see below)—equal to the fraction of the property's remaining recoverable oil or gas that is extracted in the current tax year. The state severance tax and property tax are also both deductible. Sales and use taxes paid on items that are eligible for complete current-year deduction ("expensing") are deducted as part of the cost of the items. If, however, the sales or use tax is paid on items whose cost must be deducted over a number of years through depreciation, then the sales or use tax for the item must be treated in the same way. Utah state corporate income tax is deductible for the purpose of the federal corporate income tax, but federal corporate income tax is not deductible for the purpose of the Utah corporate income tax.

Table 4
Federal Corporate Income Tax Rates

Federal Taxable Income	Tax Rate
\$0–\$50,000	15%
\$50,000–\$75,000	25%
\$75,000–\$100,000	34%
\$100,000–\$335,000	39%
\$335,000–\$10,000,000	34%
\$10,000,000–\$15,000,000	35%
\$15,000,000–\$18,333,333	38%
> \$18,333,333	35%

Source: The Tax Foundation.

Operators are also allowed deductions related to the depletion of the oil and gas deposit that occurs as extraction proceeds. These deductions are the cost and percentage depletion allowances. An operator may use only one of these for any given tax year, but need not use one exclusively during the lifetime of the deposit.

The percentage depletion allowance is only available to operations producing less than 1,000 barrels of oil and gas equivalent (on an energy basis) and without integrated refining operations. The deduction is 15 percent of adjusted gross income, which is gross income minus the "owner payments" as given above. The deduction is limited to taxable income as computed in the absence of the percentage depletion allowance itself.

All oil and gas projects are eligible for the cost depletion allowance. The allowance is equal to a portion of the current-year cost of the oil or gas property. The portion is the same as that for allocating the cost of the bonus payment: the share of current-year extraction in total remaining recoverable oil or gas. The adjusted cost basis is the original cost of acquiring the oil or gas property, minus the sum of past depletion and certain other deductions. From the adjusted cost basis, an operator subtracts current-year deductions, including depreciation charges allowed in the current year, the expected salvage value of the land once extraction is complete, and exploration and development costs. The result is the "cost" on which the allowance is based.

For tax purposes, the costs of an oil or gas operation are divided into two categories: tangible drilling costs and intangible drilling costs (IDC). Intangible drilling costs are those costs related to preparing a well for production, but generally include costs only for items with no salvage value. This includes wages, the cost of clearing land, engineering and design consulting, and any contract work that does not create salvageable value. Tangible costs are limited to the cost of items with salvage value. Pipes and tubing fall into this category. It has been reported that about 70 percent of the drilling costs of a typical development well are classified as IDCs.

Tax policy treats these categories of drilling costs quite differently. Independent operators—those without downstream refining units—may deduct 100 percent of their IDCs in the current year. (They are not obligated to do so; they may instead amortize their IDCs.) Other operators may deduct only 70 percent of their IDCs in the current year; the remainder must be capitalized and deducted as depreciation over the subsequent five years. All tangible costs must be capitalized and deducted through depreciation. The costs of drilling a nonproducing well need not be capitalized; an operator may deduct these in the current year.

To determine depreciation deductions for capitalized expenses, operators must use the Modified Accelerated Cost Recovery System (MACRS). Under MACRS, the operator may choose between three depreciation schemes, which differ in how they distribute the depreciation over a specified period (at the end of which an item is, for tax purposes, considered completely depreciated). Two of the three schemes are declining-balance methods with differing basic depreciation rates. In the declining-balance scheme with a basic rate of 150 percent, the depreciation deduction in the current year is a constant portion of the undepreciated part of the item's value. The portion is obtained by dividing the basic rate (1.50) by the length of the depreciation period for the item (which varies by category of item). The other declining-balance method uses a basic rate of 200 percent, which increases the depreciation deductions in the early years of an item's lifetime.

The third scheme is the straight-line method. With this method, an operator deducts a constant amount—rather than a constant percent, as in the declining-balance methods—from an item's undepreciated value. Each year, the undepreciated value is reduced by a proportion equal to the reciprocal of the remainder of the item's depreciation period.

Generally, an operator would prefer the 200 percent declining balance method since as long as inflation-adjusted interest rates are positive, a deduction obtained nearer the present is worth more than one obtained farther in the future. However, there is one condition that compels the operator to choose the straight-line method. Whenever the straight-line method results in a larger depreciation deduction than the declining-balance methods, the operator must use straight-line depreciation in that and all subsequent years.

For example, if the cost of a new item of depreciable capital is $100, the item is depreciated over five years, and the operator elects to use the declining-balance method with a 150 percent basic rate, then in the first year the depreciation deduction is $30 (equal to 100×1.5/5). The undepreciated value in the second year is therefore $70 and the depreciation deduction for that year is $21. For the third year, undepreciated value is $49 and the deduction computed from the 150 percent declining-balance method is $14.70. The straight-line method for this example, if used from the beginning, implies deductions of $20 each year for 5 years. The straight-line method, when used only after application of the 150 percent declining-balance method, yields annual deductions of $17.50 if applied beginning in year two and $16.33 if applied beginning in year three. Thus, the taxpayer using the 150 percent declining-balance method would be required to switch to straight-line depreciation beginning in year three and the complete five-year depreciation schedule of the $100 item would be: $30, $21, $16.33, $16.33, $16.33.

In summary, to determine taxable income the operator takes gross sales income and subtracts royalties, land rents, the allocable part of bonus payments, state severance, property, and income taxes, operating expenses, a cost or percentage depletion allowance (not both), costs associated with drilling nonproducing wells, intangible drilling costs, and depreciation charges on depreciable capital.

Table 5
Federal Mineral Royalty Payments and Disbursements to Utah, 2001–2010
(Current Dollars)

	Oil		Natural Gas		Total	
Year	Royalties	Disbursements	Royalties	Disbursements	Royalties	Disbursements
2001	$32,799,794	$4,392,667	$58,553,527	$26,210,621	$91,353,321	$30,603,288
2002	$26,028,911	$3,493,794	$37,653,050	$11,921,373	$63,681,961	$15,415,167
2003	$37,462,357	$5,575,810	$55,369,036	$26,040,706	$92,831,293	$31,616,515
2004	$45,743,590	$7,235,629	$87,075,857	$38,228,494	$132,819,447	$45,464,122
2005	$71,489,932	$12,286,671	$113,505,639	$51,766,652	$184,995,571	$64,053,323
2006	$113,205,052	$25,255,268	$186,668,680	$84,162,255	$299,873,732	$109,417,522
2007	$109,195,966	$27,599,743	$158,015,158	$68,156,674	$267,211,124	$95,756,417
2008	$189,966,887	$52,385,647	$225,826,461	$91,554,104	$415,793,348	$143,939,751
2009	$122,214,068	$39,521,883	$146,220,780	$76,387,212	$268,434,848	$115,909,094
2010	$155,557,438	$45,489,493	$165,609,717	$73,756,623	$321,167,155	$119,246,116

Note: Years are federal fiscal years. Oil includes condensates; natural gas includes coalbed methane and liquids from gas processing plants.
Source: U.S. Department of the Interior, Minerals Management Service.

Payments to Resource Owners

Royalties, bonus payments, and rents are payments to the owner of the resource as compensation for its use. When mineral extraction rights are awarded in a competitive auction conducted on behalf of a mineral owner, the bonus payment is the amount of the winning bid. Between the time mineral rights are obtained and production starts, the producer will usually be responsible for annual rental payments, which often amount to a few dollars per acre. The rental rate for a conventional oil lease on federal and tribal lands is $1.50 per acre per year for the first five years and $2.00 per acre per year thereafter. Royalties are periodic payments, usually determined by a percentage of either the gross or net value of production. In some cases, royalty payments are made "in kind," meaning that the mineral owner receives a specified proportion of the volume of oil produced in lieu of payments as a percentage of the oil's value. The mineral owner may then sell or store the oil. The Strategic Petroleum Reserve was filled with royalty-in-kind crude oil. Royalties are deductible from gross revenue for the purpose of determining taxable income subject to both the federal and state corporate income tax. Royalties are also deductible for the purpose of computing severance tax liability. For example, if the value of oil is $80, the royalty rate is 12.5 percent, and the severance tax rate is 5 percent, then the severance tax due is 0.05×(1−0.125)×$80=$3.50.

The standard royalty rate for onshore federal oil and gas leases is 12.5 percent of value, where value is defined as the gross proceeds from the sale minus allowable transportation expenses. The deductible transportation expenses are those incurred in moving the oil off the lease and to the point where the transfer to the buyer takes place. For example, if sales proceeds are $80 per barrel and transportation expenses are $1 per barrel, then the royalty payment is 0.125×(80−1)=$9.875 per barrel. Heavy oil production on a federal lease is no longer entitled to a royalty reduction.

Federal oil and gas royalty payments for production in Utah since 2001 are shown in Table 5. A portion of the payment is returned to the state of origin, generally one-half. Royalties from production on tribal lands are returned to the appropriate tribe, not to the state government. Since a large portion of the crude oil production in Utah occurs on tribal lands, the amount of crude oil royalty returned to the state government is significantly less than one-half of the amount paid.

Oil and gas extraction on Utah state lands is subject to a royalty payment based on gross sales, not on profit. Until recently, 12.5 percent was the standard rate applying to conventional oil production on state lands in Utah. Newly acquired conventional oil leases on lands managed by the State of Utah School and Institutional Trust Lands Administration (SITLA) and located within the eastern half of the state—this includes virtually all currently producing areas in the state—are now subject to a royalty rate of 16.67 percent.

The federal government administers and approves oil and gas leases on tribal lands and BLM is the leasing agent for these leases. The standard lease term calls for a 16.67 percent royalty rate, although the Secretary of the Interior may authorize a lower royalty rate when such rate is approved by the Indian landowner and the Secretary.

Profit-Based Fiscal Systems

Oil and gas production that takes place in Utah is subject to a fiscal system substantially based on gross revenues. Gross revenues, however, are only a crude measure of economic rent, more so across resources that present great variations in extraction costs. Utah's vast oil shale and oil sands deposits generate far less economic rent than the state's conventional oil deposits. Yet, under a pure gross revenue fiscal system, a barrel of oil extracted from either deposit would be taxed at the same rate. In actual gross revenue systems, resources on the fringe of economic viability often find a lenient tax treatment that can be viewed as an approximate way to lessen the rent differential among resources.[4]

Particularly since the late 1970s, there has been strong interest in alternative fiscal arrangements based on profit rather than gross revenue. Part of the appeal of a profit-based fiscal system stems from the notion that under such a system a project pays according to its ability (as measured by profits). If profits rise with oil or gas prices, then so do tax collections. If profits fall with falling oil or gas prices, then so does the tax burden on oil and gas operations. Under a gross revenue system, when oil or gas prices rise, projects that may have been on the economic fringe at lower prices become healthier and better able to tolerate a higher effective tax rate. This often increases pressure to rescind the exemptions that were deemed essential at lower prices. For instance, the Government Accountability Office estimates that the Deepwater Royalty Relief Act of 1995 (DWRRA), which was advertised as a way to stimulate oil and gas production where it may not have otherwise taken place, ended up costing the federal government billions of dollars in foregone royalties.[5] Because of the increase in prices during the 2000s and high expected future prices, many projects that may not have gone forward at the prices and expectations prevalent when DWRRA was put in place went forward and would have done so even in the absence of DWRRA. When prices fall, oil and gas producers often seek, and obtain, relief from taxing authorities. Thus the features of the fiscal system tend to change somewhat with oil and gas prices. This lack of stability in the fiscal system is often said by industry to have an inhibitive effect on investment.

Two important profit-based fiscal systems are those of Alaska and the Canadian province of Alberta. Each system is discussed in turn.

All oil and gas production within Alaska is subject to the Alaska Clear and Equitable Share (ACES) tax that was introduced in 2007. The ACES is a profits tax, where profit is defined as the difference between the wellhead value of the oil or gas and its extraction costs, including capital costs. The base tax rate is 25 percent but increases by 0.4 percent for every dollar that profit exceeds $30 per barrel until reaching $92.50 per barrel, at which point the rate increase drops to 0.1 percent per barrel.

4. Whether these measures, briefly reviewed earlier, compensate too little or too much is an important question, but not one addressed in this article.
5. The Deepwater Royalty Relief Act (1995) exempted royalties on certain amounts of production from leases in the central and western Gulf of Mexico issued between 1996 and 2000 for fields on which production had not taken place in the past. The amount of royalty-exempt production increased with the depth of the water (water depth being a proxy for extraction costs) at the lease-site. The stated purpose of the program was to provide incentives to explore and develop high-cost deepwater fields.

Costs that are deductible from gross revenue include capital costs and operating expenditures as well as several credits. First, a 20 percent credit is allowed for capital expenditures such as drilling equipment and infrastructure. For the purposes of the credit, capital expenditures must be spread over a two-year period. Second, companies with total in-state production of less than 100,000 barrels per day are eligible for up to $12,000,000 of credits annually. Third, in the event of a net loss in a given year, 25 percent of the net loss is available as a credit against the ACES tax in the subsequent year. Lastly, between 30 percent and 40 percent of qualified exploration expenses may serve as credits under the Exploration Incentive Credit program.

Just as oil and gas production in Utah is not subject to a pure gross revenue tax (it is subject to state and federal income tax), Alaska's is not purely profit-based (production is still subject to fairly standard royalty terms). But the tax basis for the ACES is quite different from Utah's (and other states'). This is particularly worth emphasizing since the ACES, with its high base tax rate of 25 percent, has been cited as evidence that the oil and gas industry can be taxed at much higher rates than those applying in typical western states. Direct comparisons such as these are in error as they compare rates against very different tax bases; 25 percent of profit, particularly as it is defined under the ACES, is equivalent to a gross revenue severance tax much smaller than 25 percent.

In recent years, Canada surpassed Mexico, Saudi Arabia, and Venezuela as the leading exporter of crude oil to the U.S. The rise of Canada as a major oil producer is due to the commercial development of the Alberta oil sands. Production from oil sands is substantially more expensive and capital intensive than onshore oil production in the U.S., and in this sense probably compares best with deepwater offshore production. The hydrocarbon resource that is extracted, called bitumen, will not flow through a production well unless heated. There are two basic forms of production: mining, in which the oil sands are surface-mined and the bitumen is then separated from the sediment, and in situ, in which heat is applied to the deposit as it is situated in the ground, allowing the oil to flow through production wells.

Canadian policy with respect to oil sands projects has always been concerned with stimulating their development in light of high costs and special risks. However, as development has advanced (e.g., production costs have decreased and special risks associated with early-phase production are somewhat abated), concern has increasingly turned toward extracting more of the value of oil sands production for the public.

Fiscal systems bearing on oil sands projects can be divided into three periods. Although these periods correspond to specific and official rules governing royalties and taxes, they also correspond to three phases in the development of the industry.

The commercial beginning of the Canadian oil sands industry was marked by initial production in 1967 by what is now the Suncor Energy Company, following decades of basic research and significant financial support from the Albertan government. Following Suncor in commercial operation was Syncrude, which came online in July 1978. Both Suncor and Syncrude are said to be "integrated" mining operations, meaning they incorporate facilities for upgrading mined bitumen to synthetic crude oil (SCO) with physical features similar to a light, sweet crude.[6]

During this early stage of development, royalties were negotiated on a case-by-case basis with the Albertan government. Royalty rates ranged from 1 percent to 5 percent of gross revenue and 25 percent to 50 percent of net revenue. Both Suncor and Syncrude had royalty agreements that called for revenue calculations based on the price of synthetic crude oil rather than the cheaper bitumen—the price of which tends to fall between 25 percent and 75 percent of the marker crude West Texas Intermediate—reflecting the additional upgrading, refining, and transportation costs incurred in creating higher-value products from bitumen. These agreements expired in 2009 and have been replaced with interim agreements that are in effect until 2016, at which point both Suncor and Syncrude will fall under the current royalty regime (see below).

The commercial development of oil sands languished during the 1980s and through the early 1990s. By the end of this period, the commercial oil sands industry consisted of Suncor, Syncrude, and a small number of in-situ operations. Several planned projects, including the 70,000-barrel-per-day Alsands operation, were cancelled due to challenges that included the low oil prices of the period compared with the high cost of production and fiscal system uncertainty.

In 1993, the National Task Force on Oil Sands was formed by members of industry and government. The purpose of the Task Force was to determine what policies could be undertaken to accelerate development of the oil sands industry. In 1995, the Task Force delivered, and the Alberta government accepted, its recommendation that royalty provisions be uniformly applied rather than applied through individual agreements with the government. This new regime, known as the Generic Oil Sands Royalty Regime (GOSRR), began in late 1997.

GOSRR was in effect until 2007. The new system was designed not only to replace the old system of individual agreements (which was believed to stifle investment by creating an uncertain tax environment) with rules that applied broadly, but to limit the involvement of the Alberta government to that of being the resource owner. GOSRR also had the explicit goal of keeping oil sands crude competitive with other petroleum projects worldwide. Under GOSRR, after a project reached payout—the point where cumulative revenue from the project equals cumulative costs—royalties were either 1 percent of gross revenue or 25 percent of net revenue, whichever was greater. This risk-sharing arrangement was meant to encourage and support new projects until they have returned their investor's costs plus a return. As of February 2009, 48 oil sands projects were in pre-payout and 43 were in post-payout.

Under GOSRR, producers could choose whether to base royalties on bitumen production or synthetic crude oil production (SCO). If they chose to base royalties on SCO production, then the capital (including return on investment) and operating costs involved in upgrading would be deductible from gross revenue, but gross revenue would be based on the higher price for SCO. If they chose to base royalties on bitumen production, then capital and operating costs for upgrading would not be deductible from gross revenue, but gross revenue would be based on the lower price of bitumen. Apparently, bitumen-based royalties were more lucrative, as they were chosen by all producers who had a choice.

By the mid-2000s, oil prices had risen well above the level that prevailed near the time of the 1997 regime change. Oil sands production nearly doubled between 1997 and 2005, increasing from 192,493,000 barrels to 361,978,000 barrels. This rapid rise in prices and production led to and supported a growing belief that the 1997 regime had already become outdated. In response, the Alberta government commissioned the Alberta Royalty Review Panel to consider alternative fiscal regimes.

The Panel released its findings in 2007. The conclusion was drawn that the GOSRR regime was not providing Albertans with a fair share of the oil sands wealth. The Panel argued that the total government take from oil sands projects, in light of the then-present royalty structure and oil prices, was less onerous than projects in other parts of the world and could be increased without significantly curtailing development.

The Panel recommended a total government take from the oil sands sector of 64 percent, an increase over the 2007 total take of just under 50 percent. The National Oil Sands Task Force of 1995 (whose recommendations had led to GOSRR) had identified 60 percent as the total take level appropriate to the needs of a fledgling oil sands industry. The Panel justified the 64 percent level of government take on the grounds that the industry had matured and no longer needed the delicate handling of the prior regime.

Following the Panel, a new royalty regime—the one currently in effect—was implemented entitled the New Royalty Framework. The New Framework retains the previous regime's differential treatment between pre- and post-payout projects, but in the new regime the rates are tied to the price of oil. For pre-payout projects, the royalty is still 1 percent of gross revenue, provided that the price of West Texas Intermediate (WTI) crude is less than C$56 per barrel. However, when the price of WTI is at or above C$56 per barrel, the royalty is 1 percent of gross revenue plus an additional 0.12308 percent of gross revenue for every (Canadian) dollar that the price of WTI is above C$56 per barrel up to C$120 per barrel. At C$120 per barrel (and beyond), the applicable royalty is 9 percent of gross revenue. In the post-payout period, royalty rates are 25 percent of net revenue while the price of WTI is less than C$56. The royalty rate increases by 0.23077 percent for every dollar that the price of WTI is at or above C$56 per barrel but below C$120 per barrel. Thus, post-payout royalty rates on net revenue range from 25 percent to 40 percent. The Panel also recommended a severance tax, but this recommendation was not accepted.

Suncor's in-situ projects became subject to the new regime beginning in 2009. However, Suncor's mining operations do not come under the new regime until 2016 due to an agreement with the Alberta government that predated the New Royalty Framework (and its predecessor). Until 2016, Suncor's royalties will be based on bitumen prices instead of on SCO. Syncrude, which also had a prior agreement with the Alberta government, will become subject

6. Upgrading can be regarded as "pre-refining."

to the new regime in 2016 as well. All other oil sands producers are immediately subject to the New Royalty Framework.

Like U.S. operators, oil sands operators pay bonus bids and annual land rental fees to acquire and maintain their leases. They also pay property taxes, federal and provincial corporate income taxes, and sales taxes. Alberta receives four types of payments from oil sands development: bonus bids, which are winning bids on the right to develop offered sites[7]; rental fees of C$3.50 per hectare[8] per year (with total rental collections of C$160 million in 2008–09); royalties of C$2.973 billion collected in 2008–09; and provincial corporate income taxes, which are in addition to the corporate income tax levied by the Canadian federal government. Royalties are deductible from Canadian federal income tax.

The current oil sands royalty regime and the one it succeeded (GOSRR) were shaped by the promise of a profit-based fiscal system to extract the rent of the oil sands without unduly discouraging production. However, given the special difficulty of measuring economic rents, it is not clear how the new regime will be appraised.

The Effects of Fiscal Policy on Production

Taxes, including taxes on oil and gas extraction, generally distort economic decisions. That is, the course of action a producer would take in the absence of the tax is usually different from the course of action that would be taken in the presence of the tax. An EOR project, for example, that would be viable in the absence of all taxes, may not be so under a typical array of oil production taxes. A low-production oil or gas well with particularly fragile economics may be shut down if it loses its severance tax exemption or royalty reduction. Taxing a product usually leads to less of it. Indeed, proposals to use tax policy in order to reduce negative externalities rely on this effect. The critical challenge in crafting a tax policy that is aimed primarily at raising revenue is to balance revenue losses due to lower levels of activity with the revenue gains due to higher tax rates on those activities that remain. For example, if a doubling of the tax rate on oil production only reduced production by one-quarter, revenue from the tax increase would increase by 50 percent. But if doubling the tax rate resulted in a three-quarter decrease in oil production, then tax revenue from oil production would be cut in half.

From a strictly revenue-raising point of view, the landowner's problem of choosing the optimal tax rate—the one that nets the greatest tax revenue—is very much like the problem a major commercial enterprise faces when deciding the price of one of its products. It is possible, however, that the oil and gas tax policy that leads to the highest oil and gas tax revenue does not lead to the highest total tax revenue (from all sources, including the oil and gas tax). This could happen if above- or below-optimal production happens to complement other sectors in the economy, just as a firm may price one of its products well below the level that would maximize its sales revenue from that product alone, but with the aim of maximizing total sales revenue.

These are general statements about taxes on oil and gas extraction. Specific statements concerning the effect a particular style of tax has on oil and gas production require certain assumptions about the operator, oil and gas prices, the nature of the oil and gas deposits, etc. The following are findings that are widely accepted in the area of natural resource taxation research. They pertain to production from known deposits and in which the investment in extraction has been made. The effects may be quite small compared with other influences, chief among them the prices of oil and gas.

Ad valorem taxes levied on the value of oil or gas deposits, such as Utah's oil and gas property tax, tend to shift production toward the present. This is because extracting the oil or gas reduces the value of the remaining deposit, lowering the property tax in all future periods. Severance taxes levied as a percentage of value, such as Utah's oil and gas severance tax, have an ambiguous effect on the time profile of production. If an operator expected future oil or gas prices to rise sufficiently—perhaps because recent prices have been rising—then the operator would also expect to pay a greater amount of severance tax per unit in the future than nearer the present. In this case, production tends to be shifted toward the present, relative to the case with an identical price trend but where there is no severance tax. Of course, the increasing-price-effect itself will tend to shift production into the future (where it is worth more). If future prices are expected to decrease enough, then for the same reasons production is shifted to the future compared with the case of identically decreasing prices but no severance tax. Again, the price-decreasing-effect may be strong enough to pull production toward the present (where it is worth more) in the net, but the shift will be somewhat mitigated by the incentives generated by the tax. Other levies in the form of a percentage of value, such as standard royalties, have the same effect.

Deductions from oil and gas income, such as the federal percentage and cost depletion allowances, generally act as negative taxes (subsidies). Like positive taxes, subsidies may distort production decisions. In an actual economy, where there are numerous imperfections in sectors other than oil and gas, a nondistorting tax may or may not improve on a given distorting tax.

The choice of tax policy instruments is complicated by a number of other factors. The taxes that fall on oil and gas extraction are levied at federal, state, and local levels of government. In effect this creates competition among these levels of government to capture the resource rent. As discussed earlier in this article, taxes like the severance tax are deductible from the federal income tax: if the state increases the severance tax rate, the increase comes partly at the expense of federal tax revenue. In this arrangement, the existence of a nondistorting tax instrument wouldn't be sufficient since there may be little incentive to use it. A single taxing authority could, together with revenue sharing for oil- and gas-producing areas, conceivably improve on this situation, but the prospects for such an arrangement seem quite weak.

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7. Bonus bids totaled C$1.112 billion in 2008–09, down from C$2.463 billion in 2006–07.
8. A hectare is 10,000 square meters, which is equivalent to 2.471 acres.

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