INSTITUT
C.D. HOWE
INSTITUTE

No. 333, September 2011

C.D. Howe Institute
COMMENTARY

Fiscal And Tax Competitiveness

Rethinking Royalty Rates:
Why There Is a Better Way to Tax Oil and Gas Development

Colin Busby
Benjamin Dachis
Bev Dahlby

In this issue...

Provinces should reduce their reliance on royalties and increase their reliance on auction payments in the conventional oil and gas industry.

C.D. HOWE INSTITUTE
50
1958–2008
INSTITUT C.D. HOWE

The Study in Brief

The Authors of This Issue

COLIN BUSBY is a Senior Policy Analyst at the C.D. Howe Institute.

BENJAMIN DACHIS is a Policy Analyst at the C.D. Howe Institute.

BEV DAHLBY is a Professor of Economics, University of Alberta, and Research Fellow, C.D. Howe Institute.

Rigorous external review of every major policy study, undertaken by academics and outside experts, helps ensure the quality, integrity and objectivity of the Institute's research.

$12.00
ISBN 978-0-88806-847-7
ISSN 0824-8001 (print);
ISSN 1703-0765 (online)

The system of taxing oil and gas in Canada consists of two main elements: an auction payment, known as a bonus bid, where firms purchase rights to explore and drill for Crown-owned resources for a specified period of time; and royalties that apply to the value of resources extracted. Governments levy these resource taxes — over and above other taxes on income — to capture an appropriate share of the revenues earned from the extraction and sale of a natural resource.

In 2007, Alberta announced it would increase royalty rates on oil and gas production, which reduced the rewards to companies from oil and gas extraction, and therefore reduced the amount they were willing to pay to explore and develop new resource projects. Because government revenues from resource extraction rely on both up-front auctions and royalties upon production, any increase in the latter should naturally reduce government revenues from the former. This *Commentary* investigates the effect of royalty rate increases on bonus bids and the mix of revenue tools that apply to the development of natural resources.

To measure the effect of the change in Alberta's royalty rates, we look at its effect on bonus bid values by comparing bonus bids near Alberta's borders with British Columbia and Saskatchewan, provinces that did not change their royalties. Comparing bids for otherwise similar geographical and geological areas — where resource deposits are of similar quality and labour and capital are mobile — we find that Alberta government revenues collected through bonus bids declined by nearly as much as the projected increase in royalty payments.

We recommend that provinces reduce their reliance on royalties and increase their reliance on bonus bids in the conventional oil and gas industry. Increasing reliance on bonus bids could make government revenues more predictable and help policymakers better understand that resource revenues are akin to asset sales. Further, increased reliance on bonus bids will reduce the economic distortion caused by royalties. Where possible, provinces should also adopt less distortionary cash-flow taxes.

The oil and gas sector is Western Canada's engine of economic activity, and reaping a share of the resource profits generated by that sector is crucial for provincial finances. Designing the tax policies to accomplish this task is, however, a daunting challenge, involving multiple tax instruments and potential tradeoffs between tax instruments and economic activity, revenues, and the provinces' fiscal positions.

Because Canada's Constitution grants provinces ownership over natural resources within their respective borders, provinces allocate the rights to oil and gas deposits to private producers — usually through an auction — and then tax the production from those deposits through royalties. In theory, auctions capture the expected future value of deposits, and royalties capture the realized value of production. In this *Commentary*, we assess the interdependence of the government revenues from these tax tools: an up-front auction and production royalties.

As resource prices have risen over the past 10 years, a debate has intensified over whether the public is receiving its "fair share" of the profits of the oil and gas sector. In Alberta — the province most dependent on that gas sector and on the government revenues derived from it — this debate seemed to culminate in October 2007 with the announcement of a substantial increase in maximum oil and gas production taxes, or royalties, that would be more sensitive to upward resource price movements and larger producing wells (Alberta 2007a,b). In March 2010, however, in response to declining resource prices in 2008 and 2009 and concerns that the exploration and development business was relocating to other provinces and shutting down because of the higher royalty rates, the Alberta government reversed the increase in the maximum royalty rate on conventional oil and gas (Alberta 2010).

With resource prices rising yet again as the world economy emerges from the 2008/09 financial crisis and as pressure increases to make royalty payments more responsive to oil and gas prices, policymakers must understand how the fiscal instruments the public sector uses to tax oil and gas production — namely, royalties and auctions — affect total net provincial revenues in present-value terms. Indeed, comparing our estimates of lost bonus revenues from potential future production from oil and gas projects to the Government of Alberta's estimates of total increases in royalty revenues from existing wells, we find that, in fact, Alberta's 2007 royalty increase led to little total net revenue increase for the province. Rather, increased royalty revenues were offset by up-front losses on auction revenues — which, for private bidders, represent the net present value of profits from a well over and above expenses, royalties, and a reasonable rate of return.

In particular, by comparing otherwise identical resource bonus bids in Alberta, British Columbia, and Saskatchewan, we can isolate the effect of Alberta's royalty change from other factors that might have influenced firms' bonus-bid decisions. Even though the three western provinces possess different types of resources and resource tax structures, most of these discrepancies remain fixed over time, allowing us to separate these factors from the change in the royalty rates by comparing otherwise identical bids by location, geology, and company type.[1]

Although this *Commentary* is a case study of the tax instruments used in the oil and gas industry in Western Canada, its lessons apply broadly to any natural resource region. Accordingly, policymakers

Thank you to the C.D. Howe Institute staff and members of the Fiscal and Tax Competitiveness Council and many reviewers who provided valuable comments. Many individuals provided valuable data and information that made this paper possible. The authors thank these individuals for their help, but absolve them of any errors in this paper.

1 As we discuss in more detail in the Appendix, our results are not influenced by the emergence of shale gas as a potential viable energy resource in British Columbia — or elsewhere.

should think twice about trying to increase revenues from non-renewable resources through higher, economically distorting royalties when a competitive bidding process is in place for exploration and production.

The Taxation of Non-renewable Natural Resources in Western Canada

Alberta, British Columbia, and Saskatchewan collect revenues from natural resource extraction activities — over and above traditional income or property taxation — through two means: up-front bonus bids to explore for new deposits (licences) or production (leases); and royalty payments upon production.[2]

Revenues from Oil and Gas Taxation

Revenues from oil and gas resources fund a significant share of provincial budgets in Western Canada — currently 10 percent in British Columbia and 20 percent in both Alberta and Saskatchewan. A number of factors, such as resource prices, royalty rates, and resource abundance, drive changes in these revenues. These three provinces also raise a substantial share of their general corporate and personal income taxes from non-renewable resource companies and their employees.[3]

British Columbia: In fiscal year 2009/10, British Columbia collected slightly more than $1 billion in bonus bids and royalties from non-renewable resources, almost entirely from natural gas (Figure 1a). More than half — a greater share than in either Alberta or Saskatchewan — of these revenues came from bonus bids,[4] and totalled more than $6 billion from 2003 through 2010. However, unlike Alberta or Saskatchewan, British Columbia spreads recognition of these revenues over a nine-year period based on the recommendations of the provincial auditor general. For instance, upon the sale of crown lands for resource exploitation, the province recognizes only 1/9th of the revenues in that year and counts the remaining revenues over the following 8 years.

Alberta: Provincial revenues from auctions of land rights and royalties in Alberta totalled approximately $6 billion in fiscal year 2009/10 (Figure 1b), representing about 20 percent of total provincial revenues. Of this amount, about $750 million came from auctions. Annual bonus-bid revenues peaked in 2006, with $3.4 billion in total revenues. Although total bonus-bid revenues are less than royalties, Alberta collected $13.4 billion in total bonus bids from 2003 through 2010.

Saskatchewan: Revenues from non-renewable resources, including potash, totalled $3.4 billion in fiscal year 2009/10, or one-third of Saskatchewan's total revenues. Excluding potash, non-renewable resource revenues were nearly $2 billion that year (Figure 1c). Bonus bids account for a relatively small share of total oil and gas revenues in the province, with only $2.3 billion in revenues raised from 2003 through 2010, most of which were collected between 2007 and 2009.

Royalties

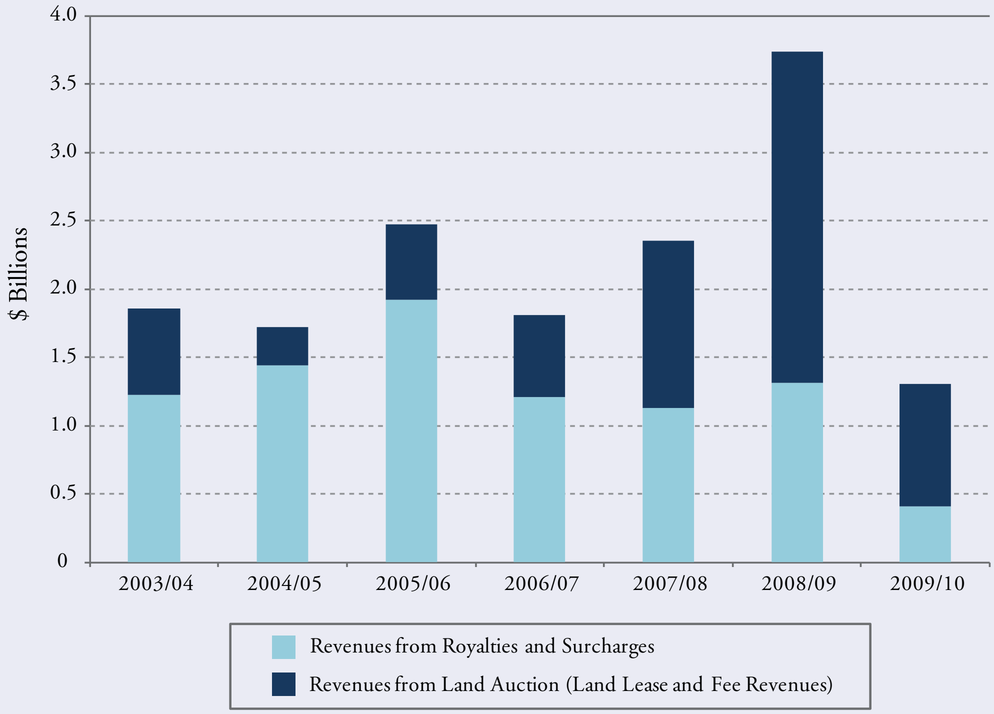
Alberta, British Columbia, and Saskatchewan calculate royalties for different hydrocarbon products on a well-by-well basis, though royalty structures, thresholds, and rates vary widely from one province to another (see Table 1). The three royalty regimes are similar in certain major aspects, however, with the level of royalties charged on oil or gas often, but not always,

2 Governments also collect revenues from rental fees for tenured bids. In Alberta, the government attaches a per hectare rental fee of $3.50 to the winners of bids on leases or licences. These revenues, however, are trivial compared with those from bonus bids and royalties.

3 Because these general taxes are not intended to extract the economic rent from resource production, however, we do not discuss them further in this *Commentary* except to the extent that they interact with resource taxation.

4 The relatively large ratio of bonus-bid receipts to royalties is due partly to recent discoveries of natural gas fields in northeastern British Columbia.

Figure 1a: Resource Revenues in British Columbia from Auctions and Royalties, fiscal years 2003/04 to 2009/10



Note: British Columbia data are adjusted from the actual budget account documents, which record auction revenues on a deferred basis over a nine-year period, to reflect the auction revenues in the year they were received.
Sources: Public Accounts documents.

adjusted for: the age of the well (its vintage or date of discovery); the volume produced (indicating a well's productivity); a factor that adjusts for changing market prices; and the density or cost of processing the oil or gas. (For a brief account of royalties in other Canadian jurisdictions, see Box 1.[5])

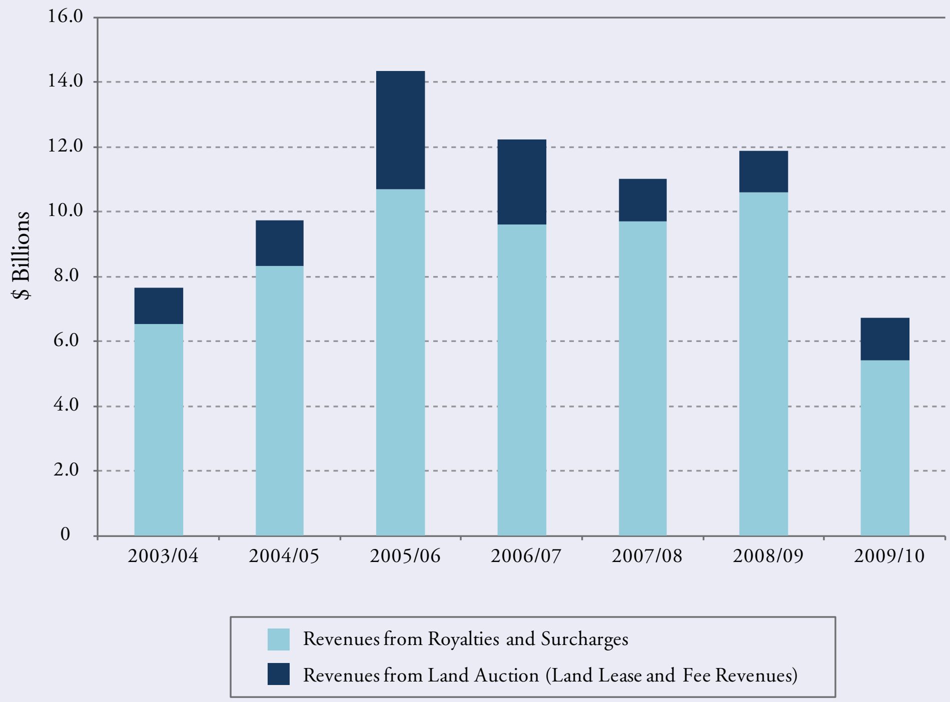
British Columbia: Natural gas production in British Columbia is taxed at a top marginal rate of 40 percent up to the point where the maximum total rate is 27 percent of the value of production. Different royalty rates apply depending on prices and well-specific characteristics, such as depth and age.[6] Oil royalties are differentiated by heavy versus light oil, production levels, and the date the well was first drilled. Oil royalty rates range from 0 to 15 percent depending on production rates, then gradually increase to 24 percent above a provincially defined production threshold.

Alberta — Conventional Oil and Gas: Before January 1, 2009, natural gas wells drilled after 1997 in Alberta had a maximum royalty rate on new natural gas discoveries of 30 percent of gross natural gas production revenues, with the actual monthly rate a function of the monthly price of natural gas, the production rate of the well, and the year in which the well was drilled. The maximum total royalty rate was applied at natural gas prices above $3.70 per gigajoule (GJ) of gas. Oil

5 For a more detailed analysis of Canadian oil and gas royalty rates, see Alberta Energy (2006c; 2011).

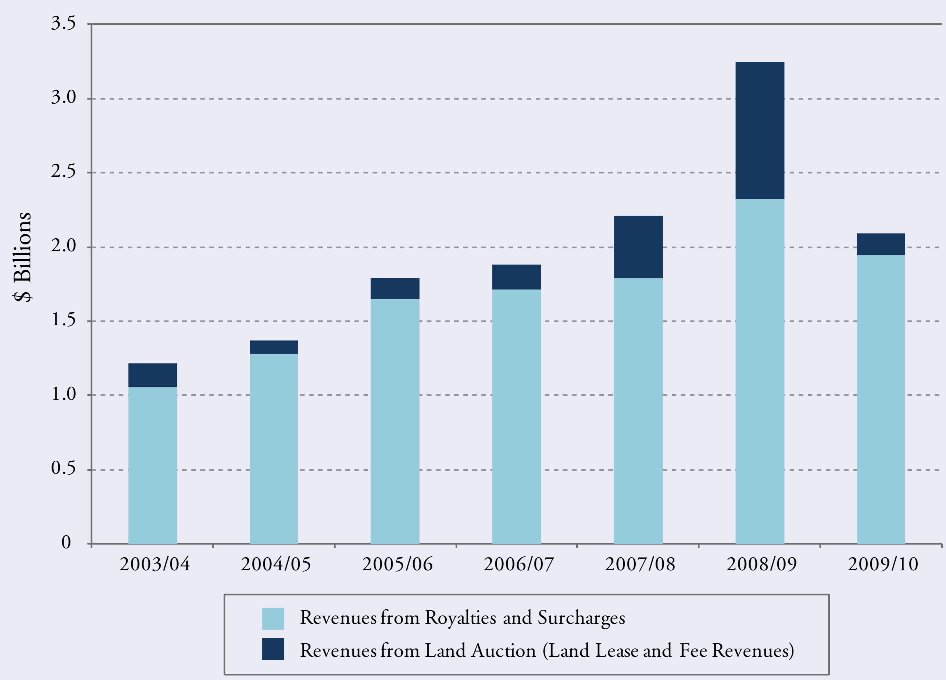
6 For example, royalty rates are reduced for wells with low levels of monthly production, and credits are given for deep wells. The province also offers a standardized deduction for infrastructure costs incurred by wells.

Figure 1b: Resource Revenues in Alberta from Auctions and Royalties, fiscal years 2003/04 to 2009/10



Sources: Public Accounts documents.

Figure 1c: Resource Revenues in Saskatchewan from Auctions and Royalties, fiscal years 2003/04 to 2009/10



Note: Saskatchewan data exclude resource revenues from potash.
Sources: Public Accounts documents.

Table 1: Minimum and Maximum Average Royalty Rates on New Wells, British Columbia, Alberta, and Saskatchewan

Energy Type	British Columbia	Alberta			Saskatchewan
		Pre-October 2007 Announcement	October 2007–March 2010	Post-March 2010 Announcement	
			(percent)		
Natural Gas	0–27	5–30	5–50	5–36	0–30
Conventional Oil	0–24	0–35	0–50	0–40	0–30
Oil Sands	N/A	pre-payout: gross revenue: 1	pre-payout: gross revenue: 1–9	pre-payout: gross revenue: 1–9	N/A
		post-payout: greater of gross revenue: 1 or net revenue: 25	post-payout: greater of gross revenue: 1–9 or net revenue: 25–40	post-payout: greater of gross revenue: 1–9 or net revenue: 25–40	
Effective Date (month, day, year):	gas: 6/1/1998 oil: 1/1/2000	7/1/1997	1/1/2009	1/1/2011	10/1/2002

Note: Minimum royalty rates based on low production levels. Rates for Pre-October 2007 announcement in Alberta are for new discoveries, rather than for new wells.
Sources: Alberta (2007c, 2010); Alberta Energy (2006a, 2011).

production from new wells had a maximum total royalty rate of 30 percent of the gross value of produced oil, which began to apply at oil prices above $30 per barrel.[7] In October 2007, Alberta announced that natural gas and conventional oil royalty rates would increase, with a new maximum rate on both conventional oil and natural gas of 50 percent of gross revenues, effective on all production as of January 1, 2009. Several special royalty programs were eliminated, as were differential royalty rates by pool discovery date. The maximum royalty rate was applied at oil prices above $120 per barrel and at natural gas prices above $16.59 per GJ. In March 2010, the provincial government announced that, effective January 1, 2011, maximum oil and gas royalty rates would return to rates closer to those that prevailed before the October 2007 announcement, but the more progressive rate structure would be maintained with regard to resource prices and well production levels.

Alberta — Oil Sands: Alberta applies a different royalty structure to the oil sands than to conventional oil and gas. Since 1997, royalties have been applied in two stages of the life cycle of a specific oil sands project. The first stage is the period before cumulative total revenues from the sales of a project's product exceed the setup costs of the facility — that is, the period before the project makes any profit — which is commonly known as the pre-payout period.[8] In the second

7 For both products, a number of credits were available for specific criteria, such as wells drilled below a certain depth, the amount of production, and other well characteristics. In Alberta, the price at the Alberta Market Hub on the Natural Gas Exchange is used to calculate the monthly reference price at which royalty rates for natural are set. Oil reference prices are set using the prices producers receive at the Hardisty hub in central Alberta. For light oil, the reference price includes a weighting to reflect the NYMEX West Texas Intermediate price. All prices are in Canadian dollars.

8 Setup costs are defined as allowed costs in the first three years before a project commences production. Allowed costs are defined as "costs that are directly attributable to the recovery, processing, and transportation of oil sands products to the boundary of the oil sands royalty project" (Alberta Energy 2006a).

Box 1: Royalties in Other Jurisdictions and for Other Natural Resources in Canada

Canadian governments collect revenue from natural resources by multiple methods. Manitoba's royalty rate on natural gas production is 12.5 percent of monthly sales, and new oil wells are subject to a maximum average rate of 19.1 percent, although deductions are available for oil production.

In the Northwest Territories and Nunavut, the federal government owns oil and gas resource rights and the royalty structure is effectively a cash-flow royalty. Royalty rates for both oil and natural gas start at 1 percent of gross revenues at start-up and increase by 1 percentage point until the payout point has been reached or the royalty rate reaches 5 percent, similar to the calculation of the royalty base for oil sands in Alberta. After payout, the royalty rate is the greater of 30 percent of net profits or 5 percent of gross revenues (Alberta Energy 2011). Quebec recently raised the top average royalty rate on natural gas production from 12.5 to 35 percent (Quebec 2011).

Offshore oil and gas royalties in Nova Scotia and Newfoundland are similar to the cash-flow royalty in the Alberta oil sands (Watkins 2001). In Nova Scotia, the pre-payout royalty starts at 2 percent and increases to 5 percent once the project has reached a defined rate of profitability. After the project payout, the royalty increases to as high as 35 percent of net revenues, but retains a base royalty of 5 percent of gross revenues.

Newfoundland's gross and net revenue royalties escalate with cumulative production to a maximum rate of 7.5 percent of gross revenues and 10 percent of net revenues. At lower levels of profitability (defined by a provincial formula) the total royalties due are the greater of net or gross revenue royalties; however, at higher levels of profitability, total royalties are the sum of gross and net revenue royalties.

Similar to the Alberta oil sands royalty, potash (used in fertilizer) in Saskatchewan is taxed using a royalty similar to a cash-flow tax, but there are many differences. First, the potash royalty is in two parts, with a base payment and a tax on profits, but there are also temporary tax holidays and an accelerated capital depreciation (Mintz 2010; Saskatchewan 2010). Unlike the Alberta oil sands royalty, the royalties are calculated based on the full set of a company's operations, rather than on the profitability of a specific project.

stage — the post-payout period — a higher royalty applies. This royalty structure, known as a cash-flow tax, is designed to capture economic rent and reduce disincentives to investment in the non-conventional sector, where large, up-front capital expenditures are required. Under the pre-2009 regime, the royalty paid was 1 percent of gross revenues during the pre-payout period; during the post-payout period, the royalty rate was the greater of 1 percent of *gross* revenues or 25 percent of *net* revenues (gross revenue minus allowable costs). A new royalty rate, announced in October 2007, took effect on January 1, 2009, and maintained the cash-flow model. The pre-payout royalty rate is now a sliding scale depending on oil prices, starting at 1 percent of gross revenues and increasing to 9 percent of gross revenues at oil prices above $120 per barrel. The post-payout royalty rate is now the greater of 25 to 40 percent, again on a sliding scale of oil prices, of *net* revenues at oil prices above $120; or, 1 to 9 percent of gross revenues with a sliding scale.

Saskatchewan: Saskatchewan distinguishes gas and oil royalties by the date a well was drilled, with a higher royalty rate applying to older wells. Regional- and product-differentiated royalty rates also apply to older wells.[9] New wells, however, are subject to the same royalty maximum total rate of 30 percent for both oil and natural gas across the province.

9 These credits are, on average, 16 percent of the royalties paid by producers (see Sawyer and Stiebert 2010).

Bonus Bids

The second-largest source of revenues from oil and gas development in Western Canada is the auctioning of parcels of land to bidders that purchase the right to explore and extract resources owned by the province. These parcels of land are known variously as "tenure rights" or "bonus bids" — see Box 2 for a detailed description of the oil and gas rights that companies purchase through auctions.[10] The amount that companies offer to pay in a competitive auction is referred to as a "bonus." For each deposit, a producer first calculates the risk-weighted revenues it can expect to collect from production, along with its expected costs of extraction; the remaining revenues over and above expenses and a pre-defined profit margin are the maximum amount a company would be willing to bid.

Assuming there is sufficient competition, bonus bids capture the "foreseeable" net present value of revenues from oil and gas deposits that remain after firms have paid royalties and other expenses over and above a normal economic rate of return — commonly referred to as the abnormal profits that a firm can earn. Bidders, however, do not know the future path of resource prices or necessarily the quality of the resource when they submit a bid. Each firm knows that, if it places a bid below the true economic value of the deposit, it runs the risk that other firms will outbid it for the exclusive right to produce the field. Thus, a firm has a strong incentive to place a bid on a field that is exactly equal to the expected future value of abnormal profits, to prevent other companies from gaining access to the resource. This result should hold as long as firms have similar information about resource values — a reasonable assumption given the extensive development of western Canadian oil and gas – and if there is strong competition for bonus bids (see Cramton 2009 for more information on oil and gas auctions).

Evidence shows that, in Alberta, bonus bids capture all, or at least a very significant portion, of the foreseeable abnormal profits from oil and gas deposits. Watkins (1975), for example, finds that the extent of competition on bonus bids is the key driver of foreseeable abnormal profits captured by bonus bids, while Winter (2010) finds that there are many bidders in the Alberta market, signifying that the market is likely still competitive today. We thus expect that the bonus bids we analyze in this *Commentary* capture the potential future abnormal profits from resource development.

British Columbia: Auctions for licences and leases are held monthly. Licences range in duration from three to five years, while leases are good for 10 years but can be continued in perpetuity as long as production continues. British Columbia has three types of tenure rights: permits that give developers the right to conduct exploration; drilling licences that permit firms to drill to a specified depth; and leases, which allow firms the exclusive right to produce oil and gas in a particular geographical and geological area.[11]

Alberta: Alberta has two types of development rights, introduced in 1976, for conventional oil and gas: licences to explore and leases to produce (Alberta Energy 2009a). Licences are intended for short-term exploration in an area with no previous exploration, but are converted to production leases if the exploration yields oil and gas that would be profitable to extract. Licences for the initial period are for five years in the Foothills

10 The main exceptions to this auction process are historic land deals between the federal government and landowners where mineral rights were also transferred at the time of sale before jurisdiction over resources was transferred to the provinces in 1930 in the *Constitution Act*, 1930. This occurs in a large tract of land in Alberta approximately bounded between Calgary, Drumheller, and Brooks held by the Canadian Pacific Railroad, where land rights included mineral rights. The provinces also do not have mineral rights in national parks, Canadian Forces Bases, or First Nations reserves. The Alberta government has Crown rights on approximately 81 percent of the province's mineral rights.

11 Of approximately 13,000 licences granted from 1955 to August 2010, the point at which we collected our data, fewer than 3,500 had been converted into producing leases.

area, four years in northern Alberta, and two years in the southeastern plains.[12] Companies are also able to purchase leases in areas with past production. Leases are intended for longer-term development of already-discovered resources. Firms often purchase leases in the hope of profiting from a low-risk — albeit low-yield — well that was previously developed but abandoned when additional production was not profitable at the resource prices and production technology that prevailed at the time. Leases are good for five years in all regions, and can be extended as long as production continues from the lease. Oil sands exploration licences are for a term of five years and leases for 15 years. Sales are held every two weeks, and are conducted separately for conventional oil and gas and oil sands.

Saskatchewan: The licence and lease structure in Saskatchewan is similar to that in Alberta, although leases are by far the more common of the two types of sales. Leases are for five years, and licences are for two years for most of the province, although in some northern areas licences can be purchased for up to four years. Auctions are held between every month and every two months.

The Effect of Changes in Provincial Oil and Gas Royalty Regimes

We now turn to examining the effect of changes in oil and gas royalty rates on the remaining net present value of oil and gas deposits that firms calculate and then pay as their bonus bids — that is, how changes in the future flow of royalties are capitalized in the current value of bonus bids. For instance, an increase in royalty rates might lead to a decrease in bonus-bid revenues today that is more than the increase in future revenues from higher royalties.

The Capitalization of a Resource Royalty Increase in Bonus Bids

With a competitive bidding process for the right to explore and extract a resource, bonus bids reflect the net present value, over and above profits at a minimum rate of return and royalties paid, that producers expect to earn from the property. Resource royalties reduce the net price that a firm obtains from producing an additional unit of the resource, thereby directly reducing a firm's profits, dollar for dollar in present-value terms, if output remains constant.

However, because a royalty also reduces the amount of the resource that will be produced, the reduction in bonus bids will exceed the increase in revenue from a royalty rate increase. A higher royalty rate changes the point where a well is no longer economical. This is because — unlike a true non-distortionary rent collection — the *ad valorem* royalty rate inhibits production by reducing the net return from an additional unit of output. Thus, bonus bids will decline by more than the increase in royalty revenue. We refer to this as the "overcompensation" effect. To state the proposition more formally, if bonus bids are based on a competitive bidding process and firms are risk neutral — an assumption we discuss below — then a royalty rate increase will reduce bonus bids on new properties by more than the expected increase in royalty revenues.[13]

12 If the lessee drills a well, it may receive an extension of the licence for another five years to prove that the well can be productive.

13 Several caveats concerning the overcompensation effect should be noted. First, the effect applies only to new resource properties, as higher revenues from existing wells will compensate for this revenue loss. Second, to the extent that firms are risk averse, their bids will be less than the expected abnormal profit. In other words, with bidding by risk-averse firms, a royalty increase may be "undercompensated," meaning that a $1.00 increase in royalty revenues might reduce the bonus bid by less than a $1.00. Third, the burden of the royalty rate increase might be shifted to workers and to other inputs used by the resources sector, not just to bid values. Fourth, as discussed in more detail in a later section, the degree of capitalization is also reduced because, under the corporate income tax, bonus bids are treated as equivalent to a capital expenditure and depreciated over time, while royalty payments are fully deductible when they are incurred. Because of these factors, the extent to which royalty increases are capitalized into bonus bids is an empirical question that our study attempts to address.

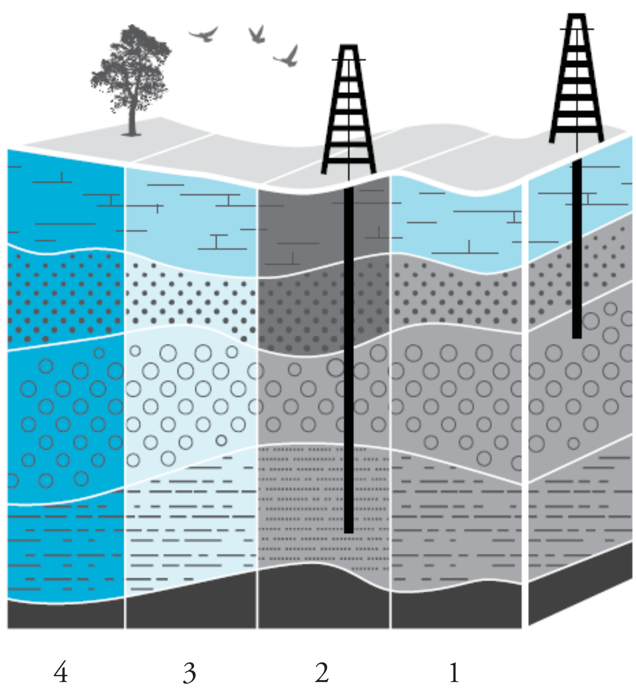
Box 2: A Summary of Tenure Rights

A lease or licence provides the owner of the rights exclusive access to a geological zone of a specified depth underneath a specified plot of land. The geological rights can range from the surface to the lowest possible depth that oil and gas might exist (this is known as the basement). Lease owners then have a specified period of time to produce oil or gas from the geological zone to which they have rights. Although details differ by province, areas that owners do not produce from in a specified period of time, or cease producing from, are returned to provincial ownership and can be auctioned again. However, owners retain tenure rights indefinitely if they continue to produce. As technology or other factors change, other developers might then choose to develop leases that were returned to the province, starting the cycle again. This results in multiple leases or licences in the same land area but often owned by different companies and for different geological zones (see figure below for a visual illustration).

Rental fees are associated with tenure, although revenues from these fees are trivial compared with those from bonus bids and royalties. Bonus bids are delineated geographically by sections (1 square mile) and sometimes by smaller units such as legal subdivisions (one-sixteenth of a section). Sections are grouped together to form a "tract" that is put up for auction. Interested firms submit sealed bids to the ministry and the parcel of land goes to the highest bidder. Resource firms often bid as a package on nearby tracts that hold different geological rights.

Firms must also negotiate access rights with the owners of the surface of the land. However, these expenses are usually trivial compared with the costs of purchasing tenure rights from governments, as the majority of land in the western provinces (94 percent in British Columbia, for example; see British Columbia 2010) is unoccupied Crown land.

An Example of Tenure Rights



Source: Alberta Energy (2009a).

Simple models indicate that the overcompensation effect could be quite significant.[14] For example, if the royalty rate is 20 percent and abnormal profit represent 40 percent of the value of output, then the bonus bid is predicted to decline by $1.60 for a $1.00 increase in royalty revenue (in present-value terms). If abnormal profit is 30 percent of the value of output, the bonus bid is predicted to decline by $2.40 for every $1.00 dollar increase in royalty revenue. These calculations indicate that a royalty rate increase might reduce bonus bids by a larger amount for marginal resource properties that yield little net present value, over and above profits at a minimum rate of return and royalties paid.

Estimating Overcompensation of a Royalty Increase in Bonus Bids

The recent, and sudden, changes in Alberta's royalty regime for oil and gas, along with the relative stability of royalty regimes in neighbouring provinces with otherwise similar oil and gas deposits, enables us to test the extent to which an increase in royalties is capitalized in bonus bids.[15]

Alberta Conventional Oil and Gas: In 2007, the Alberta government appointed The Royalty Review Panel to analyze the province's royalty regime; the report was made public on September 18, 2007 (see Alberta 2007a).[16] The government then conducted a technical review of the panel's recommendations and, on October 25, 2007, announced a suite of policy changes to the existing royalty regime (Alberta 2007c). Although the panel made 26 recommendations in its September 2007 report, the province accepted only 12 without modification and another three with modifications, strongly suggesting that the government's proposed changes in the October 2007 document were largely unanticipated — in other words, firms did not adjust to the economic effects of these royalty changes before the announcement.[17] The top marginal royalty rate on new oil and gas discoveries increased by 20 percentage points. However, concerns that Alberta's new royalty regime made it difficult for oil and gas firms to remain as profitable in that province compared to other jurisdictions resulted in another review of the royalty regime (Alberta 2010), after which the maximum rates on conventional oil and natural gas were returned to levels close to their pre-2007 levels (see Table 1), although most of the other reforms introduced in 2007 were retained.[18]

14 The model we use is based on a Cobb-Douglas production function for output and assumes that there is a fixed royalty rate. As Table 1 indicates, the actual royalty rates the provinces levy vary with the prices of oil and natural gas and with well production levels and depths. The royalty rate in our model should be interpreted as the expected effective royalty rate over the life of the project. Even if the royalty rate is zero when the well approaches the end of its production life and output is low, the higher royalty rates levied on its initial production will reduce production below its potential, resulting in a lower bonus bid.

15 The federal government changed the corporate tax treatment of royalty and bonus payments over the period between 2003 and 2007. In sum, this change reduced federal income taxes on resource companies, added a deduction of provincial royalty payments against federal taxes, and removed a fixed cost allowance for resource firms. However, this change applied equally across all three provinces, so it should not affect our analysis.

16 During the governing provincial Progressive Conservative party's 2006 leadership campaign to replace retiring premier Ralph Klein, the eventual winning candidate, Ed Stelmach, made a commitment to review royalty rates and create an independent panel with the mandate to "review whether Albertans are receiving a fair share from energy development through royalties, taxes, and fees"; see Alberta (2007a).

17 In our interviews with industry participants, all told us that their investment decisions were made only after the formal announcement of the royalty increase in fall 2007, not during the consultation stage of the Royalty Review Panel.

18 Alberta also introduced some other changes to the royalty regime between these two major announcements on maximum royalty rates that might have offset the increase in royalty rates (see the Appendix). These temporary credits were most likely to benefit firms that already held tenure rights but had yet to drill or produce from these licences or leases, and we expect that these changes had no effect on bids. We were able to confine our analysis to bonus bids made before these other announcements to test the robustness of our estimates to these other changes. However, because of the lag between bonus-bid purchases and well development, we expect that these temporary credits had little effect on bonus bids during our study period.

To estimate the average royalty rate increase, we looked at detailed Alberta well data *before* the royalty change.[19] From this, we narrowed our analysis to wells that were producing from January 2005 through July 2007 — just before the royalty rate increase announcement. We calculated the effective royalty rates for each well using the pre- and post-2009 rate schedules, holding constant both production of each individual well and natural gas prices that occurred during each well's first 12 months of production. We find that, although the top marginal rate on natural gas production increased by 43 percent after the October 2007 announcement (from 30 percent on 'new gas' to 50 percent), it was primarily high-production wells that were subject to this increase (Figure 2), while low-production wells saw a reduction in royalty rates. Natural gas wells producing more than 1,000 cubic feet of gas per day provided half of the estimated total natural gas royalties during the first 12 months of production. Had natural gas prices and output levels on existing wells not changed after the royalty increase, the royalty rate increase on these wells would have been about 33 percent.[20]

British Columbia: On August 9, 2009, the province announced a temporary stimulus program that entailed a one-year, 2 percent royalty rate for all natural gas wells drilled between September 1, 2009, and June 2010.[21]

Saskatchewan: There were no major changes in oil and gas royalty rates in Saskatchewan during our study period.[22]

Bonus Bid Data: For our analysis, we collected data on every conventional oil and gas licence and lease auctioned in Alberta, British Columbia and Saskatchewan from January 1, 2003, through at least September 2010. For every individual plot auctioned, we know the exact location, amount paid, date of sale, whether it is a lease or a licence, the geological rights, purchaser, and number of hectares. For each plot, we calculated the exact distance from the centre of that tenure to either the British Columbia-Alberta or Saskatchewan-Alberta border, whichever is closest.[23]

In the two years both before and after the October 2007 Alberta royalty change announcement, there were more tenure sales in that province than in either British Columbia or Saskatchewan. However, British Columbia raised more revenue from bonus bids, auctioned larger individual plots, and sold plots at a higher price per hectare than Alberta did in the two years prior to and after the royalty change (see Table 2). The total number of bonus sales in Saskatchewan stayed relatively constant in the two years after the Alberta royalty increase, although the average size, number of hectares sold, and total revenues from sales increased relative to the two prior years.

19 Our Alberta well data give us the average daily production of oil and gas for the first and last 12 months of observations of all past and present wells as of July 2007.

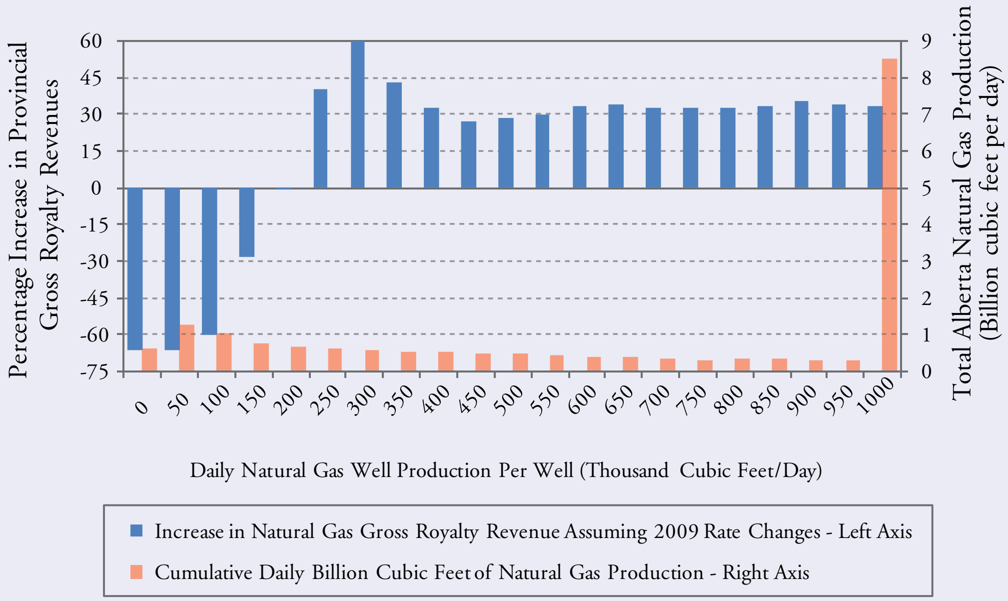
20 These rate changes, however, do not take into account the removal of credits that also occurred during the royalty change. The graph of the average increase in royalty rate increases for oil is similar to that of natural gas and is available from the authors upon request.

21 The province also announced a number of Infrastructure Royalty Credit Programs in 2008 and 2009, with tax credits provided for infrastructure investment spending and royalty reductions and credits for wells with certain characteristics. Because these royalty credits were temporary measures and were not subsequently renewed, we ignore their effect because of the long lead time between the initial bonus bid and the commencement of drilling.

22 A few changes in other taxes that occurred before the Alberta royalty review might affect the value of bonus bids in Saskatchewan. First, the province reduced corporate income and capital taxes over the period of study. At the same time, it announced a reduction in the surcharge on the value of oil and gas production from 2 to 1.7 percentage points by 2008. However, these changes were announced well in advance of actual implementation, meaning the value of lower corporate taxes likely was incorporated into bonus bids after the original announcement in early 2006. Saskatchewan's general tax rate on corporate taxable income was reduced from 17 percent to 14 percent effective July 1, 2006, to 13 percent on July 1, 2007, and to 12 percent effective July 1, 2008. See Saskatchewan (2006).

23 We were able to calculate the precise distance to the border for conventional oil and gas bonus bids on auction results only through September 2010.

Figure 2: Natural Gas Gross Royalty Revenue Changes, by 2005-2007 Daily Well Output



Note: Well production from January 2005 through July 2007.
Source: Authors' calculations from Winter (2010).

Table 2: Bonus Sales Two Years Before and After Alberta's October 2007 Royalty Changes

		Average Number of Sales/Year	Average Total Hectares Sold/Year (thousands)	Total Bonus Revenue/Year ($ millions)	Average $ per Hectare	Average Total Bonus ($ thousands)
Alberta	Before	7,726	2,456	1,340	318	173
	After	5,399	1,817	650	337	121
British Columbia	Before	875	596	680	682	779
	After	688	632	1,910	919	2,778
Saskatchewan	Before	1,513	350	157	449	104
	After	1,712	553	535	967	312

Note: Sales two years before the royalty change are from November 2005 through October 2007; sales two years after the royalty change are from October 2007 through October 2009. Prices use nominal dollars.
Sources: Alberta Energy; British Columbia Ministry of Energy, Mines and Petroleum Resources; Saskatchewan Ministry of Energy and Resources.

Changes in the Value of Bonus Bids: Between 2003 and 2007, the monthly total amount that companies paid for conventional oil and gas tenure rights in Alberta closely tracked the Bank of Canada's energy commodity price index (Figure 3, panel A). Total bonus revenues in Alberta were especially high during the increase in natural gas prices in late 2005 and early 2006. After the royalty increase announcement in October 2007, however, total royalty revenues did not increase in line with the increase in prices.

In contrast, in Saskatchewan, immediately after Alberta's royalty rate increase, the total bonus amounts paid increased in line with the commodity price index (Figure 3, panel B). Bonus payments in that province saw a similar increase in prices in 2010 as those in Alberta due to the increase in oil development along the Alberta border. Similarly, the total bonus amounts paid in British Columbia increased in line with the increase in natural gas prices after October 2007 after having been flat over the previous five years (panel C), but stagnated with flat natural gas price growth.

As Boychuk (2010) points out, bonus bids in Alberta did increase shortly after the royalty increase announcement. However, the only way to assess the effect of the royalty increase on bonus bids is to ask how much the bids would have changed had royalty rates not increased — as was the case in British Columbia and Saskatchewan. We now turn to identifying this counterfactual and to estimating the effect just of the Alberta royalty increase on bonus bids.

Isolating the Effect of Royalty Changes: Provincial borders are completely arbitrary with respect to deposits of oil and gas reserves — when they were determined, there was limited knowledge of the bounty of oil and gas in that region, as major oil development began only in the 1940s. The location of these arbitrary borders thus provides a dividing line to identify how policies within each province affect the value of land that is different only by virtue of being separated by a geologically arbitrary boundary.[24] The patterns of exploration and development of conventional oil and gas — but not oil sands, which we exclude from our analysis — are continuous across the British Columbia-Alberta border.[25] Our methodology is based on a now-common approach in economics, whereby otherwise arbitrary cutoffs and boundaries are used to create what is close to a natural experiment in which one group of observations acts a control group (see Lee and Lemieux 2009).[26] Changes in resource prices over the period between 2003 and 2010 affected all three provinces equally, and do not influence the results when the only comparison is among the three provinces. In 2007 and 2008, however, the borders of Alberta are the ideal places to analyze the effect of the royalty increase for several reasons:

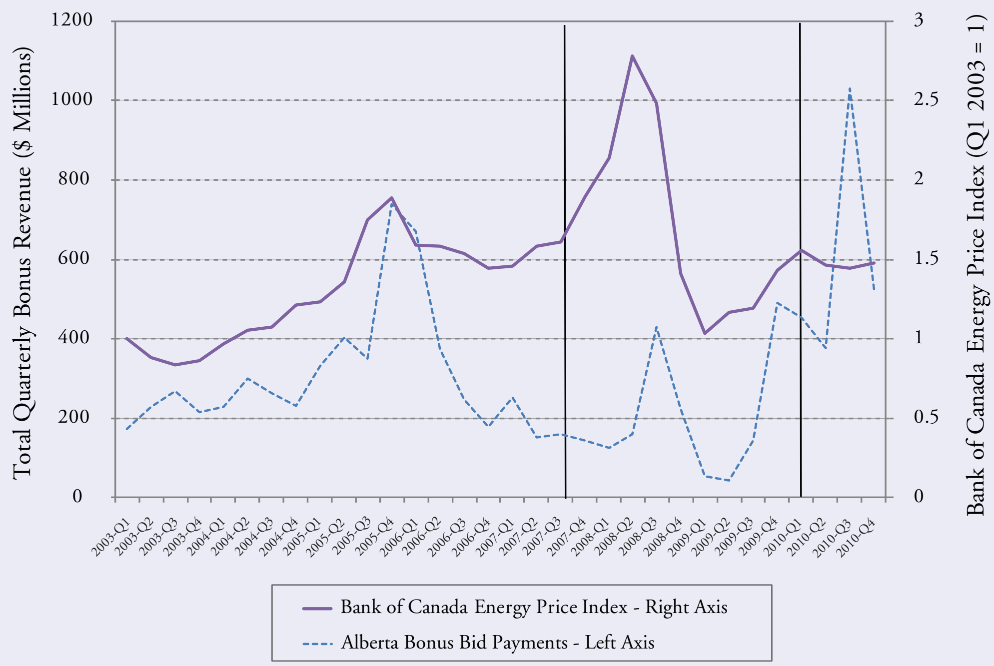
- the increase was largely unanticipated, allowing us to create a defined period of study in which the increase was the only major policy change;
- the provincial borders that cross the Western Canadian Sedimentary Basin (WCSB) are geologically arbitrary, meaning that they were located independently of fixed oil and gas deposits;
- within this narrow band of producers straddling the border, developments elsewhere in the world (such as the introduction of shale gas, the global financial crisis, and changes in the price of energy commodities) had the exact same effect regardless of which province the producers were located in; and
- since labour and capital are highly mobile across these borders — and although many firms might

24 By geological accident, however, some prolific shale gas formations that have been developed recently (notably the Horn River formation) happen to be disproportionately located in British Columbia. We discuss how we resolved this problem in the Appendix.

25 Significant oil and gas deposits do not extend into other areas of British Columbia, and there are few such reserves in central Saskatchewan.

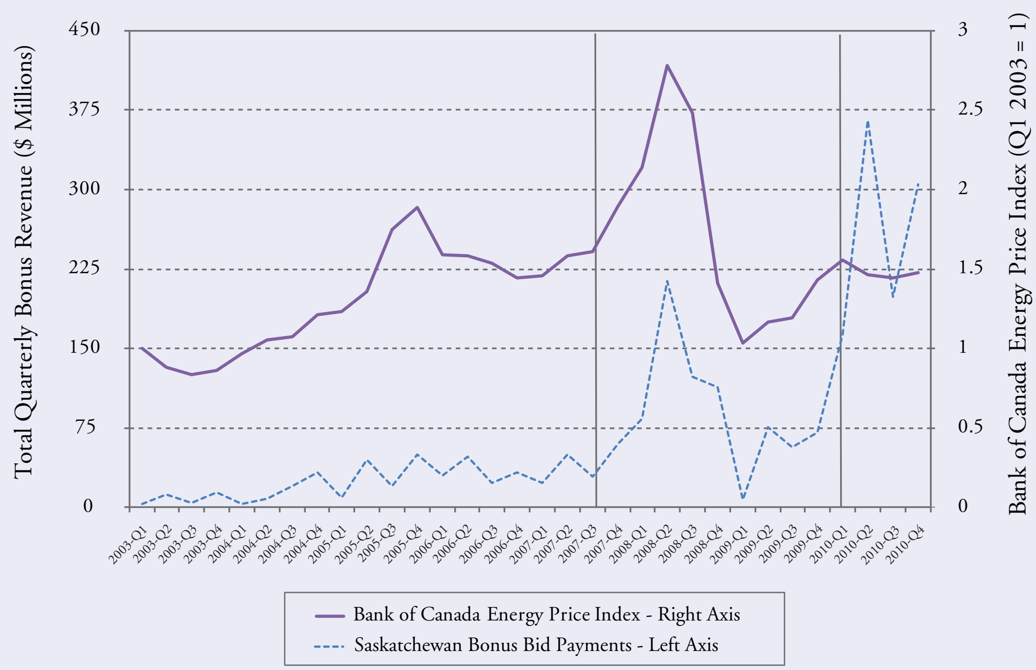
26 This approach to measuring the effect of taxes has been applied in papers using detailed geographic data; see, for example, Dachis, Duranton, and Turner (2008, forthcoming); and Duranton, Gobillon, and Overman (forthcoming).

Figure 3a: Total Bonus Revenues Collected from Conventional Oil and Natural Gas Auctions in Alberta, 2003/Q1 to 2010/Q4



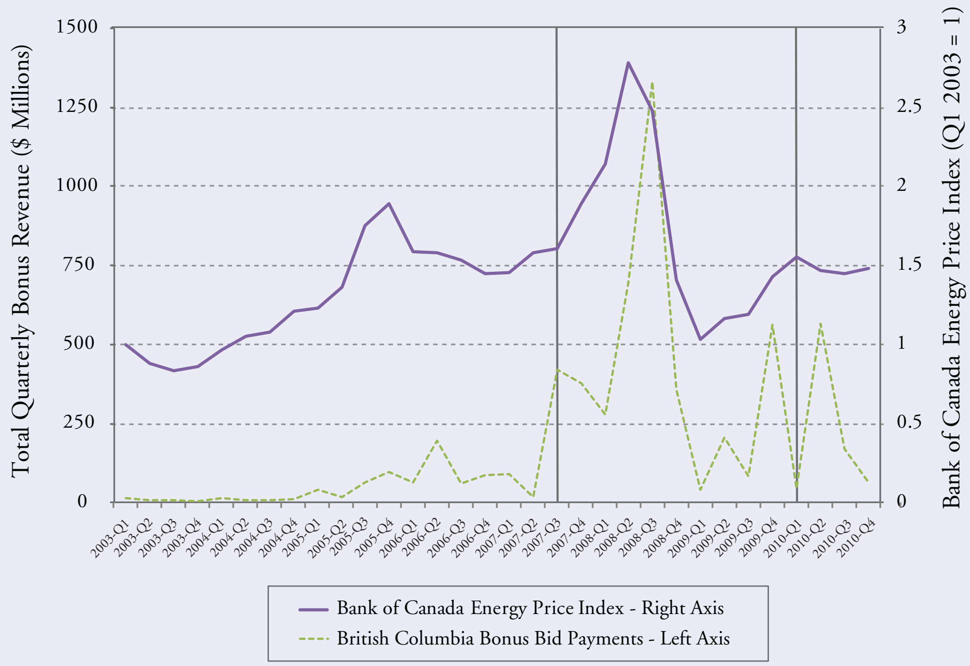
Sources: Alberta Energy; Bank of Canada.

Figure 3b: Total Bonus Revenues Collected from Conventional Oil and Natural Gas Auctions in Saskatchewan, 2003/Q1 to 2010/Q4



Sources: Saskatchewan Ministry of Energy and Resources; Bank of Canada.

Figure 3c: Total Bonus Revenues Collected from Conventional Oil and Natural Gas Auctions in British Columbia, 2003/Q1 to 2010/Q4



Sources: British Columbia Ministry of Energy; Bank of Canada.

have left parts of Alberta before the royalty increase — the border regions of provinces likely draw from the same input markets and will have similar labour and capital costs.[27]

Comparing Geologically Similar Leases: Leases can be compared not only across geographical borders, but also across *geological* borders. Alberta, British Columbia, and Saskatchewan provide detailed geological information on the exact geological zone on which the lease or licence holder has rights.[28] Thus, we were able to compare geographically and geologically identical bonus bids that straddle the Alberta border in the WCSB east of the Rocky Mountains. By comparing bonus bids for the same geological area within the same region, we avoid having recent natural gas or oil price developments influence the results, given that deposits do not change substantially at the Alberta border.

The Effect of the Royalty Increase: Results

Using the data and techniques discussed above and after controlling for other possible confounding factors, we used a regression analysis to measure the effect of the royalty increase on bonus bids in Alberta. In summary, we find that revenues from bonus bids fell by about the projected revenue increase in royalty rates.[29]

27 If companies were reducing their bidding in Alberta before the royalty increase due to higher inflation, this would bias our results downward, meaning that we would have underestimated the impact of the royalty rate increase.

28 See the Appendix for details on how we extracted geological information from bonus bids.

29 See the Appendix for details on how we conducted these regressions and the detailed results behind our presentation here.

The Effect on Bonus Bids: The average value of oil and gas bonus bids fell by 57 percent in Alberta during the period of high royalty rates between October 2007 and March 2010. Many potential factors might underlie this finding, such as a reduction in the productivity of Alberta fields and higher costs of production in Alberta because of higher labour costs during this period. Thus, to identify the true effect of the increase in royalty rates as opposed to these other factors, we compared bonus bids within 100 km of the Alberta border, an area that, in all three provinces, is similar in terms of relative remoteness, labour markets, and other geographical characteristics to the respective adjacent province. We find that, within this region, Alberta's royalty increase reduced bonus bids by 42 percent, when both the geological zone and geographic factors[30] are held constant across all bonus bids (Table 3).[31] Thus, the overall effect of the increase in royalty rates relative to a counterfactual example of otherwise similar bonus bids in other provinces was to reduce by 42 percent the average bonus payment that Alberta otherwise would have captured through bonus bids. Changes in the number of bids also would have affected total provincial revenues from bonus bids. Because deposits that were marginal, at the previous royalty rate, would have been non-economic at the higher rate, it is likely that, after the rate increase, firms reduced the number of projects on which they were prepared to bid. We counted the number of bids within concentric bands of land measuring one kilometre in width and extending east and west from the Alberta borders with Saskatchewan and British Columbia. We found that, in response to the royalty increase, the number of bids in each of these one-kilometre-wide bands, in Alberta, declined relative to otherwise similar bands in adjacent provinces, and in Alberta before the royalty change, by 27 percent.[32]

The Effect by Company Size: Larger companies with operations in multiple provinces — indeed, worldwide — likely would have had greater flexibility than smaller companies with more limited operations in other provinces to redeploy capital and workers outside Alberta. Thus, we find that larger companies reduced their average bid by 68 percent, while smaller companies reduced theirs by 35 percent (Table 4).[33] These results suggest that larger firms were more responsive to the royalty increase than those with less flexible inputs.

The Effect of Borders: One expected empirical result is that the royalty increase should have greatly reduced bonus bids in areas with fewer productive reservoirs remaining, but should have had less effect on the value of reservoirs with high economic value. Again, this is because deposits that were just economically marginal before the increase would have become non-economical at the higher rate. We find that conventional oil and gas rights in Alberta have a lower average value

30 We controlled for permanent factors specific to each township. These could include the location of processing facilities, previous rates of development, or other geographical factors that are constant over time that we cannot control for directly. Such a "fixed effects regression" provides even greater detail on location-specific factors than assuming that bonus bids within 100 km of the Alberta border share similar characteristics. It also allows us to control for regionally distinct royalty rates in northeastern British Columbia, west of the so-called East/West line, where wells pay a lower royalty rate. This estimate controls for accessibility of bids even if one side of the border is relatively more accessible to begin with as long as there were no dramatic changes in accessibility over time. Our inspection of Statistics Canada road network files from 2005 through 2010 suggests this assumption is fair.

31 Limiting our analysis to the period before February 2008 — that is, before the increase in drilling credits and temporary royalty relief changes in Alberta, and the introduction of the Net Profit Royalty Regulation, which we discuss further below, and the carbon tax in British Columbia — does not materially change the effect of the royalty increase. See the Appendix for additional tests of the sensitivity of our results to different parameters.

32 We tested this using a "Poisson regression," in which the dependent variable is the number of bonus bids counted within bands of land measuring 1 km in width extending outward from the border of Alberta with both British Columbia and Saskatchewan; see the Appendix for details. This result comes from a 50km threshold, with larger results at a 100 Km threshold.

33 See the Appendix for details. One caveat is that we were able to perform this calculation only when large firms revealed themselves as a bidder in the post-auction results. For competitiveness reasons, some firms have agencies bid on their behalf to protect the actual bidder's identity.

Table 3: Change in Alberta Conventional Oil and Gas Bonus Bids Due to Royalty Increase

All bids	100km from both borders
Controls: None	Controls: Geology and Geography
-57%	-42%

Source: Authors' calculations from BC Ministry of Energy, Mines and Petroleum Resources; Alberta Energy; Saskatchewan Ministry of Energy and Resources; Statistics Canada.

Table 4: Change in Alberta Conventional Oil and Gas Bonus Bids Due to Royalty Increase, By Company Size

Majors	Non-Majors
-68%	-35%

Note: Both estimates control for geology and local geographic factors.
Sources: Authors' calculations from BC Ministry of Energy, Mines and Petroleum Resources; Alberta Energy; Saskatchewan Ministry of Energy and Resources; Statistics Canada.

along the Saskatchewan border — an area that has seen substantial past development, with few remaining large reservoirs — than rights near the border with British Columbia, which has seen a recent surge in development as a result of finds of large natural gas deposits. In 2006, the average value of a conventional oil and gas bid in Alberta within 100 km of the Saskatchewan border was $91,000, while the equivalent value along the British Columbia border was $282,000. The average reduction in bonus bids in southeastern Alberta as a result of higher royalties was 54 percent; in contrast, royalty bids in western Alberta declined by 32 percent.[34]

The Effect on Exploration versus Production: Companies bid either for licences for the right to explore — and eventually produce — undiscovered oil and gas deposits or for leases for the right to produce oil and gas. We find that the average value of an exploration licence in Alberta fell by 59 percent due to the royalty increase, likely because licences are geared toward finding highly productive oil and gas reserves and the royalty increase was particularly high for these large deposits, which disproportionately reduced the expected return from exploring for them. The average value of a lease declined by only 21 percent. Leases are geared toward relatively low-yielding deposits, for which the royalty increase likely was negligible in many cases.

The Net Revenue Effect of the Royalty Increase on Conventional Oil and Gas

To determine the total revenue effect of Alberta's royalty increase just on conventional oil and gas, we first estimated the new average bonus amount due to the increase — holding changes, for example,

34 As discussed in greater detail in the Appendix, these results do not change substantially when we remove the potential effect of some natural gas deposits that are disproportionately located in British Columbia. Likewise, controlling for additional factors that are inherent to a company (or bidding agent) in all of their bids also does not appreciably change the results. Our results thus appear robust to a number of different specifications and controls.

in resource prices, constant — using the average bonus bid in 2006 of $175,000 and the estimated reduction in the average bonus. An approximately 40 percent reduction in average bonus amounts, which we reported above, would have resulted in a counterfactual average bonus bid of $105,000.We calculate the counterfactual number of bids that there would have been, in response to the change in royalty rates, by multiplying the average annual number of sales in the two years preceding the royalty increase by 73 percent (one minus the 27 percent reduction in the number of bids, reported above). To estimate the counterfactual total bonus revenues, under the higher royalty regime, we multiplied the counterfactual average bonus amount by the counterfactual number of total bids.

The total annual revenue from bonus bids in the counterfactual case of higher royalty rates, based on these estimates and holding all else equal, would have been $600 million in 2006, in comparison to actual revenue of $1.5 billion that year — a revenue reduction of $900 million. In contrast, in its announcement of the New Royalty Framework, the Government of Alberta estimated that, by 2010[35] — assuming no change in production due to the increase in royalties and at projected 2010 prices — total conventional oil and gas royalties would increase by $930 million (Alberta 2007c).[36] Thus, the increase in royalty rates should have yielded, at best, a marginal revenue increase if producers did not change their production.

But producers likely reduced their production from wells made uneconomical as a result of the higher royalty, making the net revenue from the royalty increase closer to zero or even negative.[37]

Policy Discussion and Recommendations

Our results show the desirability of finding alternatives to royalty rate increases as a means of collecting more public revenues from future production. Bonus bids do not affect production decisions, while royalties make wells less profitable to develop. In relying more on auctions, however, governments must consider the effects of price, political and information uncertainty, alternatives to the existing gross royalty system, and accounting for the different timing of provincial revenues that would result.

The Role of Risk and Uncertainty in Bidding

Among the factors that might affect potential bidders is uncertainty over deposit quality, future government policy, and future resource prices.

Creating a Competitive Bidding Environment

The key to extracting the highest possible revenues from oil and gas auctions is to ensure a highly competitive auction market for deposits, which would minimize the risk of collusion among bidders. However, the extent to which some producers have more knowledge about geological reserves in certain areas, particularly areas with little existing development (see Watkins and Kirkby 1981), will reduce both the competition over deposits and the amount producers are willing to pay for licences or leases, in turn reducing the total revenues collected by government.

A lack of information on deposits also makes bidding riskier if firms are uncertain about the quality of what they are buying, further reducing

35 Bonus payments between 2005 and 2007 would have been strongly related to production around 2010, given the lag between lease purchase and well development. The Royalty Review Panel also provided estimates of total revenues had the higher royalty rate applied to 2006, 2010 and 2016 production. We use estimates from the Government of Alberta final report based on production in 2010 as this amount is most closely related to the production and price expectations producers made in bonus purchases during the Royalty Review Panel's study period in 2007.

36 This estimate is based on $470 million from higher natural gas royalties and $460 million from higher conventional oil royalties.

37 We were not able to estimate the reduction in total production due to the royalty increase, however, because of the lack of well-level production data after October 2007.

Table 5: Change in Alberta Conventional Oil and Gas Bonus Bids Due to Royalty Increase, By Nearest Bordering Province

100km from SK border	100km from BC border
-54%	-32%

Note: Both estimates control for geology and local geographic factors
Sources: Authors' calculations from BC Ministry of Energy, Mines and Petroleum Resources; Alberta Energy; Saskatchewan Ministry of Energy and Resources; Statistics Canada.

Table 6: Change in Alberta Conventional Oil and Gas Bonus Bids Due to Royalty Increase, Licences and Leases

Licences 100km from both border	Leases 100km from both border
-59%	-21%

Note: Both estimates control for geology and local geographic factors.
Sources: Authors' calculations from BC Ministry of Energy, Mines and Petroleum Resources; Alberta Energy; Saskatchewan Ministry of Energy and Resources; Statistics Canada.

their willingness to pay. In such cases, information asymmetry is a classic example of a market failure where there is an argument for governments to intervene to put all participants on the same footing — by, for example, facilitating the dissemination of geological information to encourage more firms to enter. In areas where geological information does not exist, governments might subsidize explorers to find new – and publicly available – geological information. Indeed, this is the rationale for the generous tax treatment of exploration and development costs under the corporate income tax system.

Political Uncertainty — Holding Governments to Commitments: Reducing royalty rates would be effective only so long as firms believed that successive governments will keep them low.[38] Any such uncertainty on the part of investors would dampen the amount producers would be willing to pay, since future increases in royalty rates would amount to retroactive taxation on existing tenure holders.

If there was a way to assure producers — say, through contracts enforceable by a third party, such as a court, whose authority would trump that of a provincial government[39] — that royalty rates would stay low or that any increase would be grandfathered, the risk producers face would be reduced, and they likely would be willing to pay a higher auction price for deposits. In turn, if producers were seen to be paying out as much as could reasonably be expected through auctions, the provinces would have little incentive to increase royalties.

Low, stable royalty rates and fully competitive auctions to maximize government revenues thus would become self-fulfilling prophecies. To establish this trust with producers, governments

38 An additional element of government policy uncertainty for firms is the role of environmental regulations, such as prices on greenhouse gas emissions. Certainty about future costs on emissions, such as a carbon tax, would reduce the risk that producers face due to indeterminate emissions policy or uncertain future costs of emitting, such as under a cap-and-trade system without a cap on emissions permit prices.

39 Lack of contract enforcement is a key reason auctions are less heavily relied upon in developing countries.

might consider pilot projects where producers in designated areas are guaranteed low rates on new bonus-bid purchases. A comparison of total revenues in these areas to otherwise similar areas – similar to the methodology we use in this study – could provide a model for royalty rates in the rest of the province.

Price Uncertainty — Should Royalty Rates Increase with Resource Prices and Well Productivity? Our analysis has focused exclusively on *ex ante*, or foreseeable, abnormal profits — profits over and above the cost of production at the expected price of oil or gas at the time of bidding. If, however, prices increase relative to that expectation or if wells turn out to be more productive than expected, firms earn abnormal profits over and above the foreseeable amount at the time of the auction. This has led to the creation of progressive royalty regimes with respect to prices and production, whereby relief is provided when prices are low and royalties are increased when prices are high, to remove any risk asymmetries that would reduce the willingness of firms to invest (see Boadway and Keen 2009).

Cash-flow taxation, which we discuss in more detail below, would remove much of this risk by taxing companies' net revenues, in which price and production risks are already fully factored. However, because cash-flow taxation might not be applicable to all types of wells, we recommend lowering royalty rates for production but maintaining the same progressivity of rates. This would amount to shifting down the royalty curve for all production and limiting the change in risk protection that current royalty regimes provide.

Public versus Private Risk: A government that applies royalty rates that are more progressive as oil and gas prices increase might collect more total abnormal profits when it is less risk averse than firms, as the government then would absorb most of the price risks. If uncertainty about future resource prices is a major deterrent to investment in exploration and development by firms, royalty rates that vary with the price of oil and gas remove some of the risk that the firms face and increase their willingness to bid for licenses and leases. It is unclear, however, whether governments are better able than firms to tolerate the risk that the future value of a mineral deposit will be less than that expected at the time of bidding. This is true for both prices and well production. Multinational enterprises with projects in many jurisdictions are able to offset less productive wells in one area by more productive wells elsewhere, while negative price shocks will affect governments and taxpayers in resource-dependent economies much more adversely than investors with diversified portfolios of assets. At the same time, government revenues are limited by the productivity of wells in a particular jurisdiction, exposing governments to greater risk that wells in their area will be less productive than expected. On the other hand, the exploration and discovery risks associated with a particular tract might be greater for a firm than for government.

In sum, it is by no means certain that a royalty rate that increases with the value of production will increase the amount of total revenues that governments collect (see Boadway and Keen 2009, 31). The relative increase in bonus bids because of reduced royalties ultimately depends on the relative risk profiles of firms and government. If a province were to take steps to reduce the sovereign risk that firms face in bidding for oil and gas projects, the case for flatter and lower taxation resulting in higher bids would grow.

Lower Royalties on New Production, Higher Bonus Bids

Provinces have a long history of charging different royalty rates based on the year a well was drilled or a pool discovered.[40] Although it has the benefit of

40 For example, Saskatchewan has many different classes of royalty rates, with high rates for wells drilled before the mid-1970s, slightly lower rates for wells drilled between then and 2002, and lower rates yet for wells drilled after 2002. Until 2009, Alberta levied different royalty rates based on the year a pool was discovered, not when a will was drilled.

stimulating new production, this distortion in rates of return between new and old wells could result in the otherwise earlier abandonment of existing wells or deposits that became subject to higher rates and the drilling of new wells and new deposits, which would pay a lower royalty rate on production. Such a tax change would result in higher taxes on incumbent production relative to new production and skew the allocation of labour and capital.

Limiting the Unintended Consequences of an Uneven Playing Field: We recommend lower rates on new production, but with one major difference from past tax reforms that decreased royalty rates on new production: new wells that should be subject to the lower royalty rate are those that go into production on leases purchased *after* the announcement of lower royalty rates. This would ensure that firms have fewer incentives to abandon existing wells for which they have already paid a bonus bid for access. Producers thus would not be able to earn higher profits by letting their old lease expire and repurchasing the same lease in a competitive auction.

The only advantage that producers on existing leases would have in repurchasing a new lease at a low royalty rate would be the existing expertise and capital investment to extract that specific lease. To the extent that other producers can relocate their capital and labour to produce from the same lease, firms would have a strong incentive to pay the higher royalty rate to maintain their exclusive lease.

Such a reform, however, would lead to higher fixed costs — a larger upfront bonus bid — for new producers than for existing producers, although new producers would have lower marginal costs, due to lower royalties, than would existing producers. Firms with limited access to capital to finance larger upfront expenses would find their ability to pay in auctions — especially for potentially highly productive deposits — reduced (see Boadway and Flatters 1993).

Corporate Tax Interactions: Provincial oil and gas royalties do not exist in a policy vacuum. Companies that pay royalties and bonus bids must also pay federal and provincial corporate income taxes. Under current federal income tax rules, companies are able to fully deduct royalties as a cost of production from their federal corporate income taxes due.[41] Thus, a dollar increase in royalty payments now reduces corporate taxes owed by 25 cents ($1 times 25 percent, the joint federal-provincial corporate income tax rate in Alberta). Bonus bids, however, are classified as a "Canadian oil and gas property expense," and companies are able to deduct only a maximum of 10 percent of the value of such bids, per year, under the federal corporate tax. Thus, a dollar in bonus bids is worth a maximum of 2.5 cents ($1 times 10 percent times 25 percent) per year in lower corporate taxes, for a total of 25 cents, spread, by discretion, over the life of the deduction.[42]

A decrease in royalties that resulted in an equal increase in bonus bids thus would cause companies to pay higher federal corporate income taxes in terms of net present value. The reason is that firms prefer an immediate tax reduction from royalties over the gradual deductions associated with bonus bids. A reduced provincial royalty rate that resulted in higher bonus bids thus would amount to a transfer of tax base from the provinces to the federal government under the current corporate tax model.[43] If the provinces

41 This deduction became effective as of January 2007. Before that time, companies were given an allowance of 25 percent of their expenses to proxy royalty expenses; the allowance was phased out gradually over a number of years. The provinces once provided similar allowances, but phased them out at slightly different rates, with Alberta taking the longest. We ran an additional regression test, starting when Alberta removed its royalty deduction, to see if the tax policy change resulted in different treatment effects, but we found little change in the results. See the Appendix for details. For details on the provincial policy, see Alberta Energy (2006b).

42 The 2011 federal budget reduced the amount that oil sands developers were able to deduct from 30 percent to 10 percent, to be phased in through 2016.

43 This also could have implications for equalization payments, but this is a policy question we leave for additional research elsewhere.

were to rely more on bonus bids than on royalties to collect revenues, to maintain the current federal tax base, the federal government might want to increase the deduction rate for bonus bids.

Implications for Provincial Finances of Relying on Auctions

A greater reliance on auctions, rather than on production taxes, would change when the province received its revenues from resource projects by increasing the share that is paid up front, instead of during the production phase, as is the case for royalties. Given potentially prodigious new fields, this change could be significant.

Rapidly changing energy prices have caused massive volatility in the government revenues of resource-based jurisdictions. This revenue volatility has naturally led to stop-and-go spending practices as well, particularly for Alberta (Landon and Smith 2010). Additional fiscal concerns among resource-based provinces include the ability of governments to save resource revenues for future generations, which Alberta has a poor record of doing (Shiell and Busby 2008).

The movement toward a greater reliance on auction revenues as opposed to royalties could have some additional benefits. For instance, provinces might improve their ability to predict future resource revenues. Although Alberta and Saskatchewan count auction results as revenues when the auctions close, British Columbia's bonus and lease auctions revenues are spread out equally over a nine-year time horizon. The main advantage of this approach is that revenues are smoothed and more predictable, thus making the British Columbia model ideal for use in other provinces that want to rely more on auctions.

Another rationale for the modified accounting of resource revenues over time is that the revenues earned from extraction activities — via both royalties and auctions — represent asset sales, rather than an ongoing source of revenues. Indeed, Alberta's poor record of saving resource revenues partly stems from its high reliance on royalties. Increasing reliance on bonus bids would be a step toward taking a longer-term view of the province's natural resource values — a perspective that estimates the full value of the resources in the ground and develops a realistic outlook of how much of that value it should spend in a given year.

This would lead to more predictable spending patterns by the province, independent of the value of the resources in any one year. Moreover, receiving more of its total revenues from oil and gas activities up front, might give the province a greater incentive to save: additional, ongoing expenditure increases would be much more difficult to justify if future resource revenue inflows were limited.

The Role of Cash-Flow Taxation

The main tax policy alternative to the two-part auction and gross production royalty is the cash-flow tax. A cash-flow tax allows firms to deduct production costs on an oil and gas development project from their taxable production revenues. This creates a tax base that consists of pure abnormal profit. In theory, a government can apply a high tax rate on the cash-flow tax base without creating disincentives to invest in resource exploration and production. A low cash-flow tax that leaves some abnormal profit on the table likely would be captured by bonus bids, as was the case with the high bonus bids in the oil sands before the Alberta royalty increase.

However, a cash-flow tax is often applied to projects where costs can be attributed clearly to a specific project.[44] This "ring fencing" of project costs that are deductible against royalties prevents firms from applying costs to other projects to avoid taxes on them. Ring fencing is relatively easy to define in the case of offshore oil and gas or oil sands projects, but not conventional oil and gas wells or small-scale shale gas production (Bradley

44 Mintz and Chen (2010) argue that a firm-level cash-flow levy would be appropriate where well-by-well costs are difficult to measure.

and Watkins 1987). Furthermore, a high cash-flow tax rate might reduce incentives to control costs or the diversion of profits to affiliated companies that provide inputs to the project.

The cash-flow tax rate need not increase with oil and gas prices because, as prices rise, so do firms' profits and the total revenues governments collect from those profits. A cash-flow tax would hold constant the percentage of total abnormal profits that governments collect and would not skew investment decisions. As Mintz and Chen (2010) show, a cash-flow tax that increased with resource prices — such as was imposed on the oil sands in 2009 — would have the side-effect of encouraging producers to book their investments as deductible expenses when the royalty rate was high, which would exacerbate the boom-and-bust cycle whereby firms spend more when oil prices are high.

Applying Cash-Flow Taxation to Traditional Wells: Alberta and Saskatchewan collect gross royalties on all conventional oil and gas wells, thus taking no account of the cost of drilling wells, aside from royalty credits based on well depth, for example, as a proxy for costs, and perhaps making many wells uneconomical — a behavioural distortion associated with taxation. With more expensive horizontal wells becoming more common than lower cost shallow wells, the average well (excluding the oil sands) is forecast to cost over $2 million to drill by 2015, up from less than $1 million in 2005 (Tertzakian and Baynton 2011). These higher costs make applying cash-flow taxation to the conventional oil sector increasingly important. Higher up-front costs for wells require that firms have access to cash flow from resource developments more quickly than from less costly wells.

British Columbia recently introduced a cash-flow tax for natural gas wells that would otherwise have been uneconomical under the gross royalty regime. Under the Net Profit Royalty Program, producers are taxed at varying tiers based on the stage of production, with stages determined by when total revenues from a well are equal to eligible expenses.[45] Tax rates start at 2 percent of gross revenues in the initial phases of production, and escalate to the greater of 35 percent of net revenues or 5 percent of gross revenues. Under the program, which was open for applications only for a limited period and is currently closed, firms had to apply to have a well taxed in this way and had to disclose the geographic extent of the well's eligible expenses along with other off-site expenses such as research and development expenses that were applicable to the well.

If the Net Profit Royalty Program could be restarted and expanded to allow firms to apply at any time, and if the number of applications did not become too great for tax authorities to process in a reasonable time, it would offer a useful model for other provinces to follow in implementing cash-flow taxation for conventional oil and gas wells. But applying cash-flow taxation to the tens of thousands of existing wells in Western Canada would be a daunting task.

Following the principle of subjecting new wells located on new leases to lower royalties, however, certain types of wells — particularly new, high-yielding, high-cost wells — would be more amenable to the application of cash-flow taxation. Such a tax regime would have to avoid the potential problem of firms' increasing their costs merely to become eligible for cash-flow taxation, or of making large "step" changes in royalty rates in response to a change in a well's costs. There are, in fact, many ways to design a cash-flow tax, but recommendations on the application of specific designs are outside the scope of this *Commentary*.[46]

45 For details of the Net Profit Royalty Program, see the website of the British Columbia Ministry of Energy, Mines and Responsible for Housing, available at http://www.empr.gov.bc.ca/OG/OILANDGAS/ROYALTIES/NETPROFITROYALTYPROGRAM/Pages/default.aspx.

46 See Boadway and Keen (2009) for details.

Conclusion: The Path Forward for Resource Taxation in Canada

Western Canadian provinces can increase their total resource revenues by increasing their reliance on auctions, rather than on royalties. In response to Alberta's 2007 royalty increase, the average bonus bid fell substantially in value and the number of such bids declined because producers stopped making bids on otherwise marginal reserves. The overall effect of a royalty increase depends on the relative balance between existing wells and production yet to be tapped. Although we are not able to point to a specific "optimal" royalty rate, our analysis does indicate the superiority of lower royalty rates and the substantial effect that gross royalty rates have on distorting investment decisions.

We therefore recommend that provinces reduce royalties on new, conventional oil and gas and shale gas production, whether these industries are mature or emerging in any particular jurisdiction. In emerging fields — such as in Quebec and British Columbia, which have significant potential reserves of natural gas that have yet to be exploited — a high royalty rate would restrict development and have a net negative effect on provincial revenues if there are few existing producers to which a high rate would apply.

A high royalty rate also would discourage new development in mature areas, if it made remaining marginal resources uneconomical. Accordingly, jurisdictions with mature developments, such as the oil and gas fields of Saskatchewan and eastern Alberta, must understand the trade off of higher royalty revenues they can get from existing fields against reduced bonus bids from new developments.

Appendix

A number of small changes were made to royalty rates and tenure in Alberta between October 2007 and March 2010. On November 19, 2008, the province allowed natural gas producers to opt for a longer transition to a higher royalty, with a maximum rate of 30 percent applying for five years, a move that had a fiscal cost to the province of $172 million in 2009 (Sawyer and Stiebert 2010). On March 3, 2009, Alberta introduced — initially temporarily but made permanent in the 2010 review — a maximum royalty rate of 5 percent in the first two years of production on new wells drilled between April 1, 2009, and March 31, 2010. Alberta also offered a temporary credit against royalties due of $200 per metre that each well drills (Alberta Energy 2009b). However, given the low prices that then prevailed for oil and natural gas and the temporary nature of these programs when they were announced, the temporary royalty reduction and $200 per metre credit were unlikely to have had a significant effect on firm bidding (Phasis Consulting 2009).[47]

Regression Model: Difference-in-Difference

In our model, we isolate the effect of the Alberta royalty change on conventional oil gas relative to the counterfactual of no royalty increase in other provinces using a regression analysis. We regress the log of each bid amount *Yipt* on individual plot characteristics $\beta_1 X_{ipt}$ (such as geological zones or company identifiers), common time effects estimated with $\beta_2 AFTER_t$ indicates the dates of the higher Alberta royalties, permanent differences between Alberta and Saskatchewan relative to British Columbia using dummy variables $\beta_3 SK_p$ and $\beta_4 AB_p$ and the coefficient of interest β_5 which estimates the effect of the product of the interaction between being in Alberta during the higher Royalties. An error term u_{ipt} captures factors not directly controlled for with these variables. Thus,

$$Y_{ipt} = \alpha + \beta_1 X_{ipt} + \beta_2 AFTER_t + \beta_3 SK_p + \beta_4 AB_p + \beta_5 (AB_p \times AFTER_t) + u_{ipt}$$

Data

British Columbia and Saskatchewan provide details of bonus bids in a Geographical Information System format that provides the exact geographical dimensions of the bonus bid along with all other information in one file. Alberta provides the geographical coordinates and geological rights of a bonus bid put up for sale, which occurs every two weeks, in a text file; the sales results of those bids are presented in a separate spreadsheet posted on the Alberta Energy website.[48] We merged the bid information to a geographically referenced list of all geographic points in Alberta[49] to create a comparable dataset to the geographically referenced British Columbia and Saskatchewan data. As well, since each province reports the specific geological zone (or multiple zones) for which a tenure right is applicable, we created a dummy variable for whether a bonus bid contains rights to one of 75

47 The only significant change to tenure rights in Alberta at the time of the royalty change was that geological zones below the lowest depth producers were drilling would no longer revert to the Crown.Tenure purchases between October 2007, but before January 1, 2009 were not subject to this change until 2015 or later upon renewal or conversion

48 The text files are in a consistent format from 2003 through the present. We extracted the geological information and the exact geographic coordinates for each sale using a string search algorithm, which we then merged to the dataset of sales results. All data are available online at http://www.energy.gov.ab.ca/Tenure/1314.asp.

49 This merge was successful for all but 15 of 56,980 individual bonus bids in Alberta between 2003 and October 27, 2010. We were able to specify the location of tenure bids to the nearest quarter-section, giving us a precision of no less than 2.6 sq. kms. We used the mean distance between the centre of all quarter-sections in a bonus bid (most bids include more than one quarter-section) and the nearest north-south border segment in the WCSB.

major geological zones that exist in the WCSB along one of Alberta borders,[50] and a separate variable when the tenure rights are for all geological zones below the surface (applicable to approximately half of all observations).[51] All data and stata code used in these regressions are available from the authors upon request.

Detailed Results

We present detailed results of our methodologies under various assumptions of date ranges, distances from borders, and other controls to show the sensitivity of our results. As is common with dollar values, we take the natural logarithm of the dependent variable of the bonus bid of each parcel sold, which requires exponentiation of coefficients reported in the appendix tables to reach that we report in the main text above. All results use nominal dollars. The baseline regression is a basic difference-in-difference regression using all bonus bids in all three provinces with no controls for region or geological zones (column 1 of Appendix Table A- 1). We then progressively refine our regression by limiting our analysis to bids within 100 km of the Alberta border (column 2), limiting our analysis to bonus bids for the entire geological area from surface to basement (column 3), controlling for geological zone (column 4), and limiting our analysis to the period before the introduction of a temporary drilling credit by Alberta in March 2009 (column 5) and British Columbia's carbon tax in February 2008 (column 6). We then test the model from January 2006 through September 2010, in case the results change as a result of the change in royalty treatment under corporate taxes from an allowance to a deduction. All specifications provide similar results, although the last regression falls just shy of statistical significance. Adding controls for oil, natural gas prices, or month dummies does not appreciably change any results.

Appendix Table A-2 shows results when we control for factors that are inherent to sub-regions in Western Canada — within a specific "township" in Alberta and Saskatchewan, and a slightly smaller geographical region in some areas of British Columbia. Townships are roughly squares approximately 9.6 km on each side. Including the fixed effects of townships controls for factors specific to a township that are constant over time and that might affect the value of a bonus bid, such as proximity to towns, road access, oil and gas support facilities or other geographical factors we cannot control directly.[52] We first show the basic results of a township fixed effect at a threshold of 100 km, with observations from the full period (column 1 of Table A-2), then narrow our analysis to 50 km from both borders; we find results similar to those of the previous models.

We also separately tested whether the response to the royalty increase differed by company size. Using the names of companies that identified themselves as bidders in land sales, we find that "major" petroleum companies dramatically changed their bidding behaviour in response to the royalty increase, but companies we could not identify as majors did not.[53]

50 Using Stata's string variable matching function, we searched for whether the zone rights contain any of the key words that identify the 75 major geological zones in the WCSB in the border region of Alberta. This process identified the geological zone of 96 percent of all bonus bids.

51 Bonus bids are usually for one nearly-contiguous area of land, known as a tract. Some bonus bids, however, are for multiple tracts. When this occurs, we combined all rights in the string search for tenure rights and took the average distance of all tracts in the bonus bid to the nearest provincial border. Multiple tracts are usually located near to one another, but often are for different geological zones.

52 There are also specific geological factors that vary directly with geographical location. For example, there is a distinct east-west pattern in depths at which oil and gas is found. The depths at which oil and gas are found also vary, with more variability in geology along the Alberta-British Columbia border than along the Alberta-Saskatchewan border. see, for example, "A Geological Cross Section of Alberta," available online at http://www.abheritage.ca/abnature/geological/crosssection.htm.

53 We identified the following as "major" petroleum companies: Anadarko, Apache, Arc, Baytex, BP, Canadian Natural Resources Limited, Cenovus, Chevron, ConocoPhillips, Devon, Encana, Ensco, Exxonmobil, Hess, Hkn, Husky, Imperial, Koch, Marathon, Nexen, Occidental, Pengrowth, Penn West, Shell, Sovereign, Suncor, Talisman, Vaalco, and Xto. However, we do not know what company placed a bid for a parcel when a bidding agent placed the bid on its behalf. Some companies may not be active in the WCSB.

Table A-1: Difference-in-Difference Results, No Geographic Controls

During royalty change period	0.332***	0.135	0.113	0.0626	0.147	0.230	–0.0327
	(0.090)	(0.102)	(0.122)	(0.102)	(0.127)	(0.242)	(0.115)
In Alberta (relative to British Columbia)	–1.329***	–1.292***	–1.410***	–1.214***	–1.149***	–1.114***	–1.526***
	(0.075)	(0.088)	(0.098)	(0.083)	(0.081)	(0.081)	(0.139)
In Saskatchewan (relative to British Columbia	–1.646***	–1.449***	–1.502***	–1.264***	–1.251***	–1.187***	–1.305***
	(0.081)	(0.093)	(0.113)	(0.093)	(0.099)	(0.101)	(0.129)
Effect of royalty increase	–0.836***	–0.479***	–0.642***	–0.474***	–0.446***	–0.471*	–0.271
	(0.124)	(0.147)	(0.174)	(0.141)	(0.168)	(0.256)	(0.169)
Distance from border threshold	none	100 km	100 km	100 km	100 km	100 km	100 km
Geological zone controls	no	no	only bids for all zones	yes	yes	yes	yes
Date range	Jan. 2003–Sept. 2010	Jan. 2003–Sept. 2010	Jan. 2003–Sept. 2010	Jan. 2003–Sept. 2010	Jan. 2003–Mar. 2009	Jan. 2003–Feb. 2008	Jan. 2006–Sept. 2010
Observations	69,122	25,114	11,470	25,114	21,227	18,211	13,570
R-squared	0.068	0.081	0.103	0.17	0.174	0.168	0.188

Notes: Robust standard errors in parentheses; *** p<0.01, ** p<0.05, * p<0.1.
Sources: Authors' calculations from Alberta Energy; British Columbia Ministry of Energy, Mines and Petroleum Resources; Saskatchewan Ministry of Energy and Resources.

We separated the results by whether bonus bids are closer to the Alberta or Saskatchewan border. At the 100 km threshold from the border, bonus bids fell the most along the Saskatchewan border, although, within 50 km from the border, the results are largely the same. We also split our dataset into bids for licences and leases. We find that bids fell much more for licences than for leases.[54] To test whether the level of geographical detail affects our results, we narrowed our analysis to 50 km from each border, where the royalty increase had a large effect on bids on both the Saskatchewan and British Columbia borders.

Within this 50 km threshold, we then include controls for each individual company using a dummy variable to indicate each unique bidding entity name. This does not change any results appreciably, but does increase the explanatory power of the regression.

We apply additional controls to isolate the potential effect of the emergence of shale gas. By geological accident, the shale gas formation located in the Horn River areas of the WCSB happens to be located predominantly on the British Columbia side of the WCSB.[55] To control for this, we removed the bids in all regions of

54 We also tested whether the daily value of the Toronto Stock Exchange (TSX) affected bonus bids. Although the effect of the TSX value is economically and statistically significant, including this in regressions did not change the results of the effect of the royalty increase.

55 The other major emerging shale gas formation, the Montney shale, is evenly distributed across the Alberta-British Columbia border, and we thus included it in our results.

Table A-2: Difference-in-Difference Results, with Township Fixed Effects

Effect of Royalty Increase	–0.544***	–0.377***	–1.151***	–0.427***	–0.773***	–0.391***	–0.894***	–0.232*
	(0.094)	(0.109)	(0.365)	(0.115)	(0.116)	(0.149)	(0.238)	(0.121)
Distance from border threshold	100 km	50 km	100 km	100 km	100 km from SK border	100 km from BC border	100 km	100 km
Geological zone controls	yes	yes	yes	yes	yes	yes	yes	yes
Date range	Jan. 2003–Sept. 2010	Jan. 2003–Sept. 2010	Jan. 2003–Sept. 2010	Jan. 2003–Sept. 2010	Jan. 2003–Sept. 2010	Jan. 2003–Sept. 2010	Jan. 2003–Sept. 2010	Jan. 2003–Sept. 2010
Geographic controls	yes	yes	yes	yes	yes	yes	yes	yes
Observations	25,114	12,629	2,653 (majors only)	14,005 (non-majors only)	12,200	12,908	16,140 (licences only)	8,953 (leases only)
R-squared	0.036	0.052	0.115	0.046	0.040	0.043	0.039	0.060

Notes: Robust standard errors in parentheses; *** p<0.01, ** p<0.05, * p<0.1.
Sources: Authors' calculations from Alberta Energy; British Columbia Ministry of Energy, Mines and Petroleum Resources; Saskatchewan Ministry of Energy and Resources.

Table A-3: Difference-in-Difference Results, with Township Fixed Effects

Effect of Royalty Increase	-0.389**	-0.370**	-0.345**	-0.372***	-0.380**	-0.402**	-0.079
	(0.154)	(0.143)	(0.145)	(0.135)	(0.149)	(0.179)	(0.214)
Distance from border threshold	50 from BC border	50 from SK border	50 from BC border	50 from SK border	50 from BC border	25 from SK border	25 from BC border
Geological zone controls	Yes	Yes	Yes	Yes	Yes - Horn River bids excluded	Yes	Yes
Date range	Jan 2003-Sept 2010	Jan 2003-Sept 2010	Jan 2003-Sept 2010	Jan 2003-Sept 2010	Jan 2003-Sept 2010	Jan 2003-Sept 2010	Jan 2003-Sept 2010
Geographic Controls	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Company controls	No	No	Yes	Yes	Yes	Yes	Yes
Observations	6,165	6,458	6,164	6,458	5,840	3,158	2,901
R-squared	0.082	0.028	0.326	0.313	0.331	0.359	0.368

Sources: Authors' calculations from BC Ministry of Energy, Mines and Petroleum Resources; Alberta Energy; Saskatchewan Ministry of Energy and Resources.

Table A-4: Poisson Regression Results of Number of Sales in 1 km Bands from the Border of Alberta

Effect of Royalty Increase	–0.480***	–0.441***	–0.312***
	(0.023)	(0.032)	(0.044)
Distance from border threshold	All observations	100 km from both borders	50 km from both borders
Date range	Jan. 2003–Sept. 2010	Jan. 2003–Sept. 2010	Jan. 2003–Sept. 2010
Observations	84,000	38,112	18,912
Geographic controls	no	yes	yes
Pseudo R-squared	0.082	0.106	0.099

Sources: Authors' calculations from Alberta Energy; British Columbia Ministry of Energy, Mines and Petroleum Resources; Saskatchewan Ministry of Energy and Resources.

British Columbia and Alberta that might have been for Horn River shale gas, and find that the effect of the royalty change was substantial regardless of the role of recent activity in Horn River. Further, the Horn River formation is about 100 km away from the border, so we largely eliminate these bids when we isolate our bids to those less than 50 km from the Alberta border.

At 25 km, however, the result on all bonus bids was no longer statistically significant in British Columbia, partly because of a much smaller sample size. The effect was still substantial in Saskatchewan.

Table A4 reports Poisson regression results of the drop in the number of sales in 1 kilometre bands from the border of Alberta from both BC and Saskatchewan, with separate results for all observations.

References

Alberta. 2007a. "Our Fair Share: Report of the Alberta Royalty Review Panel." Edmonton. September.

———. 2007b. "Our Fair Share: Methodology Appendix." Edmonton. September.

———. 2007c. "The New Royalty Framework." Edmonton. October 25.

———. 2010. "Energizing Investment: A Framework to Improve Alberta's Natural Gas and Conventional Oil Competitiveness." Edmonton. March.

Alberta Energy. 2006a. "Alberta Oil Sands Royalty Guidelines: Principles and Procedures." Edmonton. November 30.

———. 2006b. "Energy minister confirms end of Alberta Royalty Tax Credit Program." Press Release. Edmonton. September 21.

———. 2006c. "Oil and Gas Fiscal Regimes: Western Canadian Provinces and Territories." Edmonton: Alberta Energy, Natural Gas Division. December.

———. 2009a. "Alberta Oil and Gas Tenure 2009." Edmonton. Available online at http://www.energy.gov.ab.ca/Tenure/pdfs/tenure_brochure.pdf.

———. 2009b. "Additional Details on the Three-point Stimulus Plan and Drilling Activity in Alberta." Edmonton. March 3. Available online at http://alberta.ca/ACN/200903/25402CDEFE818-F1BC-5D66-DF309066E457F2A4.html.

———. 2011. "Oil and Gas Fiscal Regimes of the Western Canadian Provinces and Territories." Edmonton: Alberta Energy, Resource Development Policy Division, Economics and Project Analysis Unit. July.

Boadway, Robin, and Frank Flatters. 1993. "The Taxation of Natural Resources: Principles and Policy Issues." Washington, DC: World Bank. October.

Boadway, Robin, and Michael Keen. 2009. "Theoretical Perspectives on Resource Tax Design." Working Paper 1206. Kingston, ON: Queen's University, Economics Department. June.

Boychuk, Regan. 2010. "Misplaced Generosity: Extraordinary Profits in Alberta's Oil and Gas Industry." Edmonton: Parkland Institute. November.

Bradley, P.G., and G.C. Watkins. 1987. "Net Value Royalties: Practical Tool or Economist's Illusion?" *Resources Policy* (December): 279–88.

British Columbia. 2010. "Crown Land — A Definition." Available online at http://www.for.gov.bc.ca/resort_development/crown_land/index.htm.

Cramton, Peter. 2009. "How Best to Auction Natural Resources." *Handbook of Oil, Gas And Mineral Taxation*. Ed. Philip Daniel, Brenton Goldsworthy, Michael Keen, and Charles McPherson. Washington, DC: International Monetary Fund.

Dachis, Benjamin, Gilles Duranton, and Matthew Turner. 2008. *Sand in the Gears: Assessing the Effect of Toronto's Land Transfer Tax*. C.D. Howe Institute Commentary 277. Toronto: C.D. Howe Institute.

———. Forthcoming. "The Effects of Land Transfer Taxes on Real Estate Markets: Evidence from a Natural Experiment in Toronto." *Journal of Economic Geography*.

Duranton, Gilles, Laurent Gobillon, and Henry Overman. Forthcoming. "Assessing the effects of local taxation using microgeographic data." *Economic Journal*.

Landon, Stuart, and Constance Smith. 2010. *Energy Prices and Alberta Government Revenue Volatility*. C.D. Howe Institute Commentary 313. Toronto: C.D. Howe Institute.

Lee, David S., and Thomas Lemieux. 2009. "Regression Discontinuity Designs in Economics." NBER Working Paper 14723. Cambridge, MA: National Bureau of Economic Research.

Mintz, Jack. 2010. "The potash royalty mess." National Post. October 14.

Mintz, Jack, and Duanjie Chen. 2010. "Taxing Canada's Cash Cow: Tax and Royalty Burdens on Oil and Gas Investments." SPP Briefing Papers 3 (3).

Phasis Consulting. 2009. "March 2009 Alberta Royalty Incentive." March 4.

Quebec. 2011. "A Fair and Competitive Royalty System for Responsible Shale Gas Production." Quebec City: Ministère des finances.

Saskatchewan. 2006. "Saskatchewan promotes its sweeping business tax reform." Press Release. Regina. May 10.

———. 2010. "Potash Information Circular." Regina. Available online at http://www.er.gov.sk.ca/Potash-Tax-Guide.

Sawyer, Dave, and Seton Stiebert. 2010. "Fossil Fuels — At What Cost? Government Support for Upstream Oil Activities in three Canadian Provinces: Alberta, Saskatchewan, and Newfoundland and Labrador." Winnipeg: International Institute for Sustainable Development.

Shiell, Leslie, and Colin Busby. 2008. *Greater Saving Required: How Alberta Can Achieve Fiscal Sustainability from Its Resource Revenues*. C.D. Howe Institute Commentary 263. Toronto: C.D. Howe Institute.

Tertzakian, Peter, and Kara Baynton. 2011. "Turmoil and Renewal: The Fiscal Pulse of the Canadian Upstream Oil and Gas Industry, a Five-year Review and Outlook." Calgary: ARC Financial Corp. April.

Watkins, G.C. 1975. "Competitive Bidding and Alberta Petroleum Rents." *Journal of Industrial Economics* 23 (4): 301–12.

———. 2001. "Atlantic Petroleum Royalties: Fair Deal or Raw Deal?" AIMS Oil and Gas Papers 2. Halifax, NS: Atlantic Institute for Market Studies. June.

Watkins G.C., and R. Kirkby. 1981. "Bidding for Petroleum Leases: Recent Canadian Experience." *Energy Economics* (July): 182–6.

Winter, Jennifer L. 2010. "An Investigation of Petroleum and Natural Gas Lease Auctions in Alberta." Working paper, University of Calgary.

C.D. Howe Institute Commentary© is a periodic analysis of, and commentary on, current public policy issues. Barry Norris and James Fleming edited the manuscript; Yang Zhao prepared it for publication. As with all Institute publications, the views expressed here are those of the author and do not necessarily reflect the opinions of the Institute's members or Board of Directors. Quotation with appropriate credit is permissible.

To order this publication please contact: the C.D. Howe Institute, 67 Yonge St., Suite 300, Toronto, Ontario M5E 1J8. The full text of this publication is also available on the Institute's website at www.cdhowe.org.

NOTES

September 2011	Allan, David C., and Philippe Bergevin. "Transparency Is Not Enough: Creating Antilock Capital Markets." C.D. Howe Institute E-Brief.
August 2011	Dachis, Benjamin. "Congestive Traffic Failure: The Case for High-Occupancy and Express Toll Lanes in Canadian Cities." C.D. Howe Institute E-Brief.
August 2011	Laurin, Alexandre, and Finn Poschmann. "Western METRics: Marginal Effective Tax Rates in the Western Provinces." C.D. Howe Institute E-Brief.
August 2011	Bergevin, Philippe, Pierre Duguay, and Paul Jenkins. *When Nightmares Become Real: Modelling Linkages between the Financial Sector and the Real Economy in the Aftermath of the Financial Crisis.* C.D. Howe Institute Commentary 332.
August 2011	Schwanen, Daniel. "Beyond the Border and Back to the Future: Seizing the Opportunity to Enhance Canadian and US Economic Growth and Security." C.D. Howe Institute Backgrounder 141.
July 2011	Laidler, David. "Natural Hazards: Some Pitfalls on the Path to a Neutral Interest Rate." C.D. Howe Institute Backgrounder 140.
July 2011	Dachis, Benjamin, and Donald N. Dewees. "Plugging into Savings: A New Incentive-Based Market Can Address Ontario's Power-Surplus Problem." C.D. Howe Institute E-Brief.
July 2011	Parkin, Michael. "Overnight Moves: The Bank of Canada Should Start to Raise Interest Rates Now." C.D. Howe Institute Backgrounder 139.
June 2011	Poschmann, Finn, and Alexandre Laurin. "The Time is Still Right for BC's HST." C.D. Howe Institute E-Brief.
June 2011	Dobson, Wendy. "Does Canada Have an India Strategy? Why it Should and What Both Sides Can Gain from Comprehensive Talks." C.D. Howe Institute Backgrounder 138.
June 2011	Loyns, Al, and Richard Pedde. "Pulling the Plug on Monopoly Power: Reform for the Canadian Wheat Board." C.D. Howe Institute E-Brief.
June 2011	Coulombe, Serge. *Lagging Behind: Productivity and the Good Fortune of Canadian Provinces.* C.D. Howe Institute Commentary 331.
June 2011	Robson, William B.P. "Don't Double Down on the CPP: Expansion Advocates Understate the Plan's Risks." C.D. Howe Institute Backgrounder 137.
May 2011	Dachis, Benjamin, and Jan Carr. "Zapped: The High Cost of Ontario's Renewable Electricity Subsidies." C.D. Howe Institute E-Brief.
May 2011	Chant, John F. "Strengthening Bank Regulation: OSFI's Contingent Capital Plan." C.D. Howe Institute E-Brief.
May 2011	Laurin, Alexandre, et Finn Poschmann. "Que sont devenus les taux effectifs marginaux d'imposition des Québécois?" C.D. Howe Institute E-Brief.
May 2011	Laurin, Alexandre, and Finn Poschmann. "What Has Happened to Quebecers' Marginal Effective Tax Rates?" C.D. Howe Institute E-Brief.
May 2011	Brubaker, Elizabeth. *A Bridge Over Troubled Waters: Alternative Financing and Delivery of Water and Wastewater Services.* C.D. Howe Institute Commentary 330.
May 2011	Koeppl, Thorsten V. *Time for Stability in Derivatives Markets – A New Look at Central Counterparty Clearing for Securities Markets.* C.D. Howe Institute Commentary 329.

Support the Institute

For more information on supporting the C.D. Howe Institute's vital policy work, through charitable giving or membership, please go to www.cdhowe.org or call 416-865-1904. Learn more about the Institute's activities and how to make a donation at the same time. You will receive a tax receipt for your gift.

A Reputation for Independent, Nonpartisan Research

The C.D. Howe Institute's reputation for independent, reasoned and relevant public policy research of the highest quality is its chief asset, and underpins the credibility and effectiveness of its work. Independence and nonpartisanship are core Institute values that inform its approach to research, guide the actions of its professional staff and limit the types of financial contributions that the Institute will accept.

For our full Independence and Nonpartisanship Policy go to www.cdhowe.org.

C.D. Howe Institute
67 Yonge Street
Toronto, Ontario
M5E 1J8

Canadian Publication Mail Sales
Product Agreement #40008848