Errata

Changes and updates have been made to the Independent Assessment Report published on this site on October 8, 2021. The current posted Independent Assessment contains changes and updates as described in the table below.

Page Number	**Change**
5 (Executive Summary)	The amounts of infrastructure royalty credits awarded, released and outstanding have been updated
x, 35	The amounts of infrastructure royalty credits awarded, released and outstanding have been updated
32-33	New Figure 3-23 highlighting the deep well credit allocation as a function of the deep well depth based on the well category (Tier 1 or Tier 2 West/East Sweet/Sour), as well as textual references to the figure
59	Update to example highlighting deep well credit allocation based on depth
All	General formatting and layout changes

A Review and Assessment of the Natural Gas Royalty System in British Columbia

Prepared for the Government of British Columbia

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Executive Summary

The Province of British Columbia is undertaking a review of its oil and gas royalty system. To inform that review, our report examines the current natural gas royalty system and its ability to support the core policy objectives for all resource development and use in the province. These objectives are securing a fair return for BC's natural resources; contributing to a strong economy with employment and training opportunities for British Columbians; supporting BC's reconciliation initiatives and partnerships with First Nations that show respect, meaningful engagement, and recognition of Indigenous rights and title; supporting BC's climate commitments; and protecting and enhancing BC's air, water, land, and ecosystem environmental resources. The BC royalty system is highly complex. It consists of components and programs that were designed and introduced when market conditions and extraction technologies were very different than they are today, and what is forecast for the future. Our report discusses these complexities and the effect they have on royalties collected and administering and auditing the system. We also discuss the incentives and outcomes these complexities may create that run counter to provincial policy goals.

This report provides a detailed description of BC's current royalty system that illustrates the combined effect of the system's many components on royalty payments over time. We cover lessons from Alberta's 2015-2016 Royalty Review and its new system introduced in 2017. We conclude with an assessment of BC's royalty system and offer a set of specific areas of concern with some suggested ways the system could be modernized and better aligned with provincial goals.

The Current Royalty System and its Challenges

As of July 2021, BC has 35,917 wells, and an additional 8,598 well authorizations granted. Of these close to 36,000 wells, 36 percent are active. Active wells are predominantly gas wells (86 percent of active wells). At least 95 percent of the petroleum and natural gas in BC is owned by the province and is on Crown lands, with revenue sharing arrangements to support co-development of resources with Treaty 8 First Nations. The Province grants rights to companies in the form of leases to develop and extract the petroleum and natural gas. The royalty system is a mechanism for sharing between the government and lease-holder the net returns arising from natural resource extraction. The structure of royalty rates is intended to maximize the net returns to the province whilst not unduly affecting the competitiveness of the industry.

The Government of British Columbia relies on oil and gas producers to develop petroleum and natural gas resources on its behalf. The energy companies, the BC government on behalf of its citizens, and some First Nations share the *economic value* created by developing those resources. This value is conceptually measured as the price received for each unit produced of the resource less the cost of producing and selling it (including the cost to transport the resource to market). Measuring economic value is challenging. It requires answers to such questions as: what price to use, which costs to deduct, and how both are measured. These are factors that a royalty system must grapple with even before determining the share going to each party; maximizing value means more than what royalty rate to set. Royalty rates in BC vary from month to month, and depend on many factors including prices, well production, well vintage, the fluid produced, well classification, cost allowances, incentives, and more. The market price of

the resource is affected primarily through competition (number of firms and volume of production in other jurisdictions) and market access. Costs are a function of geology, geography, and technology. The share of value split between the Province and the energy companies depends on what net value is available, an amount that can vary considerably over time and reflects the risks associated with the industry.

The current royalty system has its origins in the 1992 Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation. The current system began relatively simply but over its 30 years, subsequent governments added provisions and made modifications designed for conditions at the time. Many of these provisions no longer reflect the current state of the industry and market. These amendments introduced different base royalty rates depending on well vintage, programs with lower royalty rates for wells with low monthly production volumes (low productivity, marginal, and ultra-marginal programs), deep-well drilling credits, and infrastructure credits to promote access to deposits and investment in less emissions-intensive practices. Each of these component parts are described in the report in Chapter 3. With each adjustment to the system, there was generally no transition for wells developed under previous regimes, leading to a plethora of well definitions and royalty formulas and calculations.

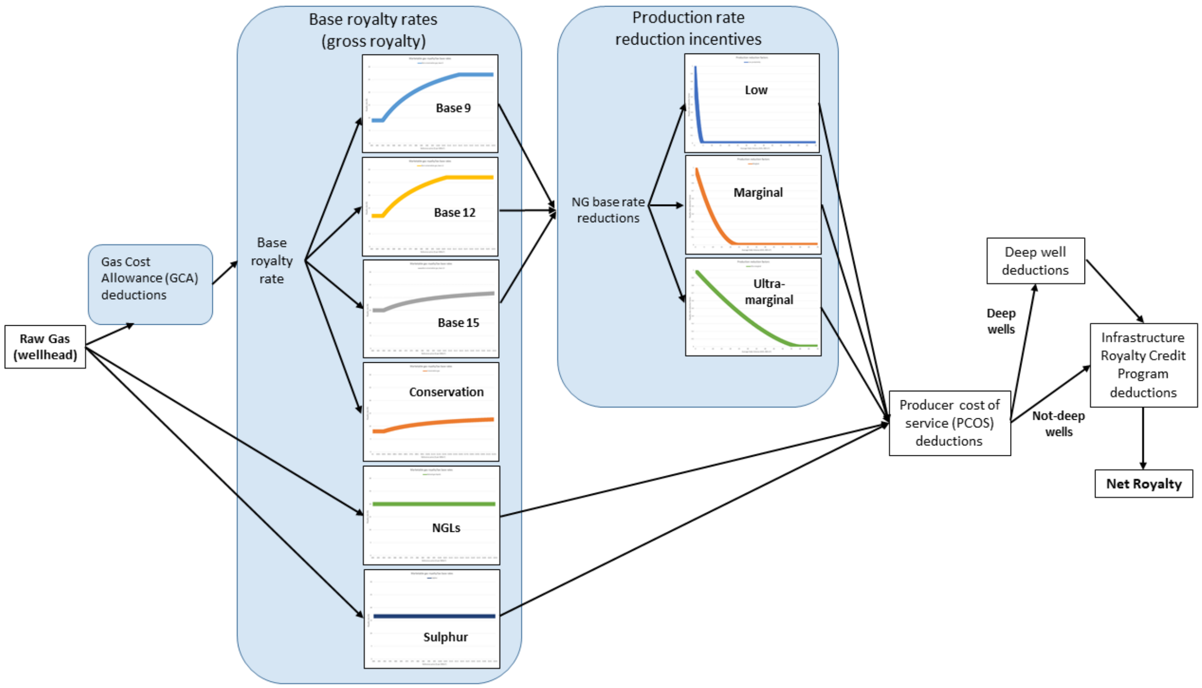
The current royalty system is complex. Administration of the royalty system is currently shared among three agencies: the Ministries of Energy, Mines, and Low Carbon Innovation (EMLI) and Finance (FIN), and the Oil and Gas Commission (OGC). EMLI is the lead in setting royalty policy. FIN operationalizes the policy set by EMLI, and the OGC is the regulator and provides data for royalty billing. The complexity contributes to administrative burden, borne by government and industry, and makes it challenging to audit and for observers to evaluate the system.

The Workings of the BC Royalty System: An Assessment

Royalty payments are calculated and paid each month. Royalty calculations start with the volume of raw product extracted from the well bound for intake at a processing plant. Numerous stages are needed to calculate the royalty payable to the government, with component parts reflecting the primary product determination, royalty rate structure for gross royalty rates, and eligibility for allowances, credits and deductions based on well classification. Combined, these stages determine the effective net royalty rate and amount payable. The figure below provides a simplified schematic of the stages between the wellhead and computation of the net royalty payable for natural gas and related products, BC’s major products. (Oil is covered in the report but not highlighted here.)

BC’s royalty system has a complex process of imputing values because transactions at the plant inlet typically do not have market-based prices. Each product — natural gas (methane), natural gas liquids (ethane, propane, butane, and pentane), gas condensates, and oil have a unique schedule of gross royalty rates. The primary product of a well determines the royalty system it is subject to. There are also different schedules for natural gas depending on when drilling commenced. The component parts of BC’s royalty system: gas processing costs, production rate reduction incentives, producer costs of service, and credit programs are core to understanding the complexity of the system and where issues arise. Each is briefly described along with our assessment of the issues arising from each component.

Natural Gas Royalty System



Gas Processing Costs

Gas processing costs are accounted for with the *gas cost allowance* (GCA). This allowance represents the Crown's share of capital and operating costs of processing the raw gas and thus is a component in determining the value of the resource. The average GCA per gigajoule (GJ) as a share of processing plant inlet prices has risen from 10 percent in fiscal 2003/04 to approximately 75 percent in 2020/21. The GCA was 26 percent of total plant outlet value in 2013 and is 34 percent in 2020. (Plant inlet prices are used to determine royalty payments.) Why have costs for processing natural gas risen considerably? Our concern is that by placing the starting point for the royalty system at the intake of gas processing plants, BC may be getting a smaller share of the net value due to the method for computing these processing costs. The process of determining GCA is a mixture of 'market-based' processing and imputed costs that may also be contributing to making BC a higher cost region as well as adding to complexity. This is because an individual firm's costs directly affect its royalty payment. Increasing costs are partially borne by the province via a lowered royalty payment by the firm, and so an individual firm has a reduced incentive to lower its gas processing costs. Moving to the plant outlet, as in the Alberta system, for the point of determining gross royalties is a potential solution by having more of the costs (and prices) market-based and their determination more transparent and auditable.

Production Rate Reduction Incentives

The current programs — low productivity, marginal, and ultra-marginal well rate reductions — comprise a class of incentives that are designed to encourage production by reducing the royalty rate per unit volume from wells that might otherwise be shut in and encourage development of new wells that might otherwise be uneconomic. Each of these programs was initiated at times when there was concern over the viability of BC's gas supply due to projections of declining output, and they are designed for vertical drilling (i.e., prior to the 'shale revolution'). These incentives are not price sensitive. They are based on wells' monthly volumes (low productivity designation) or initial classification of the well (marginal and ultra-marginal designation); the magnitude of the royalty rate reduction is a function of the volume of production. The incentives can reduce royalty rates substantially depending on the level of daily production. For each incentive category there is a reduction factor that decreases as daily production volumes increase. In other words, the incentive and the reduction in the royalty rate is strongest when little natural gas is extracted. The goal in each case was to maximize volumes, not values. At the time the incentives were introduced, maximizing volume was more strongly connected to generating value than is the case today.

The rate-reduction programs are outdated given shale technology and current market conditions. From multiple viewpoints — encouraging efficient production, meeting climate and environmental goals, and the Crown and First Nations securing a fair share of the net returns to the resource from natural resource development — provincial policy ideally should be neutral with regard to the quality of the well. The exception is if there are reasons to believe that there are market imperfections or failures that are interfering with efficient development within the industry. Efficient production should have a profile where the wells go out of production when the expected returns do not cover costs. Rate reduction programs may be encouraging continued extraction from wells that should have reached their economic end date. Encouraging the production of more gas supply, particularly from less productive wells, when natural gas markets are oversupplied, adds to downward pressure on prices and increases greenhouse gas emissions that might otherwise not have occurred.

Producer Cost of Service (PCOS)

PCOS is an allowance designed to offset the producer's cost of moving raw gas from the wellhead to the inlet of a gas processing plant — costs for gathering lines, compressors, line heaters, dehydrators, field processing units, and well-site operations. These components depreciate over time and have associated maintenance costs in order to maintain delivery of products downstream. Depreciation and technological change mean that PCOS calculations change from year to year as older equipment is replaced with newer (and potentially lower cost) equipment. The calculations also vary by geography and operator. PCOS is typically expressed as a monetary value ($) per processing volume. PCOS is a deduction from royalty payments after application of the rate reduction programs. PCOS is calculated on an annual basis for each reporting facility producing non-conservation natural gas. The PCOS allowance is calculated for each reporting facility, and the deduction from the total gross royalty is determined by multiplying the volume of raw gas produced by the weighted-average royalty rate for that well by the PCOS rate for that facility. The PCOS allowance cannot exceed 95 percent of the total gross royalty for the well.

Each component in the process of moving raw gas to the processing plant is included in PCOS. These components were identified and cost factors specified by a consulting company in 2011. These cost factors are complex, may be outdated, and have not been revised since 2011 despite attempts to secure another consultant to update them. PCOS allowances are relatively steady in aggregate but have a major effect on net royalty payments. This is at a time when studies of extraction in the Montney indicate that average costs of production may be declining. If BC's royalty system was based on the output from processing, a much more simplified system of accounting for these costs would be possible (as is the case in Alberta).

Royalty Credit Programs: Deep Well Royalty and Infrastructure Royalty Credits

These programs provide credits in the form of reducing royalty payments owing. The *Deep Well Royalty Credit programs (DWCP)* were initiated in 2003 and are designed to deliver credits to offset higher drilling and completion costs incurred by wells that are considered particularly deep. A well qualifies for a total allowable credit based on its characteristics (vertical depth and/or horizontal length) and location. From the total credit associated with a well, a portion is applied each month against royalties owing for each deep well event (i.e., after PCOS is applied up to 95 percent of the gross royalty limit). The deep well credit applied reduces the effective royalty rate, up to a minimum of three or six percent depending on the type of deep well. There is a substantial accumulation of credits, primarily due to the complex interactions within the royalty system. As of March 2021, the accumulated deep well credits total $7.325 billion. Of that, $3.56 billion have been drawn down. Once a well ceases production, the credit expires. The total draw-down of the outstanding balance could be lower than $3.755 billion if wells become non-producing prior to utilizing all their credits.

The DWCP is outdated. As with the production rate reductions, the program was introduced prior to the widespread commercialization of shale technology and likely contributes to a 'higher cost' and more inefficient industry than might otherwise occur. It may incentivize companies to drill to access the credit rather than to minimize costs and maximize revenue. Moreover, the credit allocations are not necessarily aligned with current cost structures.

The *Infrastructure Royalty Credit Programs* were established in 2004 to encourage companies to invest in infrastructure that allows development of oil and gas wells. Examples are costs of building roads or pipelines to explore and access new and under-developed areas of the province. Starting in 2016, the program was expanded to cover investment in infrastructure that reduces companies' greenhouse gas emissions. In response to request for applications, producers submit their proposals to EMLI specifying the intended investments. The proposals are evaluated on what percent of total economic activity the project represents, how quickly royalty credits issued would be applied against royalty payments from incremental production enabled by the infrastructure, and would the project have gone ahead without the credit. The program can cover up to a maximum of 50 percent of the specified capital costs; it is typically oversubscribed so not all applicants are successful. Credit holders have three years to complete their infrastructure project but no timeline is specified for drilling wells. Once monthly production begins, earned infrastructure credits apply automatically to any royalties owing and can result in a zero balance for that month. Overall, from 2004 to 2020 a total of $1.733 billion has been awarded, $0.679 billion released, leaving a balance of $1.054 billion. A total of $409.3 million over all three programs has been cancelled or represents stranded assets, leaving $644.8 million in net outstanding credits.

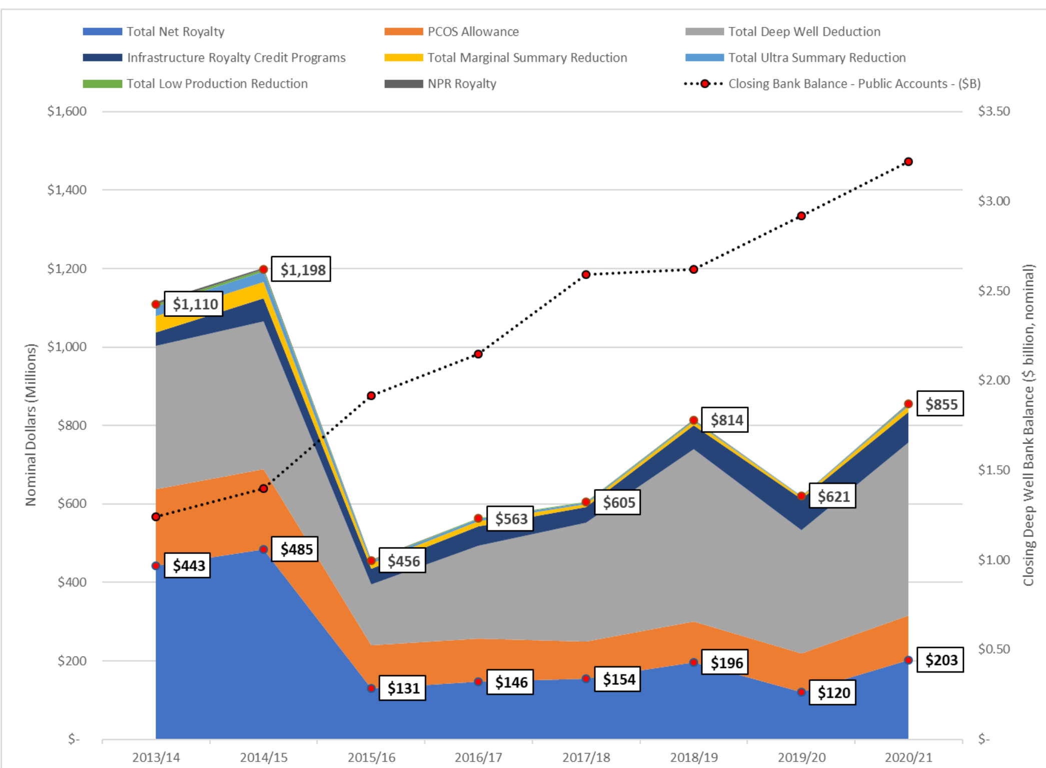
Are these infrastructure credit programs needed to generate additional investment and GHG reductions that would otherwise not occur? Due to the complexity of the royalty system and existence of other programs in the province incenting reductions in GHG emissions, infrastructure credit holders may receive multiple deductions for the same costs. In other words, there may be inadvertent double dipping due to overlapping components in multiple programs. There are also other programs in the province to support reductions in GHG emissions under CleanBC.

The deep well royalty and infrastructure credit programs can encourage extensive development beyond what would occur in their absence. They are not compatible with environmental goals to the extent that they contribute to more GHG emissions, land disturbance, and do not take into account cumulative effects from road and pipeline development. Without the infrastructure credits, production might be less dispersed. If there were no deep well credits or infrastructure credits, it is likely fewer wells would be drilled. A rationale for royalty credits is to lower effective royalty rates at the beginning of a well's productive life to help offset the costs of establishing the asset. Generally, effective royalty rates (and royalties collected) rise as the well produces over time. This has not happened in BC due to market conditions and the use of these credits to drive net royalty payments to close to zero. As more wells are drilled under the various credit programs — and production from wells that never received any credits declines with age — the contribution of wells with credits to total production rises and hence the province's royalty revenues will decline. There is a fundamental question of how much the Crown should offset the costs of fossil fuel development given its multiple objectives. It is appropriate to account for costs in determining the net economic value from developing the resource, but the credit programs may be contributing to or possibly overcompensating for costs with the combined effect of all the programs (credits, rate reductions, PCOS, GCA). There is no apparent market failure that currently justifies the continuation of these credits.

Natural Gas Royalties Collected

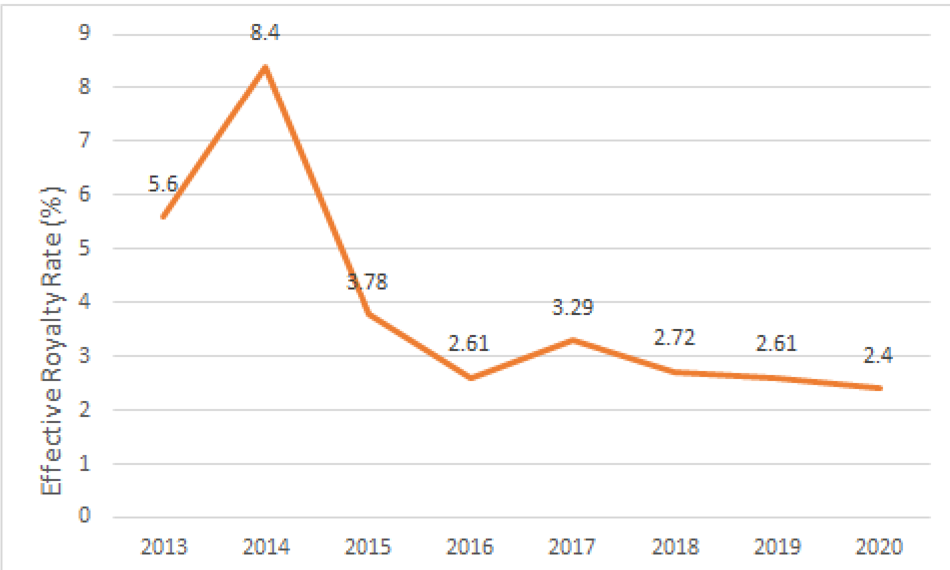
Natural gas royalties paid have declined over time. The figure below provides natural gas royalties by fiscal year and depicts the impacts of the components of the system in reducing gross royalty revenues to net. Net royalty revenues range from 40 percent of gross in fiscal 2013/14 and 2014/15 to a low of 19 percent in 2019/20. Royalty revenues would be significantly higher in the absence of the various credit programs and deductions, all other factors being equal.

Value of Gross Royalties, Net Royalty and Royalty Credits by Fiscal Year



An effective royalty rate provides another measure of the share of natural gas revenues accruing to the Province. To be comparable to other jurisdictions such as Alberta, we illustrate an effective royalty rate measured as the value of net royalties per year divided by the value of natural gas at the plant outlet — the price point for determining royalty payments in Alberta's royalty system — rather than plant inlet, BC's starting point. This calculation values the gas at its market price and is inclusive of actual cost allowances that go into determining net royalty payments, making it more representative of the net economic returns from the resource. The effective royalty rate falls over the past eight years more than three-fold from a high of 8.4 percent in 2013 to 2.4 percent in 2020. Looking at the effective royalty rate provides a strong indication that the Crown's declining share of net revenues from natural gas extraction over time is due not only to the market price of natural gas but also to complex components of BC's royalty system.

Effective Royalty Rate: value of net royalties per year divided by the value of natural gas at the plant outlet (percent), 2013 - 2020



The Way Forward

The BC royalty system for natural gas and oil is broken. It does not support and contribute to government and societal goals. It consists of piecemeal modifications to a system that was designed for a different era with different risks, technology, and market conditions. The system is excessively complex, has large compliance costs for industry and large administrative and auditing costs for government. It creates incentives that do not promote efficiency in the sector. It has contributed to a significant decline in the Crown's share of the net economic value from petroleum and natural gas resources over the past 15 years and a transfer of value from the province to industry. While the appropriate share of value for the Province is not within our scope, we identified areas of concern with each of the program areas that indicate the system also fails to maximize *shared* value. It is our view that nothing short of a comprehensive overhaul of the royalty system will 'fix' it. The royalty review should be comprehensive and broad ranging, aiming to put in place a modern system that is simpler, accountable, transparent, less costly to operate, promotes efficiency, and supports government and societal goals.

The following points summarize our specific areas of concern.

1. All of the royalty deduction programs are out of date. They were introduced at a time with more favourable product prices, and do not take into account changing extraction technology and shift to natural gas liquids in the product mix and investment profile.

2. The exploration and extraction risk profile of the sector has declined substantially since the early 2000s and the combined effect of the programs has resulted in an over-compensation for risks that are no longer as apparent and relevant.
3. The system is characterized by piecemeal changes over time with programs that have led to compounding effects that substantially reduced royalty payments as a share of net value of the resource.
4. The system is set up to incentivize lower-value wells. A firm has a fixed amount of capital to spend in a year and the system may be inducing investment and operating decisions that target these lower-valued wells. This is by incentivizing behaviour where these decisions are based more on accessing royalty payment reductions than would be warranted under efficient operation. This may be one factor contributing to BC being deemed a 'high cost' region and lower overall resource value in the province.
5. Wells benefitting from deep well credits or deep well credits and marginal programs now form a large share of natural gas production. Adding in the other programs and credits which reduce gross royalty rates and royalty payments (e.g., low productivity production or an infrastructure royalty credit), further reduces the Crown's share of net resource value.
6. Given existing market conditions, virtually no wells face a price-sensitive gross royalty rates. Unless there is a change in the way in which product prices are incorporated into the calculations of royalties, this situation will persist for as long as the supply-demand balance for oil and gas sustains current prices.
7. The current system relies on primary product and natural gas production volumes to determine wells' eligibility for different royalty rate reductions and credit programs. This increases complexity and creates incentives for firms to chase specific products and credits rather than the most valuable outcome.
8. The system accounts for costs in ways that are administratively burdensome, reduces the Crown's share of the total net value of the resource by reducing the effective royalty rate, can promote inefficiencies, and thus may also contribute to lower total net economic value. To appropriately define value and shared value requires an accurate picture of the net economic value of the resource: something more akin to the way profits under corporate taxation are calculated, or as a proxy for this, Alberta's revenue minus cost model.
9. The cost calculations (PCOS and GCA) are well-specific, meaning that a company's decisions about costs directly affects their royalty payment. This reduces companies' incentives to lower their costs and preserve value. Moving to a system where companies are granted an industry average cost allocation would eliminate this problem.
10. Determining gross royalties at the intake of raw product to processing plants with extraction costs determined by the PCOS methodology adds to complexity, administrative costs, and use of non-market values. It is an outdated and complex system that cannot be readily audited and updated. Moving the gross royalty calculation to processing plant outflows, as in the Alberta system, and adopting Alberta's methodology for computing costs would serve to alleviate these issues.
11. The current cost calculations (PCOS and GCA) are meant to account for the Crown's share of costs. However, unlike a royalty payment on the value of the products, the cost calculations are

not scaled by the royalty rate. If the PCOS allowance and GCA are already fractions of firms' costs, this is not an issue. Still, it is worthwhile to assess relative cost-sharing.

12. Alberta undertook a major reform of its oil and gas royalty system, phasing in its new system in 2017. Given the Montney's shale deposits straddle the BC-Alberta border, moving to a system such as Alberta's would better align production, reduce any incentive to shift production from one province to the other to minimize royalty payments, and overall promote a more efficient and equitable system.
13. A simpler system would substantially reduce administrative burden for the government and compliance burden for industry, as well as reduce reporting errors that require many hours to revise royalty calculations. The total costs of administering BC's oil and gas royalty system include all the costs incurred by the three agencies (EMLI, FIN, OGC) to collect and analyse the data, compute monthly royalties, correct for errors, and send out the invoices. Industry faces all the costs of compliance for the system in collecting and providing the data to government. Administration of the current system with all its complexity means accounting for multiple past and current structures applying to wells of different vintages and classifications. Any "tinkering" with the system without a comprehensive overhaul would add to the administrative burden requiring more grandfathering of the multiple structures in the system.
14. Goals such as transparency; ease in understanding the system; and ability to update cost, price, and other elements are not met in the current system. The complexity of the system makes it extremely difficult to explain it to anyone not deeply immersed in the system and can lead to misinterpretations of the data and impacts the system has. The BC Royalty Handbook is 192 pages of dense technical complexity. Alberta's guidelines are presented in 57 pages. The multiple entities responsible for the system make it challenging to communicate with industry and the public.
15. Removing or 'fixing' problematic aspects of the system (e.g., removing one type of credit) may result in unintended consequences. In our view, a system wide and comprehensive reform of the entire system is warranted.

Transition from an old to a new system is always challenging and requires careful analysis of ways to minimize any potential adverse impacts. The royalty system is one part of a well's lifecycle, and changes to the system will affect lifecycles of future wells and current wells, depending on the transition mechanisms relative to the status quo. By engaging with affected and interested parties, building on the knowledge and expertise within BC's three governmental entities, and learning from other jurisdictions' approaches, the royalty review can examine ways to address these challenges and move forward.

Chapter 1 - Introduction

The Province of British Columbia is undertaking a review of its oil and gas royalty system. To inform and support public discourse for the review, our report examines the current natural gas royalty system and its ability to support the core policy objectives for petroleum and natural gas development and use in the province. These policy objectives are: securing a fair return for BC's natural resources; contributing to a strong economy with employment and training opportunities for British Columbians; supporting BC's reconciliation initiatives and partnerships with First Nations that show respect, meaningful engagement, and recognition of Indigenous rights and title; supporting BC's climate commitments; and protecting and enhancing BC's air, water, land, and ecosystem environmental resources. The BC royalty system is highly complex and consists of components and programs that were designed and introduced when market conditions and extraction technologies were very different than they are today, and what is forecast for the future. Our report discusses these complexities and the impact they have on royalties collected, and administering and auditing the system, as well as incentives they may create that run counter to provincial policy goals. Our focus is the royalty system as it applies to BC's major producing sector: natural gas (methane) and its associated products — natural gas liquids (ethane, propane, butane, and pentane), gas condensates, and oil.

Our specific mandate is to provide independent advice to the Government of British Columbia on the current design and operation of the royalty system. Questions we are tasked to answer include:

- Are the royalty programs performing as they were originally intended?
- Are the royalty programs effective in maximizing net royalty revenue?
- Are the incentive and allowances in the royalty regime applicable in the context of modern technology and resource availability?
- Are the royalty programs supporting achievement of emissions reduction or environmental goals?
- Does the current royalty system provide sufficient public transparency and administrative and audit ease?

We assess the performance of the royalty programs over time and in the context of the current market setting and extraction profiles. This entails evaluating:

- Royalty payments and rates (gross[1], net[2] and effective[3]), incentives, deductions, credits, and allowances in the context of modern technology, resource availability, current industry cost structures, competitiveness and a comparison with other relevant jurisdictions

[1] The gross royalty rate is the percentage share per dollar of marketable value that the Province receives before any deductions or adjustments. The gross royalty payment is the gross royalty rate multiplied by the marketable value. The price used to determine marketable value is the one set by the royalty system.
[2] The net royalty rate is the percentage share per dollar of marketable value, after rate deductions and royalty credits. The net royalty payment is the net royalty rate multiplied by the marketable value. The price used to determine marketable value is the one set by the royalty system.
[3] The effective royalty rate is the net royalty payment for all products divided by the marketable value for all products. The price used to determine marketable value is the market price, rather than the price set by the royalty system.

- Programs within the system: marginal, ultra-marginal, and low productivity royalty rate programs; the Deep Well Royalty Credit Program, and the Clean Growth Infrastructure Royalty Credit Program
- How costs of extraction and processing are addressed in the system
- Net royalty income
- Administrative and audit ease and public transparency
- Alignment with BC's GHG emission targets and environmental policies

We cover the nature of the challenges with the current system and how the system's various components affect royalty revenue and effective royalty rates. We provide a high-level projection of what might happen if the current system prevails and discuss areas where we advise reform is needed to better align with government objectives. An important point at the outset is that the system as it currently exists consists of connected interdependencies, so changing one component without addressing others may lead to unintended consequences.

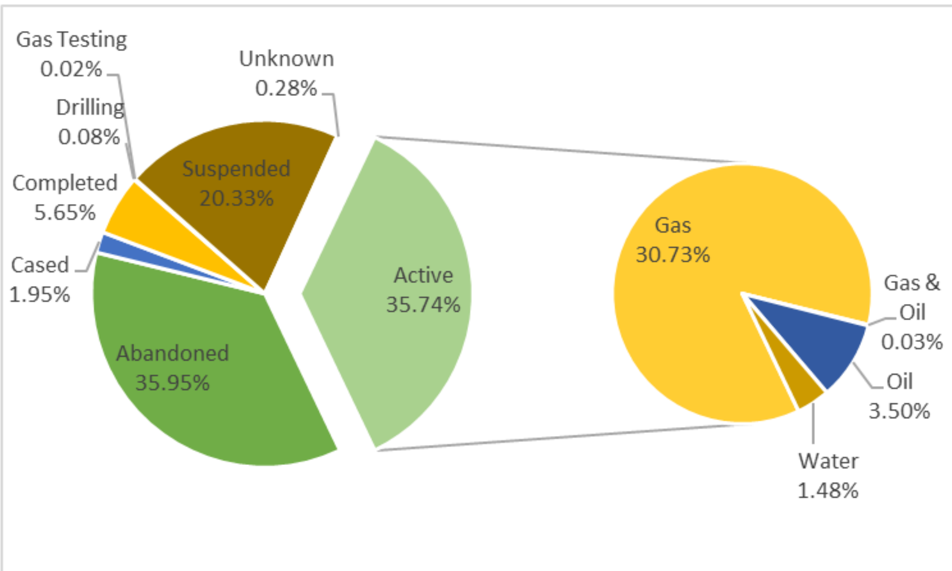
Our report proceeds as follows. Chapter 2 provides a background on the current state of upstream oil and gas production in the province. Chapter 3 is a detailed description of BC's current royalty system that illustrates the combined effect of the system's many components on royalties paid over time. Chapter 4 covers lessons from Alberta's 2015-16 Royalty Review and its new system introduced in 2017. Chapter 5 assesses and evaluates BC's royalty system. Chapter 6 concludes with a list of specific areas of concern and ways the system could be modernized and better aligned with provincial goals.

Chapter 2 - Natural Gas and Oil Wells in British Columbia

Evaluation of BC's royalty system requires understanding the context of natural resource development in BC. The royalty system is one part of a well's lifecycle, and changes to the system will affect lifecycles of future wells (and potentially current wells, depending on the transition mechanisms) relative to the status quo. This is particularly relevant for BC's core policy objective relating to climate and protecting and enhancing environmental resources.

As of July 2021, BC has 35,917 wells[4], and an additional 8,598 well authorizations granted, clearing the way for drilling.[5] Of these close to 36,000 wells, 36 percent are active (Figure 2-1). Active wells are predominantly gas wells (86 percent of active wells).

Figure 2-1: Distribution of Wells by Current Operational Mode

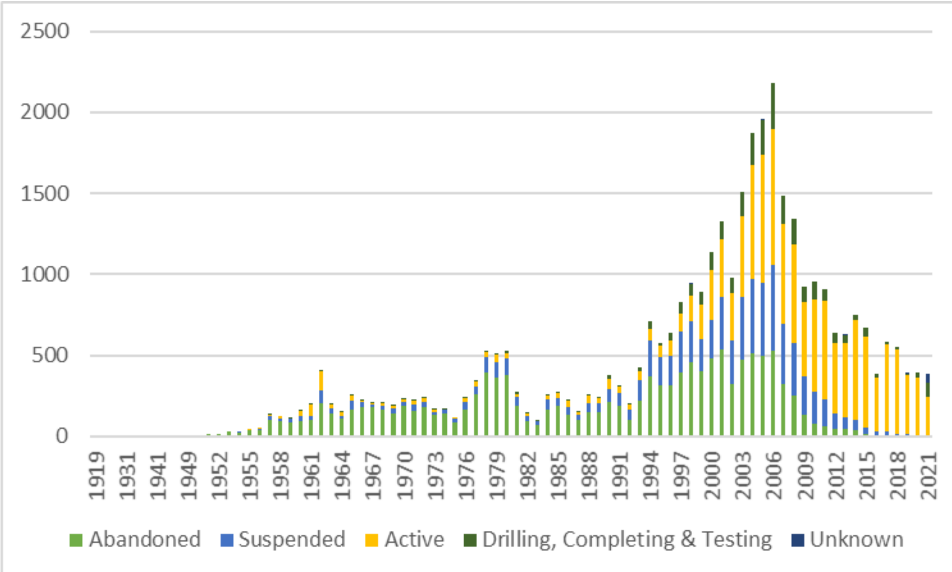


Source: BC Oil and Gas Commission data.
Note: The right pie shows the types of active wells as a share of total wells, not as a share of active wells.

Figure 2-2 shows the number of active wells by vintage (defined as in-production date) and operational mode. The majority of active wells are modern, brought into production in the last 20 years. We return to other well operational modes in our discussion of environmental impacts.

[4] For simplicity, we use the term "wells" to encapsulate well events (wells with multiple producing events). In this sense we are over-counting the true number of surface wellbores. However, as different well events can produce different products and have different royalty treatments, for our purpose well event is the appropriate unit of analysis.
[5] Another 5,799 well authorizations were cancelled, and never drilled.

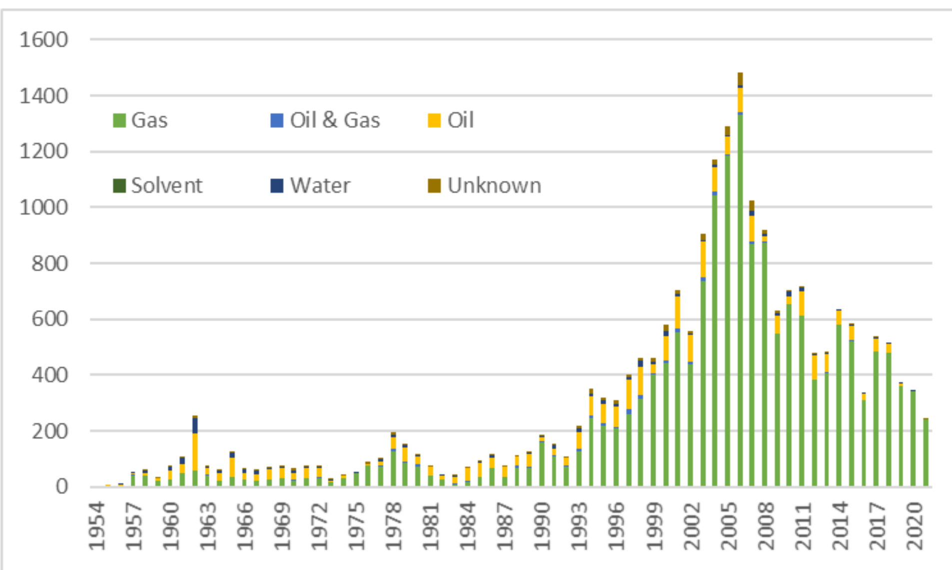
Figure 2-2: Number of Wells by Vintage and Operational Mode



Source: BC Oil and Gas Commission data.
Note: Well vintage determined by in-production date, and if there is no in-production date, then rig-release (drilling ends) date.

Figure 2-3 shows the number of active wells by vintage (defined by in-production date) and their primary producing fluid. The vast majority of wells are defined as gas wells, with a small share of oil wells and wells with mixed oil and gas.

Figure 2-3: Number of Wells by Vintage and Primary Production Fluid for Wells Brought into Production



Source: BC Oil and Gas Commission Well Index
Note: Well vintage determined by in-production date. This figure presents all wells with an in-production date, though the wells did not necessarily produce.

Chapter 3 - Current Royalty System in British Columbia

At least 95 percent of petroleum and natural gas resources in BC are owned by the province and underlie Crown lands, with revenue sharing arrangements to support co-development of resources with Treaty 8 First Nations.[6] The Province grants rights to companies in the form of leases to develop and extract the petroleum and natural gas. These companies are also required to comply with other regulations and legislation that pertain to the development of their leases, including environmental laws, worker health and safety, taxation, and royalties. The royalty system is a mechanism for sharing the net returns arising from extraction of the natural resource between the government and lease holder. The structure of royalty rates is intended to maximize net returns to the province whilst not unduly affecting the competitiveness of the industry.

The Government of British Columbia relies on oil and gas producers to develop petroleum and natural gas resources on its behalf. The energy companies, the BC government on behalf of its citizens, and some First Nations share the *economic value* created by developing those resources. This value is conceptually measured as the price received for each unit produced of the resource less the cost of producing and selling it (including the cost to transport the resource to market). Measuring the economic value is challenging: what price to use, which costs to deduct, and how both are measured are all factors that a government must grapple with in designing a royalty system even before determining the share going to each party.

Between 2006 and 2020, economic benefits agreements with individual Treaty 8 First Nations in BC's northeast[7] yielded approximately $22 million in aggregate royalty revenue paid to the Nations. The amount of revenue shared has varied over time due to the same market factors that affect total royalties collected by the Province. The appropriateness of current revenue-sharing regimes between the Government of British Columbia and First Nations or other Indigenous communities is beyond the scope of our review. Indigenous Peoples have traditional territorial rights distinct from those of other Canadians. The extent of these rights over minerals is evolving with recent legal decisions affording greater control of resource development to First Nations and in particular, the need for the province to account for cumulative effects from development.[8] New agreements are being negotiated under a government-to-government reconciliation framework. In addition, negotiations for Treaty Land Entitlement agreements are underway with Treaty 8 First Nations denied all the lands promised to them when the treaty was signed over a hundred years ago. Once completed, the Province will relinquish subsurface rights to oil and gas tenure as well as rights to royalty revenues on the transferred territory.[9]

Maximizing value means more than what royalty rate to set. Royalty rates in BC vary from month to month, and depend on many factors including price, well production, well vintage, the fluid produced, well classification, cost allowances, incentives, and more. The resource price is affected primarily through

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[6] Natural gas or oil extracted from privately held lands pay a freehold production tax, which is covered in the same legislation for royalties on Crown land. The freehold production tax may be commonly referred to as a 'royalty'. Our focus is on the royalty system for production from Crown land.

[7] These are Blueberry River, Doig River, Fort Nelson, Halfway River, McLeod Lake, Saulteau, West Moberly, and Prophet River First Nations. Some nations, e.g., Blueberry River First Nation, have terminated their agreement on a principled basis related to their ongoing litigation over cumulative effects and the impact on their treaty rights.

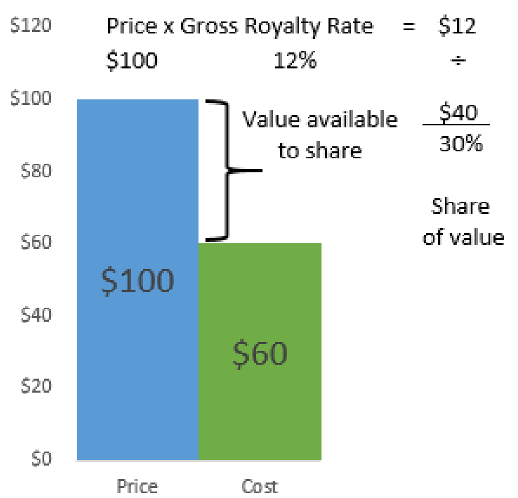
[8] See Yahey v. British Columbia, 2021 BCSC 1287, No. S151727 (Supreme Court of British Columbia June 29, 2021).

[9] There will likely be other transfers of Crown land to First Nations that is in fee simple form. Whether to include subsurface rights with these lands is a topic under active discussion.

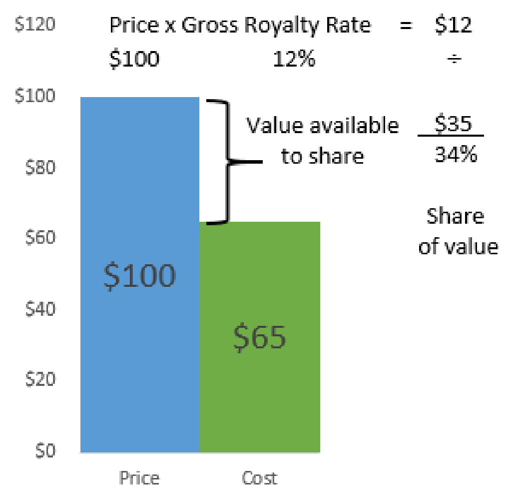
competition (number of firms and volume of production in other jurisdictions) and market access. Costs are a function of geology, geography, and technology. The share of value split between the Government and the energy companies depends on what value is available. Figure 3-1 provides a conceptual illustration of how the available value is affected by the resource price and costs with a given and fixed royalty rate.

Figure 3-1: Illustrative Example of how Share of Value Depends on Value Available

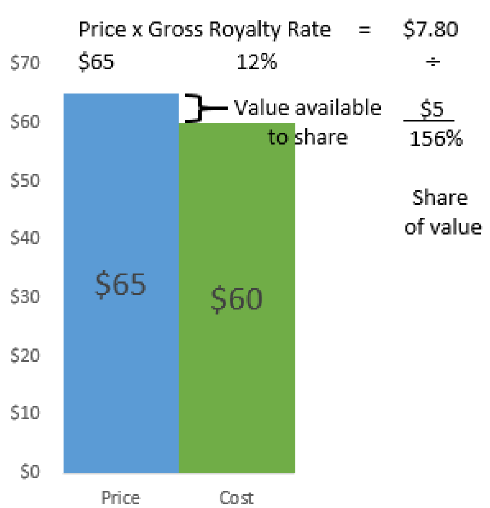
Panel A



Panel B



Panel C



If the price of natural gas is $100 per thousand m^3 and costs are $60 per thousand m^3, the value to be shared is $40 (Panel A in Figure 3-1). At a fixed gross[10] royalty rate of 12 percent, the government's share is $12, or 30 percent of the available value. If costs are instead $65, then the government's share of value

[10] The gross royalty rate is the percentage share per unit of production that the Province receives before any deductions or adjustments. A fixed royalty rate is one that does not vary with price or production volumes.

rises to 34 percent (Panel B in Figure 3-1). In a situation where prices are low at $65 and costs are $60 (Panel C) then the value available to share is small, and the government's share of that value increases to 156 percent — the royalty take is greater than the economic value and the firm operates at a loss. The lesson from these simple examples is that maintaining a consistent share of value requires royalty rates that adjust with price and costs.

3.1 Sources of Revenue

The Government of British Columbia receives revenue from petroleum and natural gas development from three main sources: payments by firms to acquire mineral right tenure (called bonus bids), annual lease[11] and licence rental payments, and royalties on production. These three sources of revenue are interrelated and are a form of risk-sharing between the province and firms.

The bonus bids are an up-front payment by companies for access to the resource. In determining the amount to bid, companies take into account competition from other bidders, expected product prices, likelihood of sufficient production volumes warranting well development, capital and operating costs, and royalty payments. All else equal, an increase in royalty rates (and hence the province's share of value) would decrease a bid. Because bonus bids are a payment before production occurs, all the risk at this stage in the potential development of a well is borne by the bidder. Similarly, the annual rental payments are a per-hectare cost that (absent default) is guaranteed to the government. Again, risk lies wholly with the lease holder.

As mentioned above, royalty payments are meant to capture the government's share of value from a producing well. Here, though, there is risk-sharing between firms and government. The government only receives royalty payments if a firm incurs the cost of drilling a well and discovers petroleum or natural gas in sufficient quantities for commercial production. As the firm's revenue depends on both volume and the price of each fluid produced from a given well, as does the province's royalty take, both share in the risks of exploration, development, and production. The risk of exploration and development for oil and gas has changed over time, and in general is much less risky today. The majority of BC's production is from regions with known and substantial reserves, reducing the risk of dry holes.[12] For production in known areas, the risk is only that a well will be less productive than expected, though in general productivity is improving over time.[13]

BC's current system provides revenue to the province via the bonus bids and rental payments, and the Province risk-shares with the producing firm the value of subsequent production through the royalty system. Any changes to the royalty system faced by producers would be reflected in changes to bids made for tenure. However, most of the high-value Crown lands have already been offered in land sales; under

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[11] A lease grants a firm the right to explore for and produce natural gas and petroleum products. A licence only grants a firm the right to explore. If a firm discovers petroleum and natural gas by drilling a well with tenure covered by a licence, the firm must convert the licence to a lease.

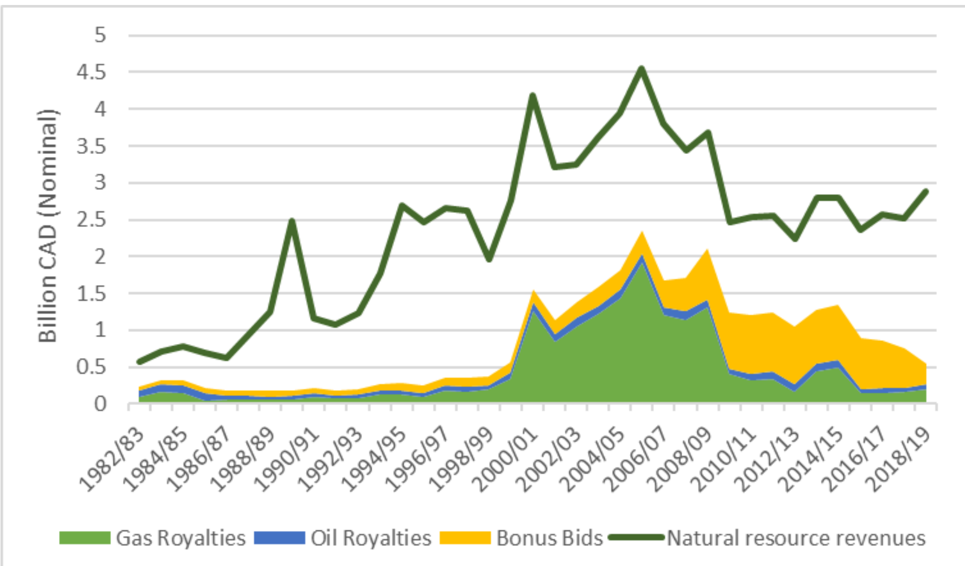
[12] BC Oil & Gas Commission, "British Columbia's Oil and Gas Reserves and Production Report 2019," November 19, 2020, https://www.bcogc.ca/files/reports/Technical-Reports/2019-Oil-and-Gas-Reserves-and-Production-Report-FINAL.pdf.

[13] Canada Energy Regulator, "Market Snapshot: Montney Gas Wells Increasingly Productive Due to Technological Improvements," January 25, 2017, https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2017/market-snapshot-montney-gas-wells-increasingly-productive-due-technological-improvements.html.

the assumption that all these lands will be developed, land tenure sales are likely to be a minor source of revenue going forward.

Figure 3-2 shows revenues by fiscal year from petroleum and natural gas production activities, along with total natural resource revenues.[14] Between 1982/83 and 2018/19, natural gas royalties ranged from three to 42 percent of natural resource revenues and averaged 15 percent; oil ranged from two to 16 percent and averaged five percent. (Natural resource revenues averaged 9 percent of total fiscal year revenue over the past five decades, though this has slipped to five percent in the five most recent budgets.) Royalty revenues became significant sources of revenue starting in fiscal 2000/01, driven mainly by high natural gas prices and a significant increase in unconventional gas production. Royalty revenues from natural gas peaked in 2005/06 at $1.92 billion, and those from oil peaked in 2000/01 at $136.5 million. Rental payments (not shown in the figure) average about $50 million per year. Lower prices starting in 2010 has decreased royalty revenues.

Figure 3-2: Natural Resource Revenues (Nominal Dollars) by Source and Fiscal Year, 1982/83 to 2019/20



Source: Finances of the Nation (natural resource revenues and royalty amounts) and Ministry of Energy, Mines and Low Carbon Innovation (bonus bids).

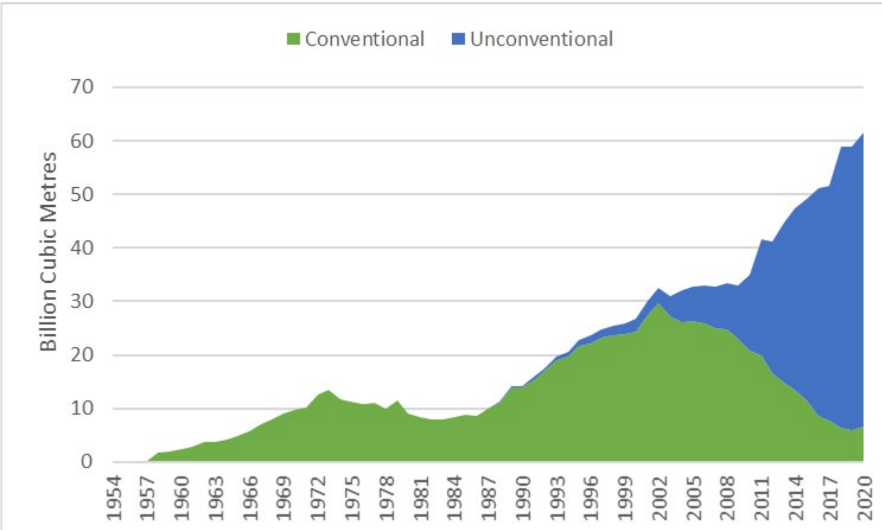
Note: Natural resource revenues include royalty revenues from oil and gas, forestry and mining; Crown land tenures; and water rentals. In the case of BC, this also includes Columbia River Treaty revenues.

3.2 Changing Market Conditions

BC has a long history of petroleum and natural gas production, though the overwhelming majority of production is natural gas (Figure 3-3; Figure 3-4). Natural gas production is an order of magnitude higher than oil and condensate production. While production from unconventional formations occurred as early as 1977 (Figure 3-6), the transition from conventional to unconventional wells as primary sources of production took place in the early 2000s, along with most North American production.

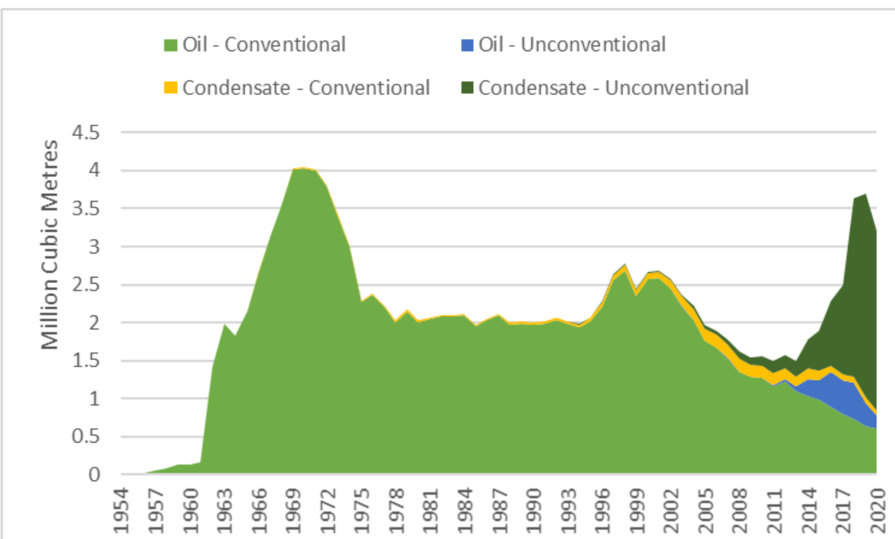
[14] Natural resource revenues include royalty revenues from oil and gas, forestry and mining; Crown land tenures; and water rentals. In the case of BC, this also includes Columbia River Treaty revenues.

Figure 3-3: Annual Raw Natural Gas Production, 1954 to 2020



Source: BC Oil and Gas Commission data.

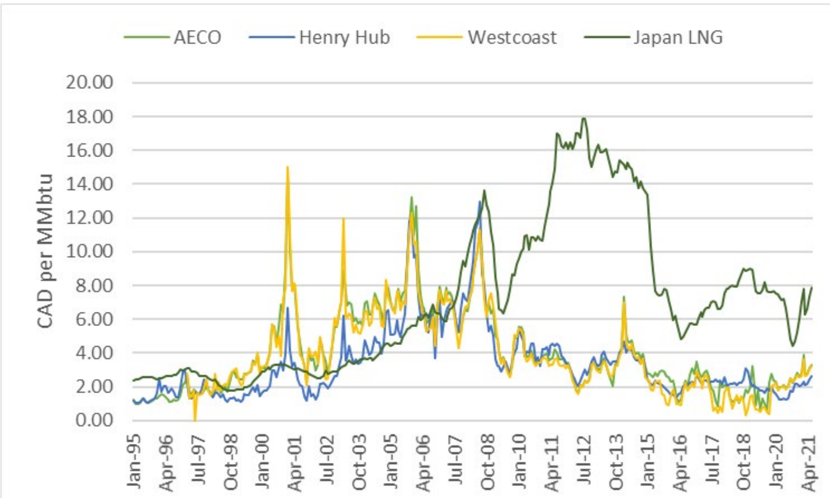
Figure 3-4: Annual Crude Oil and Condensate Production, 1954 to 2020



Source: BC Oil and Gas Commission data.

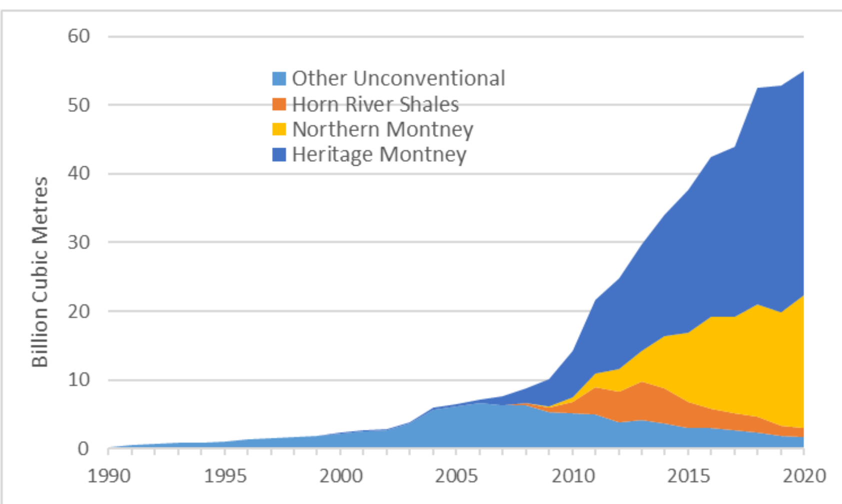
Rising prices in the early 2000s (Figure 3-5), concern that North America would run out of natural gas, and increasingly common use of hydraulic fracturing changed production profiles across the continent, including BC. The rapid shift in natural gas production in BC took place in three phases (Figure 3-6). First, development of the Horn River region; second, development of the Northern Montney; and third, development of the Heritage Montney. Drilling activity was much higher in the Montney than other unconventional plays. The Horn River has 313 wells, the Cordova has 44, the Liard has nine, and other unconventional totals 3,307. This compares to 2,076 in the Northern Montney and 3,283 in the Heritage Montney. The decline of conventional and rise of unconventional oil production happened concurrently with the changes in gas production (Figure 3-3 and Figure 3-4). Most importantly for the royalty system, development of the Montney resulted in significant condensate and natural gas liquids production. In 2014, the BC Oil and Gas Commission (OGC) updated its policy for determining the primary product of a well, changing primary product and production classifications for some wells. What would previously be defined as unconventional oil production changed to condensate production from gas wells. This was followed by an update in 2019, which provided different guidance for primary product classification of Montney wells. Since June 2009, however, North American natural gas prices have decoupled from Japan's LNG spot price and have stayed persistently low. This reflects supply/demand fundamentals: both Canada and the US have vast reserves of natural gas, and for BC in particular, limited markets.

Figure 3-5: Select Nominal Monthly Natural Gas Prices, 1995 to 2021



Source: Sproule 2021-06 escalated price forecast and World Bank Pink Sheet.
Note: AECO is the Alberta market hub price, and Henry Hub is the US market hub price. Prices not adjusted for transportation costs.

Figure 3-6: Annual Unconventional Natural Gas Production, 1990 to 2020

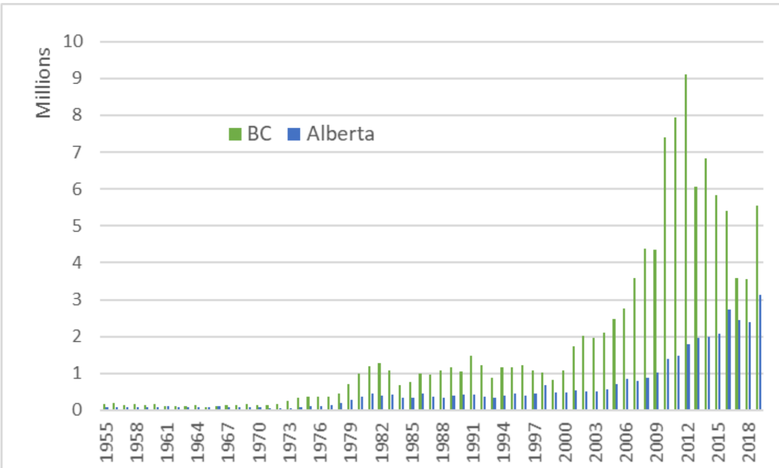


Source: BC Oil and Gas Commission Production data.
Note: "Other Unconventional" includes production from the Cordova Ebayment, Liard Basin, Deep Basin Cadomin, Jean Marie and Doig Phosphate formations.

3.3 Changing Cost Structures

Costs of exploration, development and operations are important to consider in a royalty system. As discussed previously, the economic value (revenue less costs) of a producing well for purposes of determining the royalty payment is shared between the owner of the resource and the producing company. All else equal, higher costs mean less value to share.

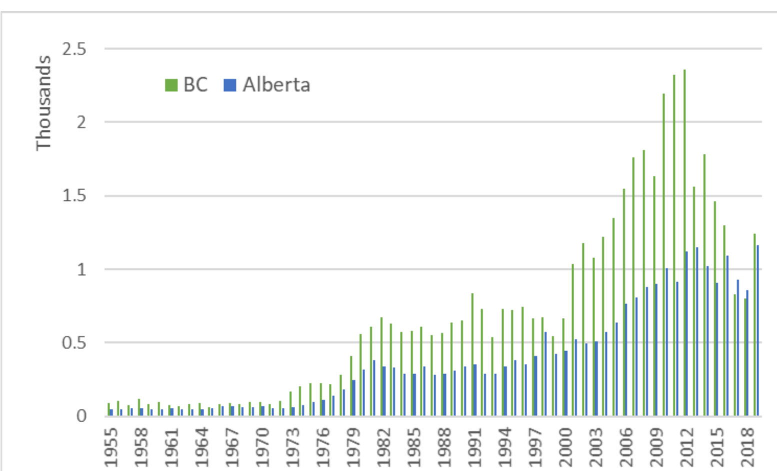
Figure 3-7: BC and Alberta Drilling Capital Cost per Well, 1955 to 2019 (Nominal CAD)



Source: Canadian Association of Petroleum Producers Statistical Handbook.
Note: Alberta excludes oil sands.

The rise of horizontal drilling and hydraulic fracturing changed the cost structure of the oil and gas industry. Figure 3-7 and Figure 3-8 present drilling capital costs per well and per metre drilled, respectively, for Alberta (excluding oil sands) and BC. In both jurisdictions, nominal costs have steadily increased over time, though BC is clearly a higher-cost jurisdiction. Importantly, however, drilling costs per metre have aligned in recent years. BC's higher cost per well reflects the larger depth and length of wells relative to Alberta.

Figure 3-8: BC and Alberta Drilling Capital Cost per Metre Drilled, 1955 to 2019 (Nominal CAD)

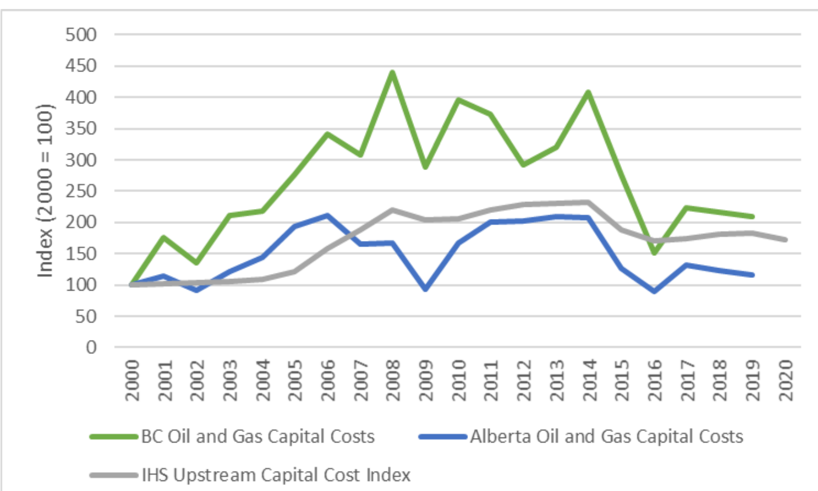


Source: Canadian Association of Petroleum Producers Statistical Handbook.
Note: Alberta excludes oil sands.

Figure 3-9 presents capital costs indexed to the year 2000 (capital costs in 2000 equal 100), to show the percentage change in costs over time. Capital costs include geological and geophysical expenses, drilling costs, land costs, field equipment, enhanced recovery expenditures, and gas plant costs. We compare Alberta (excluding oil sands), BC and a global capital cost index[15] from consultancy IHS Markit. While BC's upstream capital costs have increased substantially relative to 2000, and relative to Alberta's and global capital costs, in the last few years these costs have come down to the same level as the early 2000s, suggesting market pressures have helped to reduce costs.

Figure 3-10 presents operating costs indexed to 2000 for BC, Alberta (excluding oil sands) and a global index produced by consultancy IHS Markit. Operating costs include wells and flow lines, and gas plants, and exclude royalties. The indices reflect total annual operating costs rather than costs per unit of production. BC's costs increased slightly more than Alberta's and global costs, with increasing divergence starting in 2013 and a substantial increase in 2017 and 2018. The cost increases in BC are driven primarily by a doubling of operating expenditure between 2017 and 2019, while Alberta's stayed relatively stable. This is not actually cause for alarm, however, as operating costs per cubic metre of production are relatively similar between BC and Alberta (Figure 3-11). Costs per cubic metre declined relative to Alberta between 2010 and 2017, converging in 2018.[16] The operating cost increase observed in BC between 2018 and 2019 may be due to the Enbridge natural gas pipeline explosion, which reduced takeaway capacity between October 2018 and December 2019.[17] Further data, as yet unavailable, is needed to determine if the increase in operating costs in BC is a temporary aberration.

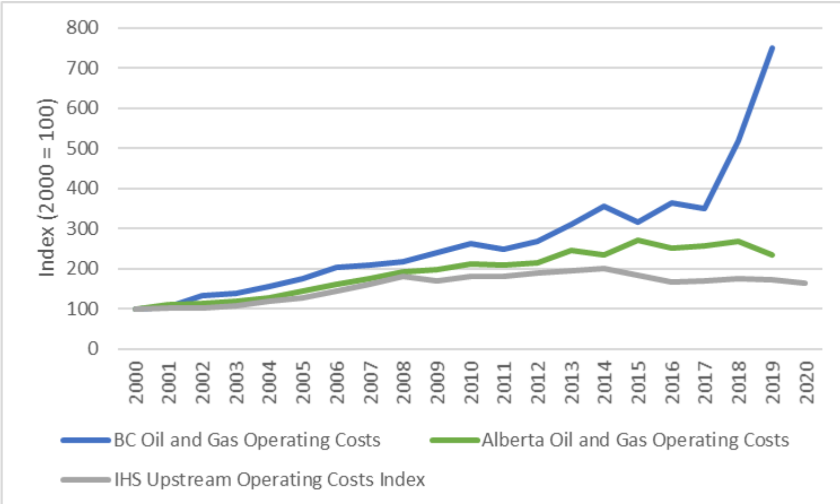
Figure 3-9: BC, Alberta and Global Indexed Total Capital Costs, 2000 to 2020 (2000=100)



Source: Canadian Association of Petroleum Producers Statistical Handbook and IHS Markit.
Note: Alberta excludes oil sands. Capital cost data for BC and Alberta are only available to 2019.

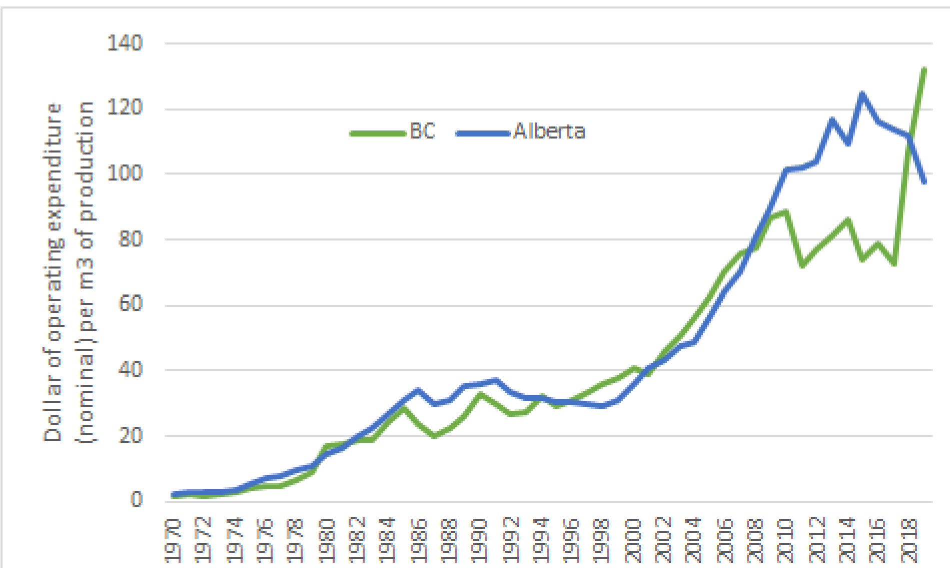
[15] The IHS Upstream Capital Costs Index is a global index based on 28 upstream projects (onshore, offshore, pipelines, LNG). It measures total capital costs, as opposed to costs per unit of added capacity. IHS Markit, "Energy Cost and Technology Indexes," accessed September 24, 2021, https://ihsmarkit.com/info/cera/ihsindexes/index.html.
[16] Alberta's spike in operating costs in the 2010s is likely due to spillover effects from intensive oil sands development.
[17] Enbridge, "Enbridge Responds to Natural Gas Transmission Pipeline Incident North of Prince George," October 9, 2018, https://www.enbridge.com/media-center/media-statements/prince-george-pipeline-incident.

Figure 3-10: BC, Alberta and Global Indexed Total Operating Costs, 2000 to 2020 (2000=100)



Source: Canadian Association of Petroleum Producers Statistical Handbook and IHS Markit.
Note: Alberta excludes oil sands. Operating costs include wells and flow lines, and gas plants, and exclude royalties. Operating cost data for BC and Alberta are only available to 2019.

Figure 3-11: Nominal operating costs per cubic metre of production, 1970 to 2019

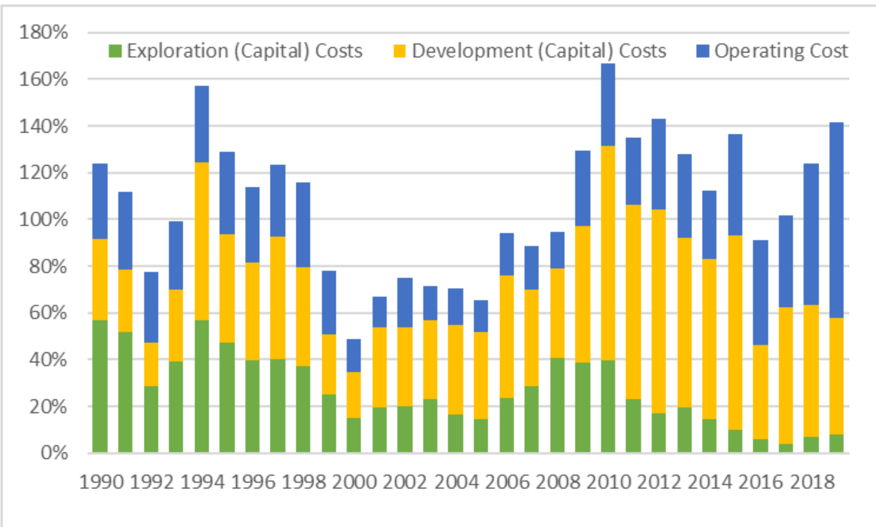


Source: Canadian Association of Petroleum Producers Statistical Handbook
Note: Alberta excludes oil sands. Operating costs include wells and flow lines, and gas plants, and exclude royalties. Production includes oil, marketable natural gas, condensates, and natural gas liquids. Marketable natural gas volumes converted to oil-equivalent volumes using the Alberta royalty system's volume conversation rate of 1.7811.

Our final point of discussion for costs is to provide data on total costs as a share of upstream revenue, defined as the value of producers' sales (Figure 3-12). For simplicity we present all cash costs in the year spent, though capital costs are amortized over many years in firms' financial statements. Exploration costs have declined in importance, with development costs accounting for the predominant form of capital costs. This reflects the lessening risk as plays become known and developed. An important point from

Figure 3-12 is that total costs (excluding royalties) are frequently greater than upstream revenues. We return to this point in our evaluation of the royalty system, but this figure emphasizes that costs are significant. Note that this does not necessarily imply the industry is losing money; capital costs are investments in future production. Between 1990 and 2019, operating costs averaged 30 percent of revenue, similar to Alberta.[18] That said, periods of significant capital investment have pushed costs above 100 percent of the value of the produced resource. Features of a royalty system that incentivize more efficient and lower cost approaches may therefore have merit.

Figure 3-12: Nominal BC Capital and Operating Costs as a share of Total Upstream Revenue, 1990 to 2019



Source: Canadian Association of Petroleum Producers Statistical Handbook.
Note: Upstream revenue is value of producers' sales of crude oil, natural gas, condensate and natural gas liquids.

3.4 The Current System

The current royalty system has its origins in the 1992 Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation, which distinguished freehold[19] and Crown royalty rates and included cost allowances for the Crown's share of costs to bring natural gas to market. Subsequent amendments introduced different base royalty rates depending on well vintage, as well as programs with lower royalty rates for low productivity, marginal, and ultra-marginal wells, deep well drilling credits, and infrastructure credits, including those to promote less emissions-intensive practices. With each adjustment to the system, there was generally no transition for wells developed under previous regimes, leading to a plethora of well definitions and royalty formulas and calculations. The current system thus began relatively simply but over its 30 years, subsequent governments added provisions designed for conditions at the time, many of which no longer reflect the current state of the industry and market.

The current royalty system is, in a word, complex. The complexity contributes to administrative burden borne by government and industry and makes it challenging to audit and for observers to evaluate the system. The royalty system has been modified numerous times over the last several decades. However,

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[18] Alberta Royalty Review Advisory Panel, "Alberta at a Crossroads: Royalty Review Advisory Panel Report" (Government of Alberta, January 29, 2016), 33, https://open.alberta.ca/publications/9781460126882.

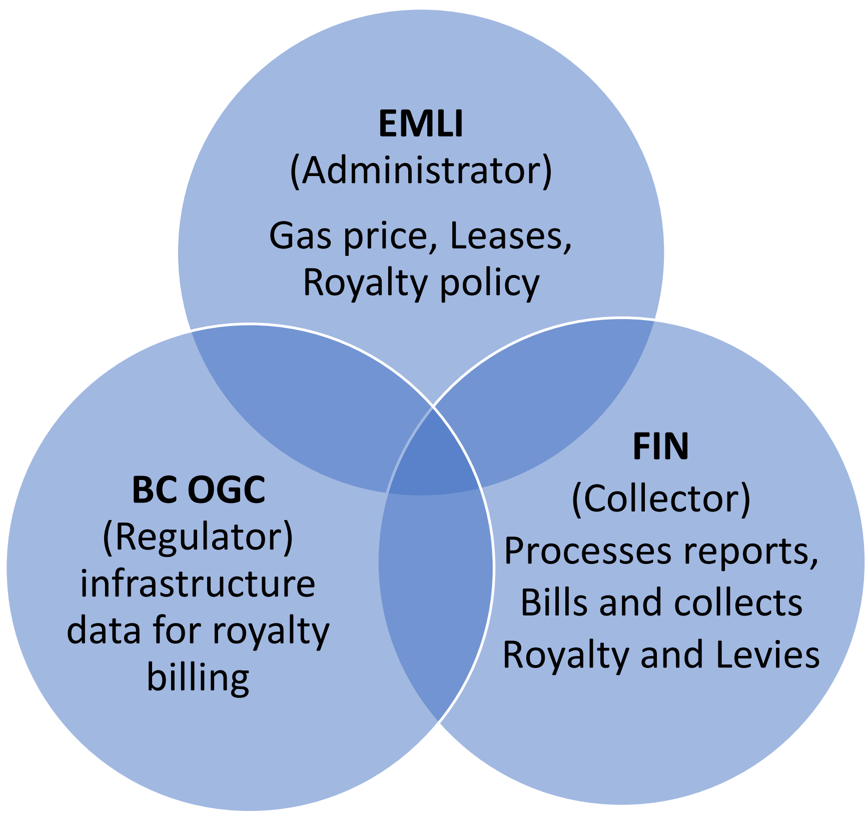
[19] Freehold land is where the Crown has divested the ownership of petroleum and natural gas rights to a person.

the system today does not reflect current extraction technology, changing natural gas markets, and industry conditions. The royalty system has many moving parts that apply to BC's gas and oil wells that depend on factors such as the type of well, where it is located, when it started producing, what it is producing, eligibility for allowances, deductions and credits, and more. To understand the challenges, we begin with an overview of the current royalty system and the characteristics of its wells.

3.4.1 Administrative Responsibility

Administration of the royalty system is shared among three agencies: the Ministries of Energy, Mines, and Low Carbon Innovation (EMLI) and Finance (FIN), and the Oil and Gas Commission (OGC). EMLI is the lead in setting royalty policy. FIN operationalizes the policy set by EMLI, and OGC is the regulator and provides infrastructure data for royalty billing. A simplified view of responsibilities in Figure 3-13 depicts their overlapping roles.

Figure 3-13: British Columbia Royalty Administration



3.4.2 Determining Royalty Payments

Starting with the raw product extracted from the well, there are numerous stages to calculate the royalty payable to the government, with component parts reflecting the primary product determination, royalty rate structure for gross royalty rates, and eligibility for allowances, credits, and deductions based on well classification. Together, these components determine the effective net royalty rate and amount payable. The government provides producers with their royalty payment owing each month.

3.4.2.1 *Primary Product Determination*

The primary product produced by a well determines both regulatory requirements (well spacing, metering requirements, etc.) and royalty rates and credits. There are two classifications — oil well and gas well — determined by OGC. The OGC uses a set of criteria to define a well's primary product as oil or gas, which then determines the royalty structure it falls under and producers' eligibility for royalty credits. The criteria are[20]:

- Gas-to-oil ratio (if greater than 1781 m^3/m^3 then a well is defined as gas)
- Liquid API[21] gravity (if greater than 50 a well is defined as gas)
- Hydrocarbon liquid production rate (if greater than 10 m^3/day then a well is defined as oil)
- Relative molecular mass of hydrocarbons with six or more carbon molecules (if greater than 150 then a well is defined as oil)
- Stage of pool development

These criteria (beginning in 2019) differ for new Montney wells[22]:

- API gravity of hydrocarbon liquid (if greater than 44 a well is defined as gas)
- Gas-to-oil ratio (if greater than 1781 m^3/m^3 for five of the first six producing months then a well is defined as gas)
- Hydrocarbon liquid production rate (if less than 10 m^3/day in the sixth production month then a well is defined as oil)

For Montney wells, all three criteria for a gas well must be satisfied for a well to be defined as a gas well.

Crucially, primary product designation affects royalty rates and eligibility for royalty credits. We discuss each royalty system below.

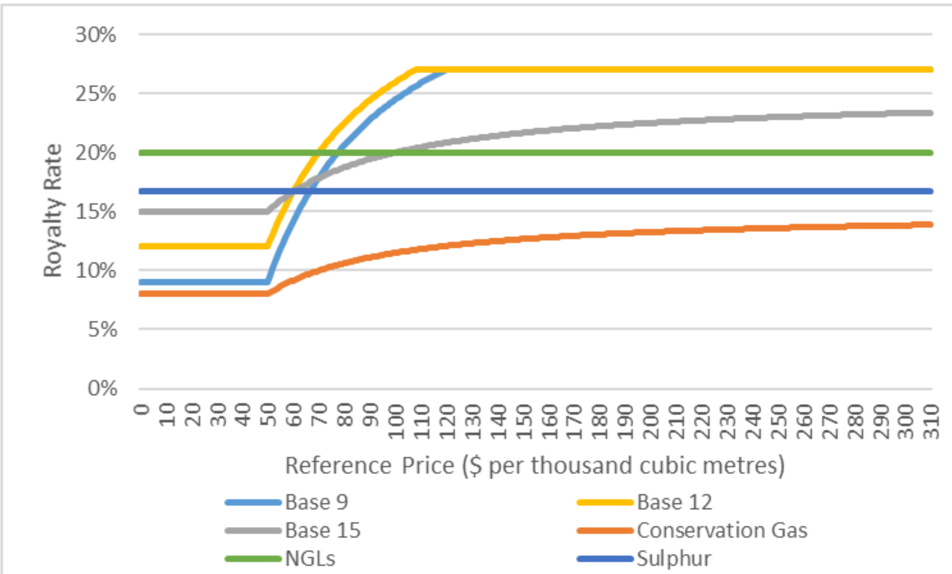
3.4.2.2 *Calculation of Gross Royalties*

The determination of the gross royalty — royalty rate before deductions — is perhaps the simplest calculation of the royalty system, but even here there are complexities. For each well, the gross royalty payable is based on each hydrocarbon produced. We start with the simplest rates then move to those that are more complex. Natural gas liquids are the simplest, with a flat royalty rate of 20 percent, regardless of price or volume of production. Sulphur, as a by-product from some formations, also has a flat royalty rate of 16.667 percent.[23]

[20] BC Oil & Gas Commission, "Policy for Determining Primary Product of Oil or Gas," August 6, 2014, https://www.bcogc.ca/files/operations-documentation/Reservoir-Management/Production-Allowables/policy-determination-primary-product-gas-or-oil-august-release-2014.pdf.
[21] American Petroleum Institute, or API, gravity is a commonly used measure of crude oil density, converted to a degree index. For more information, see: McKinsey & Company, "API Gravity," accessed September 12, 2021, http://www.mckinseyenergyinsights.com/resources/refinery-reference-desk/api-gravity/.
[22] BC Oil & Gas Commission, "Primary Product Determination for Montney Formation Wells," January 9, 2019.
[23] Between October 2012 and May 2021, sulphur royalties averaged 0.4 percent of gross natural gas and byproduct royalties, and, as a by-product, are not considered material in royalty reform.

For natural gas production from natural gas wells on Crown lands[24], there are three royalty formulas: Base 15, Base 12, Base 9. There is also a formula for natural gas recovered from oil wells: Conservation Gas (Figure 3-14). Base 9 and Base 12 are the most common royalty structures for gas wells. Royalties are computed monthly for each producing well. The Ministry of Finance invoices producers after they report their marketable gas available for sale at the point of intake at a processing plant along with by-product sales volumes and the values of each. This starting point for royalty calculation differs from other royalty systems, e.g., Alberta, where royalty calculation is based on values after initial processing (see Chapter 4 for lessons from the Alberta system).

Figure 3-14: Gas, Natural Gas Liquid and Sulphur Gross Royalty Rates



Source: Oil and Gas Royalty Handbook.

In each case, there is a base royalty rate that is a constant until an administratively set minimum price is reached. What happens to the rates above this minimum depends on the base classification. The royalty rate also relies on a reference price, which is the greater of the Province's Posted Minimum Price or the Producer Price.[25] The Posted Minimum Price is 80 percent of the average sales price for marketable gas produced in a given area; the area is defined by five processing plants. The Producer Price is the average price a producer receives at the gas-processing-plant inlet and is specific to each producer-plant combination. We elaborate on these prices and their interaction with royalties below.

[24] Natural gas and oil are also produced from freehold lands. Under the *Petroleum and Natural Gas Act*, the Crown collects royalties from wells on Crown lands and a production tax from wells on freehold land (see *The Royalty Handbook*). Taxation of wells on freehold land is out of our scope. Thus, hereafter we do not refer to Crown land when discussing the royalty system.

[25] Government of British Columbia, "Gas Reference Prices" (Province of British Columbia), accessed September 12, 2021, https://www2.gov.bc.ca/gov/content/taxes/natural-resource-taxes/oil-natural-gas/oil-gas-royalty/reference-price.

Base 15 wells are those producing non-conservation[26] gas where drilling began before June 1, 1998 or where royalty payments are part of a revenue-sharing agreement. The base royalty rate for these wells is 15 percent, increasing as a function of the reference price for prices above \$50 per thousand m^3.

Base 12 wells are those producing non-conservation gas that are not Base 15, Base 9 or subject to revenue-sharing agreements. The base royalty rate for these wells is 12 percent, increasing as a function of the reference price for prices above an administratively determined price (called the select price, currently \$50 per thousand m^3), to a maximum of 27 percent.

Base 9 wells are those producing non-conservation gas where a lease was acquired or drilling began after May 1998, where drilling must be completed within five years of the initial disposition of rights by the Crown (whether a lease or a licence)[27], and where royalty payments are not part of a revenue-sharing agreement. The base royalty rate for these wells is 9 percent, increasing as a function of the reference price for prices above an administratively determined price (the select price, currently \$50 per thousand m^3), to a maximum of 27 percent.

Conservation Gas wells are those producing gas from an oil well where marketable gas is conserved to maximize oil recovery. The base royalty rate for these wells is 8 percent and rises as a function of the reference price above \$50 per thousand m^3. (There is technically no maximum on the royalty rate for conservation gas, but practically it reaches its maximum at 14 percent, with very small incremental increases with reference price increases.) Natural gas produced from oil wells where the well is granted concurrent production status is subject to Base 9, 12 or 15 royalty regimes.

3.4.2.3 *Natural Gas and Oil Royalty Wells*

The Ministry of Finance has over fourteen thousand wells that it tracks for royalty purposes; we designate these wells as “royalty wells” to distinguish them from the universe of wells described above. Table 3-1 presents the number of royalty wells, tabulated by the royalty system each faces. As discussed above, a well’s initial primary product determines its classification and royalty system. The table underscores the complexity of the system, particularly for oil wells. The Government of British Columbia and firms producing natural gas and other products face (currently) 23 royalty regime combinations of 70 possible combinations.[28] The majority of oil wells are subject to the Conservation Gas regime. For gas wells, the overwhelming majority of oil is classified as condensate. Importantly, very few wells (six) produce only one fluid and have one applicable royalty regime.

Figure 3-15 shows raw natural gas production over time, by royalty regime applicable to that production. The introduction of Base 9 and Base 12 royalty rates in the late 1990s displaced Base 15 as the main source of royalty production. The majority of 2020 production was subject to Base 12 royalties (79 percent), followed by Base 9 (16 percent) and Base 15 (four percent). A corollary is that any change to BC’s royalty system (even with a transition period) would be felt more amongst Base 12 and Base 9 wells.

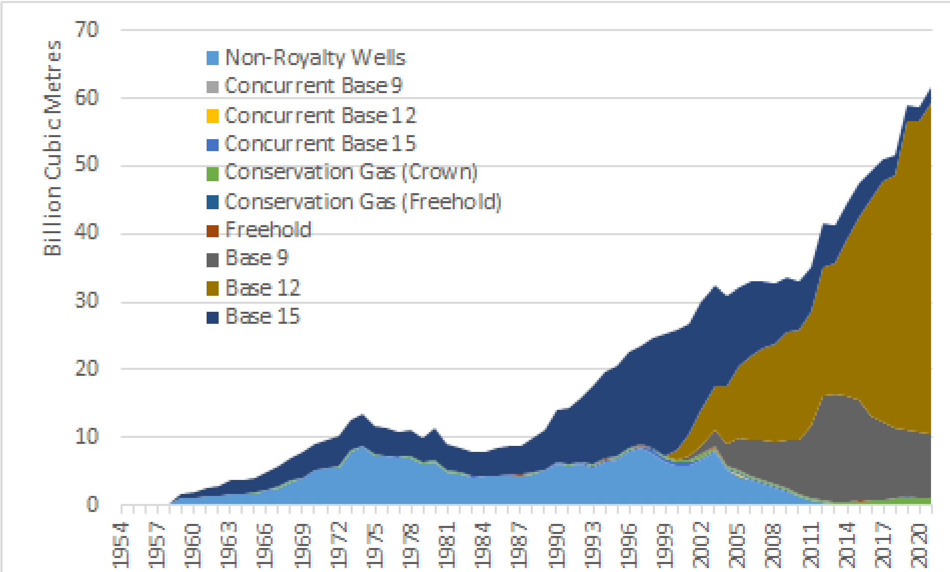
[26] Gas other than Conservation Gas.
[27] In some cases a licence may be sold then converted to a lease. In this case it is the date the licence is granted, not the date of the lease, that governs whether a well qualifies for Base 9.
[28] Not all are probable, as wells reach the end of their economic life the number of wells subject to the older royalty regimes decrease.

Table 3-1: Number of Wells by Natural Gas and Oil Royalty Classifications

		Gas Royalty System										
		Oil Wells						Gas Wells				**Total**
		Granted Concurrent Production Status			Conservation Gas		No Gas	Non-Conservation				
		Base 9	Base 12	Base 15	Crown	Freehold		Freehold	Base 9	Base 12	Base 15	
Oil Royalty System (Oil and Gas Wells)	Freehold Oil	0	0	0	0	10	0	0	0	0	0	**10**
	Heavy Oil	0	5	2	316	0	0	0	0	0	0	**323**
	New Oil	2	38	129	604	0	1	0	0	0	0	**774**
	Old Oil	0	1	13	106	0	0	0	0	0	0	**120**
	Third Tier	10	30	2	246	0	0	0	0	0	0	**288**
	No Oil	0	0	1	0	0	0	0	0	1	3	**5**
Condensate		0	0	0	0	0	0	12	3,177	8,209	2,046	**13,444**
Total		**12**	**74**	**147**	**1,272**	**10**	**1**	**12**	**3,177**	**8,210**	**2,049**	**14,964**

Source: Ministry of Finance data

Figure 3-15: Raw Natural Gas Production by Royalty Regime, 1954 to 2020



Source: BC Oil and Gas Commission production data and Ministry of Finance data.
Note: "Non-royalty wells" are wells not present in the Ministry of Finance dataset. Unless otherwise noted, wells are non-conservation natural gas wells.

3.5 Determining Royalties for Natural Gas Wells

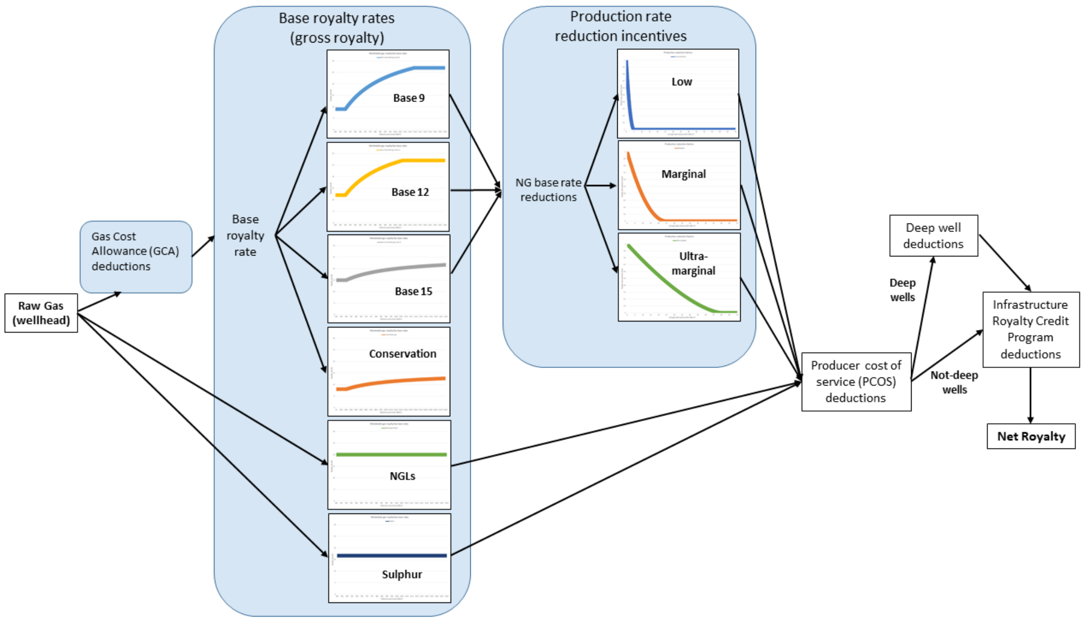
Figure 3-16 depicts the system for determining net natural gas royalties with each component described in more detail below.[29]

Determination of the royalty payable to the Crown begins when raw gas leaves the well and heads to a processing plant. Producers report their marketable gas volume to EMLI each month, where marketable gas volume is based on the volume of raw gas processed during the production month and raw gas that may be used as fuel.[30] The value of the gas is determined at the intake to processing (plant inlet). This differs from Alberta's system (see Chapter 4) where valuation occur at the outflow from processing (plant outlet). While most processing is done by the owner of well, if the producing entity does not have its own plant, it will have its raw gas processed at a third party's plant. There are then different gas processing costs to the well owner depending on whether there is vertical integration in the industry at the stage of wellhead to processing plant that we discuss below. The gross royalty is calculated for marketable gas produced per well by multiplying (1) the reference price set by EMLI, (2) the volume of marketable gas[31] and (3) the base royalty rate as defined in the previous section. Gross royalties per month for by-products are their sales values multiplied by the royalty rate for each product and summed over the different

[29] Very detailed definitions and processes for determining gross and net royalties by product be found in the Royalty Handbook. Ministry of Finance, "Oil and Gas Royalty Handbook" (Government of British Columbia, July 2014), https://www2.gov.bc.ca/assets/gov/taxes/natural-resource-taxes/publications/royalty-handbook-oil-gas.pdf.
[30] The *Royalty Handbook* notes that marketable gas volume may not be the same as actual volumes delivered to buyers.
[31] Marketable gas volume is the volume of marketable gas available for sale each month plus any raw gas used for fuel.

products. The gross value of royalties payable is the sum of the natural gas and by-product royalty values. One can also determine a weighted average gross royalty rate for gas and its by-products per well by weighting the gross royalty rates for natural gas and by-products by their respective sales value (marketable volume multiplied by reference price). The weighted-average royalty rate is used to calculate the Producer Cost of Service Allowance (discussed further below).

Figure 3-16: Natural Gas Royalty System



The reference price is the greater of the producer price and the posted minimum price (PMP). The producer price is based on sales of marketable gas at the processing plant intake from companies' invoices. The process to determine the producer price is as follows (see the *Royalty Handbook).* For each producer, a volume-weighted average sales price is determined at a common pricing point. This price is then netted back to the inlet of each plant used by the producer using producer- and plant-specific transportation charges and processing fees (custom processing fees or the gas cost allowance; see below). A weighted average of this price and prices of any sales made by the producer at the plant inlet are blended to yield the producer price for each plant. The PMP is not a market price; it sets a minimum price floor in determining royalties and serves as a proxy for fair market value. PMPs are 80 percent of estimated volume-weighted average prices of all natural-gas sales net of applicable gathering, processing, and transportation charges. There are hundreds of gas processing plants, and all the actual contracts must be corrected to specific geographical points that reflect the transportation costs. The result can be seen as a 'geographically corrected' price. Table 3-2 presents the gas inlet prices per GJ for each fiscal year from 2003 to 2020.

3.5.1 Gas Processing Costs

The Gas Cost Allowance (GCA) is a rate per thousand cubic metres of raw gas — it can be expressed in energy units (gigajoules, or GJ) —approved by the Royalty Administrator (EMLI) to offset capital and operating costs of the processing plant to reflect:

(a) Processing the Crown's share of raw gas at a producer-owned gas plant and,
(b) Transmission of the Crown's share of residual gas through producer-owned sales. There are three potential scenarios that can arise:
    (1) Gas is processed in a plant owned by a producer and receives a GCA based on that plant's rate;
    (2) Gas is processed in a plant owned by a third party who is also a gas producer and receives a GCA based on the rate assigned to that plant; and
    (3) Gas is processed in a plant owned by a third party that is not also a natural gas producer and receives a custom processing deduction based on the bill the natural gas producer receives from its service provider.
(c) GCA rates are based on the previous year's throughput at the processing facility and the cost base is spread across that throughput to create the rate. This means that facilities with low gas throughput relative to the design capacity of the facility (and thus their cost base) may have very high GCA rates. Table 3.2 illustrates average GCA rates in fiscal years 2003/04 to 2020/21 where these averages are for producer-owned plants (which represent the majority of gas processed each year).

Allowable expenses related to processing at the plant include direct operating costs of the plant, including an overhead allowance of 10 percent of total direct operating costs over the year. There is provision for depreciation of allowable capital expenditures equal to 5 percent of the undepreciated cost of depreciable assets. A return of 15 percent on invested capital is also allowed, which includes (i) the average undepreciated cost of the capital asset between the beginning and end of the year; (ii) cost of the land on which the facility is located; and (iii) an allowance for working capital equal to one-sixth of the allowable direct operating costs per year. The GCA is not well production costs (e.g., costs of extraction, gathering, field compressing, field dehydration, injection, etc.). These are captured under the *producer cost of service allowance* (PCOS); discussed below. Table 3.2 indicates ranges of GCA for each fiscal year from 2003/04 to 2020/21, along with the computed average gas inlet price. The average GCA for these plants as a share of average plant inlet prices has risen over time from 10 percent in 2003/04 to approximately 75 percent in 2020/21. Recall that the plant inlet price is not a market price and does not represent the price per unit for gas sold once processed. If we take GCA as a percentage of plant outlet value, we find that GCA costs are rising considerably over time relative to the market value of natural gas. From 2013 to 2020, total GCA in BC rose by 43.8 percent. Over that same period, total value at the plant outlet grew by just under 10 percent. The GCA was 26 percent of total plant outlet value in 2013 and is 34.1 percent in 2020.

Table 3-2: Average Plant Inlet Price and Average GCA by Fiscal Year

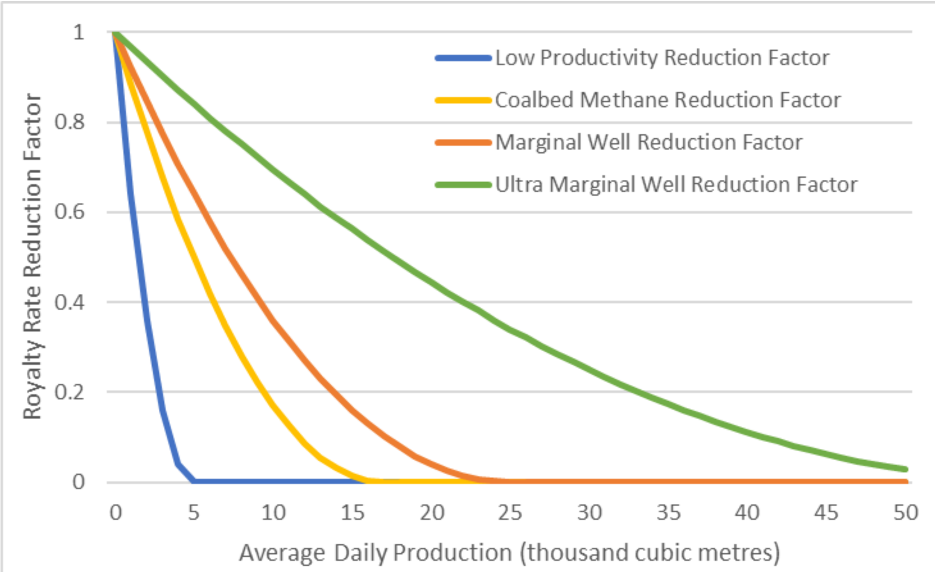
Fiscal Year	Average Plant Inlet Price ($/GJ)	Average GCA ($/GJ)
2003/04	5.06	0.51
2004/05	5.61	0.45
2005/06	7.60	0.41
2006/07	5.35	0.45
2007/08	5.46	0.49
2008/09	6.33	0.62
2009/10	2.98	0.62
2010/11	2.61	0.63
2011/12	2.13	0.64
2012/13	1.53	0.67
2013/14	2.57	0.73
2014/15	2.47	0.77
2015/16	1.16	0.78
2016/17	1.20	0.81
2017/18	0.97	0.78
2018/19	0.93	0.86
2019/20	0.65	0.90
2020/21	1.24	0.94

Source: Ministry of Energy, Mines and Low Carbon Innovation data.
Note: Average GCA represents the average for gas flowing from producer owned plants into Alberta only and into North-T only. The volume of gas flowing through these plants represents the majority of gas processed per year.

3.5.2 Production Rate Reduction Incentives

Four incentive programs comprise a class of incentives that are designed to accomplish one of following goals: (a) encourage continued production from marginal wells that might otherwise be shut in; (b) encourage development of new sources of natural gas that might otherwise be uneconomic; (c) encourage development of new wells that might otherwise be uneconomic. A well event that qualifies for one of these incentives cannot simultaneously qualify for another production rate-reduction incentive. If a well event qualifies in one of these categories, *its gross royalty rate is reduced over specified volumes of output*. Each of these programs was initiated at times when there was concern over the viability of BC's gas supply due to projections of declining output. The programs are designed for vertical drilling (i.e., prior to the 'shale revolution'), and these incentives are not price sensitive. They are based on the monthly volumes (low productivity designation) or initial classification of the well (marginal and ultra-marginal designation) and the magnitude of the incentive is a function of the volume of production. The goal in each case was to maximize volumes, not values. At the time the incentives were introduced, maximizing volume was more strongly connected to generating value than is the case today.

Figure 3-17: Production Related Gas Royalty Reduction Factors



Source: Royalty Handbook, p. 42

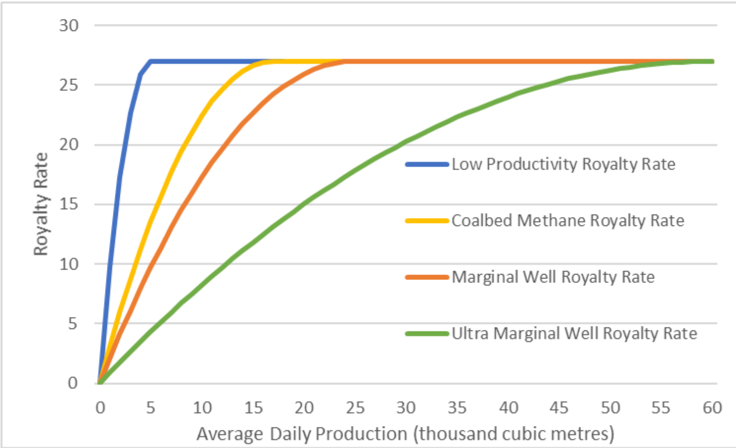
The production incentives currently in use can substantially reduce the royalty rates, depending on the volume of daily production. For each incentive category there is a reduction factor that decreases royalty rates as daily well volumes increase. In other words, the incentive and hence the reduction in the royalty rate is strongest when little gas is extracted. The reduction factor for each incentive has a specific formula that is a function of the threshold for daily volume when the rate reduction goes to zero.[32] Figure 3-17 illustrates these reduction factors by incentive as daily volumes rise. Figure 3-18 illustrates the gross royalty rate reductions for Base 9 and 12 wells as a function of daily volumes produced.

The gross royalty rates for all well events deemed low productivity, marginal, and ultra-marginal are then reduced by the amount of their associated royalty rate reduction. Gross royalties from all natural gas products are then adjusted by the *Producer Cost of Service* for all producing well events and additional credits discussed below may also be deducted.

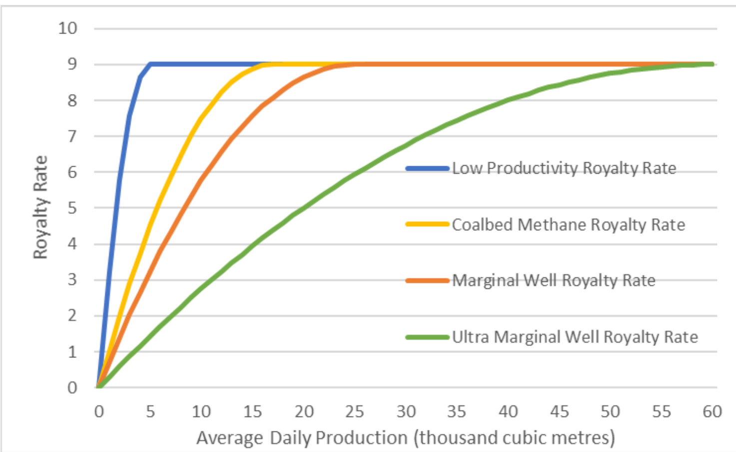
[32] The thresholds in terms of thousand cubic metres per day are 5000 for low productivity wells, 17,000 for coalbed methane, 25,000 for marginal wells, and 60,000 for ultra-marginal wells.

Figure 3-18: Gas Royalty Rate Reductions as a Function of Daily Production for Base 9 and Base 12 Wells

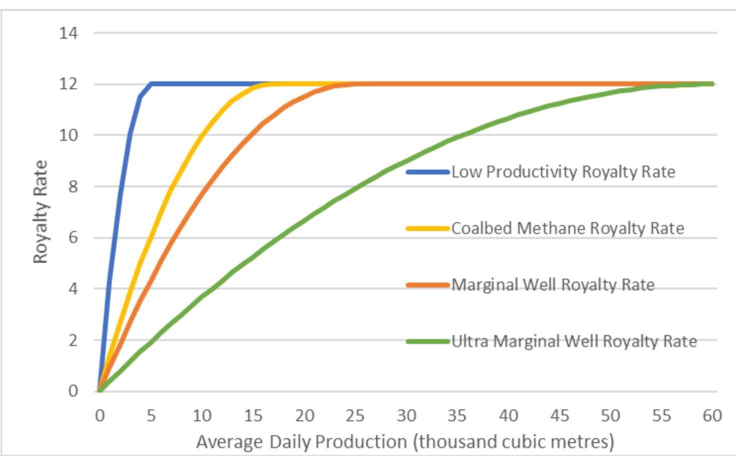
Panel A: At a Reference Price above $120 per thousand cubic metres



Panel B: Base 9 Wells, Reference Price below $50 per thousand cubic metres



Panel C: Base 12 Wells, Reference Price below $50 per thousand cubic metres



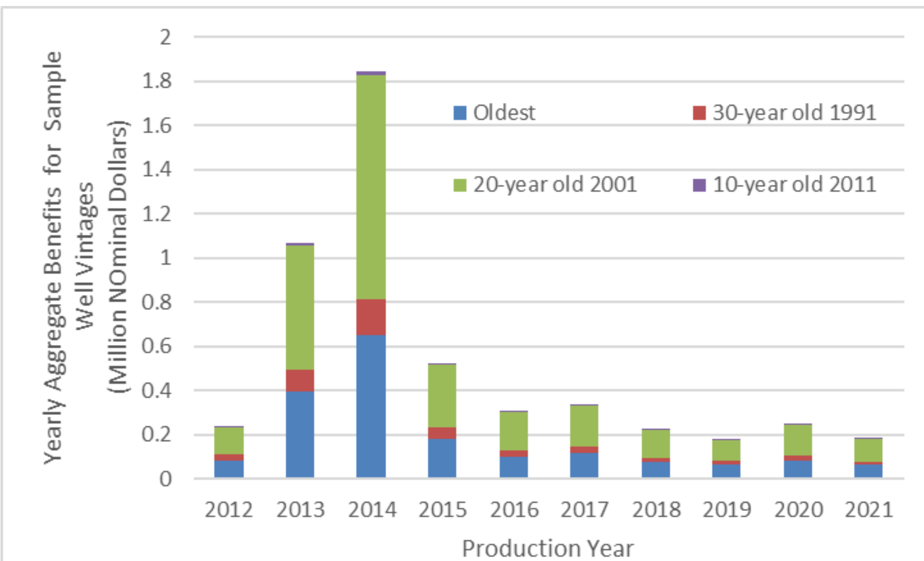
Source: Royalty Handbook, p. 43.

3.5.2.1 *Low Productivity Wells*

Introduced in 2001, the intent of this incentive was to encourage companies to keep wells near the end of their productive lives in production and prevent wells being shut in when rates of production were too low to cover operating costs. The objective was thus to prioritize the volume of gas produced, not optimize net value.[33] Low productivity wells are defined as wells where average non-conservation raw gas production is less than 5000 cubic metres per day during a month and are not otherwise classified as marginal, ultra-marginal, or coalbed methane (see below for these definitions). A well event may thus be classified as low productivity one month but not the next if its volume of production rises above 5,000 m^3 per day in that month. The program also applies to oil wells with natural gas that is part of a concurrent production scheme.

Figure 3-19 shows the aggregate value of royalty rate reductions (the dollar benefit to the well operators) of being designated a low-productivity well for wells of several different vintages (chosen simply to represent younger to older vintage wells). The well vintages are wells that are 10, 20 and 30 years old in 2021, as well as older wells. The figure is illustrative rather than definitive for all wells that are deemed low productivity in the months they operate.

Figure 3-19: Aggregate Benefit from Low Productivity Designation by Production Year for a Sample of Well Vintages



Source: Ministry of Energy, Mines and Low Carbon Innovation data
Note: Vintages defined by in-production year. Vintages shown are wells' age in 2021.

The vintages identified illustrate a few points. Benefits are generally higher for all vintages in years where natural gas prices are higher, namely 2014 (see Figure 3-5). The winter of 2013/14 had extremely cold temperatures and high natural gas prices in much of North America (the 'Polar Vortex'). However the total benefits from the vintages shown have remained relatively constant over the past four years even when prices have risen somewhat. While Figure 3-19 does not show all wells receiving the low productivity incentive, it suggests the benefits from this incentive may be declining over time as older wells become

[33] The policy was also introduced prior to BC's climate policy and thus did not reflect concern over greenhouse gas emissions.

uneconomic and newer wells produce at volumes above the threshold for the incentive. Wells in the 10-year old vintage (first in-production in 2011) accumulated reductions of just $62,879 from 2012 to 2021. However, one would expect older wells to benefit more from the low productivity incentive. In this sample, the wells in the 20-year old vintage (first in-production in 2001) accumulated a larger value of rate reductions than those of oldest and 30-year old vintages.

3.5.2.2 *Coalbed Methane*

A credit for natural gas produced from geological strata containing mainly coal was introduced in 2002 at a time of natural gas price volatility and price spikes. The value of the credit was set in a later year to $50,000 per well event if the well was drilled prior to 2008. While a number of coalbed methane projects were initiated in BC, none reached commercial operation prior to the technological revolution in shale gas and oil, and thus no coalbed methane credits have been utilized.

3.5.2.3 *Marginal Wells*

Again, to encourage development of wells that might otherwise be uneconomic to drill and operate due to their depth and flow rates (pressure and permeability), the Province introduced the marginal well designation in 2003. A well event must meet the following criteria to be designated a marginal well:

(a) the primary product has to be natural gas;
(b) it is not part of a coalbed methane project;
(c) the drilling start date must be after May 31, 1998 (the well is subject to Base 9 or 12 royalty rates, unless it is part of a revenue sharing agreement with one of three First Nations (Fort Nelson, Blueberry, Doig) and then subject to Base 15 royalty rate);
(d) the first month of marketable gas production must be after June 2003 (unless well production was suspended and reactivated after June 2003); and
(e) average daily production per metre of depth in the first 12 months of marketable gas production is less than 23.

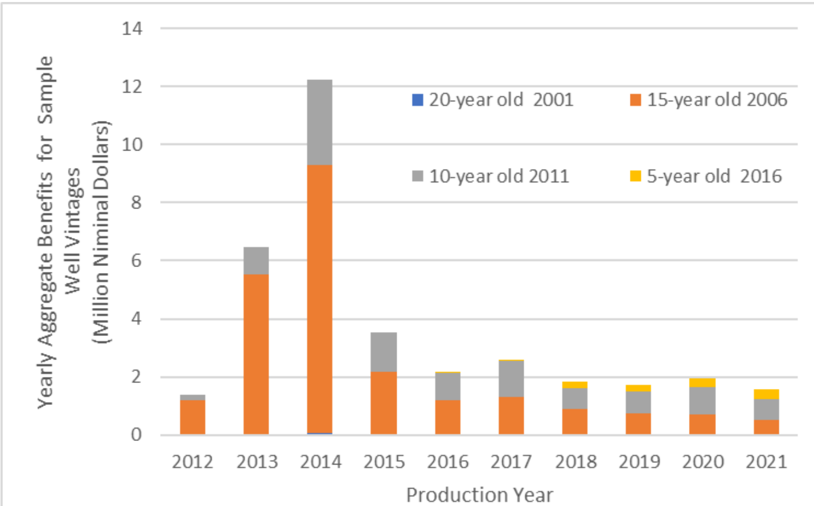
Average daily production for a period of 12 consecutive months is calculated from a formula that computes average natural gas production per day divided by the marginal well depth. The latter is measured differently for vertical versus horizontal wells.[34] Once a well is classified as marginal in its first year of operation, it remains so for its operating life. It does not apply to coalbed methane wells or conservation or non-conservation gas from an oil well event.

Figure 3-20 provides a sample of the aggregate benefits (the value of rate reductions) from a marginal well designation for wells of different vintages. The well vintages are for all wells deemed marginal that are five, 10, 15, and 20 years old respectively in 2021. They are thus not the entire population of marginal wells, but illustrative of the scale of benefits to wells in those vintages from the marginal well designation in each production year from 2012 to 2021. For example, in 2018 wells deemed marginal that began production in 2006, 2011, and 2016 received benefits (reduced royalty payments) totalling just under $2 million. The benefits for wells in the 2001 vintage are too small to be illustrated in Figure 3-20. The impact of natural gas prices is seen where the total benefit to the marginal wells in the vintages shown reach a high of $12 million in 2014 when natural gas prices were high. They decline thereafter to average around $2 million, illustrating again the impact of low prices leading to lower royalty rates and royalty payments. This is similar to the pattern for low-productivity vintages (Figure 3-19). Note, however, the order of

[34] The formula is [(total production/total production hours) X 24]/well depth. See the *Royalty Handbook.*

magnitude differences in total benefits for this sample compared to the low productivity sample for the more recent vintage years. This is because the low-productivity designation tends to occur during the last year or two a well operates while a marginal well designation is for the entire life of the well.

Figure 3-20: Aggregate Benefit from Marginal Well Designation by Production Year for a Sample of Well Vintages



Source: Ministry of Energy Mines and Low Carbon Innovation data
Note: Vintages defined by in-production year. Vintages shown are wells' age in 2021.

3.5.2.4 *Ultra-marginal Wells*

In March 2006, the Province introduced the ultra-marginal royalty rate program to encourage development of shallow natural gas reserves that would have low rates of production. It does not apply to coalbed methane wells or conservation or non-conservation gas from an oil well event. The historical context is as noted above. It also follows a practice similar to that of the other incentives in reducing the royalty rate when average daily production of natural gas is below a prescribed amount. If a well satisfies the criteria for both marginal and ultra-marginal, it receives ultra-marginal status, which provides a higher rate reduction per cubic metre of production. The qualification criteria are more stringent compared to low-productivity and marginal well programs:

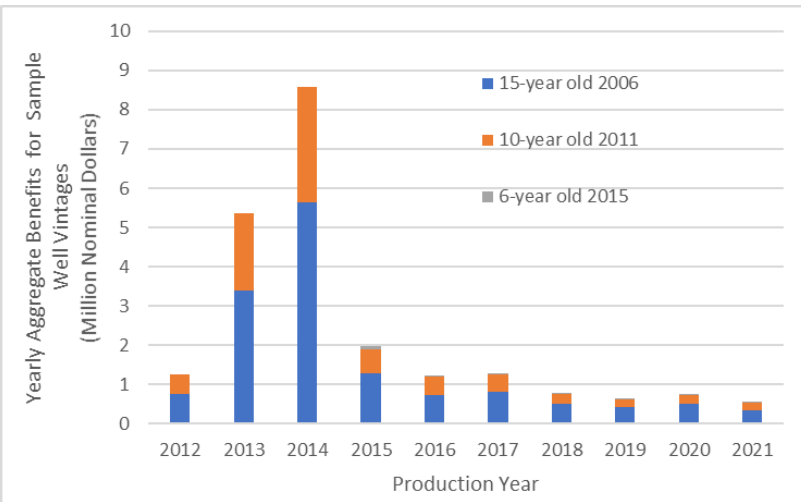
(a) the primary product has to be natural gas;
(b) it is not part of a coalbed methane project;
(c) has a drilling start date after 2005 or is a reactivated well with a drilling start date after May 1998 and is reactivated after 2005;
(d) the well event has a drilling start date prior to April 1, 2014 and is a vertical well with a true vertical depth of less than 2,500 metres or a horizontal well with a true well depth of less than 2,300 metres;
(e) for well events with a drilling start date on or after April 1, 2014, no horizontal wells qualify for the rate reduction and vertical wells must have a completion point that has a true vertical depth equal to or less than 2,500 metres;
(f) for exploratory wildcat well events there is a formula indicating maximum average daily production rates per metre of depth that has a lower maximum than that of marginal wells (17 versus 23);

(g) for exploratory outpost or development well events there is a formula indicating maximum average daily production rates per metre of depth that has a lower maximum than that of marginal wells (11 versus 23); and,

(h) the 12-month test period over which the well event's natural gas production is measured to determine whether it qualifies for ultra-marginal status ends after January 2007.[35]

Figure 3-21 illustrates the distribution of the benefits from ultra-marginal designation for a sample of well vintages following a similar methodology as in Figure 3-19 and Figure 3-20 for production from 2012 to 2021. The shift in production technology and low natural gas prices, combined with a change in regulations[36] and the different characteristics of the deposits, has greatly reduced the number of producing wells that are in the ultra-marginal category. The benefits from ultra-marginal well designation have thus diminished rapidly from over $8 million in 2014 to under $550,000 for this sample over the period and will continue to decline given current market conditions.

Figure 3-21: Aggregate Benefits from Ultra-Marginal Well Designation by Production Year for a Sample of Well Vintages



Source: Ministry of Energy Mines and Low Carbon Innovation data
Note: Vintages defined by in-production year. Vintages shown are wells' age in 2021.

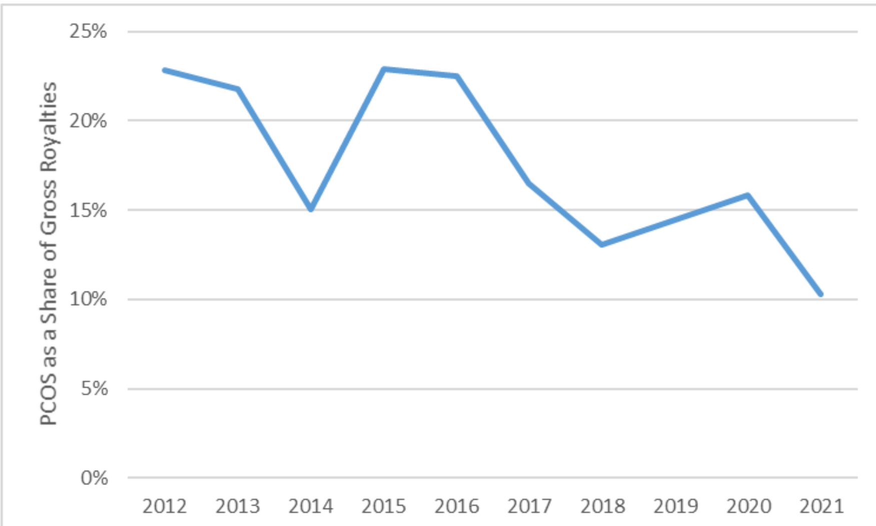
[35] As will become relevant in the discussion of deep well credits, ultra-marginal well events are, effective 2014, prevented from having both the ultra-marginal and deep statuses by the deep well requirements. Specifically, ultra-marginal wells must have a total vertical depth to top of pay *less than* 2,500 metres in vertical wells or 2,300 metres in horizontal wells, and deep well events must have a total vertical depth to completion point *greater than* 2,500 in vertical wells or 2,300 metres in horizontal wells. Prior to 2014, a well could qualify as deep, produce for a year, then based on production, qualify as ultra-marginal, requiring recalculation of the previous 12 months of royalties. This led to significant uncertainty for producers and greater administrative costs for government.

[36] A change in regulations specifically excluded horizontal wells from qualifying as ultra-marginal. The rationale was that there were numerous cases where a well would be drilled, qualify as deep and produce for a year, then qualify as ultra-marginal. This then required re-calculation of its royalties owed based on the new status (and the restriction against ultra-marginal wells receiving deep well credits). The situation created unpredictability for Industry and administrative burden for the Ministry of Finance. The value to producers of the deep well credits typically exceeds the value of the ultra-marginal designation and is thus another factor leading to the decline in ultra-marginal wells. We explore this further below.

3.5.3 Producer Cost of Service (PCOS)

PCOS is an allowance designed to offset the cost for all producers of moving raw gas from the wellhead to the inlet of a gas processing plant — costs for gathering lines, compressors, line heaters, dehydrators, field processing units, and well site operating costs. These components depreciate over time and have associated maintenance costs in order to maintain delivery of products and services downstream. Depreciation and technological change mean that PCOS calculations change from year to year as older equipment is replaced with newer (and potentially cheaper) equipment. They also vary by geography and operator.

Figure 3-22: Aggregate PCOS as a Share of Aggregate Gross Royalties, 2012 to 2021



Source: Ministry of Finance data.
Note: Gross royalties are royalties before deductions. The year 2012 only includes October through December, and 2021 includes January through May.

PCOS is typically expressed as a monetary value ($) per processing volume or rate and a deduction to gross royalties applied after the production rate reduction incentives for each well event. Methods for calculating PCOS rates changed in 2005 and they are now calculated on an annual basis for each natural gas well rather than the processing plant. For natural gas produced from an oil well, the PCOS rate is $16 per thousand cubic metres. For natural gas from a gas well, the PCOS rates depend on (a) the equipment that is in place and in use in the field; (b) the average costs of field equipment to be determined by engineering studies; and (c) the volume of raw gas that is produced from well events delivering to a reporting facility. Producers supply their PCOS-related costs to a Crown-industry entity, Petrinex,[37] whenever industry brings in new facilities or changes are made to existing facilities. The Ministry reviews the applications and determine any necessary adjustments in its next annual PCOS rate recalculation. The PCOS allowance deducted from the total gross royalty is determined by multiplying the volume of raw gas

[37] Petrinex, founded in 2002, is a unique Crown-industry entity operating under the auspices the provinces of Alberta, British Columbia, Saskatchewan, Manitoba and their ministries associated with petroleum policies and the petroleum industry as represented by the Canadian Association of Petroleum Producers and the Explorers and Producers Association of Canada. BC implemented its system in 2018. One of its key roles is to provide information to BC’s Ministry of Finance for the assessment, levy, and collection of Crown royalties.

produced by the weighted average royalty rate for that well by the PCOS rate for that facility. The PCOS allowance cannot exceed 95 percent of the total gross royalty for the well.[38] Figure 3-22 illustrates the total PCOS allowances as a share of total gross royalties across all producing wells. The trend reflects the impact of higher natural gas prices and hence greater volumes extracted up to 2015, then declines thereafter with declining volumes produced. The average rate is 18 percent for the period 2012 to 2021.

3.5.4 Deep Well Royalty Credit Program (DRCP)

Starting in 2003, the Province introduced programs to deliver credits to offset higher drilling and completion costs incurred by wells that are considered particularly deep.[39] These included the Deep Well Credit, Deep Well Re-Entry Credit, and Deep Discovery Well programs.[40] Deep wells are differentiated by their bottom-hole location and hydrogen sulfide content. Deep discovery wells are exempt from paying royalties for their first 36 months of production or 283 million m^3 of raw gas extracted, whatever comes first.[41] The procedure for determining royalties paid each month for a well qualifying for the deep well credit is as follows. When the amount of total allowable credit is determined (see below), a portion of that total credit is applied each month against royalties owing for each deep well event (i.e., after PCOS is applied up to 95 percent of the gross royalty limit).

The deep well credit applied each month of production reduces the effective royalty rate to a minimum of 3 percent or 6 percent, depending on the type of deep well (see below). Holders of deep well credits can further reduce their royalty payment if they also hold an infrastructure credit (see section 3.5.6).[42] The remaining balance of the credit is drawn down each month of production until the full amount of the credit is used. Minimum royalty rates for wells with the deep well credits were introduced for production from all well occurring after March 2013 to ensure the Province receives some compensation, regardless of market conditions.

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[38] The PCOS allowance is the lessor of (1) 95 percent of the total gross royalty or (2) the well's volume of raw gas produced multiplied by the facility's PCOS rate multiplied by the weighted average royalty rate. The weighted average royalty rate is the average of all marketable gas and by-product royalty rates weighted in accordance with their sales values. It is equal to the combined gross royalties for all marketable natural gas and natural gas by-products, divided by the combined reference price values for those products.

[39] See the Royalty Programs for Deep Gas Wells for detailed description of the deep well credit programs. There have been many adjustments to the program since its introduction that complicate application of the credits. Ministry of Finance, "Royalty Programs for Deep Gas Wells" (Government of British Columbia, February 2021), https://www2.gov.bc.ca/assets/gov/taxes/natural-resource-taxes/publications/png-001-deep-gas-wells-royalty-programs.pdf.

[40] From the *Royalty Handbook*, p. 59, a well can qualify for both deep well and deep well re-entry credits, but for royalty purposes, a gas well event is all completions in a geological zone. The deep well re-entry credit will displace the deep well credit if the well event is in the same zone. A well event may qualify for the deep discovery exemption and either other deep well credit. Producers can choose the exemption or credit providing the greatest benefit.

[41] No Deep Discovery Well has been designated to date by the OGC.

[42] Holders of deep well credits can end up paying below the minimum royalty rates if they have a PCOS rate that puts them below the minimum. By default, they do not utilize any deep well credits in the months in which this occurred. All of this occurs automatically in the system. In other words, producers do not have discretion over their access to deep well credits. Their production level, PCOS, and whether or not they are at the minimum determine their royalty payment. The only discretion that is not automatic is when to release any infrastructure credits that may be associated with the producing well.

There is a substantial accumulation of credits. The primary factor has been the relatively weak demand for natural gas in recent years, leading to lower volumes extracted. As of March 2021, the accumulated deep well credits total $7.325 billion. Of that, $3.56 billion have been drawn down (i.e., applied to monthly royalty payment. A total of $3.765 billion of credits remain to potentially be used. Wells have to be producing marketable gas each month to use the credit. Once the well ceases production, the credit expires. The total draw down of the outstanding balance could thus be lower than $3.755 billion if wells become non-producing prior to utilizing all their credits.[43] Chapter 5 discusses this issue in more detail.

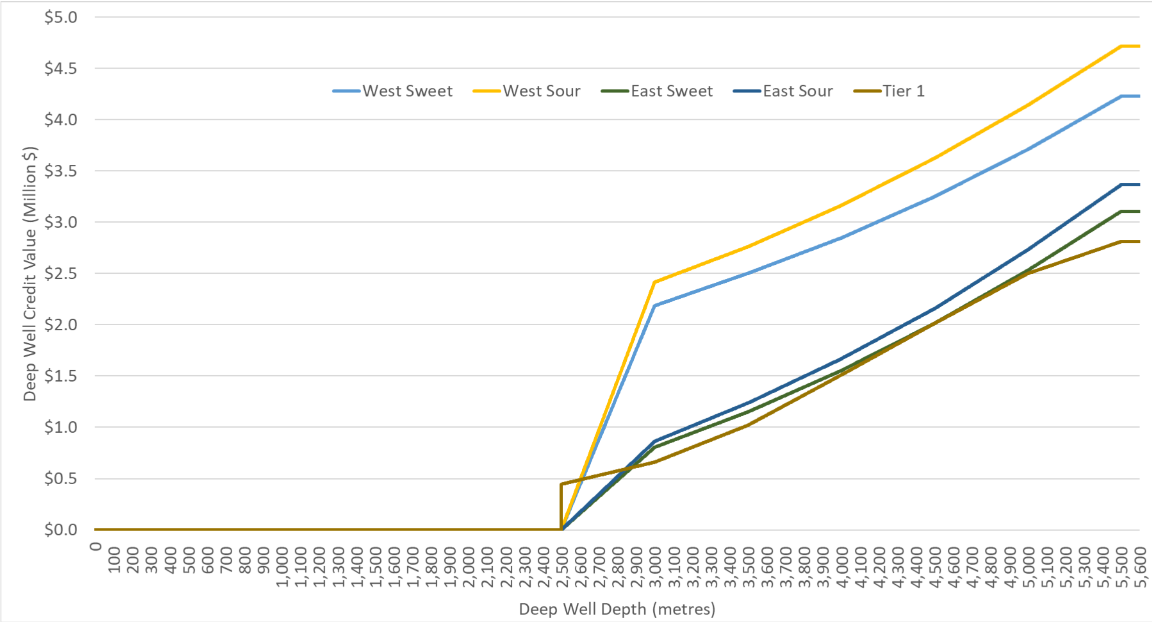
The deep well credit policies have undergone some changes over the years. From the beginning of the program, wells eligible for deep well credits were distinguished geographically to recognize higher drilling costs in specified underdeveloped areas of the province, with those in the designated "West" receiving higher credits per total depth than those in the "East". The line dividing west and east was redrawn in 2009 and applied to wells where drilling started after January 1 of that year. A permanent 15 percent increase in the Deep Credit Table was also introduced in 2009 and applied to all new wells drilled. The rationale was the rising costs of drilling. The second permanent change introduced allowed horizontal wells between 1,900 and 2,300 metres to be eligible for the DRCP; the minimum vertical depth to completion for horizontal wells was shortened from 2,300 metres to 1,900 metres, and the deepest productive well event in the well has a deep well depth[44] greater than 2,500 metres to qualify. Starting in 2014 and continuing to the present, deep natural gas wells are classified as Tier 1 or 2, where the classification depends on the depth and length of deep gas well, as well as drilling start date. The value of Tier 1 deep well credits is designed to cover a portion of higher drilling and completion costs for shallower wells with longer horizontal segments. All other wells that qualify or have qualified for deep well credits are classified as Tier 2. Minimum royalty amounts for Tier 1 are 6 percent and are 3 percent for Tier 2. The introduction of minimum royalties lengthens the time to draw down the accumulated deep well credits, but also guarantees the Crown a share of value throughout the life of the well.

The Ministry of Energy, Mines and Low Carbon Innovation categorizes the well type, determines which of the five deep well credit tables applies (east or west, sweet or sour gas depending on hydrogen sulphide content) and calculates the credit amount using the formula for each type. Qualifying wells receive a credit when their depth greater is than 2,500 metres and the credit reaches a maximum for wells with a depth greater than 5,500 metres (Figure 3-23). Table 3-3 illustrates the credit table for Tier 1 wells, and Table 3-4 illustrates the credit table for Tier 2 wells with drilling initiation dates after August 31, 2009. A credit table also covers wells with a drilling start dates on or before August 31, 2009. For each of the tables, the *Royalty Handbook* details the formula and its component parts (well depth, table depth, cumulative value, and incremental value) to calculate each producer's deep well credit for a qualifying well.

[43] The public accounts show the "deep well credits outstanding" each year. The current amount as of March 31, 2021 is $3.223 billion. This number is lower than the $3.755 billion because it excludes any wells that are deemed non-active or non-producing. To be included wells have to be classified in the "Initial Active Status" within the last two fiscal years in question. Some of these wells may be drawing down their credits, others may not yet be producing but are expected to do so.

[44] The deep well depth is calculated based on the total vertical depth plus horizontal length multiplied by a horizontal length factor.

Figure 3-23: Deep Well Credit Value by Well Category



Source: Royalty Handbook.

Table 3-3: Deep Well Credits by Category for Tier 1 Wells with Spud Dates After August 31, 2009

Deep Well Depth (metres)	Cumulative Value ($000)	Incremental Value ($/metre)
2,500	445	430
3,000	660	720
3,500	1,020	980
4,000	1,510	1,006
4,500	2,013	974
5,000	2,500	622
5,500	2,811	

Source: Royalty Handbook.

Table 3-4: Deep Well Credits by Category for Tier 2 Wells with Spud Dates After August 31, 2009

West Special Sour			**East Special Sour**		
Deep Well Depth (metres)	Cumulative Value ($000)	Incremental Value ($/metre)	Deep Well Depth (metres)	Cumulative Value ($000)	Incremental Value ($/metre)
2,500	0	4,830	2,500	0	1,725
3,000	2,415	690	3,000	863	748
3,500	2,760	805	3,500	1,236	863
4,000	3,163	920	4,000	1,668	978
4,500	3,623	1,035	4,500	2,156	1,150
5,000	4,140	1,150	5,000	2,731	1,265
5,500	4,715		5,500	3,364	
West Sweet			**East Sweet**		
Deep Well Depth (metres)	Cumulative Value ($000)	Incremental Value ($/metre)	Deep Well Depth (metres)	Cumulative Value ($000)	Incremental Value ($/metre)
2,500	0	4,370	2,500	0	1,610
3,000	2,185	633	3,000	805	690
3,500	2,501	690	3,500	1,150	805
4,000	2,846	805	4,000	1,553	920
4,500	3,249	920	4,500	2,013	1,035
5,000	3,709	1,035	5,000	2,530	1,150
5,500	4,226		5,500	3,105	

Source: Royalty Handbook.

3.5.5 Net Profit Royalty Program (NPRP)

The net profit recovery program was developed in 2008 to promote exploration and production of natural gas resources that are capital-intensive, technically complex and located in remote areas. It offers producers lower royalty rates at the initial stages of project development in exchange for higher royalty rates later when a project becomes more profitable. There are only a few proponents still active under this program and applications to the program are no longer being accepted. It was designed for shale gas and its only use was for the Horn River formation in 2010 but found to be a poor fit for that type of formation and well costs.

3.5.6 Infrastructure Royalty Credit Programs (IRCP)

The program was established in 2004 to encourage companies to explore and access new and under-developed areas of the province. A key goal of these programs has been to encourage oil and gas projects that would otherwise be uneconomic. Eligibility criteria were established at this time. In 2016 an additional program was added — the Clean Infrastructure Royalty Credit Program that gave producers the opportunity to apply for credits for investments designed to reduce GHG emissions from wells and to better align the program with environmental goals of the Province. In 2019, the two programs were merged under the Clean Growth Infrastructure Royalty Program, encouraging investment while helping meet GHG- and methane-reduction targets. The most recent request for applications occurred from March to May 2021, with decisions on those applications pending. A total of $150 million per year is currently allocated to the program.

The basic process has been the same for each version of the program. In response to a request for applications, oil and gas producers submit their proposals to EMLI, specifying the intended investments that are designed to help the producer drill new wells and bring them into production. The program can cover up to a maximum of 50 percent of the specified capital costs. Examples are costs of building roads and/or pipelines (and all the component capital costs for each). Applications undergo a competitive process, with total applications exceeding available funding each year. The Ministry assesses applications using criteria such as what percent of total economic activity the project represents, how quickly royalty credits issued to support the project would be applied against royalties from incremental production enabled by the infrastructure and would the project have gone ahead without the credit, although the latter is challenging to ascertain.

Producers have three years to complete the infrastructure project. Some never do and those credits are never realized. Once a project is built, there is no required timeline to drill for wells. If wells are not drilled or wells drilled do not produce marketable gas, no royalties are due and the credits cannot be accessed. Credit holders pay the total costs of the project up front and recover eligible costs through royalty credits once production occurs. The Ministry then determines the allowable deduction, which is only applied once the royalty payments from the wells associated with the project exceed the project's eligible royalty investment credits.[45] The credits must be used for the projects specified in the application; they are non-transferable to other projects or companies if a project changes hands. Thus, if the wells associated with the project are not producing and, not incurring royalties, no credits can be used. The credits are designed to be "revenue neutral" because none can be utilized until royalties are incurred.

In practice, it may take many years to bring a well into production, so approved credits can accumulate "on the books" and be used to reduce future royalties to zero until all the approved credits for the costs of the infrastructure are paid out. Infrastructure credits can, for example, be used to reduce royalty payments to zero for wells operating with deep well credits and thus pay under the minimum 3 or 6 percent in the DCRP. Under the original Infrastructure Royalty Credit Program, a total of $1.549 billion was awarded from 2004 to 2018 with $0.668 billion released so far. Under the 'Clean' program an additional $33.7 million was awarded and $5.6 million released, and with the 'Clean Growth' programs just under $150 million awarded in 2019 and $150 million awarded in 2020. Overall, from 2004 to 2020 a total of $1.733 billion has been awarded, $0.679 billion released, leaving a balance of $1.054 billion. A total of $409.3 million over all three programs has been cancelled or represents stranded assets, leaving $644.8 million in net outstanding credits. How quickly and how many of the outstanding credits ultimately will be used to offset royalties owed will be revealed over time.

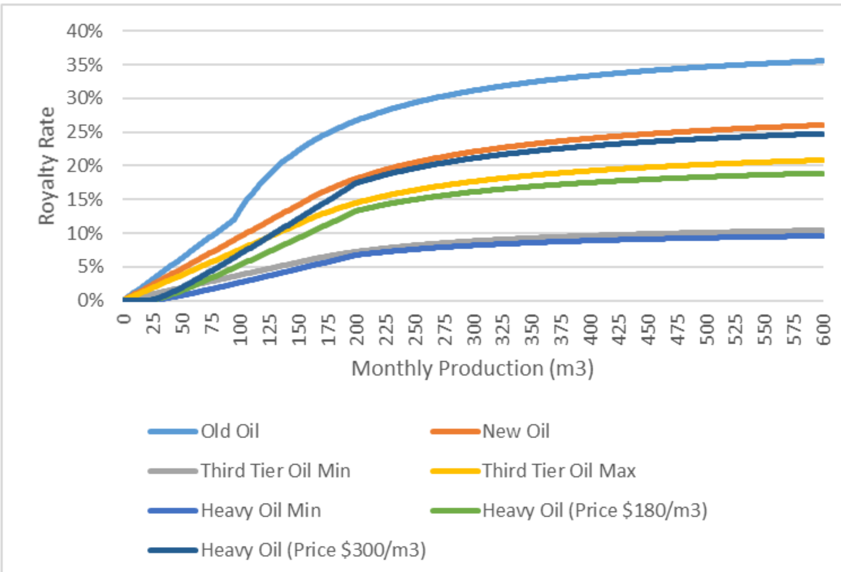
[45] Partial credit releases are allowed, up to the value of royalties paid by the wells associated with a project. This is usually determined annually.

3.6 Oil Wells

There are four royalty formulas for Crown[46] land crude oil production: Old Oil, New Oil, Third Tier Oil and Heavy Oil. Third Tier is the most common royalty structure for oil production. Figure 3-24 presents gross royalty rates for the differing royalty systems.

Old Oil wells are those with crude oil production other than New Oil, Heavy Oil or Third Tier Oil. The royalty rate is a function of production, starting at zero percent and increasing with no maximum though it effectively caps at 35 percent due to the formula structure.

Figure 3-24: Crude Oil Gross Royalty Rates



Source: Royalty Handbook.
Note: Heavy Oil minimum rates are when the administratively-set threshold price is equal to the wellhead price, and so the royalty rate is only a function of volume produced, not price. Similarly, Third Tier minimum rates are defined by the minimum and maximum price factors.

New Oil wells are those with crude oil production that satisfy one of four sub-classifications. Production from a pool without a completed well as of Oct. 31, 1975; incremental[47] oil (other than incremental oil qualifying as Third Tier Oil); oil that received a new reference price under the National Energy Program; and oil produced from a pool with first well completion after Oct. 31, 1975 and where the well resumed production after Jan. 1, 1981 after at least 36 months of inactivity. The royalty rate is a function of production, starting at zero percent and increasing with no maximum though it effectively caps at 25 percent due to the formula structure.

Third Tier Oil wells are those with crude oil production (other than heavy oil and oil subject to a revenue-sharing agreement) from a pool with first well completion after June 1, 1998 or incremental oil from an enhanced oil recovery scheme approved after Dec. 31, 1999. The royalty rate is a function of production

[46] The Royalty Handbook includes a royalty rate for Freehold Oil, though this is out of our scope.
[47] Incremental oil is non-heavy-oil recovered by an enhanced oil recovery scheme.

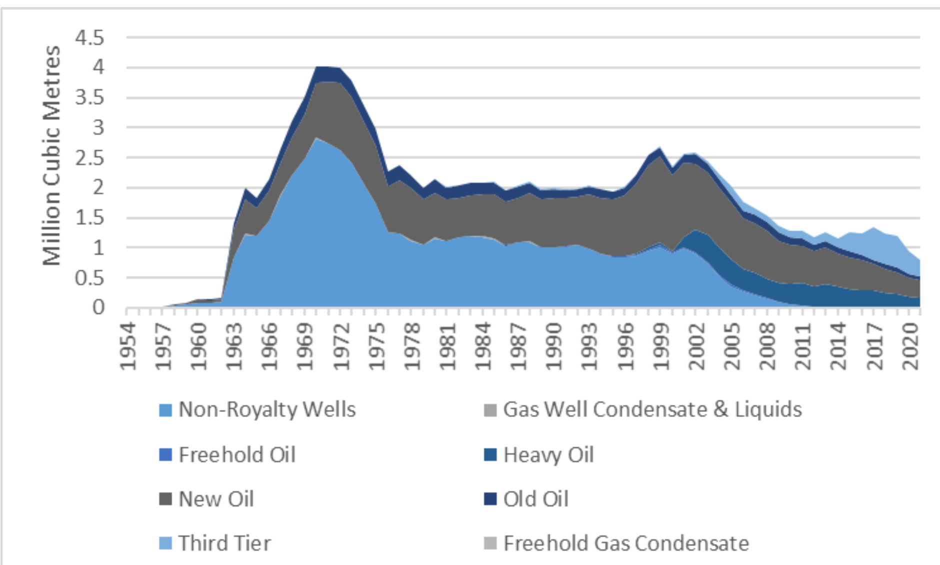
and price, starting at zero percent and increasing with no maximum though it effectively caps at 21 percent due to the formula structure.

Heavy Oil wells are those with crude oil density of at least 890 kg/m^3. The royalty rate is a function of production, with a base rate of zero. Once production is above 20 m^3, the royalty rate increases with volume of production and price, increasing with no maximum.

Oil wells cannot access the royalty credits described above for gas wells, with the exception of infrastructure and the Clean Growth Investment Royalty Credit. Oil wells only receive royalty relief when they are considered "discovery" wells: "oil discovered in a new pool … after June 30, 1974."[48] The royalty relief these wells receive is full exemption from royalty payments for oil produced within the first 36 producing months, to a maximum of 11,450 cubic metres or the sum of monthly allowable production over those 36 months.

Figure 3-25 shows oil production by royalty regime. Despite the high number of wells subject to the New Oil regime, only 37 percent of 2020 production was from these wells. Third Tier wells accounted for 34 percent, Heavy Oil wells accounted for 21 percent, and Old Oil accounted for 8 percent.

Figure 3-25: Oil Production by Royalty Regime, 1954 to 2020



Source: BC Oil and Gas Commission production data and Ministry of Finance data.
Note: "Non-royalty wells" are wells not present in the Ministry of Finance data. Freehold oil is oil produced from non-Crown leases.

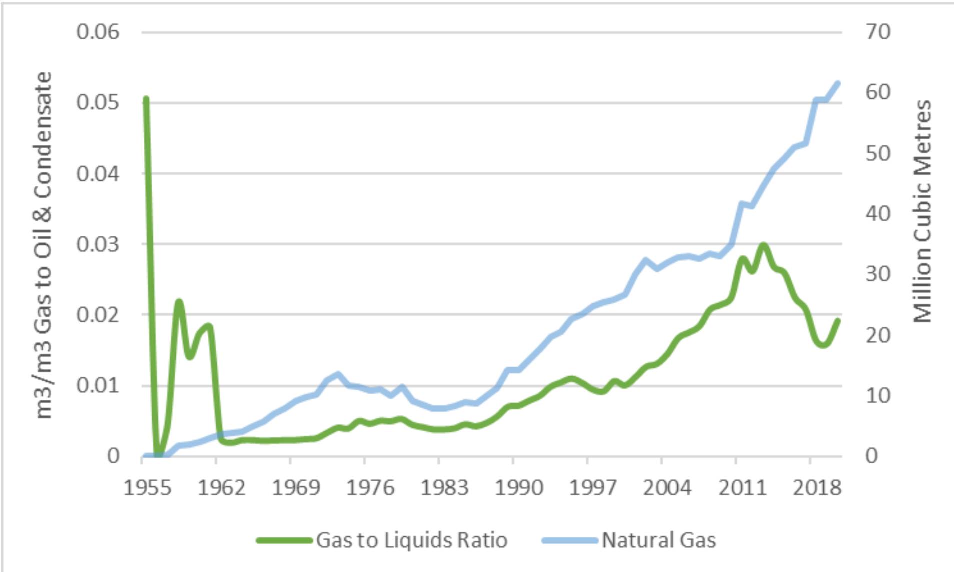
3.7 Net Royalty Outcomes

As shown above in Figure 3-2 there is substantial variability in natural resource revenues, and royalty payments more specifically. Since fiscal 2005/06, net royalty payments and net royalty rates have declined substantially over time. Factors that contribute to the decline include low natural gas and oil prices, the shift in production from dry natural gas to natural gas liquids, the impact of royalty allowances/credits, and the maturity of wells with traditional extraction profiles. We examine each in turn.

[48] Handbook page 29 (section 4.3).

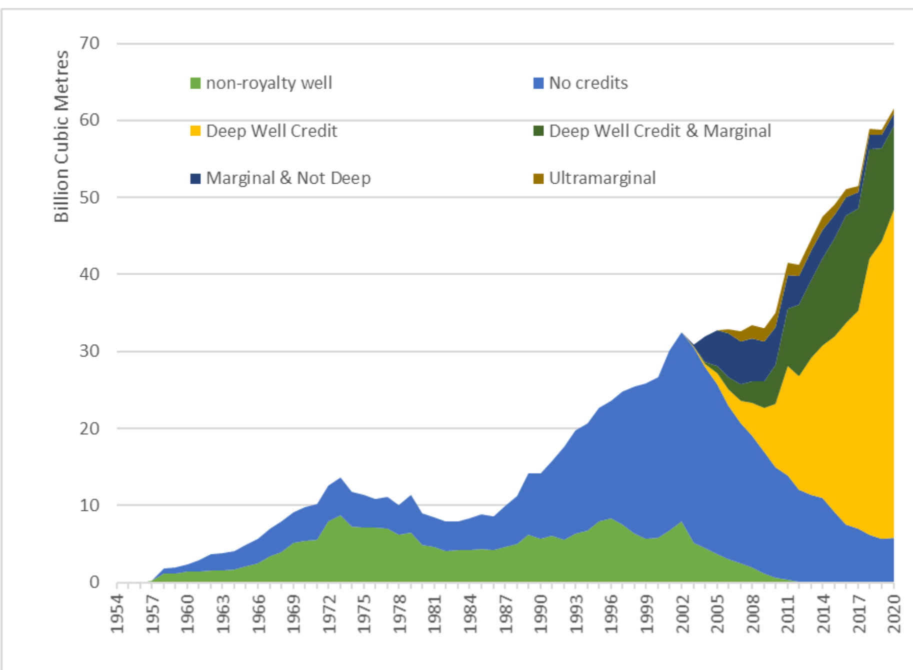
While production is overwhelmingly natural gas (as discussed above), over the past decade BC's production has been increasingly liquids-rich (Figure 3-26). This change is primarily due to higher relative prices for natural gas liquids and more attractive development opportunities in the Montney.

Figure 3-26: Gas-to-Liquids Ratio and Raw Natural Gas Production, 1954 to 2020



Source: BC Oil and Gas Commission production data.

Figure 3-27: Annual Raw Natural Gas Production by Royalty Credit Type, 1954 to 2020



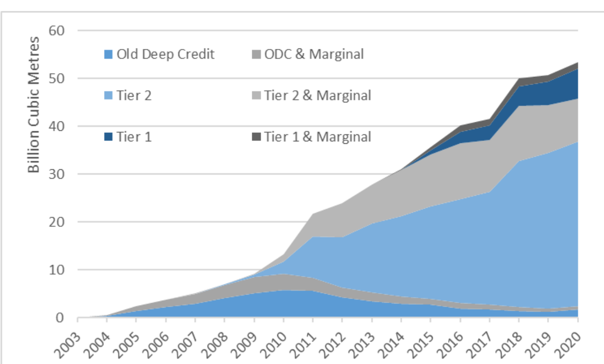
Source: BC Oil and Gas Commission production data and Ministry of Finance data.
Note: "Non-royalty wells" are wells not present in the Ministry of Finance dataset. Marginal production begins in 1999 (though the program only began in 2003 and whether a well's production is truly marginal varies month-to-month) as these wells are flagged as marginal in the Finance dataset.

Figure 3-27 shows annual raw natural gas production by royalty credit type. Production from wells without credit programs peaked in 2003. Production from non-credit wells accounted for 82 percent of production in 2003, and in 2020 this proportion fell to 10 percent. This is not surprising as it was shortly after the introduction of the Low Productivity well eligibility criteria in 2001. The Marginal Well eligibility criteria and Deep Well Royalty Credit Programs were introduced in 2003. As more wells are drilled under the various credit programs and the non-credit wells' production declines with age, the contribution to total production and hence the province's royalties will decline. While much of production over the last 20 years is from deep wells, a non-trivial amount of production came from non-deep wells subsequently designated as marginal; 14 percent in 2005 and falling to 2.5 percent in 2020. Of the deep wells, this accounted for 87 percent of production in 2020. Of note, however, is that wells designated as Marginal or Ultra Marginal do not necessarily receive the royalty rate reduction in any given month, as receiving the credit depends on average daily production.

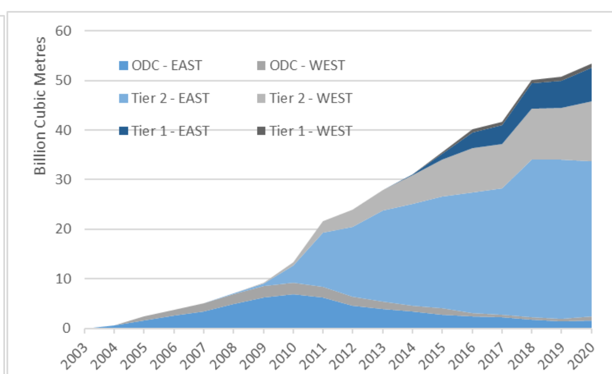
Figure 3-28 displays production from deep wells, by credit type (Panel A) and by geography (Panel B). The most production comes from Tier 2 wells, and East wells. Figure 3-30 and Table 3-5 present the number of deep wells drilled in each year by Deep Well Credit type and geography. Far more wells are drilled under the Tier 2 regime, and there is also a clear preference for wells designated as East. The East wells are more liquids rich, so this preference is economically driven. An additional effect may be that the higher value of the Deep Well Credit for West wells is insufficient to overcome the higher drilling costs. The change in the geographical boundary in 2009 may have increased the number of West wells. The East/West line was moved both west and east, but most of the changes resulted in an eastward move of the line. As the Deep Well Royalty Credit is higher for Tier 2 wells designated as West, this suggests firms took advantage of the change for wells that would have previously been designated as East, and the change resulted in a higher bank of deep well credits. Unlike Tier 2, Tier 1 wells do not have differential credits for East versus West, so it is not surprising to see far more East wells than West wells that are Tier 1.

Figure 3-28: Annual Deep Well Production by Credit Type and Geography, 2003 to 2020

Panel A: by Credit Type

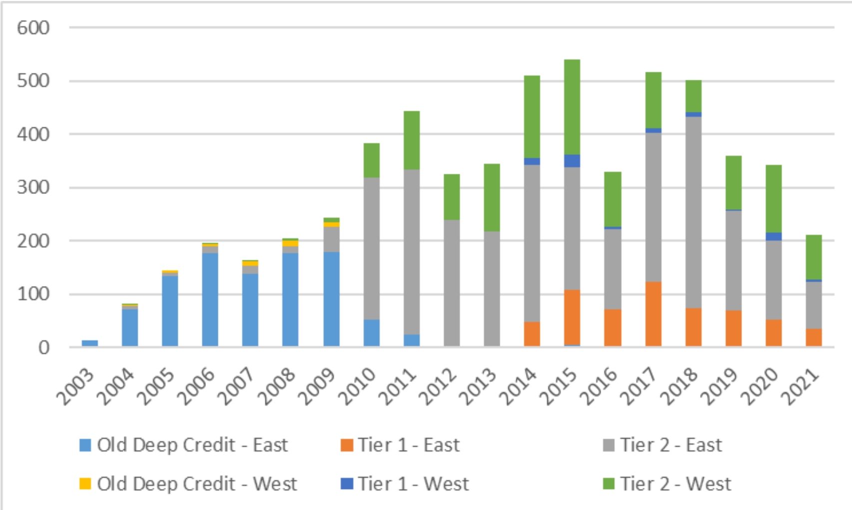


Panel B: By Geography



Source: BC Oil and Gas Commission production data and Ministry of Finance data.

Figure 3-29: Number of Deep Wells by Credit Type and Geography, 2003 to 2020



Source: BC Oil and Gas Commission production data and Ministry of Finance data.
Note: Vintage used is Oil and Gas Commission in-production year.

Table 3-5: Number of Deep Wells by Credit Type and Geography, 2003 to May 2021

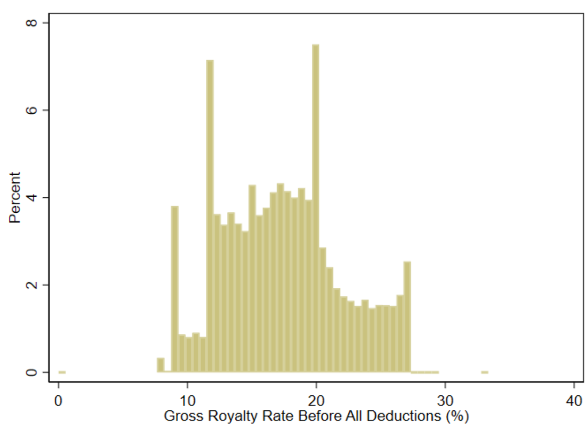
In Production Year	Old Deep Credit		Tier 2		Tier 1	
	East	West	East	West	East	West
2003	14	0	0	0	0	0
2004	71	2	8	1	0	0
2005	135	4	6	0	0	0
2006	178	5	12	1	0	0
2007	138	7	16	4	0	0
2008	178	11	12	5	0	0
2009	179	8	48	9	0	0
2010	52	0	268	63	0	0
2011	24	0	311	109	0	0
2012	2	0	238	86	0	0
2013	1	0	218	126	0	0
2014	1	0	294	155	48	12
2015	4	0	230	177	104	25
2016	0	0	151	103	72	4
2017	3	0	280	105	121	7
2018	0	0	359	61	74	9
2019	0	0	186	103	70	2
2020	0	0	148	126	52	16
2021	0	0	88	83	35	5

Source: Ministry of Finance data
Note: Vintage used is OGC in-production year. Tier 1 does not have differential credits based on geography; the East/West difference is due to geology.

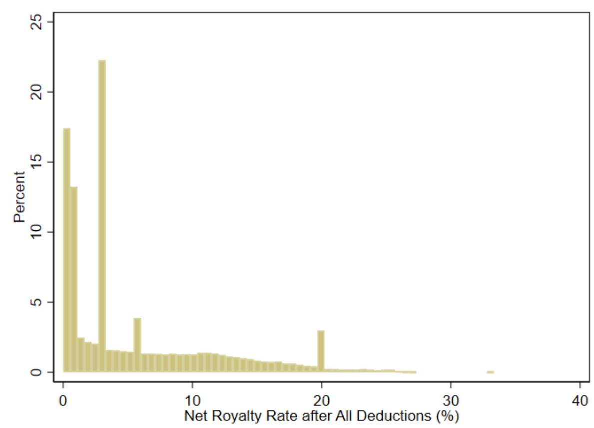
Figure 3-30 shows gross (Panel A), net (Panel B) and effective (Panel C) royalty rates for combined natural gas and by-products from well-level monthly royalty payment data between October 2012 and May 2021. The gross royalty rate is the value of natural gas and by-products royalty payments at producer prices, divided by the value of marketable natural gas and by-products. This the royalty rate before all deductions except for the Gas Cost Allowance. The effective royalty rate is the net royalty payment on natural gas and by-products after all deductions divided by the value of marketable natural gas and by-products. The difference between the gross rate before all deductions and the effective rate after the various deduction programs is striking. The average gross royalty rate is 17 percent, the average net rate is 5.5 percent and the average effective rate is 4.4 percent. The major spikes in Panel B correspond to minimum royalty rates prescribed in the Handbook.

Figure 3-30: Gross, Net and Effective Royalty Rates, Oct. 2012 to May 2021

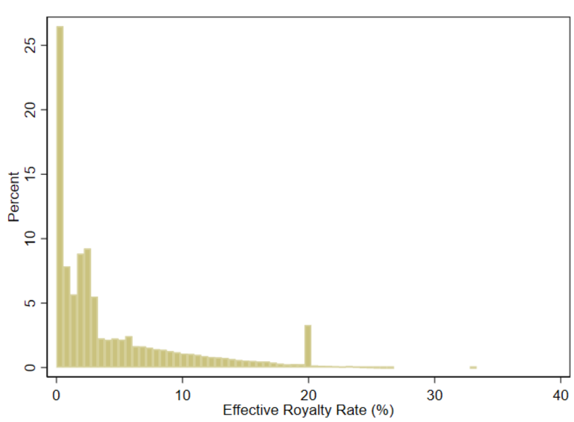
Panel A: Gross Royalty Rate



Panel B: Net Rate



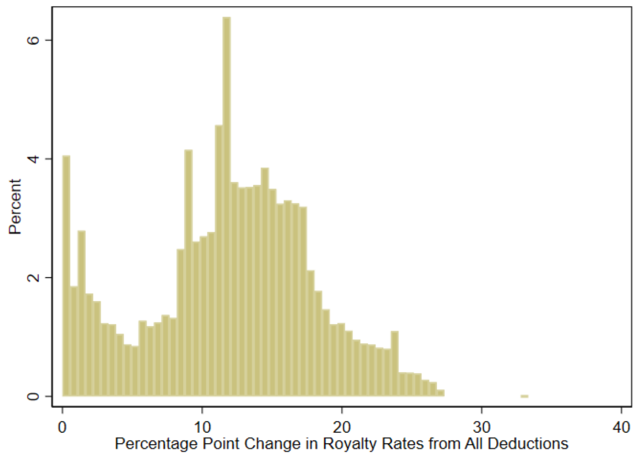
Panel C: Effective Royalty Rates



Source: Ministry of Finance data.
Note: The x-axis denotes the royalty rates in percentage. The y-axis denotes what share of observations correspond to each royalty rate. This means the figure shows the frequency of a given royalty rate between October 2012 and May 2021; the height of the bars denote frequency in percentage terms. For example, a y-axis value of 10 percent for a royalty rate of 20 percent indicates 10 percent of the well-month pairs have a royalty rate of 20 percent. Gross royalty rates are the royalty rates before all deductions; net royalty rates are the rates taking into account all deductions except for the infrastructure credits, and effective royalty rates are net royalty revenues as a share of marketable value based on market prices. Effective rate calculated using Sproule escalated forecast and monthly Westcoast Station 2 natural gas price instead of the producer price from the royalty system.

Figure 3-31 shows the effect of all deductions on royalty rates, from well-level monthly royalty payment data between October 2012 and May 2021. The difference is calculated by subtracting the net royalty rate from the gross royalty rate; the net is the effect of all deductions. As above, the royalty rates are for natural gas and by-product production. Eighty-eight percent of these monthly royalty payment records have deductions greater than zero and less than or equal to 20 percentage points. A more detailed discussion of the effect of all deductions on royalty rates for the different royalty credit programs is presented in Appendix A, though we summarise the results here.

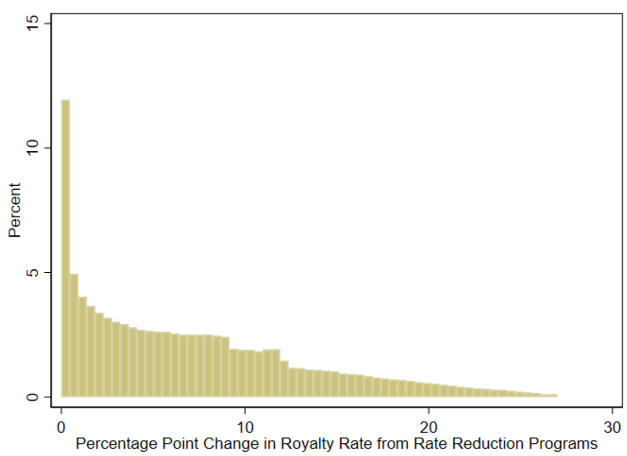
Figure 3-31: Percentage Point Royalty Rate Reduction from All Deductions, Oct. 2012 to May 2021



Source: Ministry of Finance data.

*Note: The x-axis denotes the percentage-point reduction in royalty rates, moving from a gross royalty rate **before** all deductions to the effective rate **after** all deductions. The y-axis denotes what share of observations correspond to each royalty rate reduction. For example, a y-axis value of six percent for a royalty rate change of 10 percentage points means that six percent of each well-month pair receives a royalty rate reduction of 10 percentage points. The rate reduction could be from 20 percent to 10 percent or 10 percent to zero percent; we do not distinguish in this figure. This analysis excludes infrastructure royalty credits.*

Figure 3-32: Percentage Point Royalty Rate Reduction from Rate Reduction Programs, Oct. 2012 to May 2021



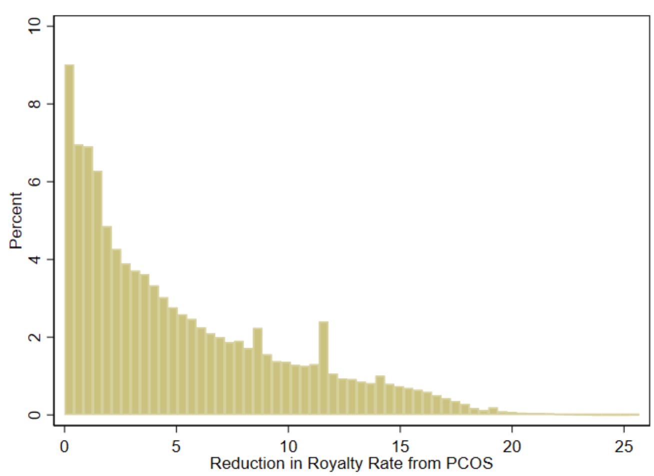
Source: Ministry of Finance data.

*Note: The x-axis denotes the percentage-point reduction in royalty rates, moving from a gross royalty rate **before** all deductions to the rate **after** rate reduction programs. The y-axis denotes what share of observations correspond to each royalty rate reduction. For example, a y-axis value of 3 percent for a royalty rate change of 10 percentage points means that 3 percent of each well-month pair receives a royalty rate reduction of 10 percentage points. The rate reduction could be from 20 percent to 10 percent or 10 percent to zero percent; we do not distinguish in this figure. This analysis excludes infrastructure royalty credits.*

Figure 3-32 shows the effect of the low productivity, marginal and ultra-marginal rate reduction programs on royalty rates, from well-level monthly royalty payment data between October 2012 and May 2021. This effect is calculated by taking the difference between the gross royalty rate before all deductions and the net royalty rate after the rate reductions are applied, but before other deductions. The average reduction in royalty rates is seven percentage points; ninety-eight percent of eligible wells in the data have a positive royalty rate reduction in the months examined. Seventy-one percent of the monthly royalty payment records have a reduction less than 10 percentage points, and 24 percent have a deduction between 10 and 20 percentage points. A more detailed discussion of the effect of these programs on royalty rates is presented in Appendix A.

Figure 3-33 shows the effect of the PCOS deduction on royalty rates, from well-level monthly royalty payment data between October 2012 and May 2021. The change is relative to a net royalty rate for natural gas and by-product production, after any deductions from the marginal, ultra-marginal and low productivity rate-reduction programs. The vast majority of PCOS deductions reduce the royalty rate between zero and 20 percentage points. The average royalty rate reduction attributable to PCOS is five percentage points. Approximately four percent of the monthly royalty payment records have no change in royalty rate from PCOS. Eighty-two percent of records have a PCOS deduction less than 10 percentage points, and 18 percent have a deduction between 10 and 20 percentage points. A more detailed discussion of the effect of PCOS on royalty rates for the different royalty credit programs is presented in Appendix A.

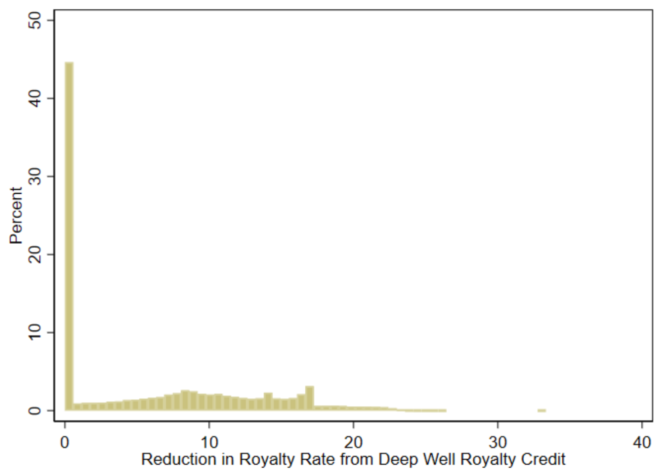
Figure 3-33: Percentage Point Reduction in Royalty Rates from PCOS, Oct. 2012 to May 2021



Source: Ministry of Finance data.
*Note: The x-axis denotes the percentage-point reduction in royalty rates, moving from a net royalty rate **after** rate reduction programs are applied to a net rate **after** the PCOS deductions. The y-axis denotes what share of observations correspond to each royalty rate reduction. For example, a y-axis value of two percent for a royalty rate change of 10 percentage points means that two percent of each well-month pair receives a royalty rate reduction of 10 percentage points. The rate reduction could be from 20 percent to 10 percent or 10 percent to zero percent; we do not distinguish in this figure. This analysis excludes infrastructure royalty credits.*

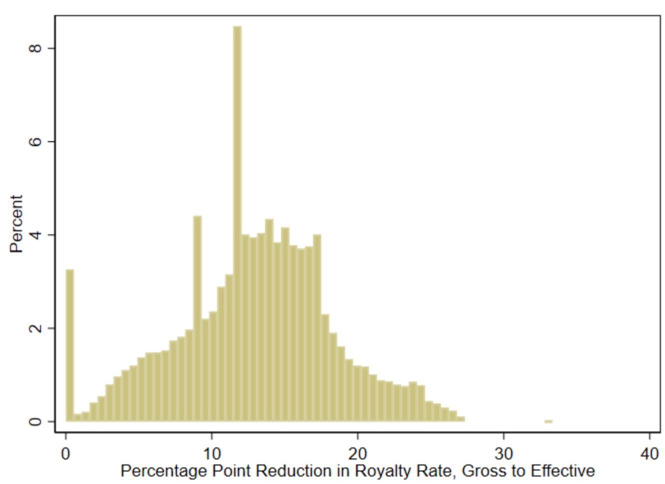
Figure 3-34 shows the effect of the Deep Well Royalty Credit (DWRC) program on royalty rates, from well-level monthly royalty payment data between October 2012 and May 2021. The change is relative to a net royalty rate for natural gas and by-product production, after deductions from rate reduction programs and the PCOS allowance. The average royalty rate reduction attributable to the Deep Well Royalty Credit program is six percentage points. Twenty percent of deep-designated wells do not use the DWRC to offset their royalty payments, suggesting for many of these wells one or both of the PCOS allowance or rate reduction programs bring the royalty payment to the minimum. A more detailed discussion of the effect of the DWRC program on royalty rates is presented in Appendix A.

Figure 3-34: Percentage Point Reduction in Royalty Rates from the Deep Well Royalty Credit, Oct. 2012 to May 2021



Source: Ministry of Finance data.
Note: The x-axis denotes the percentage-point reduction in royalty rates, moving from a net royalty rate ***after*** *rate reduction programs and PCOS are applied to a net rate* ***after*** *the DRCP deductions. The y-axis denotes what share of observations correspond to each royalty rate reduction. The rate reduction could be from 20 percent to 10 percent or 10 percent to zero percent; we do not distinguish in this figure. This analysis excludes infrastructure royalty credits.*

Figure 3-35: Percentage Point Reduction in Royalty Rates, Gross vs Effective

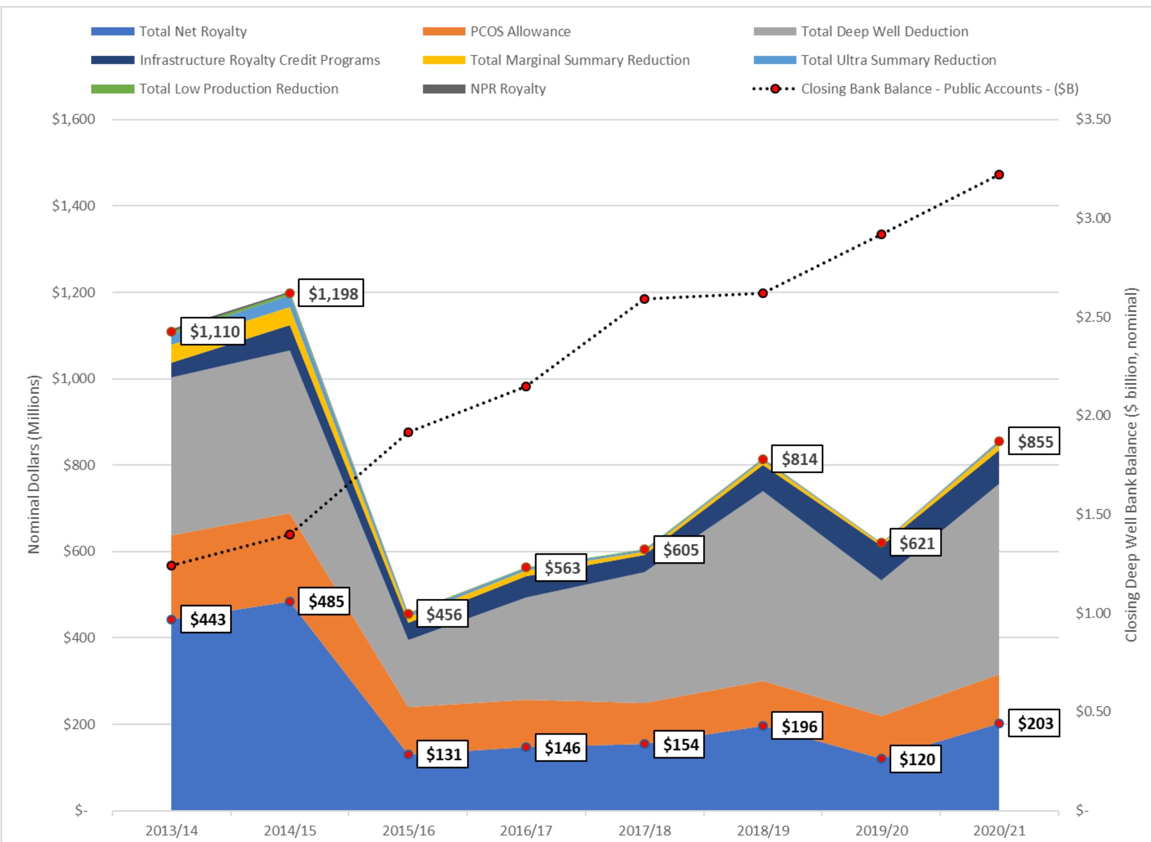


Source: Ministry of Finance data.
Note: The x-axis denotes the royalty rates in percentage. The y-axis denotes what share of observations correspond to each royalty rate. This means the figure shows the frequency of a given royalty rate between October 2012 and May 2021; the height of the bars denote frequency in percentage terms. For example, a y-axis value of 10 percent for a royalty rate of 20 percent indicates 10 percent of the well-month pairs have a royalty rate of 20 percent. Gross royalty rates are the royalty rates before all deductions; net royalty rates are the rates taking into account all deductions except for the infrastructure credits, and effective royalty rates are net royalty revenues as a share of marketable value based on market prices. Effective rate calculated using Sproule escalated forecast and monthly Westcoast Station 2 natural gas price instead of the producer price from the royalty system.

Figure 3-35 presents the percentage point reduction in royalty rates, moving from a gross rate before all deductions to an effective rate after all deductions and based on market value (rather than plant inlet value) for the natural gas. The average reduction in royalty rates is 13 percentage points. Twenty-seven percent of the monthly royalty payment records have a royalty rate reduction less than 10 percentage points and 64 percent have a royalty rate reduction between 10 and 20 percentage points.

The deductions outlined above (and discussed in more detail in Appendix A) have a significant effect on provincial revenues. Figure 3-36 shows the value of the province's gross royalty take, the royalty credits and net royalty by fiscal year. The two major credit sources that reduce the province's royalty take are the Deep Well Royalty Credit deductions and the PCOS Allowance. Net royalties range from 40 percent of gross in fiscal 2013/14 and 2014/15 to a low of 19 percent in 2019/20. Royalty revenues would be significantly higher in the absence of the various credit programs and deductions, all other factors being equal.

Figure 3-36: Value of Gross Royalties, Net Royalty and Royalty Credits by Fiscal Year



Source: Ministry of Finance and Ministry of Energy, Mines and Low Carbon Innovation data.

Chapter 4 - Lessons from the Alberta Royalty System and 2015-2016 Review

The most relevant royalty system to compare to that of BC is Alberta's. As BC's neighbouring province that shares the same Montney formation and other similarities in governance and regulatory systems, it is our focus. The other major reason for this focus is that Alberta undertook a major royalty review in 2015 and 2016, introducing a new system in 2017. Royalty systems in other jurisdictions (e.g., US, Australia) have fundamental differences in the nature of the deposits, governance structures, etc. and so comparisons were deemed to less applicable to BC.

Alberta's new royalty system came into effect January 1, 2017, after its 2015-2016 royalty review.[49] The review left the oil sands royalty system unchanged, and substantially revised the system for natural gas and non-oil-sands oil. Called the Modernized Royalty Framework (MRF), the new system applied to wells drilled after December 31, 2016. Wells drilled under the previous system are grandfathered until December 31, 2026[50], at which point they transfer to the MRF. Alberta also passed the *Royalty Guarantee Act* in 2019, providing certainty of no major changes in its royalty systems for at least 10 years (absent legislative change). To understand the scope of the changes (and improvements), a comparison to the previous royalty system is necessary.

4.1 The 2007 Alberta Royalty Framework

The 2007 Alberta Royalty Framework had two key features of relevance here. First, royalty rates that were a function of production and price, and that differed across hydrocarbons. Second, a set of drilling incentive programs that lowered the province's royalty rate (and therefore royalty take) during initial production; these programs were a function of time, volume of production, depth of the well, and combinations of the three.

The royalty formulas differ across hydrocarbons, and the royalty rate is flat for natural gas liquids. Moreover, the applicable royalty formula depends on the deemed production of a well. This means a change in the deemed production can create royalty cost shocks, and "an abrupt difference in applicable royalty rates if a well is deemed to produce crude oil, or a natural gas liquid" (Shaffer 2016, 11)[51]. The resulting incentive is that firms may avoid drilling in some areas to avoid specific hydrocarbons. The deemed liquid also determines the drilling inventive programs applicable to a given well, which also affects firms' incentives.

As noted by Shaffer (2016)[52], the drilling incentive programs did not accurately reflect costs and distorted firms' incentives. For example, the Horizontal Gas New Well Program lowered the royalty rate on the first 500 million cubic feet of production or 18 months. The effect of this program was to lower royalty rates regardless of price. An incentive program like this is low value to industry when prices are low, and high-value when prices are high. Similarly, the Natural Gas Deep Drilling Program provided a royalty credit to firms with gas wells of over 2,000 metres of vertical depth and increased with measured depth. The

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[49] Government of Alberta, "Royalty Overview," accessed September 12, 2021, https://www.alberta.ca/royalty-overview.aspx.
[50] Government of Alberta.
[51] Blake Shaffer, "Lifting the Hood on Alberta's Royalty Review," *The School of Public Policy Publications*, SPP Briefing Paper, 9, no. 7 (February 23, 2016), https://doi.org/10.11575/sppp.v9i0.42570.
[52] Shaffer.

threshold associated with the drilling program distorts drilling decisions: while a well drilled to 1,975 metres may be optimal from a resource recovery standpoint or expected profits, the presence of the royalty credit may compensate for lost profit from drilling a deeper well.

While Alberta's 2007 Royalty Framework differs from BC's in several ways, the systems share two key similarities. First, the royalty formulas differ across hydrocarbons. Second, both use a variety of incentive programs to reduce the royalty rate as an approximation of the Crown's share of costs.

4.2 The 2017 Modernized Royalty Framework

The key principles of the Modernized Royalty Framework (MRF) are that it simplifies the revenue minus cost approach to measuring rent, "harmonized royalty treatment across hydrocarbons," and "encourages industry to … reduce drilling and completion costs" regardless of the price.[53] The two major changes in the MRF were (1) replacing the various drilling incentive programs with a Drilling and Completion Cost Allowance, and (2) simplifying the royalty formulas.

The Drilling and Completion Cost Allowance (DCCA, referred to as C* or 'C-star') is a proxy for well costs, and the calculation is the same for all wells. For an individual well, the DCCA is a function of the well's true vertical depth, total lateral length, total proppant placed, number of well legs, and industry average capital costs.[54] The system treats all wells equally, regardless of the fluid the well produces, providing industry with certainty.

The DCCA then feeds into the royalty formulas. For wells with revenue below C*, the royalty rate is five percent. Revenue is calculated on a production-weighted basis using Government of Alberta administratively set prices (called par prices) for each hydrocarbon. Once cumulative revenue reaches C*, a well switches to the Post-C* royalty system, where royalty rates for each hydrocarbon vary with price. The royalty rate for oil ranges between 10 percent and 40 percent, and the royalty rate for natural gas (methane and ethane) varies between five percent and 36 percent, and the royalty rates of NGLs vary between 10 percent and 36 percent. Finally, once a well reaches a maturity threshold (based on daily production volumes) the royalty rate for each hydrocarbon is adjusted downward based on production volumes. The maturity threshold for entering the Post-C* Mature system differs for each hydrocarbon stream, and affects only that hydrocarbon's royalty rate, up to the minimum applicable royalty rate.

Alberta sets its par prices on a monthly basis. For natural gas, the par price is a weighted-average field price of all gas sales.[55] The reference price is the market price from the Nova Inventory Transfer point, less an intra-Alberta transportation deduction, pipeline fuel loss and any amendments from prior periods. The method is the same for natural gas liquids. For crude oil, the par price is gravity-specific (light,

[53] Government of Alberta, "Royalty Overview."

[54] Government of Alberta, "Alberta Modernized Royalty Framework Guidelines: Principles and Procedures" (Alberta Energy, June 1, 2020), https://open.alberta.ca/dataset/0ad025e1-3cbc-468d-88d6-2773e45c5f02/resource/4f55641b-5508-42cf-81e8-5519626d4560/download/energy-mrf-guidelines-version-2-2020-06.pdf.; Government of Alberta, "Alberta's Modernized Royalty Framework Overview" (Alberta Energy, n.d.), https://open.alberta.ca/dataset/c1254ab8-4000-452c-8b9a-19c74e8a581a/resource/9fc4cd54-1b9c-4c1e-9b87-bd5c9348613d/download/mrffactsheet.pdf.

[55] Government of Alberta, "Monthly Reference Price Calculations [2021]," August 16, 2021, https://open.alberta.ca/publications/monthly-reference-price-calculations-2021#summary.

medium, heavy and ultra-heavy).[56] The par price is again a weighted-average field price for each crude stream. The par price is a market price in Edmonton (based on market indices) less field transportation costs (which also differ by crude stream). Importantly, the natural gas par price is a weighted-average plant outlet price that each firm receives, and the crude oil par price is a "field" price that each firm receives. That means all firms face the same par price for their royalty payments.

There are several benefits to Alberta's Modernized Royalty Framework. The flat royalty rate in each well's early production guarantees the Province a return and allows firms to recover costs quickly. The parameterization of C* is based on historical industry-average costs, creating an incentive for individual firms to reduce their costs below C* and benefit from lower royalty rates even after their capital cost is recovered. As the royalty formulas and overall system are harmonized across hydrocarbons, firms are incentivized to develop the highest-value opportunities, without concern over how a well's production fluid or volumes affect the royalty framework.

The MRF also significantly improved Alberta's investment competitiveness based on the marginal effective tax and royalty rates (METRR) on capital for natural gas and oil.[57] The METRR summarises the marginal tax burden as a share of pre-tax rate of return on investment, accounting for capital costs (including corporate income taxes, sales taxes on capital purchases, capital taxes, transfer taxes, stamp duties, profit-based resource levies, and royalties) but excluding other inputs (labour and energy).[58] While imperfect, the METRR is a widely used measure of tax competitiveness, and the effect of taxes, royalties and "fiscal regimes on investment decisions" (Mintz and Chen, 2012, 1).[59] Table 4-1 summarises the METRR changes in Alberta for oil production. Importantly, Crisan and Mintz (2016) found Alberta's changes moved it from having "one of the highest METRRs for conventional oil investments in 2016" (p. 8) to below most comparator jurisdictions.

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[56] Government of Alberta, "Oil Par Prices," accessed September 12, 2021, https://www.alberta.ca/oil-par-prices.aspx.
[57] Daria Crisan and Jack M. Mintz, "Alberta's New Royalty Regime Is a Step Towards Competitiveness: A 2016 Update," *The School of Public Policy Publications*, SPP Research Papers, 9, no. 35 (October 31, 2016), https://doi.org/10.11575/sppp.v9i0.42608.
[58] Jack M. Mintz and Duanjie Chen, "Capturing Economic Rents From Resources Through Royalties and Taxes," *The School of Public Policy Publications*, SPP Research Papers, 5 (October 4, 2012), https://doi.org/10.11575/sppp.v5i0.42400; Crisan and Mintz, "Alberta's New Royalty Regime Is a Step Towards Competitiveness."
[59] Mintz and Chen, "Capturing Economic Rents From Resources Through Royalties and Taxes."

Table 4-1: Alberta Oil METRR by Investment Category

	Alberta Royalty Framework	**Modernized Royalty Framework**
Aggregate	35.0	26.7
Exploration	38.5	25.2
Development	41.7	29.1
Depreciable	25.3	25.3
Inventory	26.6	26.6
New Investment (all levies)	35.0	26.7
Taxes Only	9.4	9.4
Royalty Only	25.8	17.4

Source: Reproduced from Crisan and Mintz (2016), Table 1 and Table 2.
Note: Analysis based on a hypothetical well producing 50 barrels of oil per day.

Chapter 5 - Assessment and Evaluation of the Current System

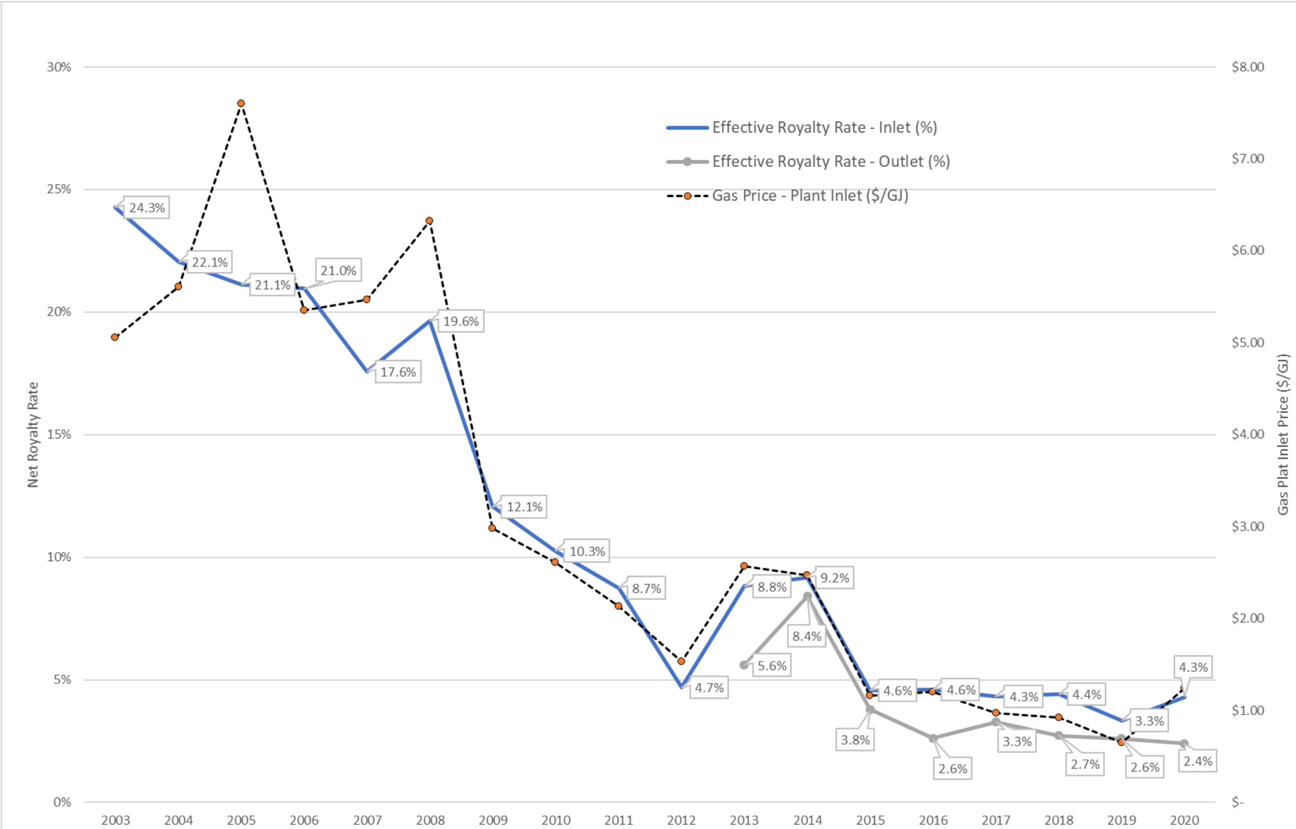
This section assesses the current BC royalty system for natural gas and oil. We evaluate the components of the system as described in Chapter 3 with regard to their contribution to net royalty income for the Province, their administrative and audit ease, public transparency, any creation of incentives not consistent with economically efficient production, alignment with BC's climate and environmental goals, and alignment with current industry extraction technologies and market conditions. Chapter 6 provides a summary of our concluding key points based on our discussion here. We note at the outset that our evaluation and assessment cannot perform a counterfactual exercise where we assess what production levels and royalty revenues would have been under a different royalty system. Instead, we rely on economic principles and assess the outcomes that we can measure to describe the challenges present in the current system's programs and incentives.

Figure 5-1 shows one measure of the effective royalty rate — the net royalty divided by the value of gas at the plant inlet. The value of gas at the plant inlet is the reference price of gas, not a market price. Chapter 3 describes how the reference price is calculated. Figure 5.1 illustrates the general decline in effective royalty rates for natural gas from their peak in fiscal 2005/06. During the fiscal years 2013/14 and 2014/15 there is a brief increase in these effective rates due to the increase in gas demand and prices; the trend thereafter is down to an average effective royalty rate of approximately 4.3 percent.

While precise attribution can be difficult to establish, the decline in effective royalty rates is due to lower natural gas prices and to the plethora of deductions and credits introduced to the system starting in the early 2000s. Drawing on Figure 3-26 that illustrates raw gas volumes produced from wells accessing some of the royalty credits (deep well, marginal) versus no credits, the share of production coming from wells accessing no credits peaked in 2002 and represented approximately half the total volume produced that year. By 2020, wells taking no credits had fallen to approximately eight percent of the total. By contrast, wells benefitting from deep well credits or deep well credits and marginal programs formed most of the balance of natural gas production. Adding in the other programs and credits by which gross royalty rates are reduced (e.g., low productivity production or an infrastructure royalty credit), further supports this argument.

To be comparable to other jurisdictions such as Alberta, we illustrate an alternative effective royalty rate measured as the value of net royalties per year divided by the value of natural gas at the plant outlet rather than inlet. Figure 5-1 shows that between 2013 and 2020 the effective royalty rate at plant outlet values is even lower than that based on inferred plant inlet values that have netted out GCA and transportation costs. Valuing the gas at its market price is a more appropriate measure of effective royalty rates over time as it is more inclusive of actual cost allowances that go into determining the net royalty payments. Effective royalty rates based on plant outlet value suggests the reduction in effective royalty rates is due not only to the market price of natural gas but also to components of the royalty system. Section 5.1 provides further analysis to support this argument.

Figure 5-1: Effective Royalty Rates and Gas Plant Inlet Price by Year



Source: Ministry of Energy, Mines and Low Carbon Innovation data.

A core issue is that some of the deductions from gross royalties are independent of the price of gas (e.g., PCOS, deep well and infrastructure royalty credits) or dependent on volume produced (low productivity, marginal and ultra-marginal programs).[60] As the market price rises, the incentive to produce more increases, but the net royalty payment can be reduced to a very low (even zero) level with the inclusion of these deductions and credits, leading to a potential disconnect between market conditions and royalty revenues. Looking back at the illustration of government's share of economic value of the resource in Figure 3-1), we illustrate the potential impact on the Crown's share of the royalties if producers are able to offset their royalty payments due to the programs and credits in the royalty system. Even in a situation with substantial net economic value (e.g., Figure 3-1 Panel A), the share of the value going to the Crown can decline considerably. For example, if the measured revenue less costs (the 'pie' generating returns to the producer and Crown), is $40 per unit of volume produced without the credits and deductions introduced into the royalty system in past 20 years, the government's share is 30 percent of the net value at a 12 percent royalty rate. If the royalty system introduces reductions of up to 95 percent through the myriad of rate reductions and deductions, the Province's share of the net value falls to 1.5 percent. These rate reductions and deductions were in principle designed to capture actual costs of different well types, so the 'pie' might indeed be smaller than $40. The presence of deductions from gross royalties that are

[60] Decisions on what volume to produce are a function of the price the producer receives, but the credit amount itself is not related to the price of natural gas.

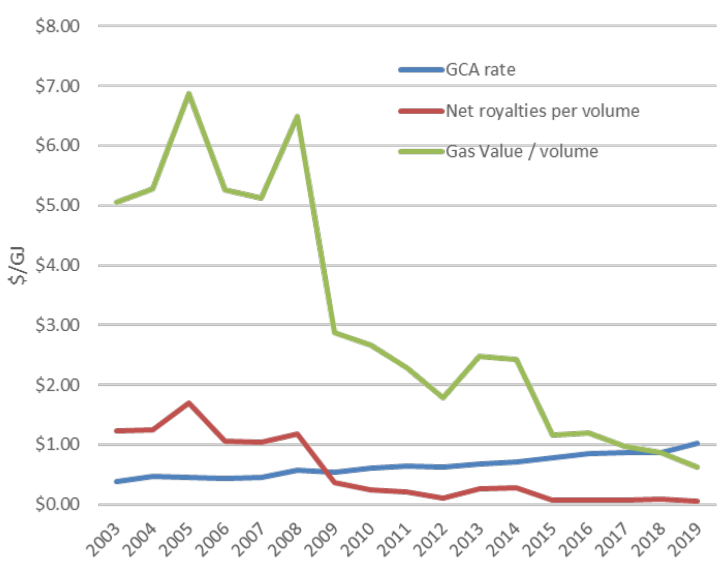
unconnected or only loosely connected to current market and cost conditions can significantly reduce the Crown's share of the economic value. Another way to express this is that while an objective of the Crown is to promote development by sharing in the risks of resource development with producers, it is doing so with downside risks, but the Crown's 'reward' for upside risk (favourable market conditions) can be quite low as virtually all the net value may go to the producer.[61] We look in more detail at the components of the system described in Sections 3.4 and 3.5 to highlight areas where issues might arise.

5.1 Costs of Production

5.1.1 Gas Processing Costs

The allowance for gas processing costs have risen at an average annual growth rate of 6.2 percent over recent years, a rate significantly above the economy-wide rate of inflation. Figure 5-2 illustrates the rise in these costs compared to net royalties and gas values per unit volume in dollars per gigajoule and in percent terms. An important question is why have costs for processing natural gas risen considerably, particularly in recent years? Is BC simply a higher cost jurisdiction and thus has to accept a lower share of resource value from the sector? Or, by placing the starting point for the royalty system at the intake of gas processing plants, is BC getting a smaller share of the net value due to the methods for computing these processing costs? Other factors might also contribute to lower net values and hence, a smaller pie in BC that are not due to higher costs. There could be irregularities in the data reported due to the complexity of the system (e.g., errors in reporting) that lead to lower claimed gas plant throughput volumes, which translates into a higher gas cost allowance and lower royalty rates.

Figure 5-2: Gas Cost Allowances versus Product Value, 2003-2019



Source: Ministry of Energy, Mines and Low Carbon Innovation data.

[61] A fulsome analysis of this conjecture would require computation of net present values over the life of a well event under a myriad of different market conditions, well attributes, with and without the various royalty credits and deduction programs. There is no "typical well event" and thus this represents a research project that is beyond the scope of our work.

Calculating processing costs is complex, with the GCA specific to where the raw gas is processed (see section 3.5.1, Gas Processing Costs). The process of determining GCA where some of the processing costs are 'market-based' and others are implicit or calculated (via internal transfer pricing) might be contributing to making BC a higher cost region as well as adding to complexity. This is because an individual firm's costs directly affect its royalty payment. Increasing costs are partially borne by the province via a lowered royalty payment by the firm, and so an individual firm has a reduced incentive to lower its gas processing costs. Moving to the plant outlet for the point of determining gross royalties might help by making more of the costs (and prices) be market based and cost determination more transparent and auditable. For example, Alberta has a natural gas reference price set at a market point of sale, with a provide-wide adjustment for processing and transportation costs. All firms face the same reference price, and hence an individual firm gains from reducing its costs-to-market vis a vis the reference price.

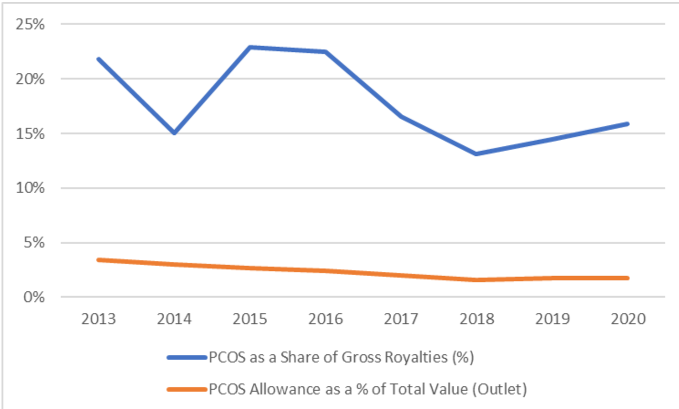
5.1.2 Producer Cost of Service (PCOS)

In 2011, a consulting company prepared the cost factors and components of capital and operating costs that are attributed to extraction of raw gas that underlie the PCOS computation. There has since been no way to update or replicate the underpinnings of PCOS. The government issued a request for proposals to update the program but received no viable submissions. In addition, technological change and innovation in the industry has reduced many of the costs that comprise the PCOS system, so it is quite likely that the factors currently in use are significantly outdated and could be higher (or lower) than actual costs. Figure 5-3 illustrates the aggregate PCOS allowances as a share of total marketable value of all natural gas and liquids products from 2013 to 2020, and compares it to PCOS as a share of gross royalties. While PCOS is quite important as a share of gross royalties, it is small relative to the marketable value of gas and byproducts. This is partially a result of royalty calculations being made at the plant inlet rather than the plant outlet. Aggregate PCOS allowances have generally declined since 2016, which combined with generally increasing total marketable values, produces a declining PCOS-to-value ratio. This is at a time when studies of extraction in the Montney indicate that average costs of production may be declining.[62] When deducted from gross royalty payable at the well level, PCOS can amount to 95 percent of the total gross royalty, leaving a residual of only 5 percent.

Figure 5-4 provides a more granular look at PCOS as a share of gross royalty revenue (before all deductions), utilizing monthly data over the period October 2012 to May 2021. Panel A shows aggregate PCOS as a share of aggregate gross royalties by production month, and Panel B shows the average PCOS share for each month, where the average is calculated from each well event. While there is considerably more variability month to month, itself a concern, the overall picture is similar — the PCOS share of royalty rose following the 2014 gas price spikes to 2020. Notably, looking at aggregate PCOS allowances as a share of royalties masks the fact that for some wells, PCOS has accounted for a substantial share of the gross royalty revenue, up to 103 percent.

[62] For example, the Canada Energy Regulator notes that "Operators have developed the Montney using a manufacturing approach, including continual application of lessons learned from previous generations of wells to improve productivity and lower costs per unit of gas recovered". Canada Energy Regulator, "NEB — Market Snapshot."

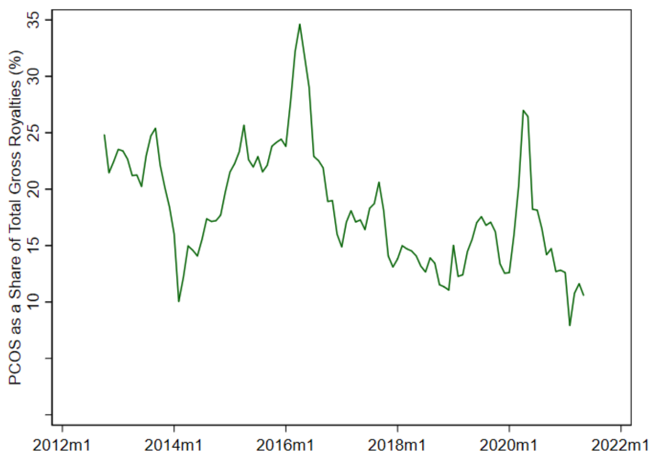
Figure 5-3: Total PCOS Allowances as a Share of Total Gross Royalties and Marketable Gas Value, 2013 to 2020



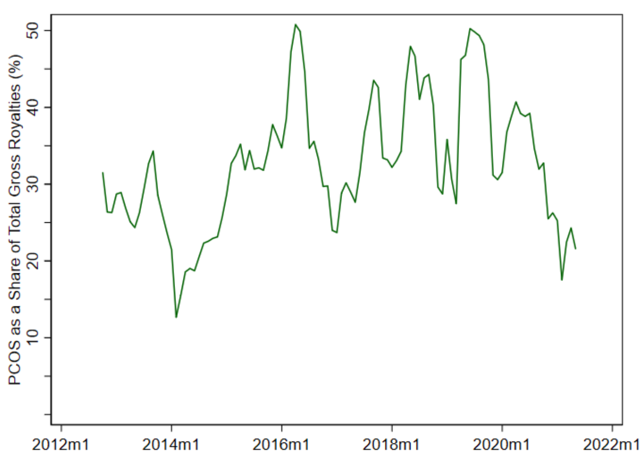
Source: Ministry of Energy, Mines and Low Carbon Innovation data.
Notes: Marketable gas value calculated at plant outlet. Gross royalty revenue is before all deductions.

Figure 5-4: PCOS as a Share of Gross Royalty Revenue, Oct. 2012 to May 2021

Panel A: Aggregate PCOS as a Share of Aggregate Gross Royalty Revenue



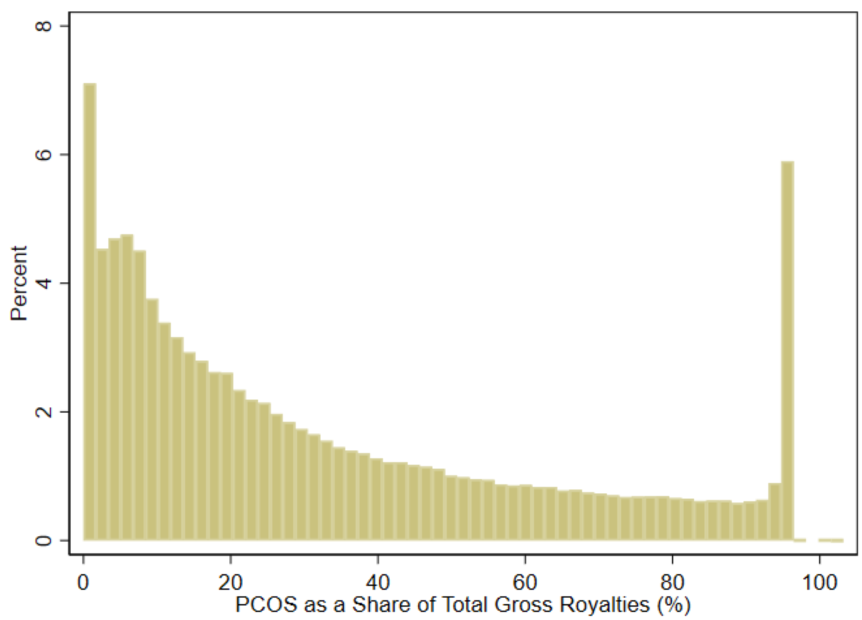
Panel B: Average PCOS Allowances as a Share of Gross Royalty Revenue



Source: Ministry of Finance data.
Note: Gross royalty revenue is before all deductions, including PCOS.

Figure 5-5 presents the distribution of the PCOS share (PCOS as a share of gross royalty revenues). The distribution is very flat, meaning that for many wells, PCOS accounts for very little of the reduction in royalty payments. Twenty-nine percent of wells have a PCOS allowance that is less than or equal to 10 percent of its gross royalty; 46 percent have a PCOS share less than 20 percent, and 74 percent have a PCOS share less than 50 percent. For a very small number of wells, the PCOS allowance is actually greater that the gross royalty. However, the fact that PCOS is applied after other royalty rate reductions means that Figure 5-5 does not paint a full picture of the effect of PCOS on net royalty revenues. We return to this point below after we discuss the effect of the various rate reduction and credit programs.

Figure 5-5: Distribution of PCOS as Share of Gross Royalty Revenues, Oct. 2012 to May 2021



Source: Ministry of Finance data.
Note: Gross royalty revenue is before all deductions, including PCOS. The x-axis denotes PCOS as a share of calculated gross royalty revenues (PCOS share). The y-axis denotes what share of observations correspond to each PCOS share. This means the figure shows the frequency of a given PCOS share between October 2012 and May 2021; the height of the bars denote frequency in percentage terms. For example, a y-axis value of four percent for a PCOS share of 20 percent indicates four percent of the well-month pairs have a PCOS allowance that is 20 percent of gross royalties.

In summary, a system that is not transparent, cannot be replicated, and may be overstating the costs of extraction is a system ripe for reform. In our view, the whole structure of the PCOS system is problematic.

5.2 Royalty Rate Reduction Incentives

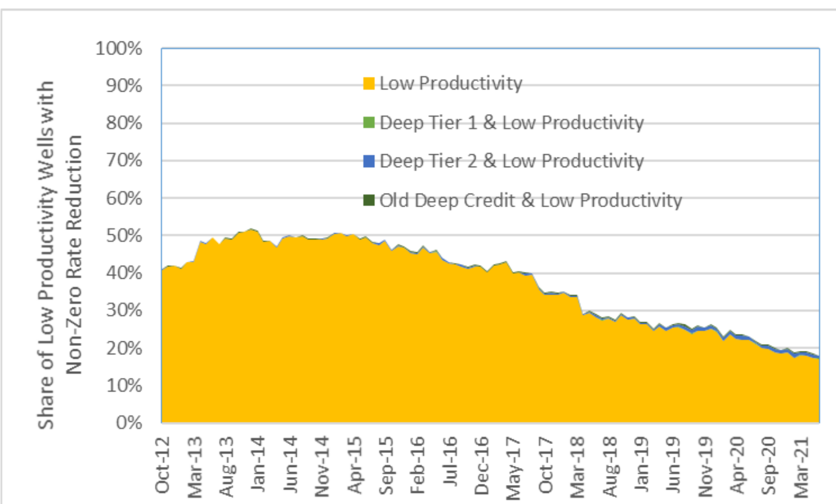
In general, the production rate reduction incentives are programs that are outdated and no longer necessary and applicable with shale technology and current market conditions. They were introduced at a time when there were concerns about the future viable supply of fossil fuels and prior to the 'shale revolution'. From multiple viewpoints — encouraging efficient production, meeting climate and environmental goals, and the Crown and First Nations securing a fair share of the net returns from natural resource development — provincial policy ideally should be neutral with regard to the quality of the well. The exception is if there are reasons to believe that there are some forms of market imperfections or failures that are interfering with efficient development within the industry. Efficient production should have a profile where the wells go out of production when the expected returns do not cover costs. Rate reduction programs may be encouraging continued extraction from well events that should have reached their economic end date. This argument can be made for each of the programs currently operating that comprise these rate reduction incentives.

Production rate programs are incompatible with and do not further provincial climate and broader environmental objectives. They encourage development of wells that are deemed 'marginal' that in principle would otherwise not be developed, and continued production from low-volume wells beyond the time they would normally produce (absent the program). Encouraging natural gas production that might otherwise not occur contributes to downward pressure on market prices for natural gas and does not help meet GHG targets.[63] In BC's current state of oversupply, this effect is exacerbated.

5.2.1 Low Productivity Wells

The low productivity rate reduction prioritizes volume, not value. Without going into monthly well data in detail we cannot show, but only speculate, that due to the provisions of this program where any well can be designed 'low productivity' in any month when its gas volumes fall below the posted minimum, producers could be gaming the system to prioritize certain wells when without this program they would not have done so. They may also reduce gas volumes and prioritize NGLs to minimize the royalty rate for the gas extracted. Figure 5-6 shows the share of low-productivity wells that receive a positive reduction in their royalty rates between October 2012 and May 2021. Historically, close to 50 percent of the wells received a rate reduction, though this has decreased to 19 percent in 2021. A very small number of Deep Credit wells also designated as low productivity receive the rate reductions.

Figure 5-6: Share of Low Productivity Wells with a Non-Zero Royalty Rate Reduction, Oct. 2012 to May 2021



Source: Ministry of Finance data.

[63] This concern may decrease over time as carbon prices rise to $170 per tonne. Unless natural gas and associated product prices rise considerably, as the carbon tax rises and covers more emissions from the sector (e.g., controlled venting, fugitive emissions, flaring), it becomes less likely that marginal and low productivity wells will continue to operate. The royalty reductions become increasingly less able to offset the higher carbon tax owed whether the well operator is an integrated company operating downstream or a standalone upstream producer.

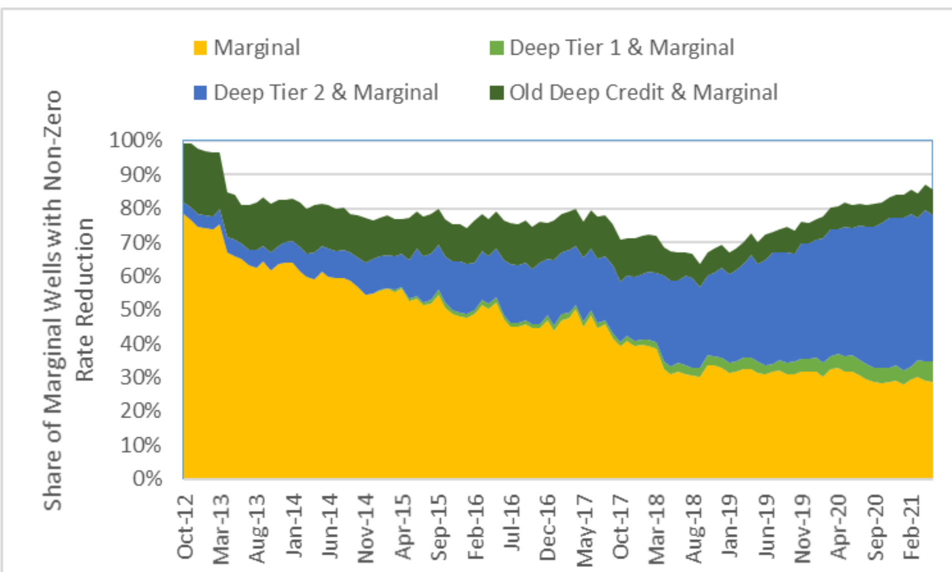
A second issue with the program is that wells defined as low productivity are those gas wells with raw gas production less than 5,000 cubic metres per day. This has two effects. First, wells with low gas production but high liquids production receive an unnecessary reduction in the gas royalty rate. Second, as only gas wells are eligible for this program, it disadvantages wells with a primary product of oil relative to those with gas as the primary product.

In Appendix A, we illustrate that volumes from low productivity wells with the application of PCOS for these wells reduces the average effective gross royalty rate by nine percentage points from 18.4 percent to 9.4 percent. Addition of other eligible deductions for these wells further reduces effective royalty rates, with 53 percent of wells facing an effective royalty rate of five percent or less.

5.2.2 Marginal and Ultra-Marginal Wells

The marginal well designation and determination of its productivity is during its initial extraction period. It is possible that there may be some gaming of the system by restricting the rate of extraction in the first year so as to be deemed marginal and thus keep that designation for the life of the well.[64] Once a marginal well, a well event is always a marginal well, as is also the case for ultra-marginal wells, and thus does not take into account whether the type of product extracted from the well changes over time in response, for example, to changing market conditions. Figure 5-7 presents the share of marginal wells that have a non-zero royalty rate reduction in a given month. This ranges from a high of 99 percent of wells in 2012 to a low of 68 percent in 2018. An increasing number of Deep Credit wells receive the marginal rate reduction, which also prolongs the use of the Deep Well Bank.

Figure 5-7: Share of Marginal Wells with a Non-Zero Royalty Rate Reduction

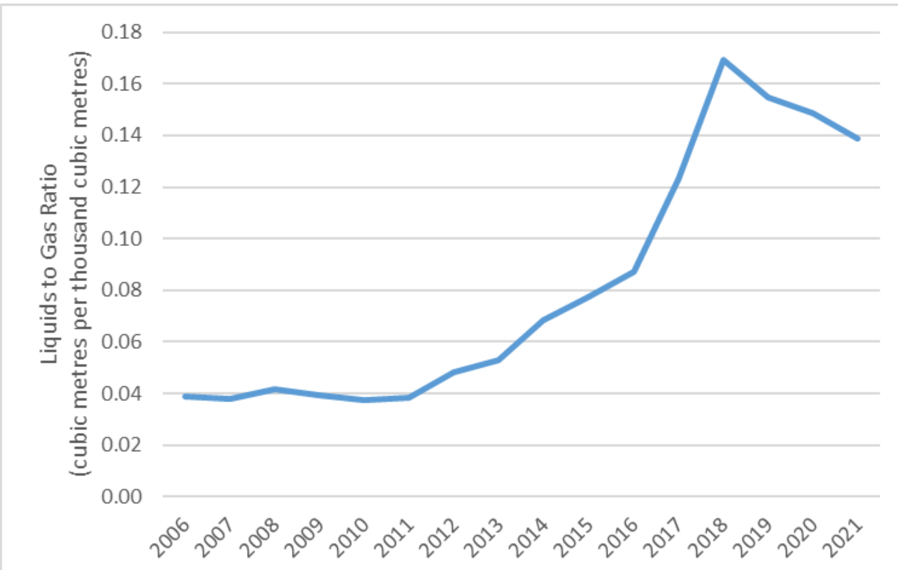


Source: Ministry of Finance data.

[64] The 'marginal' initial production may be to optimize extraction over the life of the well to e.g., sustain pressure.

The Montney is a region typified by deposits rich in natural gas liquids. Thus, the well is hardly "marginal" but continues to receive reductions in its royalty rate on the natural gas produced.[65] The well should in this case not be designated a marginal well as it could be among the "best" wells in the province in terms of total product extracted and value created. The problem is the designation at the outset of its natural gas production that may not capture the product mix coming from the well, and thus has a very weak rationale for receiving the rate reduction. Figure 5-8 illustrates the rising ratio of natural gas liquids production relative to natural gas in recent years for wells designated as 'marginal'.

Figure 5-8: Liquids to Gas Ratio for Wells Designated as Marginal



Source: Ministry of Finance and BC Oil and Gas Commission data.
Note: Liquids includes condensate, butane, ethane, pentane and propane.

Similar to the marginal well program, wells are designated as ultra-marginal based on initial natural gas production. Of wells with this designation, 100 percent of them received a positive royalty rate reduction between October 2012 and May 2021. With the 2014 changes to this program that disallowed horizontal wells and coincident shift in production with shale development and hydraulic fracturing, there is little rationale to continue to sustain an ultra-marginal well designation. For the general reasons cited above, this is a program way past its "best by" date. The same can be said for the coalbed methane program. No wells were brought into production. There are no plans to develop the resource, and the program can be eliminated.

5.3 Royalty Credits

The deep well royalty and infrastructure credit programs can encourage extensive development beyond what would occur in their absence. They are not compatible with environmental goals (see section 5.4) to the extent that they contribute to more GHG emissions and land disturbance with its associated

[65] These wells can lower their royalty payments even further (and to a zero effective rate) in months where their natural gas volumes allow them to access the low productivity rate reduction, again indicating that a highly productive well overall is paying less in royalties due to the presence of these programs than would otherwise be the case.

deleterious effects. Without the infrastructure credits, production might be less dispersed. If there were no deep well credits or infrastructure credits, it is likely fewer wells would be drilled. A rationale for supporting royalty credits is to lead to lower effective net royalty rates at the beginning of a well's productive life to help offset the costs of establishing the asset. Generally, effective net royalty rates (and royalties collected) rise as the well produces over time. This has not happened in BC due in part to market conditions, but also to the use of these credits to lower net royalties to close to zero. There is a fundamental question of by how much the Crown should offset the costs of fossil fuel development given its multiple objectives. It is one thing to account for costs in determining the net economic value from developing the resource, but the credit programs may be contributing to or possibly overcompensating for costs with the combined effect of all the programs (credits, PCOS, GCA). There is no apparent market failure that currently justifies the continuation of these credits.

5.3.1 Deep Well Royalty Credits

The program is outdated. As with the production rate reductions, they were introduced prior to the commercialization of shale technology and likely contribute to a 'higher cost' and more inefficient industry than might otherwise occur in their absence. Subsequent changes in 2009 and 2014 increased the credit allocations — as illustrated by the cost changes in Figure 3-7 through Figure 3-11 — are not necessarily aligned with current cost structures. Deep well credits can encourage inefficient production because it incentivizes firms to drill to access the credit, rather than drill to minimize costs and maximize revenues. For example, to access the current Tier 2 credit[66], the deepest productive well event in the well has to have a true vertical depth (TVD) to a completion point of 2500 metres to qualify for the credit. This threshold incentivizes firms to drill to at least that depth.

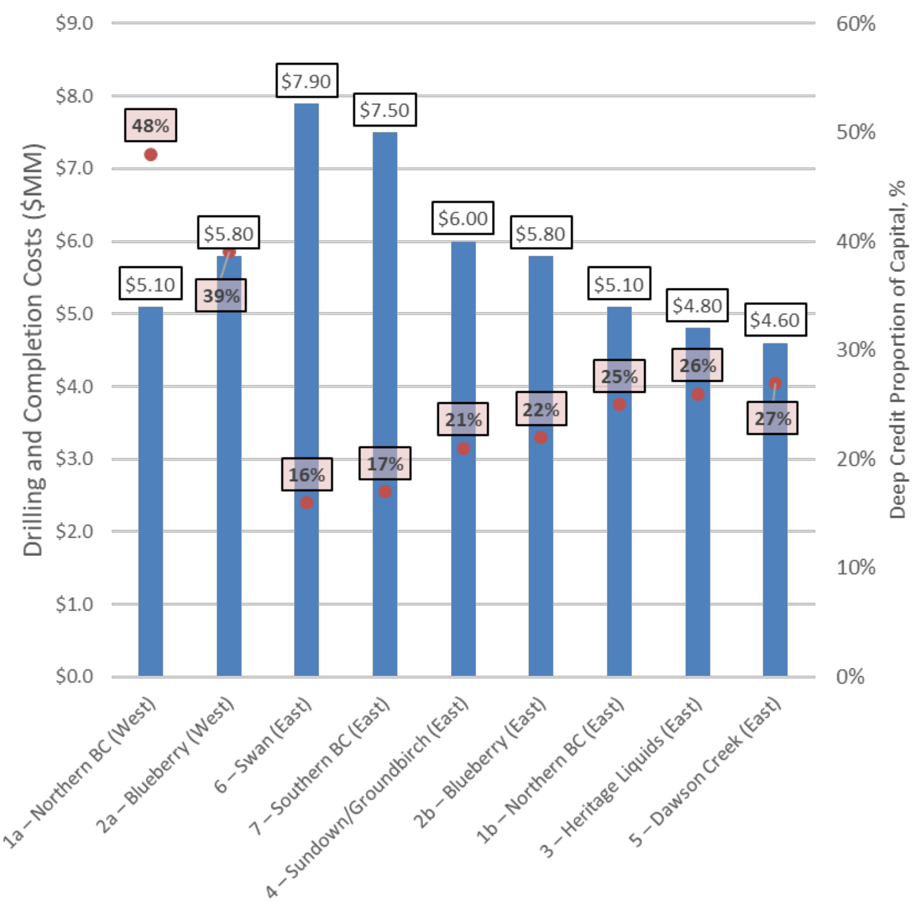
For example, for a West Sweet well drilled on or after September 1, 2009, the credit is $4,370 per metre once a depth of 2,501 metres is reached. The credit increases by additional amounts for deeper wells. A well with depth of 2,500 metres receives $0 in credit, whereas a West Sweet well with depth of 3,000 metres receives a total credit of $2.185 million. A well with depth of 4,250 metres would receive $2,846,000 plus $805 per metre beyond 4,000 metres for a total of just over $3 million. Companies then may prioritize production from wells that have obtained the credit to utilize any existing stock of credits attributed to the well event. This can lead producers to favour more costly wells because the royalty credit can decrease the net royalty rate to a negligible level, thus reducing a producer's overall royalty bill and increasing its revenue to compensate for the cost of drilling. Over $3.7 billion worth of deep well royalty credits are currently outstanding and accumulating at a rate of 20 percent annually. The accumulation occurs even with these credits offsetting over 50 percent of gross royalties annually for the wells they cover. In fiscal 2013/14, the credits issued were 33 percent of gross royalties; this has increased to 52 percent of gross royalties in 2020/21. While some of these credits will never be fully applied to offset royalties — in the case of wells that cease production before they exhaust their total credit allocation — the net balances remaining are still substantial and will lead to lower royalty payments to the Crown as they are applied.

There are a number of other issues with the program.

[66] For wells with a drilling start date on or after September 1, 2009.

- The dollar amount of credits per metre per well has been constant since 2009 while the costs per metre drilled have declined over time (Figure 3-8), effectively raising the value of these incentives over time.
- The east-west area designation that determines the size of the credits (see Table 3-4) is essentially arbitrary and thus deposits that may be essentially similar can receive larger allowances for deep well credits if on the west than the east. Deep well credit data by location also indicates that wells in the West are receiving substantially more credits as a share of total capital costs than those in the east, suggesting considerable over-allocation of credits for well events in the west. Figure 5-9 presents data from well events in East and West showing the ratio of average deep well credits as a share of total capital costs. Wells in the West have an allocation of credits as a share of their capital costs that are substantially higher (ranging from 39 to 48 percent) than that of wells in the east (ranging from 16 to 27 percent). Figure 5-9 also illustrates that the drilling and completion costs for wells in the west are not substantially different from those in the east, and are lower than some of the eastern sites, supporting the argument that the east-west distinction is unnecessary.

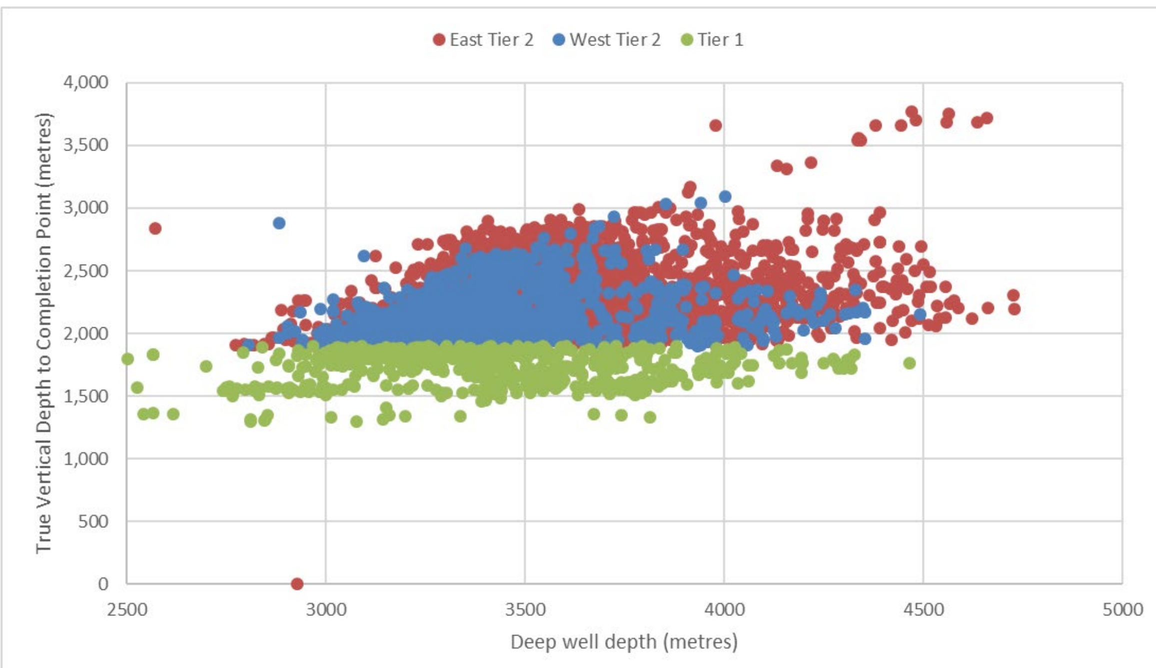
Figure 5-9: Deep Bank Credit Allocation as a Share of Capital Cost



Source: Ministry of Energy, Mines and Low Carbon Innovation and Wood Mackenzie.
Note: Drilling and completion cost data from 2019. Deep Bank Credit allocation based on Wood Mackenzie play-specific drilling depth and length assumptions.

- Examining well production and credit use shows both happen early in wells' extraction profile when typically revenues are highest (depending on market prices of course). Then, when production declines over time, the producer may qualify for rate reduction programs (Figure 5-5 and Figure 5-7 show the marginal designation matters more) and continue to pay less in total royalties than would be the case without this program. The Province's share of the net returns from the resource is thus lower overall (in both 'good' and 'bad' times) than it would be without these incentives.
- There is also scope for strategic behaviour to drill just to the point where the deep well credit applies. It is possible that a shallower well could have been profitably developed. The incentive will be greater for wells drilled in the West than the East. If the credit is encouraging developers to bypass shallower wells, there is also the risk of depleting the pressure in the area and further leading to higher costs of extraction caused by inefficiency. The Montney is 300m thick. The deep well credit applies at 1,900 metres for Tier 1 wells. The incentive to bypass shallower wells thus becomes apparent. Figure 5-10 presents a scatter plot of wells by tier and location, which shows there is a tendency for companies to drill Tier 2 wells at the edge of the eligibility threshold. While we cannot conclusively prove this, the pattern exhibited in Figure 5-10 suggests the threshold affects drilling decisions.

Figure 5-10: Deep Well Depth versus True Vertical Depth to Completion Point for Wells Accessing the Deep Well Credit Program



Source: Ministry of Finance data.

- The eligibility for the deep well credit is a function of the initial classification of the well. To access the deep well credit, a well has to be classified as a gas well; if it is classified as an oil well, it is not eligible for the credit. The result may be a devaluation of natural gas liquids. Notably, this difference prompted a revision of the well classification rules for the Montney in 2019. As a result, very few oil wells have been drilled and classified as Third Tier oil since the change.

5.3.2 Infrastructure Credits

We have a number of concerns with the infrastructure credits. The most basic is that we question whether they are needed to generate additional investment and GHG reductions that would otherwise not occur. Moreover, they may be contributing to environmental degradation and do not take into account cumulative effects from road and pipeline development. Due to the complexity of the royalty system and existence of other programs in the province incenting reductions in GHG emissions, infrastructure credit holders may receive multiple deductions for the same costs. In other words, there may be inadvertent double dipping due to overlapping components in multiple programs. We explore each of these below.

- The fundamental question of whether the infrastructure credits generate additional investment in natural gas development and additional reductions in GHG emissions that would not have occurred in their absence is challenging to assess. Both the Ministry of Energy, Mines and Low Carbon Innovation and the Ministry of Finance do not have definitive data one way or the other. On one hand, the entity applying for the credit would already have paid their bonus bid to acquire the lease, and so should have the expectation that the property would yield viable returns. There is no guarantee that they would be successful in being awarded the infrastructure credit as the program is oversubscribed each year. EMLI reviewed the programs in 2009, 2011 and 2019 to assess what percentage of applications that did not receive the credit were ultimately built and found that a relatively high percentage did not go forward. That still does not answer the question fully because those did not receive the credit might have been the projects that had weaker economics supporting their application. One could make the argument that the credit allows the producer to secure financing that might otherwise not occur or come at a higher interest rate on the basis of paying lower royalties and thus yield higher returns over time. However, that may place too high a weight on the contribution of royalty payments to the company's net returns on their investment.
- There are other programs in the province to support reductions in GHG emissions under CleanBC (e.g., the CleanBC Facilities Electrification Program and the CleanBC Industrial Incentive Program (CIIP)). It is beyond our scope to explore any potential overlap with these programs, but they warrant investigation to see if some costs for infrastructure investment to reduce GHGs are covered by multiple programs. In addition, we question whether the royalty system is the appropriate vehicle to incent GHG reductions. The intent of CIIP is to provide incentives to continually reduce emissions and reduce carbon taxes owing. The royalty system provides no such incentives. It is possible that the implicit cost per tonne of GHGs reduced though infrastructure credits reducing royalty payments is considerably higher than the current carbon tax rate of $45 per tonne.
- The application process does not include an assessment of whether the proposed GHG-reduction projects are in addition to regulatory requirements such as BC's methane emission reductions.
- The 'growth' component of the Infrastructure Credit program incentivizes extensive development — more roads and pipelines. These incentives run counter to environmental objectives (see section 5.4). Well data suggests that producers are pushing development to where they can get these credits, which means more environmental degradation of all sorts.

- Respect for Indigenous rights and title in the development of natural resources on traditional territories is an important BC goal as affirmed under the *Declaration on the Rights of Indigenous Peoples Act*. If any form of infrastructure credit continues to exist, there is the need to explicitly measure and incorporate cumulative effects in new investment as noted in footnote 8.
- The Gas Cost Allowance application requires producers to report their capital costs and annual direct operating costs. Currently, the Province does not have a program to reconcile the costs between what is submitted to receive infrastructure credits and what costs they claim for the GCA deduction. Due to this lack of audit process, it is possible producers are able to claim some share or all of the same costs for both.
- Once the Ministry of Finance receives affirmation from the Ministry of Energy, Mines and Low Carbon Innovation that the credit has been approved for the entity, the credit will automatically be used to reduce any royalties payable by that entity, thus creating the incentive to apply for the credits to lower royalties on all the company's wells.[67]

Finally, producers with infrastructure credits can continue to apply them to their royalty bill until it is reduced to zero. This means zero net benefit from the resource accrues to the Province. This is unlike other programs, where there is a minimum royalty rate. Should there be a minimum amount paid?

5.4 Environmental Impacts

All human and economic activity can adversely affect our environment — our lands, air, water, ecosystems and their creatures — by changing the state of the natural environment and the creation of waste products such as greenhouse gases (GHGs) and air and water pollution stemming from the production and consumption of the goods and services that society values. Governments are faced with weighing the trade-offs between development and economic activities that generate incomes and support wellbeing against their deleterious effects on the environment, mitigating those impacts where feasible. This section briefly discusses environmental impacts from oil and gas development and how the royalty system interacts with those impacts.

The environmental impacts of petroleum and natural gas development come in four main forms: the disturbance of natural habitat and ecosystems via physical infrastructure (e.g. wells, access roads, pipelines, etc.); water use in hydraulic fracturing and its disposal; emissions from operations and downstream combustion; and end-of-life liability management and reclamation.

In most instances, the royalty system has very little direct interaction with the environmental impacts listed above, though there are indirect effects. We note that it is not necessarily the purpose of the royalty system to manage environmental impacts — policy trying to achieve too many objectives at once often accomplishes each objective partially or not at all, or at all well — but it is important to consider how the royalty system can have unintended and negative, or unintended and positive additional consequences. We discuss impacts that may have a connection to the royalty system.

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[67] A simple example illustrates how the infrastructure credits work. For an approved producer, once the infrastructure is built and wells are drilled and begin producing natural gas, the earned credits can be applied. If the producer has a royalty owing of $100,000 for the first month of operation of wells associated with the pipeline for which it received the infrastructure credit, then EMLI issues a letter to FIN to authorize FIN to apply $100,000 of the entity's infrastructure credits to the royalty owing for those wells. For every month thereafter, the infrastructure credits will be automatically applied to all wells in BC owned by that entity.

5.4.1 Land Disturbance

The consequences of natural gas development in BC are best thought of in terms of cumulative effects and considered alongside other economic activities such as forestry. That said, there are specific oil and gas activities, including interaction with the royalty system, that are relevant here.

Recent changes in oil and gas operations to drill multiple wellbores from a single well pad lessens surface disturbance relative to historical drilling activities. The royalty system does not explicitly prioritize or penalize specific drilling activities, and so any influence of the royalty system on land disturbance is second-order at best. There are three major exceptions to this statement.

First, the royalty system exempts designated wells from royalty payments ("deep discovery well events" for natural gas wells and "discovery oil" for oil wells). To the extent that this exemption reduces the operational costs of discovery wells relative to non-discovery wells though royalty payment elimination, it is an effective subsidy of additional development and likely increases land disturbance. This is particularly true for deep discovery well events, as one of the conditions is the well's surface location must be at least 20 km away from "the surface location of any well in a recognized pool of the same formation."[68] As no wells have received this exemption, it is only of minor concern. However, there are potentially less distortionary ways to address the issue of discovery wells being higher cost, and, as noted above, should be eliminated for additional reasons.

Second, the Infrastructure Clean Growth Royalty Credit Program (and its predecessor the Infrastructure Royalty Credit Program) that was established to encourage companies to explore and access new and under-developed areas of the province, can offset up to 50 percent of the capital cost of new infrastructure associated with oil and gas development. The "clean" part of the program does incentivize investment in capital equipment to reduce emissions of GHGs and pollutants. While the "growth" aspect of the credit may be valuable for economic activities beyond natural gas development and for remote communities, this is unlikely and it does increase land disturbance. As the program offsets costs for firms, it may result in overdevelopment of infrastructure relative to what firms would pursue on their own. Additionally, as it subsidizes firms' capital costs via royalty credits, they can then use this additional capital to invest in additional production, further increasing land disturbance relative to the absence of the program.

Third, the low productivity production incentive program reduces the royalty rate paid by wells with low natural gas production and keeps these wells in production longer. These programs prolong the economic benefit of the well for a given (and sunk) level of disturbance, but also postpones reclamation.

Fourth, the marginal and ultra-marginal drilling incentive programs lower the royalty rate for designated wells with low initial production of natural gas. The lower royalty rate lowers operating costs, and hence creates an incentive to drill additional wells that might otherwise have occurred, increasing land and ecosystem disturbance. It also encourages firms to drill potentially low-value wells, and so the benefit per hectare of land disturbed is lower. The lower royalty rate also prolongs the economic life of the well, and hence also postpones reclamation.

[68] Handbook page 58.

5.4.2 Water Use

There is no direct relationship between the royalty system and water use. However, to the extent that the differing royalty credit and incentive programs increase drilling-activity relative to an absence of these programs, this also increases water use.

5.4.3 Greenhouse Gas Emissions

Emissions that contribute to greenhouse gases (GHGs) come from four sources: upstream leaks, upstream venting and flaring, on-site combustion, and downstream combustion. All are a function of production. As on-site flaring and downstream combustion is covered by BC's carbon tax, we omit those emissions sources from our discussion.[69] Additionally, BC has regulations covering methane emissions from oil and gas operations, and so we only discuss how the royalty system affects production and emissions incentives.

Broadly, the higher the royalty rate the higher the province's share of the value. The firm's share of the value determines how much a firm will re-invest in additional production, and so all else equal, a higher royalty rate will result in overall lower production and lower emissions from that production. Similarly, royalty credits increase the firm's share of value and would result in higher production and emissions relative to a scenario without credits. However, choice of royalty rate and any royalty credits is, and should be, a decision about appropriate share of value. There are other, more appropriate policy mechanisms to address emissions directly rather than through the royalty system.

As a caveat, however, the royalty system can affect emissions in other ways. As noted above, the royalty rate adjustments and other credits keep wells with low natural production producing longer by lowering firms' operational costs. Older wells, by nature of their older infrastructure, tend to leak more.[70] As a result, prolonging the producing life of the well may increase methane emissions by postponing plugging and reclamation. As leaks are not covered by the carbon tax (though they are regulated) firms have limited financial incentive to address the problem beyond the lost revenue.

However, the different producing plays have different chemical compositions. Most new and current production is from the Montney formation. Of particular interest is that Montney wells are on average 0.18 percent CO_2 and 0.1 percent H_2S[71]. This compares to conventional production that is 3.4 percent CO_2 and 1.57 percent H_2S, older unconventional that is 2.59 percent CO_2 and zero percent H_2S, and Horn-Liard-Cordova production that is 7.8 percent CO_2 and 0.01 percent H_2S. This means production in BC is declining in emissions intensity over time.

One important way in which the royalty system affects emissions is through exempting from royalty payments natural gas and natural gas byproducts that are "lost without fault on the part of the producer

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[69] We acknowledge that the current rate of the carbon tax does not reflect the social damages from the emissions. However, this is an issue not unique to petroleum and natural gas development, and so it is out of scope.

[70] Emmaline Atherton et al., "Mobile Measurement of Methane Emissions from Natural Gas Developments in Northeastern British Columbia, Canada," *Atmospheric Chemistry and Physics* 17, no. 20 (October 19, 2017): 12405—20, https://doi.org/10.5194/acp-17-12405-2017; Daniel Zavala-Araiza et al., "Methane Emissions from Oil and Gas Production Sites in Alberta, Canada," ed. Detlev Helmig and Stefan Schwietzke, *Elementa: Science of the Anthropocene* 6, no. 27 (March 22, 2018), https://doi.org/10.1525/elementa.284..

[71] While hydrogen sulfide is not a greenhouse gas, it can form sulfur dioxide and sulfuric acid when released to air, and thereby contribute to acid rain.

and for which theproducer received no compensation."[72] This means there is no monetary penality for natural gas "lost" to the atmosphere, which reduces the firm's incentive to avoid such losses. This is of concern as direct natural gas releases have a global warming potential far greater than CO_2. Moreover, this also means lost value to the province, as the natural gas does not count as marketable production.

5.4.4 End-of-Life Liability Management

As with water use, there is no direct connection between the royalty regime and end-of-life liability management, which is regulated by the OGC. Oil and gas production is not riskless, and there are instances where firms default and the reclamation liability wholly transfers to the province (known as orphaned wells). To the extent that the differing royalty credit and incentive programs increase drilling activity relative to an absence of these programs, this increases the end-of-life environmental liability faced by the province. It is possible that the royalty system induces riskier development (higher cost wells by more cash-constrained firms), thereby increasing the probability of orphaned wells. As a caveat, orphan well cleanup is funded via a levy on industry, so there is no direct impact on taxpayers.

For pipelines and other operating infrastructure, there is also an end-of-life reclamation management problem the Province must resolve. As noted above, the Infrastructure Clean Growth Royalty Credit Program (and its predecessor the Infrastructure Royalty Credit Program) may result in overdevelopment of infrastructure relative to what firms would pursue on their own, increasing the reclamation liability for future generations.

To the extent that the Province is willing to accept this end-of-life liability as a necessary part of economic development, all else equal it should ensure the laws and regulation governing such development mean the value of development is maximized.

5.5 Additional Considerations

5.5.1 Administrative and Compliance Burden

The total costs of administering BC's oil and gas royalty system include all the costs incurred by the three agencies (EMLI, FIN, OGC) to collect and analyse the data, compute monthly royalties, correct for errors, and send out the invoices. Industry faces all the costs of compliance for the system in collecting and providing the data to government. Administration of the current system with all its complexity means accounting for multiple past and current structures applying to wells of different vintages and classifications. We have no estimate of these total administrative costs, nor their share of the royalties collected, but it is obvious that the more complex the system, the higher the costs.

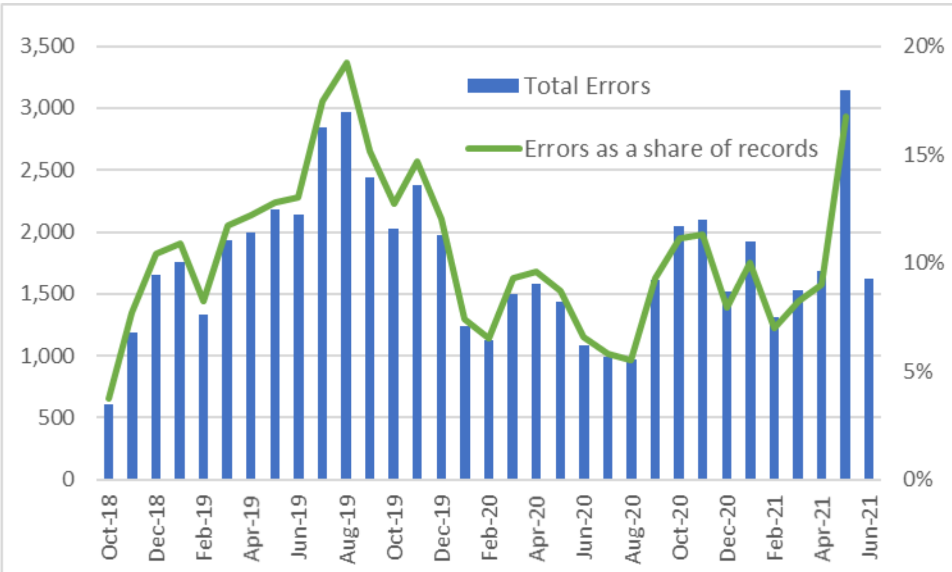
As an illustration of this complexity, consider the costs of producing the royalty invoices each month with the Petrinex system. It takes six to eight hours of computational time for the system to generate these monthly invoices. The changes in the royalty regime over time and the need to grandfather wells covered by prior provisions adds to these time costs to process invoices. A further illustration is the need to incorporate the complex rules of which program takes precedence over another if a well is eligible for multiple programs. Although there are few remaining wells in the net profit program, the provisions of that program take precedence over all others. A marginal designation trumps a low productivity designation. If a well is eligible for ultra-marginal, marginal and deep well status, the ultra-marginal deduction is the only one applied. As noted above, the determination of deep well status occurs in the

[72] Handbook page 58

first month of well operation, but then at the end of 12 months of operation, the well could be deemed ultra-marginal. If so, all the prior royalty payments for the preceding months must be recalculated.

The system's complexity also makes it more likely that errors in reporting occur. Monthly data on the number of reporting errors as a share of the total number of records shows the error rate remains quite high since implementation of the Petrinex system in 2018 (Figure 5-11).

Figure 5-11: Total Royalty Entry Errors and as a Share of Total Royalty Records by Month



Source: Ministry of Finance data.

5.5.2 Differing Natural Gas Royalty Rates

There are four different gross royalty formulas for natural gas from natural gas wells that depend on the date drilling commenced and was completed (Base 9, 12, and 15 wells). Conservation gas is natural gas that comes from an oil well, which also has a different royalty formula. We see no rationale for continuing to differentiate the natural gas by its well vintage or the well's primary product. As we discuss in section 3.1, the vast majority of the natural gas produced in 2020 is from Base 12 wells. One rate for all natural gas extracted would simplify the system.

Chapter 6 - Summary and Conclusion

The BC royalty system for oil and gas is broken. It does not support and contribute to government and societal goals. It consists of piecemeal modifications to a system that was designed for a different era with different risks, technology, and market conditions. The system is excessively complex, has large compliance costs for industry and administrative and auditing costs for government. It creates incentives that do not promote efficiency in the sector and has contributed to a significant decline in the Crown's share of the net economic value from petroleum and natural gas resources over the past 15 years. Interaction among the elements of the total system have led to a situation where on average the net royalties as a percentage of gross have declined over time from just under 40 percent to under 25 percent. The average net royalty rates over the past decade was 5.5 percent, and the average effective royalty is five percent with little sign of any change in the situation as Figure 5-1 demonstrates. Figure 3-35 demonstrates the fiscal importance of the various components of the program with the magnitude of each deduction from gross royalty amounts over the period 2013 to 2021, showing a large transfer of value from the province to industry.

While the appropriate share of value for the Province is not within our scope, the previous section identifies areas of concern with each of the program areas that indicate the system fails to maximize *shared* value. Appendix A goes deeper into the effects of specific components of the programs by well classification and product using a decomposition analysis for different combinations of product (and hence gross royalty rate) and combinations of deductions (PCOS, rate reductions, and credits). The messages are consistent and clear. Nothing short of a comprehensive overhaul of the royalty system will 'fix' it. The royalty review should be comprehensive and broad ranging, aiming to put in place a modern system that is simpler, accountable, transparent, less costly to operate, promotes efficiency, and helps meet government and societal goals.

The following points summarize our specific areas of concern.

1. All of the royalty deduction programs are out of date. They were introduced at a time with more favourable product prices, and do not take into account changing extraction technology and shift to natural gas liquids in the product mix and investment profile.
2. The exploration and extraction risk profile of the sector has declined substantially since the early 2000s and the combined effect of the programs has resulted in an over-compensation for risks that are no longer as apparent and relevant.
3. The system is characterized by piecemeal changes over time with programs that have led to compounding effects that substantially reduced royalty payments as a share of net value of the resource.
4. The system is set up to incentivize lower-value wells. A firm has a fixed amount of capital to spend in a year and the system may be inducing investment and operating decisions that target these lower-valued wells. This is by incentivizing behaviour where these decisions are based more on accessing royalty payment reductions than would be warranted under efficient operation. This may be one factor contributing to BC being deemed a 'high cost' region and lower overall resource value in the province.
5. Wells benefitting from deep well credits or deep well credits and marginal programs now form a large share of natural gas production. Adding in the other programs and credits which reduce

gross royalty rates and royalty payments (e.g., low productivity production or an infrastructure royalty credit), further reduces the Crown's share of net resource value.

6. Given existing market conditions, virtually no wells face a price-sensitive gross royalty rates. Unless there is a change in the way in which product prices are incorporated into the calculations of royalties, this situation will persist for as long as the supply-demand balance for oil and gas sustains current prices.
7. The current system relies on primary product and natural gas production volumes to determine wells' eligibility for different royalty rate reductions and credit programs. This increases complexity and creates incentives for firms to chase specific products and credits rather than the most valuable outcome.
8. The system accounts for costs in ways that are administratively burdensome, reduces the Crown's share of the total net value of the resource by reducing the effective royalty rate, can promote inefficiencies, and thus may also contribute to lower total net economic value. To appropriately define value and shared value requires an accurate picture of the net economic value of the resource: something more akin to the way profits under corporate taxation are calculated, or as a proxy for this, Alberta's revenue minus cost model.
9. The cost calculations (PCOS and GCA) are well-specific, meaning that a company's decisions about costs directly affects their royalty payment. This reduces companies' incentives to lower their costs and preserve value. Moving to a system where companies are granted an industry average cost allocation would eliminate this problem.
10. Determining gross royalties at the intake of raw product to processing plants with extraction costs determined by the PCOS methodology adds to complexity, administrative costs, and use of non-market values. It is an outdated and complex system that cannot be readily audited and updated. Moving the gross royalty calculation to processing plant outflows, as in the Alberta system, and adopting Alberta's methodology for computing costs would serve to alleviate these issues.
11. The current cost calculations (PCOS and GCA) are meant to account for the Crown's share of costs. However, unlike a royalty payment on the value of the products, the cost calculations are not scaled by the royalty rate. If the PCOS allowance and GCA are already fractions of firms' costs, this is not an issue. Still, it is worthwhile to assess relative cost-sharing.
12. Alberta undertook a major reform of its oil and gas royalty system, phasing in its new system in 2017. Given the Montney's shale deposits straddle the BC-Alberta border, moving to a system such as Alberta's would better align production, reduce any incentive to shift production from one province to the other to minimize royalty payments, and overall promote a more efficient and equitable system.
13. A simpler system would substantially reduce administrative burden for the government and compliance burden for industry, as well as reduce reporting errors that require many hours to revise royalty calculations. The total costs of administering BC's oil and gas royalty system include all the costs incurred by the three agencies (EMLI, FIN, OGC) to collect and analyse the data, compute monthly royalties, correct for errors, and send out the invoices. Industry faces all the costs of compliance for the system in collecting and providing the data to government. Administration of the current system with all its complexity means accounting for multiple past

and current structures applying to wells of different vintages and classifications. Any “tinkering” with the system without a comprehensive overhaul would add to the administrative burden requiring more grandfathering of the multiple structures in the system.

14. Goals such as transparency; ease in understanding the system; and ability to update cost, price, and other elements are not met in the current system. The complexity of the system makes it extremely difficult to explain it to anyone not deeply immersed in the system and can lead to misinterpretations of the data and impacts the system has. The BC Royalty Handbook is 192 pages of dense technical complexity. Alberta’s guidelines are presented in 57 pages. The multiple entities responsible for the system make it challenging to communicate with industry and the public.
15. Removing or ‘fixing’ problematic aspects of the system (e.g., removing one type of credit) may result in unintended consequences. In our view, a system wide and comprehensive reform of the entire system is warranted.

Transition from an old to a new system is always challenging and requires careful analysis of ways to minimize any potential adverse impacts. By engaging with affected and interested parties, building on the knowledge and expertise within BC’s three government entities, and learning from other jurisdictions’ approaches, the royalty review can examine ways to address these challenges and move forward.

Appendix A: Supplementary Net Royalty Outcomes — Program Interactions

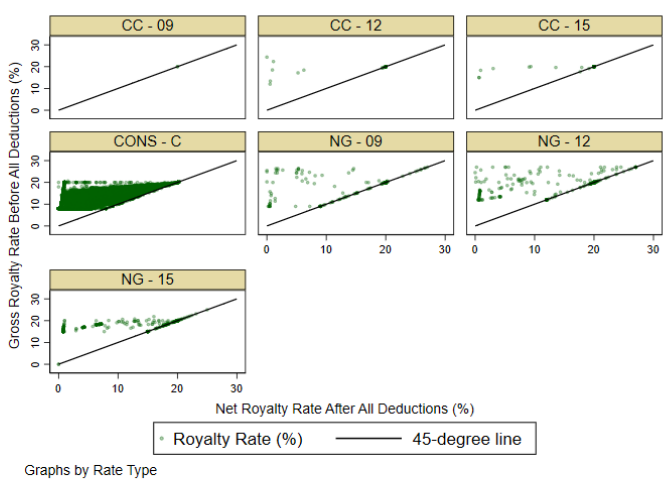
This appendix present gross versus net royalty rates for each royalty system and credit program. We sum natural gas and NGL royalty payments and present as a share of NG and NGL value to construct royalty rates and exclude oil royalty revenues from oil wells. We use several different definitions of net royalty rate to plat the effects of different royalty programs on the net royalty rate.

First, we compare the gross royalty rate against the net royalty with rate reductions but before the PCOS deduction. This plot allows us to show the effect of the rate reduction programs on the gross royalty rate. Second, we compare the gross royalty rate against the net royalty rate after rate reductions and PCOS deductions. This plot shows the cumulative effect of the PCOS deduction. For deep wells, we also compare the gross royalty rate against the net accounted for the Deep Well Royalty Credit deductions. Finally, we compare the gross royalty rate against the effective royalty rate, where the effective rate is net royalty revenues divided by marketable product value at market prices. We also compare the final net royalty rate against the effective rate. This allows us to see the effect of price choice on royalty payments.

No Credit Programs

Figure 1 presents the gross royalty rate against the net royalty rate for wells that are not subject to a credit program; the only deduction these wells receive is PCOS. The majority of monthly royalty payments are from oil wells producing conservation gas. Seventy-nine percent of the plotted data have a net royalty rate below the gross royalty rate before deductions, 6.5 percent have a net royalty rate below one percent, and 15 percent have a net royalty rate below five percent. The effect of PCOS is to lower the net royalty rate by three percentage points on average.

Figure 0-1: Gross Royalty Rate (Gas & NGLs) vs Net Royalty Rate (Gas & NGLs) for Wells Not Subject to a Credit Program by Royalty Scheme, Oct. 2012 to May 2021



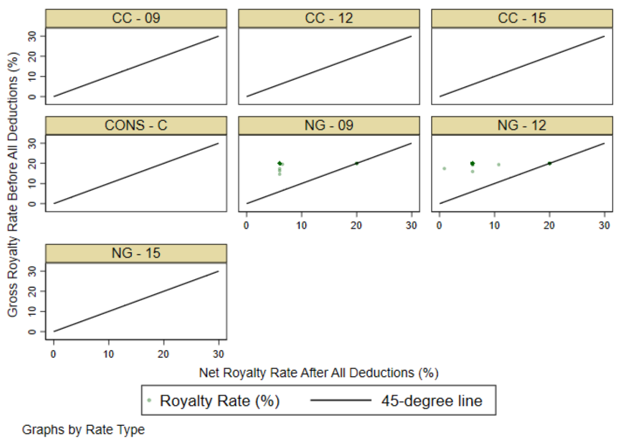
Source: Ministry of Finance data.
Note: "CC" denotes oil wells with gas production granted concurrent status on Crown leases; "CONS" denotes conservation gas from oil wells; and "NG" denotes non-conservation gas from Crown leases. Observations on the 45-degree line denote wells where the net royalty rate equals the gross royalty rate.

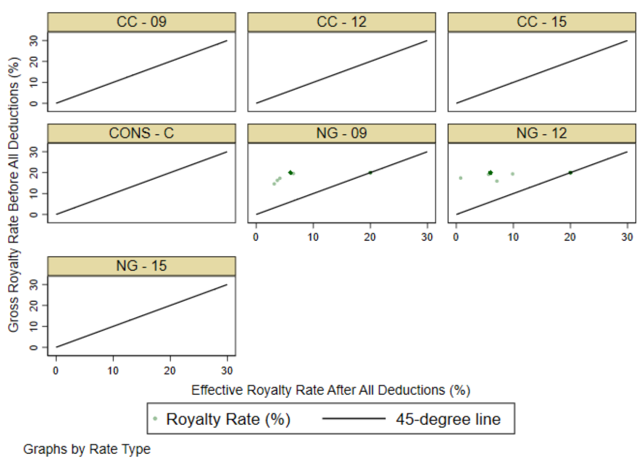
Deep Well Credit Program

Tier 1 Wells

Figure 0-2 presents the gross royalty rate before all deductions against the gross royalty rate with PCOS deductions, and gross versus effective royalty rates for Deep Tier 1 wells. There are very few wells that meet this definition as most wells accessing Deep Well Credits are also defined as Low Productivity or Marginal. PCOS does not appear to affect the royalty rate very much for these wells, as PCOS lowers the royalty rate by 0.05 percentage points on average. The Deep Well Royalty Credit lowers the royalty rate by 13.5 percentage points on average.

Figure 0-2: Gross Royalty Rate vs Net Royalty Rate and Gross vs Effective Rate for Deep Well Credit Tier 1 Wells by Royalty Scheme, Oct. 2012 to May 2021



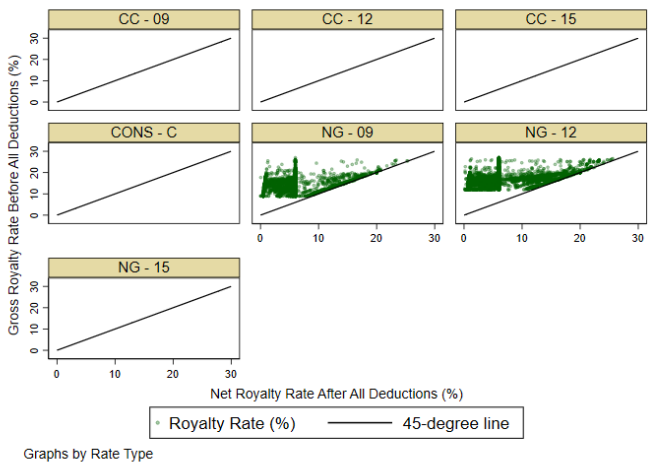


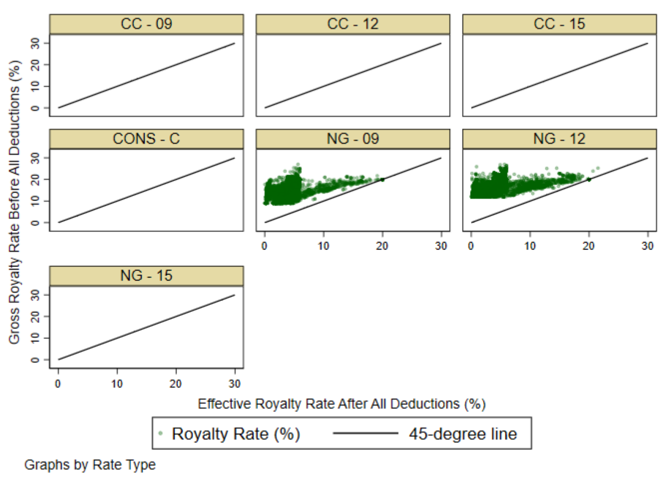
Source: Ministry of Finance data.
Note: "CC" denotes oil wells with gas production granted concurrent status on Crown leases; "CONS" denotes conservation gas from oil wells; and "NG" denotes non-conservation gas from Crown leases. Observations above the 45-degree line are wells where the net royalty rate is below the gross royalty rate.

Figure 0-3 presents the gross royalty rate before deductions against the net and effective royalty rates for Deep Tier 1 wells that are also designated Low Productivity. The deductions sharply decrease the effective royalty rate for most wells, with most royalty rates around six percent. The average effect is a

13.6 percentage-point reduction in total royalty rates. The average net royalty rate is 5.7 percent with deductions, compared to a 16.7 percent gross rate. Numerous wells appear to pay the minimum royalty rate of three or six percent. The effect of the Low Productivity program is to reduce the gross royalty rate by 0.02 percentage points, whereas PCOS lowers the royalty rate by five percentage points and the deep well credit lowers the royalty rate by six percentage points. The difference between the net and the effective royalty rate is 1.3 percentage points.

Figure 0-3: Gross Royalty Rate vs Net Royalty Rate and Gross vs Effective for Deep Well Credit Tier 1 and Low Productivity Wells by Royalty Scheme, Oct. 2012 to May 2021

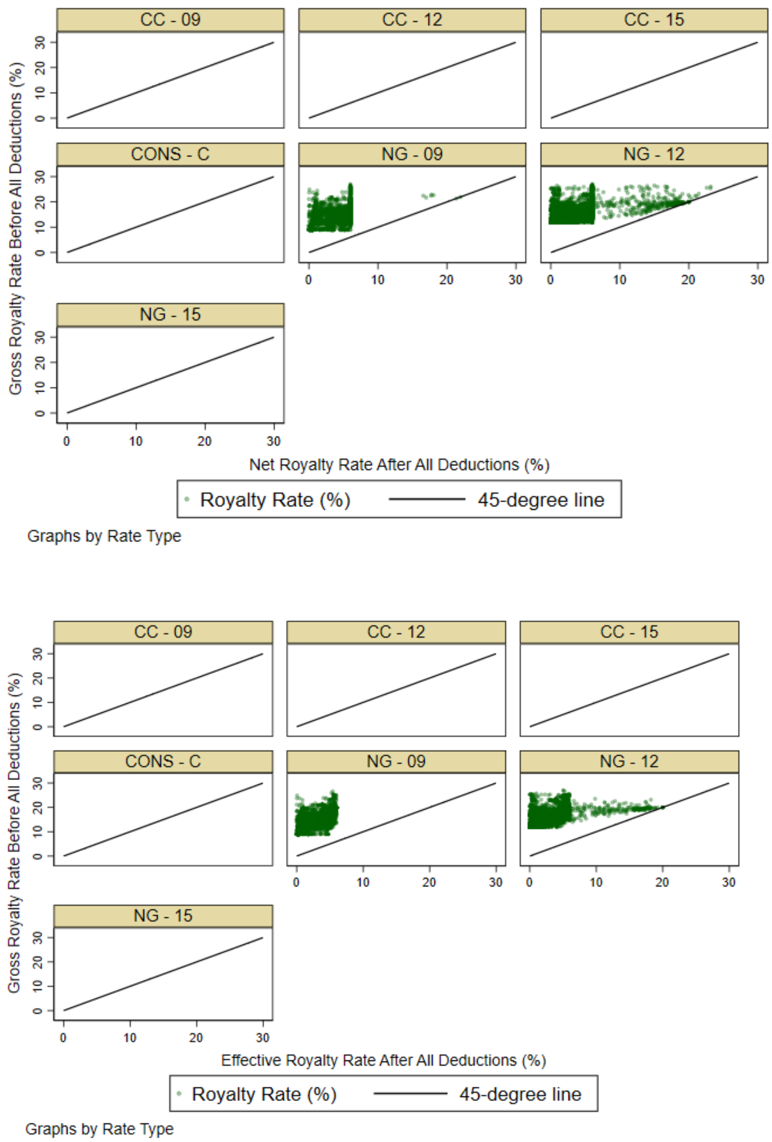




Source: Ministry of Finance data.
Note: "CC" denotes oil wells with gas production granted concurrent status on Crown leases; "CONS" denotes conservation gas from oil wells; and "NG" denotes non-conservation gas from Crown leases. Observations above the 45-degree line are wells where the net royalty rate is below the gross royalty rate.

Figure 0-4 presents the gross royalty rate before deductions against the net and effective royalty rates for Deep Tier 1 wells that are also designated Marginal. The deductions sharply decrease the effective royalty rate for most wells, with most royalty rates around six percent. The average effect is a 12 percentage-point reduction in total royalty rates. The average net royalty rate is four percent with deductions, compared to a 16 percent gross rate. Numerous wells appear to pay the minimum royalty rate of thee or six percent. The effect of the Marginal program is to reduce the gross royalty rate by 1.3 percentage points, whereas PCOS lowers the royalty rate by 7.1 percentage points and the deep well credit lowers the royalty rate by 3.7 percentage points. The difference between the net and the effective royalty rate is 0.9 percentage points.

Figure 0-4: Gross Royalty Rate vs Net Royalty Rate and Gross vs Effective or Deep Well Credit Tier 1 and Marginal Wells by Royalty Scheme, Oct. 2012 to June 2021

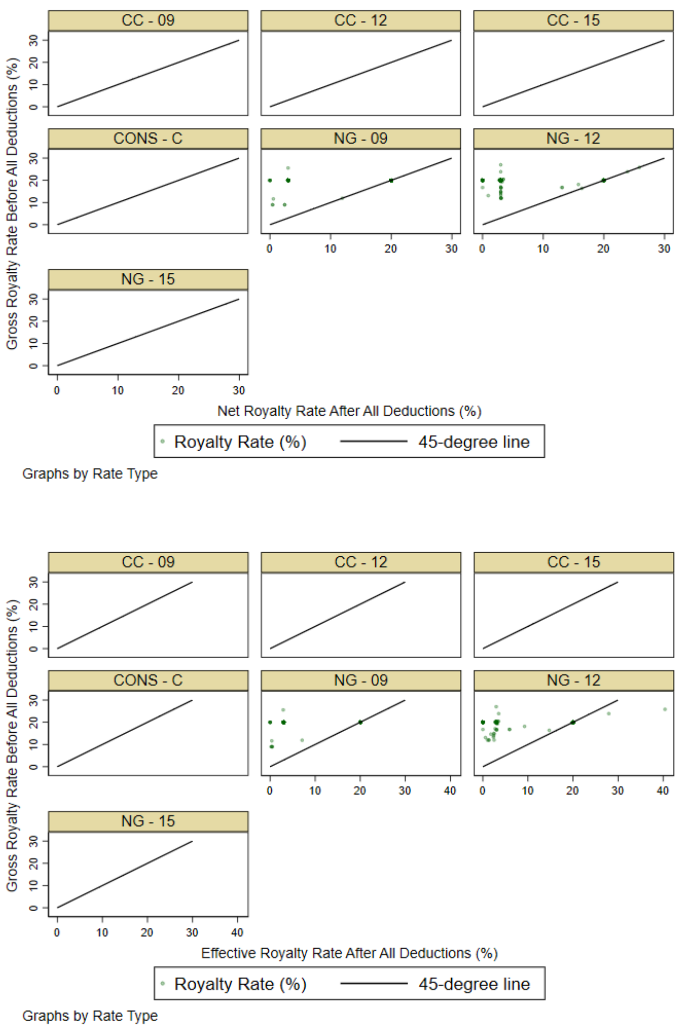


Source: Ministry of Finance data.
Note: "CC" denotes oil wells with gas production granted concurrent status on Crown leases; "CONS" denotes conservation gas from oil wells; and "NG" denotes non-conservation gas from Crown leases. Observations above the 45-degree line are wells where the net royalty rate is below the gross royalty rate.

Tier 2 Wells

Figure 0-5 presents the gross royalty rate before all deductions against the gross royalty rate with PCOS deductions for Deep Tier 2 wells. There are very few wells that meet this definition as most wells accessing Deep Well Credits are also defined as Low Productivity or Marginal. PCOS does not appear to affect the royalty rate very much for these wells, as PCOS lowers the royalty rate by 0.02 percentage points on average. The Deep Well Royalty Credit lowers the royalty rate by 13.8 percentage points on average.

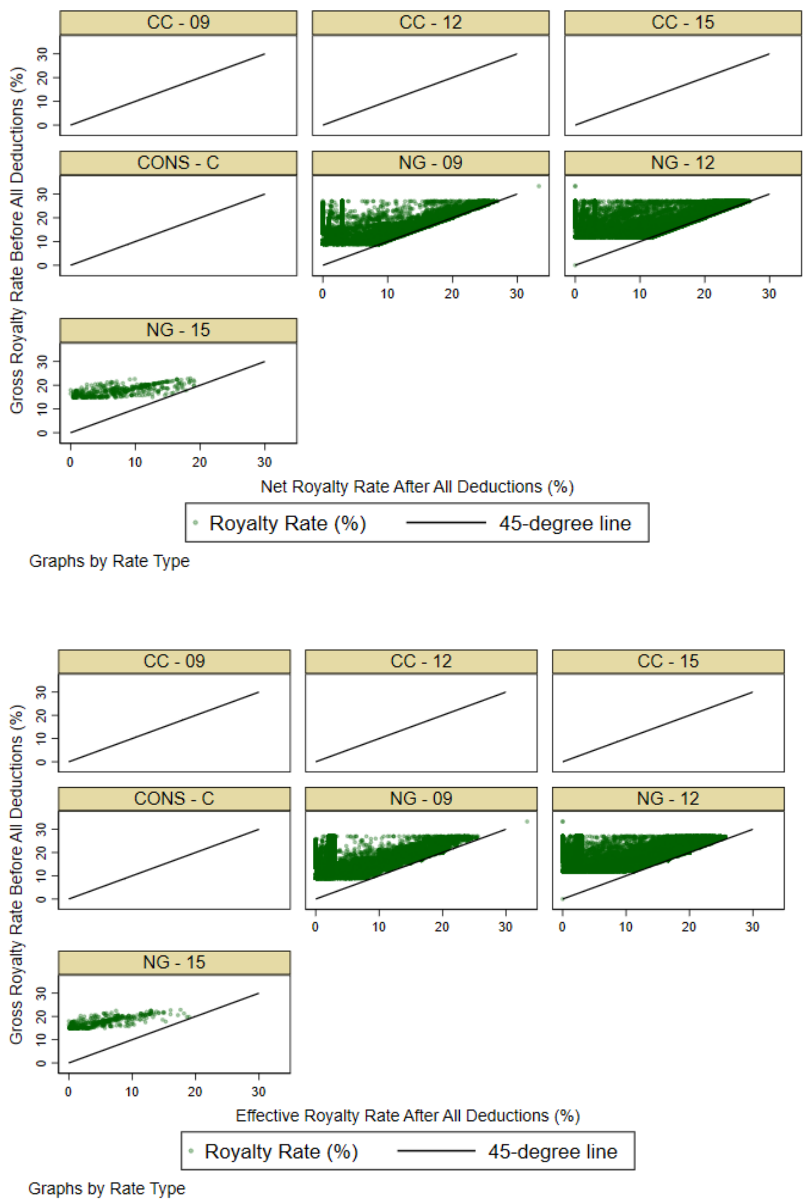
Figure 0-5: Gross Royalty Rate vs Net Royalty Rate and Gross vs Effective for Deep Well Credit Tier 2 Wells by Royalty Scheme, Oct. 2012 to May 2021



Source: Ministry of Finance data.
Note: "CC" denotes oil wells with gas production granted concurrent status on Crown leases; "CONS" denotes conservation gas from oil wells; and "NG" denotes non-conservation gas from Crown leases. Observations above the 45-degree line are wells where the net royalty rate is below the gross royalty rate.

Figure 0-6 presents the gross royalty rate before deductions against the net and effective royalty rates for Deep Tier 2 wells also designated as Low Productivity. The deductions sharply decrease the effective royalty rate for most wells. The average net royalty rate is 6.9 percent with deductions, compared to a 16.8 percent gross rate. Numerous wells appear to pay the minimum royalty rate of three or six percent. The effect of the Low Productivity program is to reduce the gross royalty rate by 0.04 percentage points, whereas PCOS lowers the royalty rate by three percentage points and the deep well credit lowers the royalty rate by 6.8 percentage points. The difference between the net and the effective royalty rate is 1.8 percentage points.

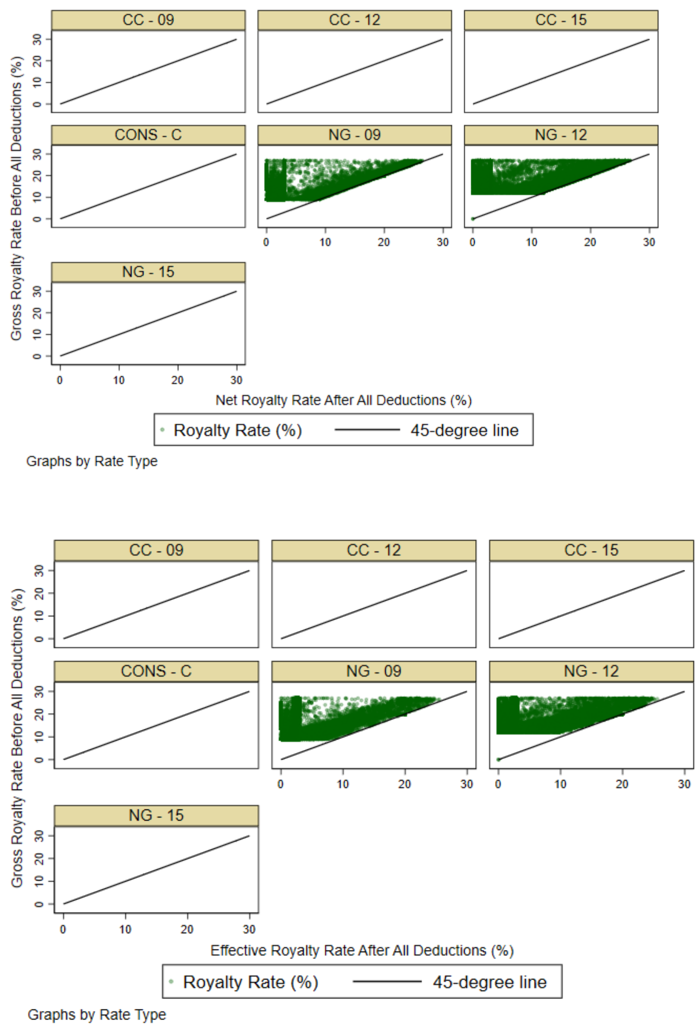
Figure 0-6: Gross Royalty Rate vs Net Royalty Rate and Gross vs Effective for Deep Well Credit Tier 2 and Low Productivity Wells by Royalty Scheme, Oct. 2012 to May 2021



Source: Ministry of Finance data.
Note: "CC" denotes oil wells with gas production granted concurrent status on Crown leases; "CONS" denotes conservation gas from oil wells; and "NG" denotes non-conservation gas from Crown leases. Observations above the 45-degree line are wells where the net royalty rate is below the gross royalty rate.

Figure 0-7 presents the gross royalty rate before deductions against the net and effective royalty rates for Deep Tier 2 wells that are also designated Marginal. The deductions sharply decrease the effective royalty rate for most wells. The average effect is a 12.1 percentage-point reduction in total royalty rates, compared to an average gross rate of 16 percent. The average net royalty rate is four percent with deductions. Numerous wells appear to pay the minimum royalty rate of three or six percent. The effect of the Marginal program is to reduce the gross royalty rate by 1.3 percentage points, whereas PCOS lowers the royalty rate by 3.8 percentage points and the deep well credit lowers the royalty rate by seven percentage points. The difference between the net and the effective royalty rate is one percentage point.

Figure 0-7: Gross Royalty Rate vs Net Royalty Rate and Gross vs Effective for Deep Well Credit Tier 2 and Marginal Wells by Royalty Scheme, Oct. 2012 to June 2021

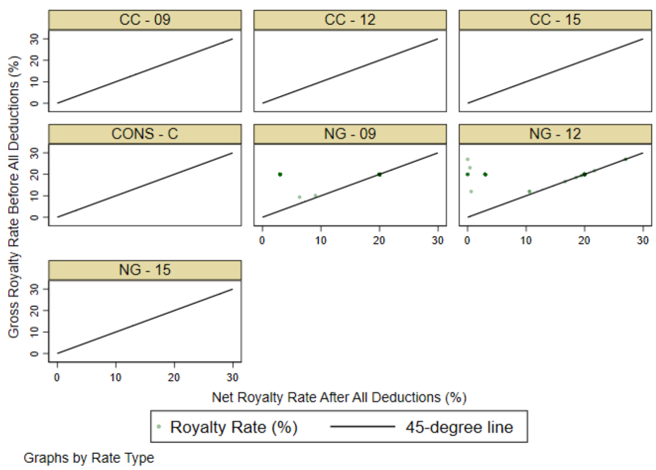


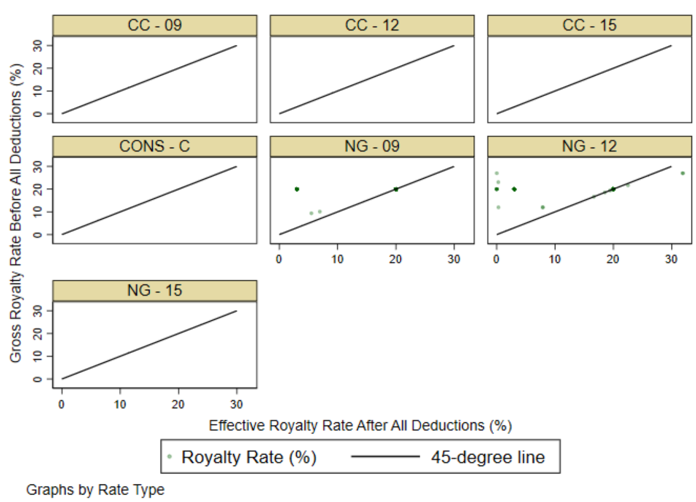
Source: Ministry of Finance data.
Note: "CC" denotes oil wells with gas production granted concurrent status on Crown leases; "CONS" denotes conservation gas from oil wells; and "NG" denotes non-conservation gas from Crown leases. Observations above the 45-degree line are wells where the net royalty rate is below the gross royalty rate.

Old Deep Credit Wells

Figure 0-8 presents the gross royalty rate before all deductions against the gross royalty rate with PCOS deductions for Old Deep Credit wells. There are very few wells that meet this definition as most wells accessing Deep Well Credits are Tier 1 or Tier 2, and also defined as Low Productivity or Marginal. PCOS does not appear to affect the royalty rate very much for these wells, as PCOS lowers the royalty rate by 0.05 percentage points on average. The Deep Well Royalty Credit lowers the royalty rate by 2.9 percentage points on average. The gross royalty rate is 19.9 percent, and the net rate and the effective rate are both 16.9 percent.

Figure 0-8: Gross Royalty Rate vs Net Royalty Rate and Gross vs Effective for Old Deep Well Credit Wells by Royalty Scheme, Oct. 2012 to May 2021

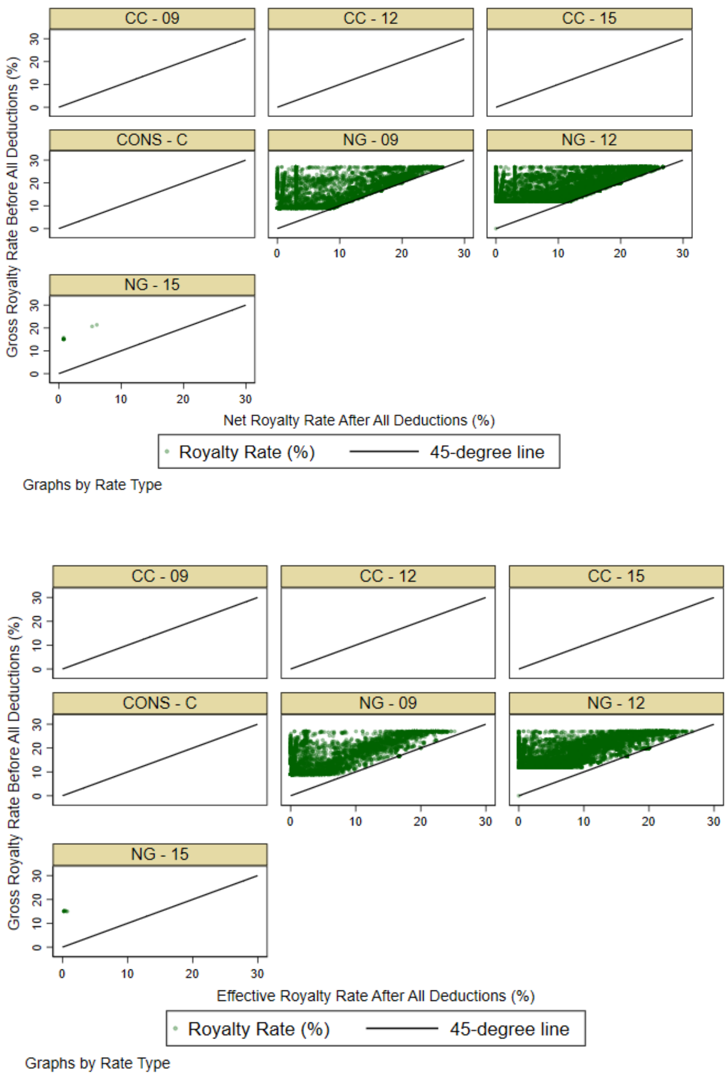




Source: Ministry of Finance data.
Note: "CC" denotes oil wells with gas production granted concurrent status on Crown leases; "CONS" denotes conservation gas from oil wells; and "NG" denotes non-conservation gas from Crown leases. Observations above the 45-degree line are wells where the net royalty rate is below the gross royalty rate.

Figure 0-9 presents the gross royalty rate before deductions against the net and effective royalty rates for Old Deep Credit wells also designated as Low Productivity. The deductions sharply decrease the effective royalty rate for most wells, with most royalty rates around six percent. The average effect is a seven percentage-point reduction in royalty rates. The average net royalty rate is 10.4 percent with deductions, compared to a 17.4 percent gross rate. The effect of the Low Productivity program is to reduce the gross royalty rate by 0.3 percentage points, whereas PCOS lowers the royalty rate by 6.3 percentage points and the deep well credit lowers the royalty rate by 0.4 percentage points. The difference between the net and the effective royalty rate is 2.4 percentage points.

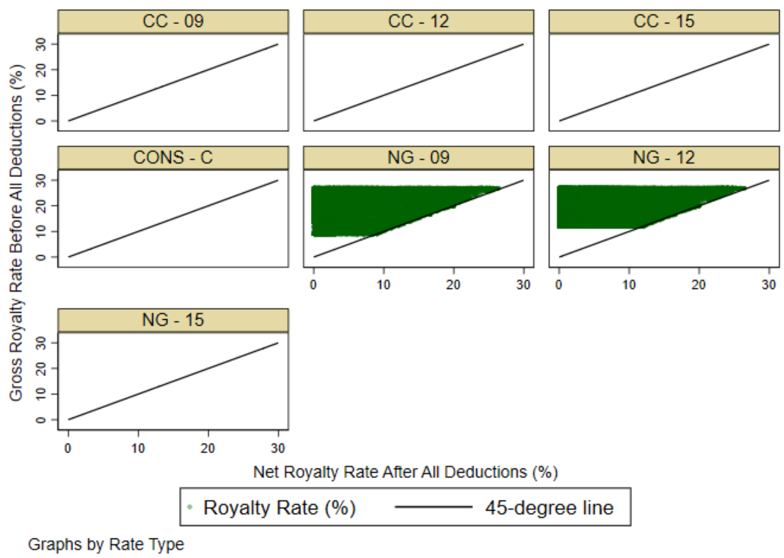
Figure 0-9: Gross Royalty Rate vs Net Royalty Rate and Gross vs Effective for Old Deep Well Credit and Low Productivity Wells by Royalty Scheme, Oct. 2012 to May 2021

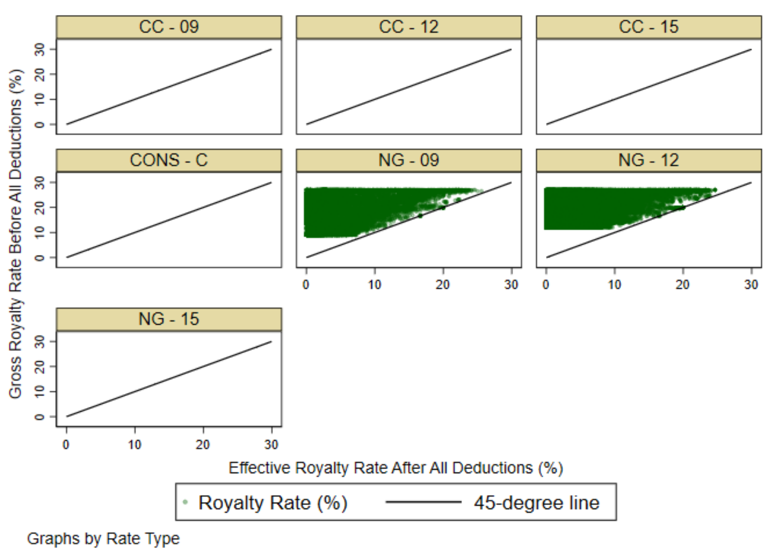


Source: Ministry of Finance data.
Note: "CC" denotes oil wells with gas production granted concurrent status on Crown leases; "CONS" denotes conservation gas from oil wells; and "NG" denotes non-conservation gas from Crown leases. Observations above the 45-degree line are wells where the net royalty rate is below the gross royalty rate.

Figure 0-10 presents the gross royalty rate before deductions against the net and effective royalty rates for Old Deep Credit wells that are also designated Marginal. The deductions sharply decrease the effective royalty rate for most wells. The average effect is a 12.1 percentage-point reduction in total royalty rates. The average net royalty rate is 5.6 percent with deductions, compared to a 17.7 percent gross rate. The effect of the Marginal program is to reduce the gross royalty rate by 7.8 percentage points, whereas PCOS lowers the royalty rate by 3.6 percentage points and the deep well credit lowers the royalty rate by 0.8 percentage points. The difference between the net and the effective royalty rate is 1.3 percentage points.

Figure 0-10: Gross Royalty Rate vs Net Royalty Rate and Gross vs Effective for Old Deep Well Credit and Marginal Wells by Royalty Scheme, Oct. 2012 to May 2021



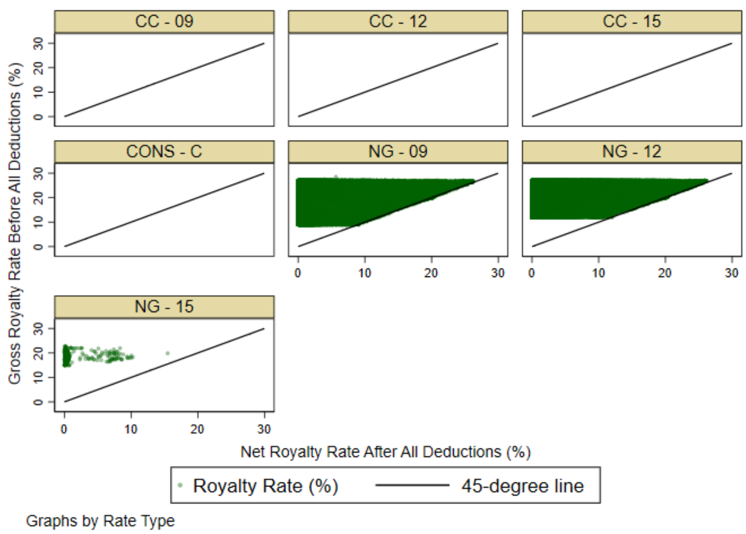


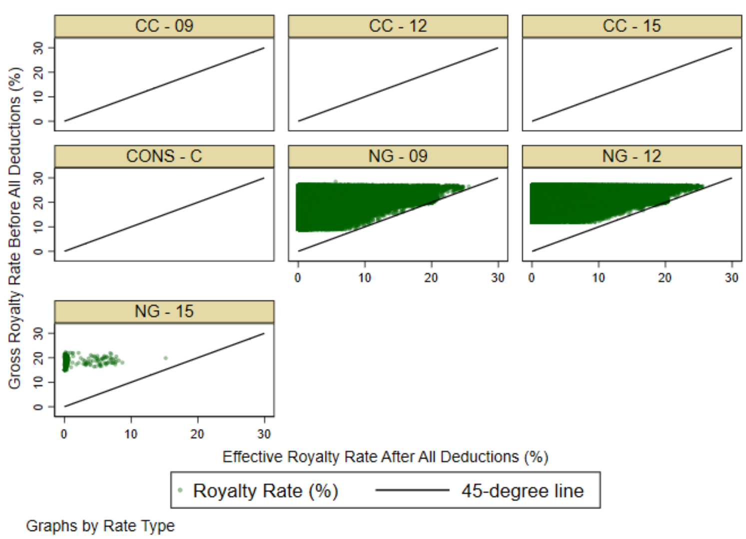
Source: Ministry of Finance data.
Note: "CC" denotes oil wells with gas production granted concurrent status on Crown leases; "CONS" denotes conservation gas from oil wells; and "NG" denotes non-conservation gas from Crown leases. Observations above the 45-degree line are wells where the net royalty rate is below the gross royalty rate.

Marginal Wells

Figure 0-11 presents the gross royalty rate before all deductions against the net royalty rate for Marginal wells, and the gross rate against the effective rate. The average gross royalty rate is 17.8 percent, compared to an average net royalty rate of 3.7 percent, for a decrease of 14.1 percentage points. The Marginal program lowers the royalty rate by 9.3 percentage points and PCOS lowers the royalty rate by 4.8 percentage points on average. The difference between the net and the effective royalty rate is 0.55 percentage points.

Figure 0-11: Gross Royalty Rate vs Net Royalty Rate and Gross vs Effective for Marginal Wells by Royalty Scheme, Oct. 2012 to June 2021



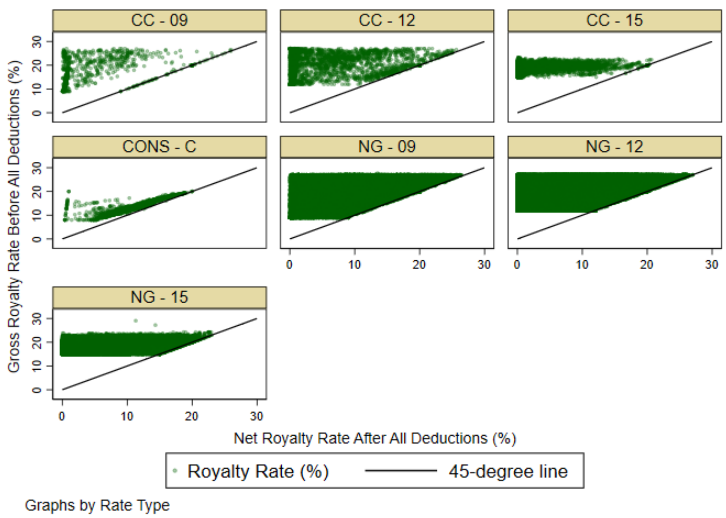


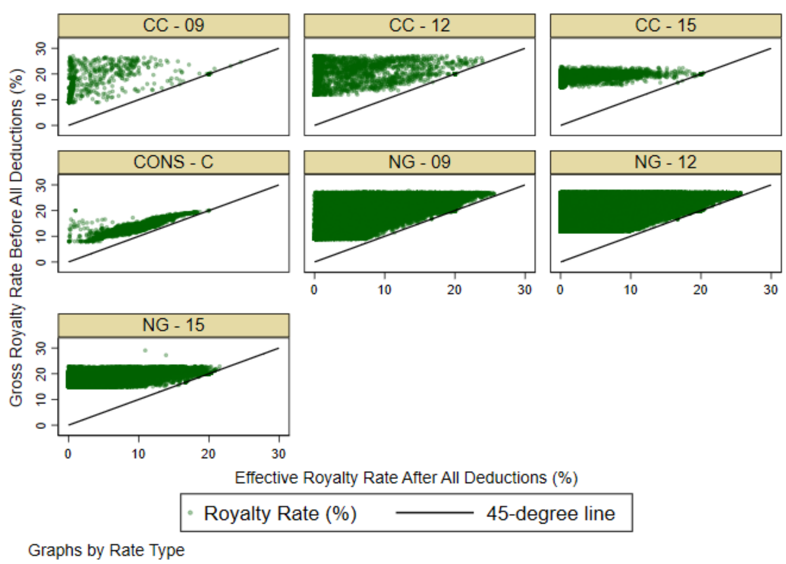
Source: Ministry of Finance data.
Note: "CC" denotes oil wells with gas production granted concurrent status on Crown leases; "CONS" denotes conservation gas from oil wells; and "NG" denotes non-conservation gas from Crown leases. Observations above the 45-degree line are wells where the net royalty rate is below the gross royalty rate.

Low Productivity Wells

Figure 0-12 presents the gross royalty rate before all deductions against the net royalty rate for Low Productivity wells, and the gross rate against the effective rate. The average gross royalty rate is 18.4 percent, compared to an average net royalty rate of 6.3 percent, for a decrease of 12.1 percentage points. The Low Productivity program lowers the royalty rate by 3.1 percentage points and PCOS lowers the royalty rate by nine percentage points on average.

Figure 0-12: Gross Royalty Rate vs Net Royalty Rate and Gross vs Effective for Low Productivity Wells by Royalty Scheme, Oct. 2012 to May 2021



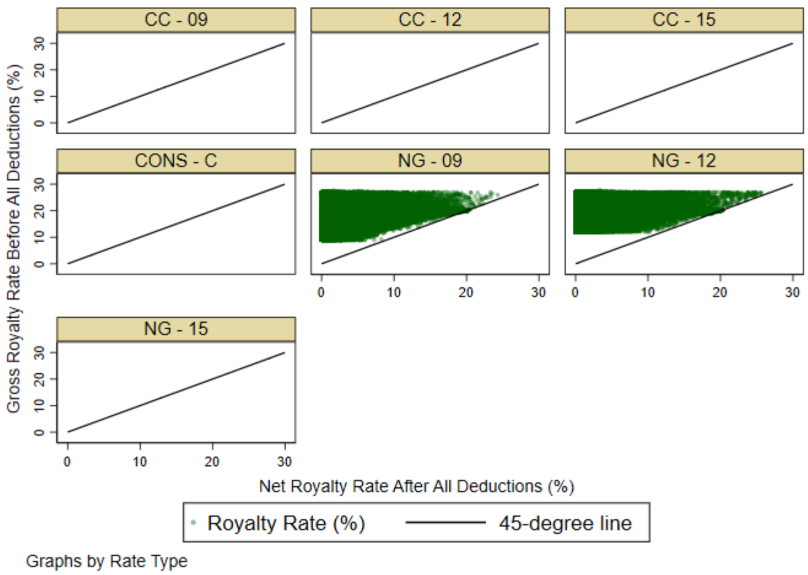


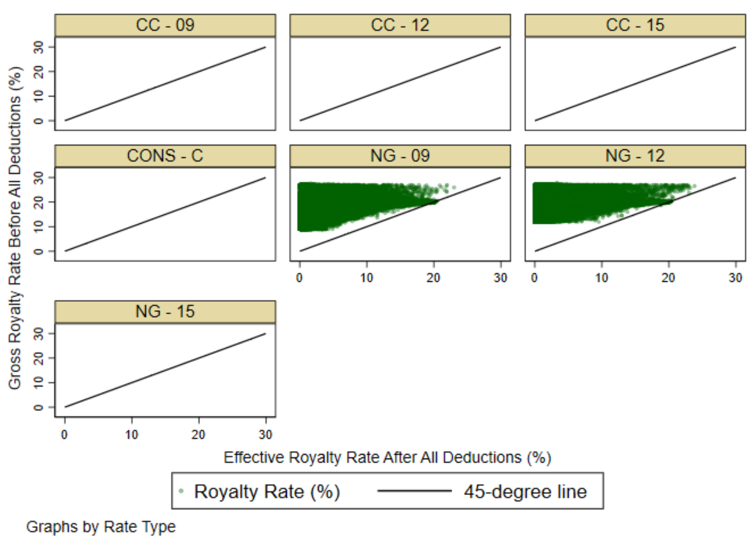
Source: Ministry of Finance data.
Note: "CC" denotes oil wells with gas production granted concurrent status on Crown leases; "CONS" denotes conservation gas from oil wells; and "NG" denotes non-conservation gas from Crown leases. Observations above the 45-degree line are wells where the net royalty rate is below the gross royalty rate.

Ultra Marginal Wells

Figure 0-15 presents the gross royalty rate before all deductions against the net royalty rate for Ultra Marginal wells, and the gross rate against the effective rate. The average gross royalty rate is 17.6 percent, compared to an average net royalty rate of 3.1 percent, for a decrease of 14.6 percentage points. The ultra-marginal program lowers the royalty rate by 11.3 percentage points and PCOS lowers the royalty rate by 3.3 percentage points on average.

Figure 0-13: Gross Royalty Rate vs Net Royalty Rate and Gross vs Effective for Ultra Marginal Wells by Royalty Scheme, Oct. 2012 to June 2021



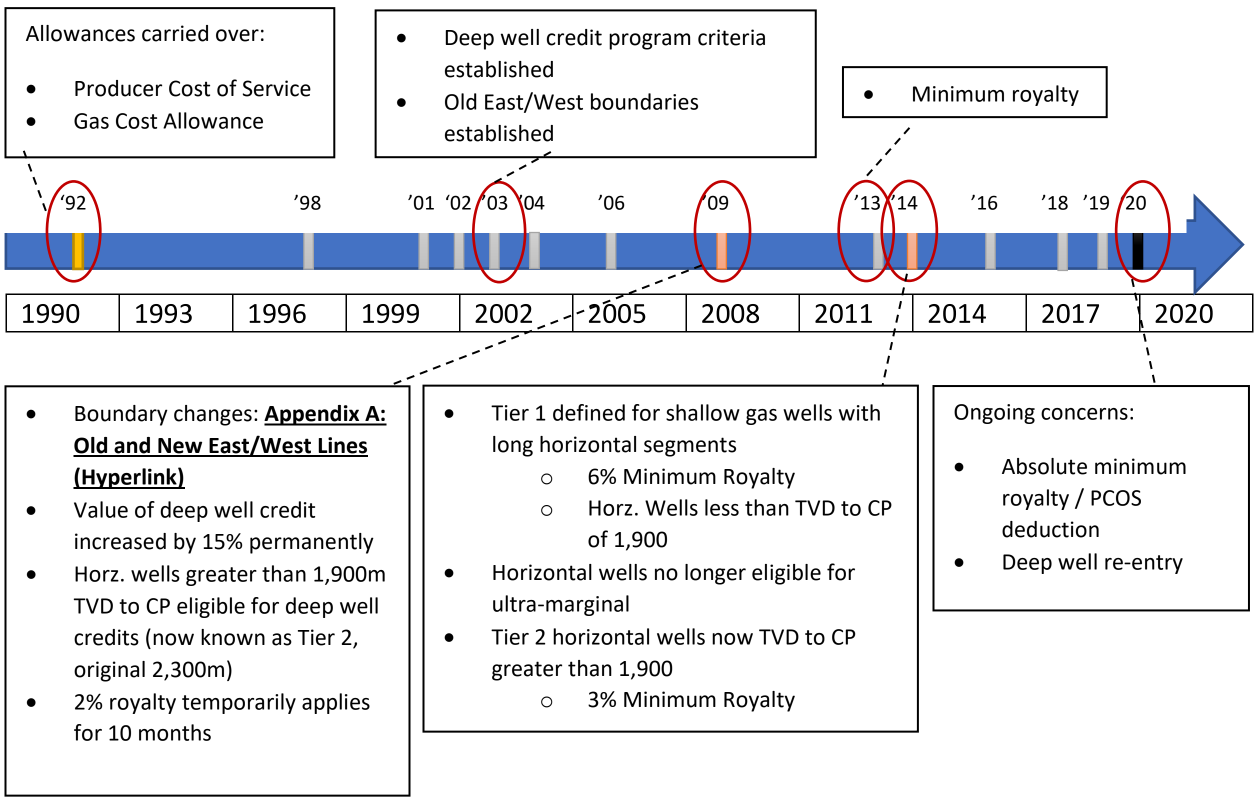


Source: Ministry of Finance data.

Note: "CC" denotes oil wells with gas production granted concurrent status on Crown leases; "CONS" denotes conservation gas from oil wells; and "NG" denotes non-conservation gas from Crown leases. Observations above the 45-degree line are wells where the net royalty rate is below the gross royalty rate.

Appendix B: Abbreviated History of the Royalty System

Timeline: Royalty Program History and Amendments to the <u>Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation B.C. Reg 495/92</u>



Year	Royalty Program / History	Description
1992	Producer Cost of Service / Gas Cost Allowances	- There are two allowances available to cover the costs associated with transporting and processing the Crown's royalty share of natural gas. The GCA and PCOS were first adopted in the Province's royalty regulation in 1985.
1998	Select Price Base 9 and 12	- Provincial royalty regulation is amended to differentiate between Base 12 and Base 9 non-conservation gas.
2001	Low Productivity	- Eligibility criteria established — a royalty rate reduction for low productivity gas wells was introduced in 2001 to prevent the government's royalty to be shut in — when rates of production are too low to cover operating costs.
2002	Coalbed Methane	- Eligibility criteria established — this program was introduced to encourage the development of coalbed methane reserves.
2003	Marginal Well Events	- Eligibility criteria established — A reduction in royalty shares for marginal gas was introduced to encourage development of gas reserves that are marginally economic because of depth and flow rate issues.

2003	Deep Well Credit Program, Deep Re-Entry Credit Program, Deep Discovery Well	- Qualifying wells receive credits to offset the higher drilling and completion costs associated with deep wells. A deep well differentiate by: Bottom-hole location and H_2S content - Deep discovery wells are exempt from royalty obligations — like past regulations
2004	Infrastructure Royalty Credit Program (IRCP)	- Eligibility criteria established — royalty credits to encourage companies to explore and access new and under-developed areas of BC.
2006	Ultra-Marginal Low Productivity Program	- Eligibility criteria established - Ultra-Marginal well events are virtually prevented from having both the ultra-marginal and deep statuses by the deep requirements i.e. Ultra-Marginal must have a TVD to top of pay **less than** 2,500 metres in vertical wells or 2,300 metres in horizontal wells, and deep well events must have a TVD to completion point **greater than** 2,500 in vertical wells or 2,300 metres in horizontal wells.
2008	Net Profit Royalty Program (NPRP)	- NPRP was developed in 2008 to promote exploration and production of natural gas resources that are capital-intensive, technically complex and located in remote areas. It offers producers lower royalty rates at the initial stages of project development in exchange for higher royalty rates later when a project becomes more profitable.
2009	Deep Well Credit Program: New East/West Boundaries	- As of January 1, 2009, the Deep Well Credit Table distinguishes a new location criterion to allocate amounts for wells spud after this date. - New geographical boundaries are drawn i.e. "East" and "West" to recognize the higher costs associated with drilling specified underdeveloped areas of the province.
2009	Royalty Relief Program	- The one-year, 2% Royalty Relief Program was introduced for wells drilled in the **10-month period** from September 1, 2009 to June 30, 2010. Producers were only obligated to pay a minimum 2% royalty rate on production. Wells were ***also*** able to qualify for low productivity rate reduction programs; however, only one incentive could be utilized at a moment of time. - The Deep Credit Tables were increased by 15%. The 15% increase is a permanent change to the Deep Credit Tables and applies to all new wells drilled. The increase of royalty credits was intended to offset the higher drilling costs since the Deep Royalty Program was introduced in 2003 (6 years). - Horizontal wells between 1,900 and 2,300 metres were eligible for the Deep Royalty Credit Program; the minimum vertical depth to completion for horizontal wells was shortened from 2,300 metres to 1,900 metres. However, horizontal wells must also have a deep well depth greater than 2,500 metres to qualify. This change was permanent.

		- IRCP was allocated an additional $50 million in royalty credits to encourage companies to explore and access new and under-developed areas of BC.
2013	Minimum Royalty Program	- The minimum royalty program limits the amount of deep well credit or deep re-entry credits may deduct from the gross royalty payable less Producer Cost of Service; it sets an absolute minimum bound on royalties payable to Government.
2014	Deep Well Credit Program: Tier 1, Tier 2	- Deep gas wells are now classified as Tier 1 or 2. The tier depends on the type of deep gas well, as well as spud date. The value of Tier 1 deep well credits is designed to cover a portion of drilling and completion costs for shallower wells with longer horizontal segments. All other wells that qualify or have qualified for deep well credits are classified as Tier 2. - Minimum royalty amounts apply to Tier 1 (6%) and Tier 2 (3%) wells.
2014	Ultra-Marginal Low Productivity Program	- Horizontal wells are no longer eligible to qualify for the Ultra-Marginal Low Productivity Program - Vertical wells must have a true vertical depth (TVD) to completion point and TVD to top of pay equal to or less than 2,500 metres — no change
2016	Coalbed Methane Royalty Program	- Shell announced cancellation of Klappan CBM exploration, the last CBM project in British Columbia; producers shift capital away from coalbed methane in favour of the shale oil and gas reserves.
2016	Infrastructure Credit Programs — Rebranding	- Eligibility changes — Clean Infrastructure Royalty Credit Program
2018	Petrinex Adoption	- Petrinex adoption requires changes to business processes and regulation amendments
2019	Infrastructure Credit Programs — Rebranding	- Eligibility changes — Clean Growth Infrastructure Royalty Program

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