# MASTER OF PUBLIC POLICY
# CAPSTONE PROJECT

**Evaluating British Columbia's Natural Gas Royalty Regime:**
**The Benefits of a Blended Rate Royalty Structure**

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Submitted in fulfillment of the requirements of PPOL 623 and completion of the requirements for the Master of Public Policy degree

THE SCHOOL OF PUBLIC POLICY

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## Capstone Approval Page

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## Acknowledgements

I would like to acknowledge Dr. Robert Mansell for all of the supervision, time, and knowledge that he has passed down to me over the timeline of this project. Dr. Mansell has provided me with valuable resources that were helpful in creating an original work at the School of Public Policy.

## Table of Contents

## LIST OF TABLES AND FIGURES

**CAPSTONE EXECUTIVE SUMMARY**

With Alberta's thorough royalty review in 2016, it would seem timely for British Columbia to evaluate its natural gas and natural gas liquids royalty regime to ensure that it is not only competitive with Alberta but also economically efficient. While Alberta's Modern Royalty Framework treats all natural gas and natural gas liquids in a consistent manner, the BC system still separates gas and gas liquids and charges them at different rates. This study focuses on the impacts of this separation with differential rates. It is argued that by moving to a system similar to that used in Alberta, the BC government can improve the competitiveness and long run stability of gas and liquids investments in the province and optimize its royalty revenues.

## 1.0 Introduction

British Columbia (BC) has a relatively disjointed royalty system that taxes natural gas and gas liquids production at different rates and through separate structures as well. The royalty system is a mix of a 'revenue-minus-cost' model on natural gas production, as well as fixed rates on natural gas liquids (NGLs) and other by-products such as sulphur. Meanwhile, Alberta has recently reviewed and altered its royalty system. It levies the royalty similarly on all natural gas and NGLs. This change has incentivized companies to produce the highest value products, and invest more into exploration and drilling in the province. In this project, the focus is on the question of whether BC needs to change its royalty regime to be competitive with Alberta and, in particular, whether it results in a higher royalty burden for private investors than is the case in Alberta?

By looking at production in the Montney basin and applying the two different royalty structures used in BC and Alberta, it is argued that the BC system is less efficient and consistent with optimizing royalty revenues compared to the Alberta system.

The focus of this study is on the post-payout period. This is the period when the well is producing and after the capital costs of drilling a well have been recovered by a company. The post-payout period is when the company will pay its largest share of royalties, as the pre-payout period reduces the royalty paid either through a cost allowance measure, such as in Alberta, or it has credits available to reduce costs, such as in BC. Since the Alberta Royalty Review already has determined through economic modelling that the credit system results in a higher burden on a company drilling and poorly reflects operating costs, this aspect is not studied here.[1] A drilling credit system only simulates capital cost recovery, where the Drilling and Completion Cost Allowance actually emulates the revenue minus cost model.[2] Therefore, in general, a credit system distorts economic decisions such that it would be in a jurisdiction's best interest to incorporate a cost allowance structure in the pre-payout period. This would not only incentivize companies to reduce capital costs through innovation but also increase profits.[3]

By focusing on changes to the royalty system applicable to the post-payout period in BC, rather than just reducing the current rates, the government should expect an increase in investment into the province, while still generating optimal resource revenues for the citizens of the province. The objective of changing the royalty structure in BC is not to get short term royalty revenues by lowering royalty rates in order to increase, capital flowing into the province. Rather, the intention is to alter the royalty structure to optimize investment and royalty revenue over the long term and reduce the volatility of investment through risk sharing.

## 2.0 Literature Review

Given that Alberta is the heartland of oil and gas production in Canada, the BC government often uses Alberta as the standard of comparison for oil and gas investment, production and resource taxation. Since the main focus in this paper is how the current BC natural gas and NGLs royalty levy affects investment in the province, a reasonable approach is to again make the comparison with Alberta. Note that Alberta recently undertook a royalty review

1 Blake Shaffer, "Lifting the Hood on Alberta's Royalty Review," *The School of Public Policy* 9 (2016): 7.
2 Government of Alberta, *Alberta at a Crossroads* (Edmonton; Royalty Review Advisory Panel, 2016), 62.
3 Shaffer, "Lifting the Hood on Alberta's Royalty Review," 9.

that resulted in a significantly rearranged royalty structure aimed at increasing economic efficiency.

### 2.1 Understanding Efficient Royalty Structures

The Alberta Royalty Review asked two simple questions to determine the best way to calculate royalty rates. First, how can the royalty structure continue to encourage industry investment while ensuring Alberta gets a fair share of returns?[4] Then secondly, how can the royalty structure provide optimal returns to Albertans as the owners of the resource?[5] These are the same questions that need to be asked if BC is to achieve an efficient and competitive royalty structure.

An efficient royalty structure is one that maximizes private investment in a province's oil and gas market, while also maximizing the province's royalty returns. In theory, this involves determination of the elasticities underpinning a Laffer Curve.[6] If the royalty rate is too low, private investments are flourishing with increased profits, but this also allows inefficient companies to thrive. Likewise, if the royalty rate is too high, then too many private investors will leave the provincial oil and gas market as operations become uneconomic even for otherwise efficient companies. These companies will move to a more investment-friendly province, one that has a royalty structure that promotes risk-sharing. These two scenarios of under and over charging royalty rates lead to inefficient royalty structures because the government is not maximizing their royalty revenues.

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[4] Ibid, 9.

[5] Government of Alberta, *Alberta at a Crossroads*, 15.

[6] "Personal Taxation and Behaviour," in *Public Finance in Canada,* ed. Harvey S. Rosen, Jean-Francois Wen, and Tracy Snoddon (McGraw-Hill Ryerson, 2012), 383.

An efficient royalty structure also ensures that there is risk-sharing between companies and the resource owner (the government). If the oil and gas market prices collapse, a royalty structure needs to adapt to the change in the market and reduce the burden on companies. However, when the prices surge, the companies should be expected to pay a larger share of the economic rents. By risk-sharing between the government and the companies, investment will be more stable, reducing the incentive for a company to move its capital elsewhere whenever the market changes.

A competitive royalty structure is based on the relative royalty levied in two competing provinces. This requires a province to have an equally efficient royalty structure to a competing province. If one province has excessive royalty levies compared to another, then companies with flexible capital will move to the province with the lower royalty rates. However, as stated earlier, lower royalty rates do not always equal efficiency. This will be further explored later on. What is most important to understand at this time is that a government must have an efficient royalty structure if it is going to be competitive with other provinces in accumulating capital investment in the oil and gas market of the province.

## 2.2 British Columbia's Royalty Structure

The BC government understands that the royalty regime that sets their royalty rates is not the most efficient system. In the *2016/17-2018/19 Service Plan for the BC Ministry of Natural Gas Development*, the Minister concluded that the primary goal for the province in resource development is to optimize royalty revenues from BC's upstream natural gas developments.[7] To

[7] Government of British Columbia, *2016/17-2018/19 Service Plan*, (Victoria: Ministry of Natural Gas Development, 2016): 10.

do this, the Minister suggests that the best way to optimize royalty revenues is to create a royalty program that enhances the competitive environment in BC, which will generate new Crown revenues.[8]

In economic terms, the Ministers plan is to create a royalty structure that is competitive with Alberta, which means more efficient royalty rates. An increase in upstream investment would lead to an increase in exploration and drilling projects by industry. With more wells producing, there is more supply to levy a royalty on, which will create higher revenues.

It is important to note that operations and capital costs for a natural gas well are typically larger in BC than in Alberta. Of the total revenues that a well produces, 76% goes to pay for the operations and capital costs in BC, as opposed to only 53% in Alberta.[9] Thus, in order to be competitive for investments it would seem that, all other things equal, the BC royalties paid on both natural gas and natural gas liquids (NGLs) need to represent a lower burden than they would be in the case in Alberta. As of the 2016 Alberta Royalty Review, only 8% of revenue becomes company profit for a BC well, as opposed to 25% in Alberta.[10]

Every year BC completes a *Royalty Performance Report* to determine how efficient the royalty program is at generating investment to the province. The government determines the royalty burden per thousand cubic feet (mcf) between BC and Alberta.[11] Since 2009, with the exception of the 2014/15 fiscal year, the BC natural gas royalty (excluding NGLs) represented a

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[8] Ibid, 10.

[9] Woods Mackenzie, "Fiscal Benchmarking Results," (Presentation, Prepared for Alberta Energy with Interpretive Notes by the Alberta Royalty Review Panel, Alberta, 2016): 29.

[10] Ibid, 29.

[11] Government of British Columbia, *British Columbia Royalty Programs: Goals & Performance Measures 2016 Report*, (Victoria, Ministry of Natural Gas Development, 2016), 6.

lower burden than the natural gas royalty in Alberta.[12] This is opposed to the early 2000s when the royalty burden in BC was much higher, losing the competitive edge to Alberta.[13] Since this was becoming a year-by-year issue, BC lowered their royalty rates in 2003 to attempt to reduce the burden, instead of fixing their royalty structure which would have been more economically efficient.[14] By 2006, BC royalty rates were comparable to rates in Alberta again.[15] However, while the BC system had regained competitive rates with Alberta, which in turn produced a lower burden on companies in the short-term, it was also in part because Alberta had raised their own royalty rates in 2007 in an attempt increase royalty revenues and increase the government's returns.[16] This led to the BC rate on natural gas being about 13% of economic rent, where in Alberta the royalty rate averaged around 17% before the change to the Modern Royalty Framework (MRF).[17]

### 2.3 The Need to Include NGLs in Burden Calculations

In BC, the focus should not be on lowering royalty rates to compete with Alberta. Instead, it is important that the royalty issue move away from simply lowering rates, and move towards creating an economically efficient royalty structures.[18] There are two problems with how BC calculates the burden, and how they first attempted to reduce the burden. First by reducing the royalty rates in 2003, BC created a distorted royalty regime that increased private investment

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[12] Ibid, 6.
[13] Ibid, 6.
[14] Government of British Columbia, *British Columbia Oil and Gas Royalty Programs, Program Goals & Performance Measures 2011 Report*, (Victoria: Ministry of Energy and Mines, 2011), 1.
[15] Ibid, 1.
[16] Colin Busby, Benjamin Dachis, and Bev Dahlby, "Rethinking Royalty Rates: Why There is a Better Way to Tax Oil and Gas Development," *C.D. Howe Institute Commentary Fiscal and Tax Competitiveness* 333 (2011): 1.
[17] Woods Mackenzie, "Fiscal Benchmarking Results," 29.
[18] Temitope Tunbi Onifade, "Alberta, Canada, Royalty Review and its Lessons for Resource Economies," *Journal of Energy & Natural Resources Law* 35 (2017): 195.

for a short time. However, the increase in private investment came from both efficient and inefficient companies. The lower royalty rates allowed inefficient companies to continue using inefficient operations practices, without having to reduce operations or capital costs to increase economic rents. The lower royalty rates allow for inefficient companies to exist in their current form and do not create an incentive for these companies to find a more efficient operations structure.[19]

There is also a flaw with how BC currently compares their natural gas royalty to that in Alberta. BC's natural gas royalty and the NGL royalty are two separate royalty structures. While the natural gas royalty is a rent-based system, which is calculated through a reference price and a select price (which is revenue minus costs), the NGL royalty is a standard 20% fixed rate on all revenues.[20] This is opposed to the new Alberta royalty structure, where natural gas and NGLs are all a part of the same royalty structure and add up to give a single royalty rate that is applied to the company's economic rent. Economic rent is the surplus value of a resource after all costs have been subtracted from the revenues produced by the resource.[21] An example of this would be a company making $100 revenue from a natural gas well, but it costs $40 to operate and maintain the well. The economic rent for this company's well will be $60.

In the Alberta Royalty Review break down of revenues for a gas well in BC, the NGL rate, as well as NGL revenues were not included. It focused strictly on marketable gas. For this reason, the BC fixed NGL rate skews the generally lower natural gas royalty rate, making it a higher burden on a company. The rate will diminish the small profit a company may have while

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[19] Government of Alberta, *Alberta at a Crossroads*, 42.

[20] Government of British Columbia, *Oil and Gas Royalty Handbook,* (Victoria: Ministry of Finance, 2014), 112.

[21] Jack Mintz and Duanjie Chen, "Capturing Economic Rents from Resources Through Royalties and Taxes," *The School of Public Policy* 5 (2012): 3.

operating in BC. While including NGLs will increase revenues, there is an offset in the form of operation and capital costs. Capital needs to be invested into processing facilities that ensure the NGLs are separated from the natural gas where it is fundamentally economic to do so. There will also need to be investments in transportation and marketing infrastructure for the NGLs once they are separated. This means building a more permanent NGL pipeline system, or paying transport trucks to move the NGLs from the plant to the consumers (for example petrochemical companies). Secondary costs also exist before the NGLs are separated at the plant. With high volumes of liquids being transported by pipeline to the plant, more chemicals are necessary to avoid corrosion and the creation of hydrates which could cause pipeline failures. While chemical costs are smaller than the much larger capital costs that the plant must spend on transportation and the creation of separation facilities, it is a cost that is necessary as long as the well and the plant are in operation.

Moving to a standardized revenue minus cost model of resource taxation across all natural gas hydrocarbons is the most economically efficient way to create government revenue while ensuring companies will invest into the province's resources based on economic fundamentals.[22] Companies, without a standardized model across natural gas hydrocarbons, will drill for what will cost them the least in economic rents, and not for the hydrocarbons that have the highest value to the market. This is the investment distortion that can develop out of an inefficient royalty system.

Using a revenue minus cost model will ensure that the companies that produce resources at the lowest cost (assuming revenue is static), will still pay the same share of the economic rent

[22] Shaffer, "Lifting the Hood on Alberta's Royalty Review," 12.

(based on a percentage of the rent) as a more inefficient, high cost company will pay.[23] While the dollar figure may be larger for the low-cost company than the inefficient company, the low-cost company is still more profitable. The revenue minus cost model also works in the opposite sense, where the companies that have produced the most revenue with costs remaining static still pay the same share of economic rents as a low-revenue company. Thus, there remains an incentive to reduce costs and increase revenues.

The primary objective of resource taxation should be to collect a portion of the economic rents that are available. When a royalty is applied only to the pure economic rent, there will not be a distortion in the use of capital or other production factors.[24] When a royalty fails to levy just the rent, a producer will either not invest into what could be a profitable project, or they will invest into a low value project. This is because rent-based royalties are considered neutral. They do not discourage investment, nor do they encourage it in a stand-alone system.[25] However, if the comparison is relative, and one jurisdiction has an exhaustive rent-based system on its natural gas wells and all NGLs produced from these wells, while the other system has a mix of rent-based royalties and fixed rates on revenue, then a rent-based system encourages investment in comparison to the other system which has disincentives attached to it.

The 'revenue-minus-cost model' must apply to all of the resources that a company may produce from a single well. If the model is inconsistent, there will be inefficiencies that create an environment that discourages investment. This is because, in such a hybrid system, different resources will face a different royalty rate that is unrelated to the relative profitability. The

[23] Ibid, 1.
[24] Ibid, 1.
[25] Ibid, 1.

optimal royalty structure will be a system that that has a standard share of rent (represented as a percentage) that is determined by the royalty rate divided by the rent (revenue minus cost). Thus, if the size of the rent changes, the royalty rate will change with it to ensure the share of rent remains at the specified percentage.[26]

In BC, the natural gas royalty (excluding NGLs) follows this system. The royalty rate fluctuates with changes in revenues and costs of production of a well to ensure the share of economic rent captured by the government is reasonably constant. That is, the share of economic rents going to the government will always stay the same for similar wells, no matter how much revenue a company makes or how much its operations and capital costs are to create the aforementioned revenue. All companies pay the same share of economic rent. The revenue minus cost system of natural gas royalties also involves risk sharing between the government and the company, while encouraging economic activity in the resource economy.[27] By sharing risk, a company does not need to avoid drilling and exploration activities because of the royalty regime in a province when the oil and gas market is performing poorly with low prices.

However, the NGL rate, which is the 20% fixed rate on revenue, is inefficient as it will, at a certain point, exceed the economic rent that a company gets from a particular well. Since a natural gas well does not produce only dry gas (methane with no other NGLs), but a mix of other hydrocarbons, including condensate, this 20% fixed rate will defeat the purpose of having a rent-based natural gas royalty structure. This can lead to a well being no longer profitable to produce the NGL resources. Let's say for example the 20% rate is on a revenue of $40, and the rent is

[26] Shaffer, "Lifting the Hood on Alberta's Royalty Review," 3.

[27] Marc Lee, "Path to Prosperity? A closer Look at British Columbia's Natural Gas Royalties and Proposed LNG Income Tax," *Canadian Centre for Policy Alternatives* (2014): 7.

only $5 (meaning there is an operating cost of $35).[28] The royalty collected by the province will be $8 ($40*0.20), which means there is no longer any profit for the company to produce the NGL in question. The share of the rent actually exceeds 100%, creating a highly inefficient royalty system.[29]

This will lead to companies doing one of three things. First, the company can begin to stop separating lower value NGLs from their gas. This would occur if the royalty is at its most inefficient, and a company can make a profit without separating some NGLs from the gas. For example, of all the NGLs produced in the BC Montney Play, 71% is ethane.[30] However, ethane separation does not occur for many reasons. One reason is that the primary market for ethane is chiefly for regional petrochemical demand. Most ethane from BC and Alberta goes to the olefin crackers in Alberta, although there was a point in time when some ethane was transported to Sarnia, Ontario to help satisfy demand.[31] Now ethane production is at a tipping point according to the Canadian Energy Research Institute, where ethane production in BC and Alberta is past the demand capacity, leading to rejection of the ethane, and leaving it in the gas pipeline.[32] With the ethane supply being so large and with the high capital costs that are associated with separating ethane, this means there is a reduction in the economic incentive to extract ethane at the plant.

[28] Ibid, 7.

[29] Ibid, 7.

[30] Filippo Ferri, Mark Hayes, and Aaron Nelson, "Liquids Potential of the Lower to Middle Triassic Montney and Doig Formations, British Columbia," *British Columbia Ministry of Natural Gas Development Geoscience Reports* (2013): 2.

[31] Laura Johnson and Paul Kralovic, *Competitive Analysis of the Canadian Petrochemical Sector*, (Calgary: Canadian Energy Research Institute, 2016): 8.

[32] Ibid, 6.

The addition of an inefficient 20% fixed royalty leads to most upstream companies leaving ethane in their marketable gas, only to separate the heavier liquids such as propane, butane and condensate.[33] Then the company sells the marketable gas either to end users or another downstream company at a higher value since it includes ethane, allowing it to utilize the rent-based natural gas royalty that provides an efficient arrangement of resource taxation.[34]

It is important to note here that NGLs are priced mainly based on the crude oil market rather than the dry gas market. Both historically and into the future, crude oil prices (on an energy equivalent basis) are greater than dry gas prices.[35] When the natural gas is measured in barrels of oil equivalent to match the energy content of one barrel of crude, crude is often still worth twice as much as the dry gas. For this reason, the incentives for most natural gas companies is to drill for liquid rich gas, as the NGLs have more value than the gas on its own.

Second, the company may shut in a well if it is producing too much wet gas. This is because a company cannot stop a well from producing undesirable NGLs. Consequently, wells with NGLs, which have the highest production value, will be shut in since they are no longer economic for the company. Finally, the company may begin drilling wells exclusively in dry gas basins. This will ensure that the company is only paying the more efficient rent-based natural gas royalty. However, dry gas is not valued as highly as wet gas because wet gas has a higher energy content, and produces more revenue if there are no distortions through government regulations.[36] Thus, in an attempt to stay economically viable, a company may no longer be producing the

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[33] Ferri et al. "Liquids Potential of the Lower to Middle Triassic Montney and Doig Formations, British Columbia," 6.

[34] Ibid, 6.

[35] Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 13-14.

[36] Charles K. Ebinger and Govinda Avasarala, "Natural Gas Briefing Document #1: Natural Gas Liquids," *Brookings Energy Security Initiative Natural Gas Task Force* (2013): 5.

highest-value resources. Now, not only are the company's investments misplaced, but the government will be missing out on valuable NGL resource taxation that has been foregone.

What is interesting is that all these distortions and inefficient royalties may actually cause the largest companies to leave a jurisdiction before the small companies exit. This is because a large company has more flexible capital, which means they are better able access financial capital in other regions and to redeploy their capital outside of the province as a response to the increases and decreases of royalty rates.[37] Smaller companies cannot redeploy capital in new jurisdictions as easily as they lack the necessary profits to move capital that is already in place. Thus, those companies that likely have the largest rents to levy a royalty on will leave the province, causing junior companies to pay royalties with their smaller rents, and lower production volumes. Again, the government loses optimal royalty returns, as well as future investments. The royalty system should not be structured in a way that creates incentives for large companies to move their investments based on excessive royalty burdens.

### 2.4 Alberta's Modern Royalty Framework

What did Alberta do to create a more efficient royalty regime? The Royalty Review panel suggested that the MRF treat various hydrocarbons with a similar technique, in a revenue minus cost model, as the old model treated different hydrocarbons discriminatorily (like the current BC royalty system).[38] By doing this, a company can produce hydrocarbons that are the highest value. Companies then have a strategic interest to drill wells where the natural gas, NGLs, and other by-

[37] Busby et al. "Rethinking Royalty Rates," 16.
[38] Government of Alberta, *Alberta at a Crossroads,* 9.

products are produced according to market signals rather than making investment decisions based on the relative difference of royalty burdens.

It also removes the risk of producing an unintended product.[39] Having different royalty structures for different hydrocarbons means that companies need to be particularly careful about where they drill and what they are drilling for. For example, with all other things equal, if the conventional crude oil royalty rates are significantly higher than those for natural gas, there will be an artificial incentive for companies to inefficiently move their drilling activities from oil to dry gas prone areas, even though crude is more valuable.

Finally, the royalty payments should be stabilized.[40] In the MRF, the majority of the royalty payments occur during the post-payout period of the well's life. Given that payout has occurred, production should be less variable and this will serve to have a stabilizing effect on royalty revenues. Further, a system where royalty payments are tied to economic rents (rather than gross revenues) allows a sharing of the risks and returns as prices and costs fluctuate, thereby reducing variations in investment and ensuring royalty revenues for the government are optimized over the longer run.[41] In this case, sharing risk means that a government is prepared to take less in royalty revenues when the oil and gas economy is in recession, while companies are prepared to pay more in royalty levies when the resource economy is prospering. By removing the 20% fixed rate on NGLs in BC and replacing it with a rent-based structure tied to the natural gas royalty would be a major step towards long term stability.

[39] Ibid, 11.
[40] Ibid, 63.
[41] Onifade, "Alberta, Canada, Royalty Review and its Lessons for Resource Economies," 172.

## 2.5 USING COST ALLOWANCES IN THE PRE-PAYOUT PERIOD

In both BC and Alberta, the majority of the royalties that are paid come from what is considered the post-payout period, which is after capital expenditures associated with a well have been recovered. In the pre-payout period, drilling credits or a cost allowance are utilized so that in the initial production phase after the well is drilled the company can recuperate the capital costs for exploration and drilling without a large additional resource taxation burden.

According to economic theory, the drilling credit system often fails to reflect the costs that a producer will encounter when drilling a well.[42] When product prices change during the investment stage, it can alter what a company will invest in drilling and development. At low prices, the credit system allows for the royalty structure to take too much of the company's rent, making the project appear unprofitable.[43] Vice versa when the prices are high, royalties during the pre-payout period are low and generous, causing the government to not receive its fair share from the resources.[44]

This situation occurred in practice in BC between 2009 and 2014. During that five-year period, natural gas production had increased, but royalty revenues were dropping significantly because of poorly executed deep drilling credits and infrastructure credits.[45] As the profitability decreases because of low prices, the credit system distorts investment decisions, as is suggested

[42] Shaffer, "Lifting the Hood on Alberta's Royalty Review," 8
[43] Ibid, 8.
[44] Ibid, 8.
[45] Lee, "Path to Prosperity?" 2.

in theory. The two factors working together decreased royalty revenues from $2.4 billion in the 2008/2009 fiscal year to $300 million in 2011/2012 and $100 million in 2012/2013.[46]

Instead, what should be adopted is what Alberta has incorporated into its system, which is a drilling and completion cost allowance (DCCA). This system is used to shift a well from the pre-payout period to the post-payout period when the cumulative revenues from the well are equal to the determined DCCA.[47] The DCCA does not affect investment decisions like the credit system, and thus royalty revenues should not drop so significantly because resource companies are still investing into the province. The DCCA is triggered to change to the post-payout system at the same revenue generation point no matter what the price is. Thus, companies are not going to invest solely based on resource pricing. On the first 50,000 barrels of production, the DCCA is triggered at either $1.5 million, $2.5 million or $5 million in revenue depending on the costs to drill and complete the well.[48] Instead, the focus, as stated before is to reduce costs which would increase their resource rent. Based on this theory, the BC government should move to a DCCA in the pre-payout period, tied to the overall structure change that will generate increased investment and royalty revenues during the post-payout period.

Following the suggestions of the Alberta Royalty Review Panel, it is apparent that in theory the BC government needs to make changes to its royalty structure. But how does the BC post-payout royalty structure for a natural gas well actually compare to the Alberta post-payout structure?

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[46] Ibid, 8.
[47] Ibid, 8.
[48] Government of Alberta, *Alberta at a Crossroads*, 11.

## 3.0 Methodology

The comparison between the BC royalty structure and the Alberta royalty structure is dependent on the actual production numbers in BC. As opposed to the BC system of comparison that only compares the natural gas royalty, this comparison will include BC's royalty on NGLs as well. This will help to determine how much different the actual royalty burden is depending on whether the BC or Alberta MRF structure is used. To do this the comparison will look at a set of similar wells that produce at different levels (high, medium, and low) and at different prices (high, medium, and low).

### 3.1 Well Location

The wells that will be used to compare the BC and Alberta royalties will be based in the Montney Play, in three particular basins: the Doig Phosphate, the Heritage Montney and the Northern Montney. It is important that the comparison differentiates between these three basins for two of reasons. First is the difference in production levels. For example, the Doig Phosphate produces more gas on average than the Northern Montney.[49] Meanwhile a Heritage Montney well will produce more barrels per million cubic feet of natural gas (bbl/mmcf) of condensate, propane and butane than both the Doig Phosphate and the Northern Montney.[50]

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[49] Government of British Columbia, *British Columbia's Oil and Gas Reserves and Production Report*, (Victoria: BC Oil and Gas Commission, 2015): 14.

[50] Government of British Columbia, *Montney Formation Play Atlas NEBC,* (Victoria, BC Oil and Gas Commission, 2012): 31-32.

Table 1: Individual Well Monthly Natural Gas Production ($e^3m^3$)

| | Low Production | Medium Production | High Production |
|---|---|---|---|
| Doig Phosphate | 42 | 95 | 170 |
| Heritage Montney | 43 | 68 | 131 |
| Northern Montney | 57 | 110 | 160 |

Source: Government of British Columbia, *British Columbia's Oil and Gas Reserves and Production Report*, (Victoria: BC Oil and Gas Commission, 2015): 14.

Second, the operating costs for the three basins are different as well. According to Encana's operations plan, the operating costs in the Montney are anywhere between $68.57 per thousand cubic metres ($e^3m^3$) and $75.36 per $e^3m^3$.[51] Since large companies will be the first to leave a jurisdiction because of an inefficient royalty structure, Encana is a good resource to use to determine if a company would leave the Montney Play and set up capital investments elsewhere. Operating costs were assigned based on the travel costs associated with each of the three basins. The Heritage Montney is the closest to the two economic centres of the area, Fort Saint John and Dawson Creek. For this reason, the Heritage Montney was assigned operating costs per well of $68.57 per $e^3m^3$. Meanwhile the Northern Montney is a remote location, ~152 km northwest of Fort Saint John and is accessed by lateral roads that branch off of the Alaska Highway. For this reason, we can expect operating costs to be higher because of increased transportation for operators, maintenance crews, and the resources themselves. The Doig Phosphate, which is just south of the Northern basin can expect similar costs. For that reason, both of these basins were assigned operating costs of $75.36 per $e^3m^3$.

[51] Encana Corporation, "Encana Corporation, Corporate Presentation June 2017," Accessed June 20, 2017, https://www.encana.com/pdf/investors/presentations-events/corporate-presentation.pdf.

### 3.2 Potential Production and Revenue from Montney Wells

Once the production figures and operating costs have been determined, there is a wide variance in the potential revenues that a well can make in each production area. The total revenue that a company can make from a well is the sum of the natural gas production and NGL production multiplied by their respective prices. The prices used to determine the revenue from each of these wells comes from projected price forecasts done at the Henry Hub for natural gas and forecasts done by Deloitte for NGLs. These prices do not include the transport costs; thus, the cost must be added to get from the plant gate sales point.[52] However, they are a part of Encana's operations costs that are used in this study, so they are already covered.

By using price forecasts, we can evaluate whether the royalty structure will not just be positive for investment decisions in the present, but for what the future may hold for the oil and gas industry. The price forecasted that is used for both natural gas and NGLs is for 2026. The decision to use 2026 was based on the notion that the best royalty regime used currently should also be appropriate under conditions a decade in the future. The objective is to create a royalty regime that creates long term success rather than short term gains.

For natural gas, there is a base price alongside a high and low price that will affect revenues for any company that sells to the Henry Hub. The three corresponding prices (all in Canadian Dollars) are \$170 per $e^3m^3$, \$210.09 per $e^3m^3$, and \$299.63 per $e^3m^3$. These prices are based off of the Henry Hub forecasts presented by the Alberta Energy Regulator, and have been converted from US Dollars per million BTU.[53] . The use of the Henry Hub forecast is used

[52] Deloitte, *Price Forecast, March 31, 2017*, 14.

[53] Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.

because much of northeast BC gas is sold to either the Henry Hub or the Station 2 lines. Since the Henry Hub has access to international markets, most companies sell their gas there.

Meanwhile the NGLs have one base price for propane, butane and condensate for the year 2026. Propane is forecasted to be worth $37.10 per barrel, butane at $55.70 per barrel and condensate will be worth $92.80 per barrel.[54] Since it is determined that at a 20% fixed rate it is uneconomical to remove ethane from natural gas, it will be assumed in this study that ethane will not be extracted. It is important to note that these prices are closely tied to the forecasted oil prices, since the petrochemical industry has the largest demand for NGLs.[55] If the crude oil market either collapses or strengthens by 2026 the NGL prices will mirror these changes.

Thus, only having a single base price is not ideal, as it does not provide data on how NGL prices will react if the crude oil economy fluctuates. However, the range of production potential that is available for each NGL in each of the three basins should make up for this lack of price data.

Three tables will explain how much production of natural gas and NGLs will occur in each production basin. Table 2 (as well as Table 7 and Table 9) are not particularly easy to read. For this reason, I will explain them in detail here. The first row of data is the gas production in mmcf in the Doig Phosphate. This is how much an average well will produce in the basin based off of drill location. A natural gas well will produce 2.01mmcf, 3.88 mmcf, or 5.65 mmcf per month. Since royalties are collected monthly, we must know how much production occurs in a month.

[54] Deloitte, *Price Forecast, March 31, 2017*, 14.
[55] Ebinger et al. "Natural Gas Briefing Document #1: Natural Gas Liquids," 7.

Table 2: Doig Phosphate Natural Gas and Natural Gas Liquids Production

| Doig Phosphate | Low production | Base production | High production |
|---|---|---|---|
| Gas Production (mmcf) | 2.01 | 3.88 | 5.65 |
| Propane (bbl/mmcf) | 1 | 3 | 6 |
| Butane (bbl/mmcf) | 1 | 2 | 4 |
| Condensate (bbl/mmcf) | 2 | 10 | 50 |
| Propane * 2.01 mmcf | 2.01 | 6.03 | 12.06 |
| Propane * 3.88 mmcf | 3.88 | 11.64 | 23.28 |
| Propane * 5.65 mmcf | 5.65 | 16.95 | 33.9 |
| Butane * 2.01 mmcf | 2.01 | 4.02 | 8.04 |
| Butane * 3.88 mmcf | 3.88 | 7.76 | 15.52 |
| Butane * 5.65 mmcf | 5.65 | 11.3 | 22.6 |
| Condensate * 2.01 mmcf | 4.02 | 20.1 | 100.5 |
| Condensate * 3.88 mmcf | 7.76 | 38.8 | 194 |
| Condensate * 5.65 mmcf | 11.3 | 56.5 | 282.5 |

Sources: Government of British Columbia, *British Columbia's Oil and Gas Reserves and Production Report*, (Victoria: BC Oil and Gas Commission, 2015): 14. / Government of British Columbia, *Montney Formation Play Atlas NEBC,* (Victoria, BC Oil and Gas Commission, 2012):31-32.

Next, by looking at the NGLs, we can see that they are produced at barrels per mmcf of gas. Thus, the NGLs produced are dependent on the volume of gas that is also being produced that month. Without the pressure of the gas, no NGLs are brought to surface. More gas equals more pressure trying to escape from downhole, which means more NGLs are being pushed up into production. Since there is a range of NGL production rates as well as three gas production rates, there are potentially nine different production levels for each NGL.

Let's explain using propane.  Each of the production level columns corresponds with the propane that can be produced in the Doig Phosphate (or the other two basins) which are 1 bbl/mmcf, 3 bbl/mmcf, and 6 bbl/mmcf. The 3 rows that correspond with the production levels of propane are the mmcf of gas that is also being produced. Therefore, a well that is only producing 1 bbl/mmcf of propane means that it is potentially producing 2.01 bbls, 3.88 bbls, or 5.65 bbls total based on gas volumes. If the well is producing 6 bbls/mmcf of propane (high production column), then it can produce 12.06 bbls, 23.28 bbls or 33.9 bbls, which corresponds to the production levels of gas. This is how the table works for butane and condensate as well.

So, while we only have a single price for the NGLs, the model will provide a wide range of NGL revenues from which the government can take different levels of resource revenues from the royalty structures. Thus, it is still plausible to capture inefficiencies between the BC and Alberta systems.

### 3.3 The Royalty Structures to be Compared

The two royalty structures have different rate structures for different types of wells. The wells that are being used to produce the natural gas and NGL figures are standardized in this study to eliminate external factors. The wells will be evaluated as unconventional gas; therefore, they have been hydraulic fractured horizontal wells in deep shale basins. They will also be evaluated as wells that are drilled on Crown land instead of freehold land. Freehold land is when a well is drilled on land where someone (other than the Crown) owns the resource title, and it is not leased by the government. Since the majority of wells drilled in BC are on leased Crown land it is best that this is the structure that is assumed for the analysis.

### 3.3.1 THE BC NON-CONSERVATION GAS ROYALTY

Since we are following the standard of unconventional gas on Crown land for the wells in the Montney, the following royalty rate calculation is used in the BC royalty structure for natural gas:

$$Royalty = \frac{9 * Select\ Price + 40(Reference\ Price - Select\ Price)}{Reference\ Price}$$

This royalty rate calculation is determined by the *Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation*.[56] Here the government utilizes the royalty equation for non-conservation gas that has a spud date after May 31, 1998, otherwise known as Item 1.1.[57] Non-conservation gas is the majority of natural gas production in BC and is not produced from an oil well event that is conserved or marketed instead of flared.[58] Essentially, non-conservation gas is natural gas that was drilled to send to market instead of being a secondary hydrocarbon produced from an oil operation.

The reference price is determined by the total natural gas revenue that a well produces per month, minus production costs,[59] which have been broken down earlier into operation costs per well as determined by Encana's operations in the Montney basin. Production costs include

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[56] Government of British Columbia, *Petroleum and Natural Gas Act*, *Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation 2016,* s. 6(1)(a), https://www.canlii.org/en/bc/laws/regu/bc-reg-495-92/latest/bc-reg-495-92.html.

[57] Ibid, s 6(1)(a).

[58] Government of British Columbia, "Oil and Natural Gas Glossary," Accessed June 24, 2017, http://www2.gov.bc.ca/gov/content/taxes/natural-resource-taxes/oil-natural-gas/help-centre/glossary.

[59] Government of British Columbia, *Oil and Gas Royalty Handbook,* 36

processing fees, compression costs, transportation and gathering. When a corporation determines this price on their own, it is labeled the producer price.

The other option that exists for determining the reference price is to create use the government produced posted minimum price (PMP). The PMP is 80% of the estimated sales price for gas produced in a particular production area for each month.[60] By utilizing the 80% threshold, the PMP acts to include the production costs that may exist for a well. However, the company must take the larger of the producer price or the PMP, so in this study, the producer price will be utilized.[61]

The select price is determined by the BC government's Royalty Administrator. The select price is set for each calendar year, and is the mechanism that allows for the minimum royalty rate to take effect.[62] Currently the Administrator has the select price set at \$50 per $e^3m^3$. So, if the reference price is less than or equal to \$50 per $e^3m^3$, then the royalty rate that is applied for an Item 1.1 well is 9%.[63]

By using either the producer price or the PMP model, the natural gas royalty structure (without NGLs) is an economic rent system. If NGLs are excluded, we have seen through the *British Columbia Royalty Programs: Goals & Performance Measures 2016 Report* that the government allows companies to get a competitive return on investment and return on capital, in comparison with Alberta. However, the issue arises with the additional NGL royalty. A company operating a well in the Montney basins must also pay a 20% fixed rate on the NGL revenue that

[60] Government of British Columbia, "Gas Reference Price," Accessed June 24, 2017, http://www2.gov.bc.ca/gov/content/taxes/natural-resource-taxes/oil-natural-gas/oil-gas-royalty/understand/reference-price.
[61] Government of British Columbia, *Oil and Gas Royalty Handbook,* 32.
[62] Ibid, 36.
[63] Ibid, 36.

the well produces. In the case of this model, this would be a 20% rate on propane, butane and condensate production. This 20% flat royalty rate is not levied on only economic rents, but on total revenues. Let's compare this with Alberta's MRF.

### 3.3.2 THE ALBERTA MODERN ROYALTY FRAMEWORK FOR NATURAL GAS WELLS

Following the new royalty review recommendations, the Alberta MRF for natural gas and NGL producing wells treats all of the hydrocarbons in the same way. This creates a single royalty rate equation that encompasses all the hydrocarbons to determine a single rate that will be paid on the company's economic rent for all the hydrocarbons they produce. The royalty rate is determined using the following equation:[64]

$$GR\% = \frac{[MR\%(MQ) + ER\%(EQ) + PR\%(PQ) + BR\%(BQ) + PPR\%(PPQ)]}{MQ + EQ + PQ + BQ + PPQ} + [C\%(AF)]$$

where: GR%: The Crown's royalty share of the gas and NGLs expressed as the percentage payable by the company

MR%: The Crown's royalty share of methane (natural gas), expressed as a percentage of the methane produced

ER%: The Crown's royalty share of ethane, expressed as a percentage of the ethane produced

PR%: The Crown's royalty share of propane, expressed as a percentage of the propane produced

BR%: The Crown's share of butane, expressed as a percentage of the butane produced

PPR%: The Crown's share of pentanes plus (condensate) as a percentage of the pentanes plus produced

[64] Government of Alberta, *Mines and Minerals Act, Natural Gas Royalty Regulation, 2017,* s 4, https://www.canlii.org/en/ab/laws/regu/alta-reg-211-2016/latest/alta-reg-211-2016.html.

MQ, EQ… etc.: quantities of the respective hydrocarbon contained in the gas

C%: The additional royalty shares payable for months of gas production

AF: The Adjustment Factor as determined by the Administrator

The Alberta rate is more inclusive to all hydrocarbons that can be produced by a single well. It is also created in such a way that no hydrocarbon has a fixed rate attached to it. For example, the MQ% and the PQ% will be completely different as they are calculated based on the price (rp%) and volume (rq%). This means that a high producing natural gas and propane well in the Doig Phosphate will have a MQ% of 14.6% and a PQ% of 13.6%. Here it is important to show how the Alberta MRF allows for differing hydrocarbon rates that reflect both price and volume where the BC rate on NGLs does not account for these differences, which are constantly changing.

It is important to note that C% and AF do not have an effect on the overall royalty payable by the company in this study. This is because in this case the adjustment factor is equal to zero, since it only applies to conservation gas that exists in the McMurray Formation, the Clearwater Formation in the Fisher and Moore fields and in oil sands areas.[65] Since this study focuses on non-conservation gas, it is in the interest of the model to utilize s. 7(14) of the *Natural Gas Royalty Regulation*, which allows for the AF to be deemed zero in any producing month.[66] Thus [C%(AF)] will always equal zero and has no effect on the main variable of the Alberta MRF royalty rate equation.

[65] Ibid, s7(12).
[66] Ibid, s7(14).

Now that there are two royalty structures to use and compare, the royalty revenues from both structures will be put into a matrix to compare the absolute and relative difference in how much a company operating in the Doig Phosphate, Heritage Montney and Northern Montney will need to pay in resource taxes for their corresponding production at different price levels. In calculating the relative and absolute differences, the current BC structure will be considered the reference value. The Alberta MRF, which is considered the more efficient system, will be the comparative value. The ability to compare the two structures at every price level and production level allows for a better evaluation of the two structures.

## 4.0 Results

In every case applicable the Alberta MRF results in a system where risk-sharing is maximized between the government and private investors, and one which is a far more efficient royalty structure compared to that in BC. Both the absolute and relative differences that exist between the two structures indicate that the Alberta structure is more investment friendly in the long-term. It also indicates that as prices for natural gas increase, and production of natural gas and NGLs increase, the Alberta MRF closes the relative gap between revenue generated in each royalty structure. This suggests that the Alberta MRF is better at ensuring revenues are generated from high producing, economically strong wells as opposed to the BC system which will charge a higher rate on the less economic, low production wells. For this reason, in the long term the Alberta MRF will create stable investment, where the BC system is only competitive when there are high market prices for natural gas and NGLs.

### 4.1 Doig Phosphate

The Doig Phosphate basin is south of the Northern Montney basin, and is the second largest basin, following the Heritage Montney. The Doig has a higher gas productivity which increases the bbl/mmcf of NGLs produced from a single well. This production capability was outlined in Table 2. The results here will indicate how much a company will pay in royalties based on the BC system and then compare it to how much would be paid under the Alberta MRF.

The company needs to calculate the royalty rate payable for gas production in the area. To do this the revenue per month a well can produce must be determined. With three price levels and three production levels, a well in the Doig Phosphate can produce a revenue anywhere between $9,700 and $47,947 per $e^3m^3$ produced in a month. Having these revenue numbers allows us to start piecing together the reference price needed for the BC natural gas royalty. To finish determining the reference price one must determine the operating costs per $e^3m^3$ produced. Since the operating costs in the Doig Phosphate are estimated at around $75.36 per $e^3m^3$, this number is multiplied by the production levels to determine costs at different well production. The revenue and costs are highlighted fully in Table 3.

Table 3: Doig Phosphate: Well Natural Gas Revenue and Operating Costs

| Doig Phosphate | Low Price | Base Price | High Price | Operating Costs (75.36/e3m3) |
|---|---|---|---|---|
| Low Production | $9700.83 | $11975.13 | $17081.19 | $4310.91 |
| Medium Production | $18720.90 | $23109.90 | $32963.70 | $8319.30 |
| High Production | $27230.40 | $33614.40 | $47947.20 | $12100.80 |

Sources: Encana Corporation, "Encana Corporation, Corporate Presentation June 2017," Accessed June 20, 2017, https://www.encana.com/pdf/investors/presentations-events/corporate-presentation.pdf. / Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 14. / Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.

Using this information, the natural gas royalty in BC can be calculated by placing in the reference price and the Administrator determined select price. In this case, using the royalty structure of Item 1.1, the royalty rate is between 18% and 27%.[67] 27% is the highest royalty rate the BC government can charge. If any calculations exceed 27%, the company will still only pay the upper limit. The government will receive a royalty revenue from the natural gas that ranges between $1,836 (low price, low production) and $12,945 (high price, high production).

Table 4: Doig Phosphate: Natural Gas Royalty Revenue, BC Structure

| | Low Price | Base Price | High Price |
|---|---|---|---|
| Low Production | $1,836.65 | $3,015.86 | $4,611.92 |
| Medium Production | $3,536.88 | $5,813.55 | $8,900.20 |
| High Production | $5,140.87 | $8,452.88 | $12,945.74 |

Sources: Government of British Columbia, *Oil and Gas Royalty Handbook, (*Victoria: Ministry of Finance, 2014). / Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 14. / Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.

Now, the company needs to add the royalty payable on the NGLs that have been produced from the same well. At a 20% fixed rate that is taken from the revenues generated by the well, the government will tend to make more revenue from condensate, which is the highest value NGL. For example, in the high price, high production scenario, the BC government will make $251.54 from propane royalties, $251.76 from butane royalties, and $5,243.20 from condensate royalties.

[67] The BC system royalty rates for natural gas in the Doig Phosphate can be found in Appendix A, Table 12.

Adding the natural gas royalty revenue to the propane, butane and condensate revenues, the BC royalty structure has a total royalty payable between $1,948 and $18,692. This is a lofty amount of the total rent. In the in the low price, low production situation, the economic rent is only $5,949.51, and $1,948.56 of the rent is due to the government in royalty payments. Thus, the company only has a profit of $4000.95.

At the highest priced natural gas and NGLs, and the highest production levels, there is a total rent of $64,578.91. Subtracting the government royalty revenue of $18,693.25, there is a (before tax) profit for the company of $45885.66 (assuming no other taxes or fees that are taken off at this stage).

While in the high price, high production scenario, 29% of the rent goes to the government, in the low price, low production scenario, 33% of the economic rent goes to the government. This system produces a larger burden on companies working in a low price, low production environment. This is the exact opposite of what risk-sharing is supposed to achieve. Rather, in a low price, low production scenario, the government should receive less in royalty payments relative to rent, and when prices and production rise, the government would get more royalty revenues. This fluctuation in shares of rent is beneficial only for short term economic gain, and only when the oil and gas economy is flourishing. However, in the long-run it fails to provide investor stability, which is an issue of the NGL fixed rate. Without the fixed rate, the share of economic rent paid is much more in line with the product price and production environment.

Table 5: Doig Phosphate: BC Royalty Structure Government Revenues (Natural Gas plus NGLs)

| | Low Price | Medium Price | High Price |
|---|---|---|---|
| Low Production | $1,948.56 | $3,478.45 | $6,656.25 |
| Medium Production | $3,752.92 | $6,706.50 | $12,846.47 |
| High Production | $5,455.46 | $9,753.17 | $18,692.25 |

Sources: Government of British Columbia, *Oil and Gas Royalty Handbook, (*Victoria: Ministry of Finance, 2014). / Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 14. / Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.

With the revenue for the government determined under the BC structure, the production in the Doig Phosphate must now be incorporated into the Alberta structure. The Alberta MRF is more streamlined, as outlined before because it includes all natural gas hydrocarbons into the same royalty equation.

Table 6: Doig Phosphate: Alberta MRF Government Revenues (Natural Gas and NGLs)

| | Low Price | Medium Price | High Price |
|---|---|---|---|
| Low Production | $513.02 | $714.40 | $1,365.14 |
| Medium Production | $990.05 | $2,518.43 | $15,116.25 |
| High Production | $2,882.42 | $6,175.86 | $27,916.00 |

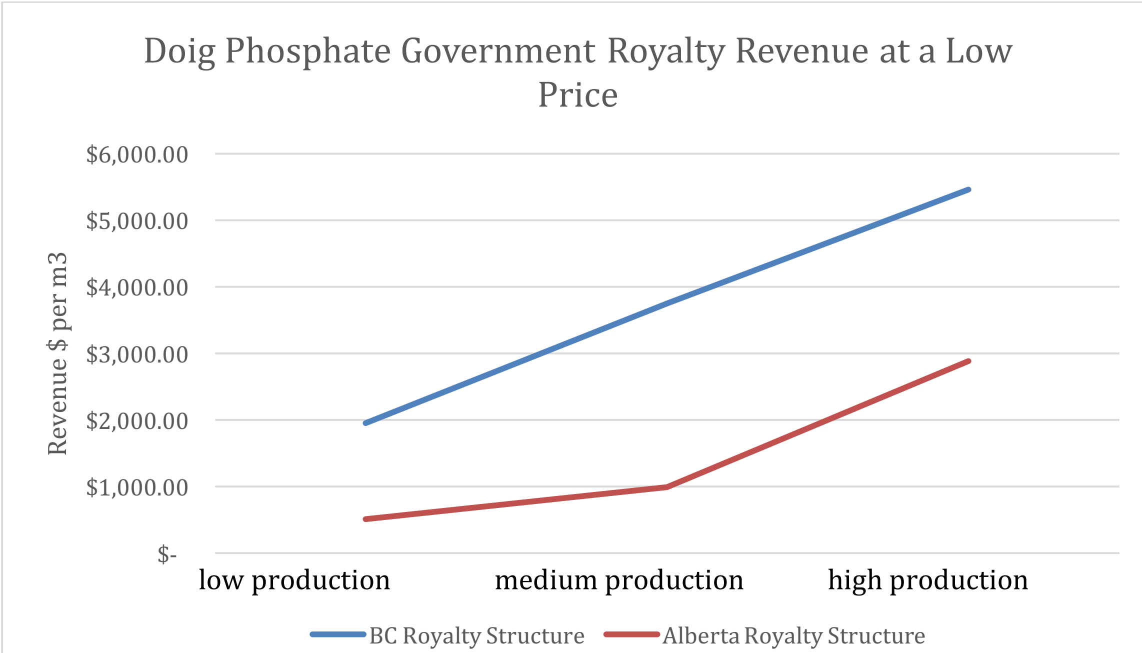
Sources: Government of Alberta, *Mines and Minerals Act, Natural Gas Royalty Regulation, 2017,* https://www.canlii.org/en/ab/laws/regu/alta-reg-211-2016/latest/alta-reg-211-2016.html.
/ Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 14. / Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.

The equation is very intricate, but in its most basic form, it is the addition of multiple royalty rates divided by the quantities of hydrocarbons produced.[68] Each hydrocarbon has its own royalty rate determined by a par price equation. In doing these calculations, the Alberta MRF will create a weighted rate applied to all revenues that fluctuates dependent on price and production. It is important to note that the rate needs to be within the bounds of 5% and 36%. If the rate is either too low, or exceeds these bounds, then the rate is bumped up or down to these two rates. In this case, only once does the royalty rate exceeded 36%, and twice the royalty rates were lower than 5% in the Doig Phosphate. In the other two basins, some of the low production and low-price rates across the different basins needed to be moved up to 5% or dropped to 36% as well. What occurred under the Alberta MRF for a Doig Phosphate well was a lower royalty rate compared to BC for lower price, lower production wells. Meanwhile, higher price, higher production wells had a higher royalty rate under the Alberta MRF than under the existing BC system.

Starting at the low price, low production level, a company will need to pay an additional $1,435.54 in royalties under the BC structure. As shown in Figure 1, in absolute terms, the BC structure forces the company to pay much more than under the Alberta royalty structure.

[68] The Alberta MRF royalty rates for the Doig Phosphate can be found in Appendix A, Table 13.

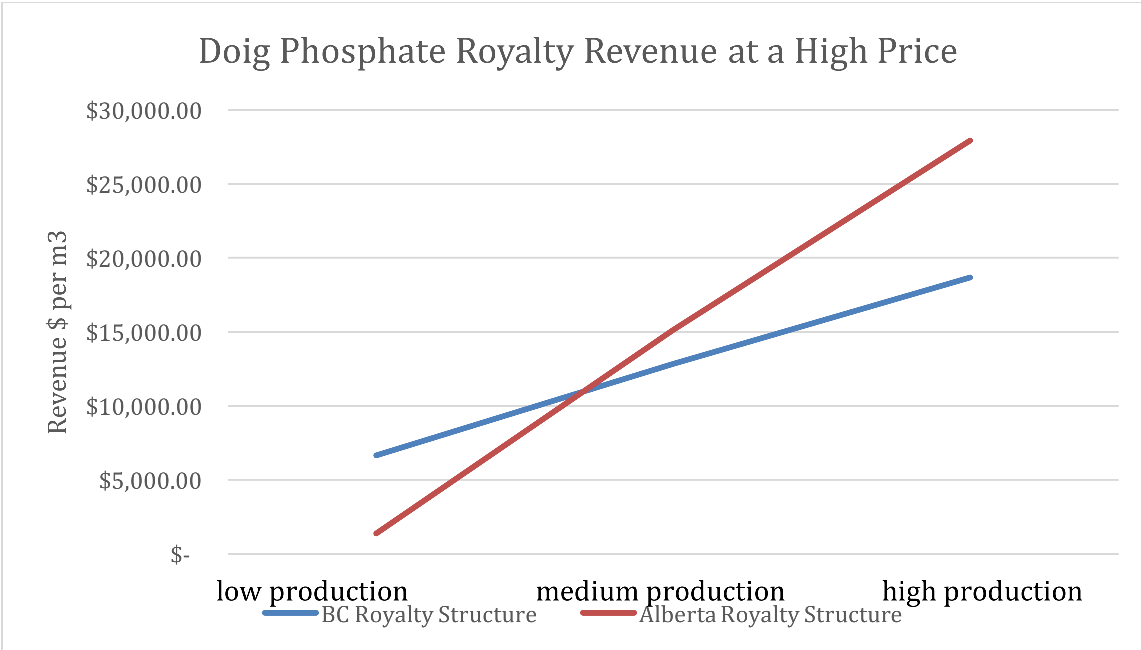
Figure 1: Doig Phosphate: Revenue Generation: Absolute Difference between Alberta and BC Royalty Structures




The BC system forces low producing wells to pay a larger share of the rents, while the Alberta system helps companies when prices are low, and then gets more royalty revenues as prices and production grow. This means that the rent of lower producing wells is diminished more quickly in the BC system, and it may force companies to shut in these wells or abandon them prematurely if it is no longer economic to keep them producing. Thus, the BC system will lose revenue generation from any of the lower producing wells, while the Alberta system will continue to generate revenues from all levels of producing wells because of risk sharing.

The absolute differences in royalty revenues under a high price scenario are shown in Figure 2. In this figure, the growth of the Alberta royalty revenues as production and prices increase is visualized. The companies making the most money in the Alberta MRF pay significantly more than companies that are not operating under the best economic circumstances.

Figure 2: Doig Phosphate: Revenue Generation: Absolute Difference between Alberta and BC Royalty Structure

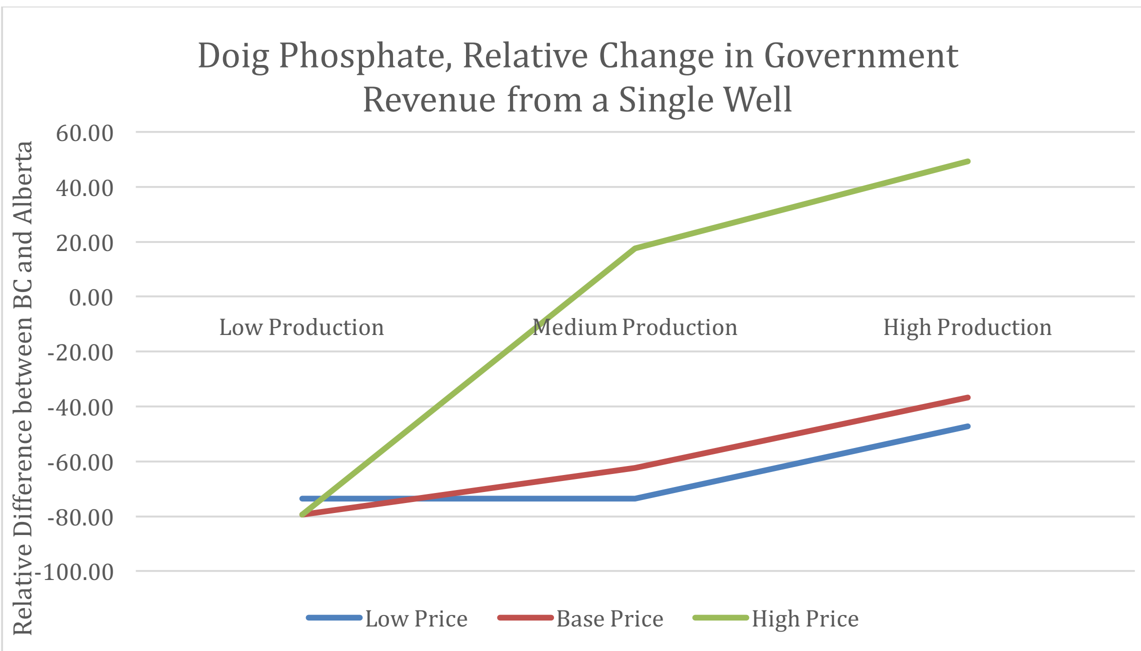



In relative terms, the Alberta system increases the royalty rate as production increases.[69] It is not until there is a high price, medium production scenario that the Alberta system results in higher royalty revenues than under the BC system. Thus, in only two scenarios, at the highest prices and production levels, is the Alberta MRF at a competitive disadvantage. This is a prime example of how risk sharing between the resource owner and a company works in resource taxation. The companies only pay a larger share of their economic rent when they are very successful, and when prices and production fall, the government takes less of the rent. This creates stability as investors realize that they can drill for highest value hydrocarbons, and if unsuccessful, or the economy begins to slide, they can still produce without having unnecessarily high royalties levied on their production. In general, the MRF for the Doig Phosphate is both an efficient and competitive royalty structure.

[69] The relative difference results for the Doig Phosphate can be found in Appendix A, Table 11.

Figure 3 visualizes the relative differences between the BC royalty system and the Alberta MRF at different prices and production levels. When the relative difference is in the negatives it indicates that the BC royalty structure is charging a higher royalty rate and thus taking a larger royalty revenue relative to Alberta. When the relative difference is positive, it indicates the Alberta MRF is charging more than the BC royalty system. Thus, as stated earlier, the Alberta MRF only charges a higher royalty relative to BC when the price is high and production is at medium to high levels.

Figure 3: Doig Phosphate: Relative Change between BC and Alberta Royalty Structures at Different Price Levels




## 4.2 Heritage Montney

The Heritage Montney, while expected to produce more NGLs that the Doig Phosphate, it is not forecasted to produce as much natural gas. The difference in production between the two basins will lead to different royalty burdens. The lower operating costs for a well in this area,

$68.57 per $e^3m^3$ as opposed to $75.63 per $e^3m^3$, will also increase the rent that is available to levy a royalty on, which will increase royalty rates as well as revenues to the government.

Table 7: Heritage Montney Natural Gas and NGL Production

| Heritage Montney | Low production | Base production | High production |
|---|---|---|---|
| Gas Production (mmcf) | 1.48 | 3.35 | 6.00 |
| Propane (bbl/mmcf) | 2 | 6 | 15 |
| Butane (bbl/mmcf) | 2 | 4 | 10 |
| Condensate (bbl/mmcf) | 2 | 25 | 100 |
| Propane * 1.48 mmcf | 2.96 | 8.88 | 22.2 |
| Propane * 3.35 mmcf | 6.7 | 20.1 | 50.25 |
| Propane * 6 mmcf | 12 | 36 | 90 |
| Butane * 1.48 mmcf | 2.96 | 5.92 | 14.8 |
| Butane * 3.35 mmcf | 6.7 | 13.4 | 33.5 |
| Butane * 6 mmcf | 12 | 24 | 60 |
| Condensate * 1.48 mmcf | 2.96 | 37 | 148 |
| Condensate * 3.35 mmcf | 6.7 | 83.75 | 335 |
| Condensate * 6 mmcf | 12 | 150 | 600 |

Sources: Government of British Columbia, *British Columbia's Oil and Gas Reserves and Production Report*, (Victoria: BC Oil and Gas Commission, 2015): 14. / Government of British Columbia, *Montney Formation Play Atlas NEBC,* (Victoria, BC Oil and Gas Commission, 2012):31-32.

As is indicated in Table 7 as compared to Table 2, more propane, butane and condensate are produced than in the Doig Phosphate. Since natural gas and NGL price forecasts remain the same, a Heritage Montney well can generate a total revenue anywhere between $7,697 and $113,304 at different price and production levels. See Table 8.

Table 8: Heritage Montney Total Revenue Generate by a Well

| Heritage Montney | Low Price | Medium Price | High Price |
|---|---|---|---|
| Low Production | $7,697.36 | $12,916.57 | $27,968.52 |
| Medium Production | $17,411.57 | $29,222.64 | $63,286.88 |
| High Production | $31,159.50 | $52,307.70 | $113,304.90 |

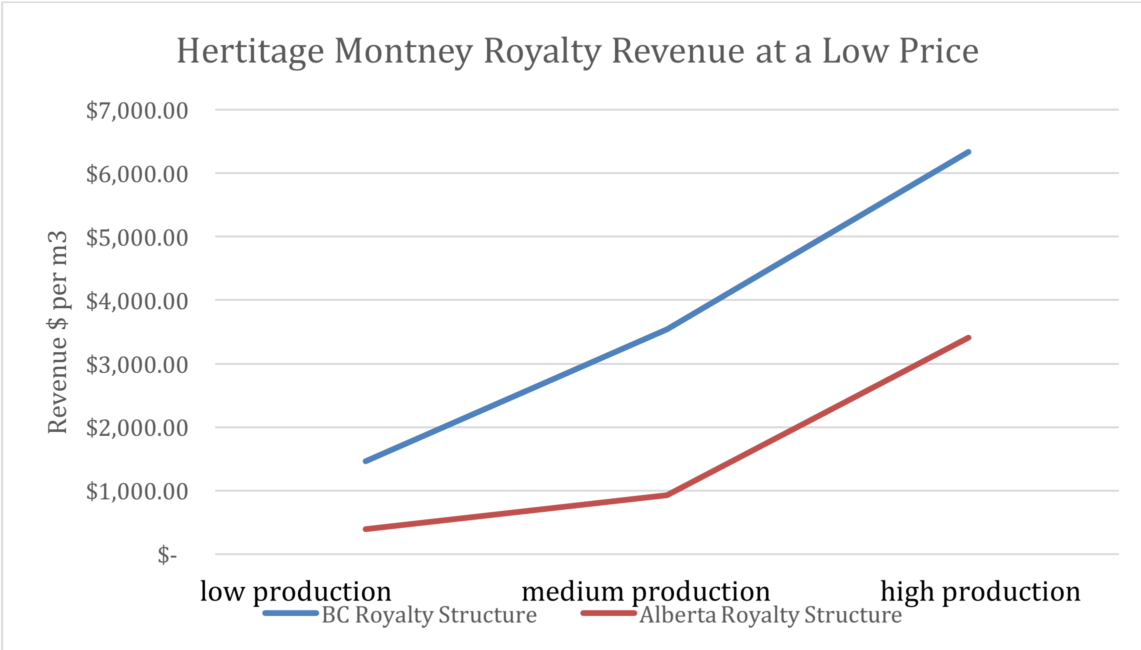
Sources: Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 14. / Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.

These revenues come primarily from the NGLs that are produced in the region. For example, in the high production and high price situation, 49% of the revenues come from condensate production on its own. All the NGLs produced are equivalent to 55% of the $113,204 in revenue that is made by a Heritage Montney well in these conditions. Thus 55% of the revenue is subject to the 20% fixed rate as opposed to the revenue minus cost model that is used for natural gas production.

However, at the lower production and lower price, a larger share of the revenue comes from the natural gas production. Of the $7,697 in a low production, low price environment, 93% comes from natural gas production. Thus, more of the revenue is subject royalties under the revenue minus cost model. However, even in the situation that has the least effect from the 20% fixed rate, the royalty burden for a company operating in the Heritage Montney is higher in absolute terms under the BC structure.[70] See Figure 4.

[70] Comparison of 20% flat rate on propane to the Alberta MRF rate on propane can be found in Appendix B, Table 16.

Figure 4: Heritage Montney Revenue Generation: Absolute Difference between BC and Alberta Structures



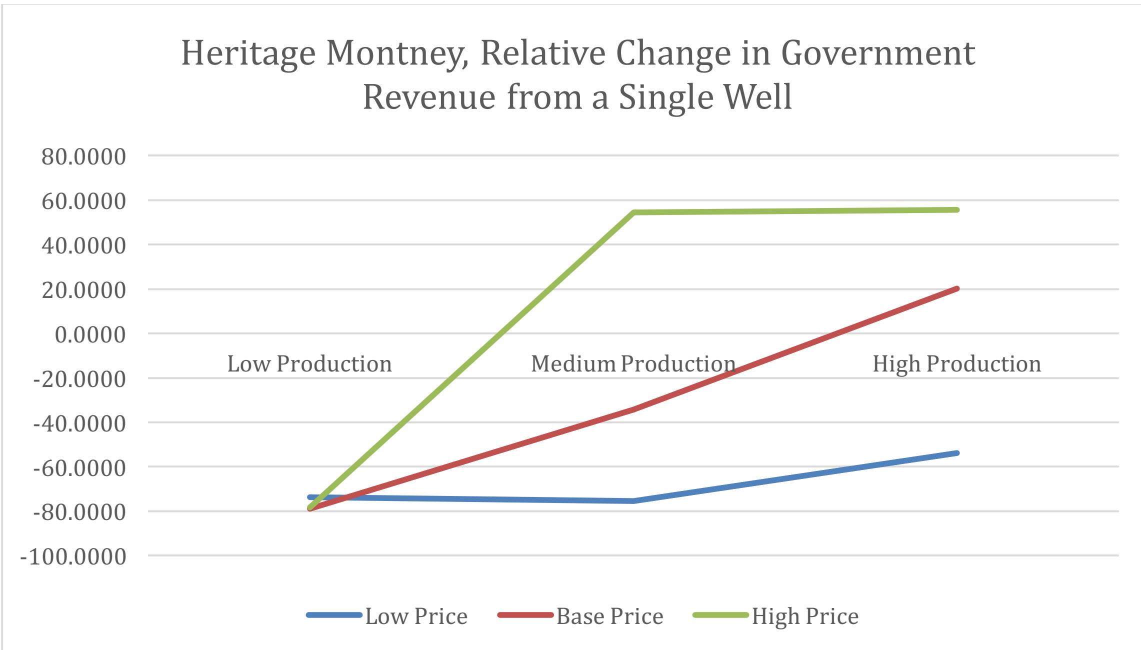

In relative terms, the Alberta structure acts in the same manner as in the Doig Phosphate area, but because of the increased profitability that drilling for NGLs brings, the Alberta MRF begins to charge more relative to the BC structure than in the Doig Phosphate.[71] At low price, and all production levels, the Alberta MRF continues to generate less of a burden on companies than under the BC royalty regime. However, at the base price, as opposed to the situation in the Doig Phosphate, the Alberta MRF would now charges more than under the BC system at high production levels. The larger economic rent that exists in the Heritage Montney as opposed to the Doig Phosphate is the reason for this relative difference.

Figure 5 operates the same as Figure 3, showing the relative difference between BC's royalty system and the Alberta MRF. In the Heritage Montney we can see that the high price

[71] The Alberta MRF royalty rates and the BC system royalty rates for the Heritage Montney can be found in Appendix B, Table 14 and Table 15.

scenario is not the only occurrence of the Alberta MRF charging more than the BC royalty structure, which was the case in the Doig Phosphate. If there is high production at the base price, then the Alberta MRF charges a higher royalty rate. This is because of the higher production capabilities of the Heritage Montney relative to the Doig Phosphate across all natural gas hydrocarbons.

Figure 5: Heritage Montney: Relative Change between BC and Alberta Royalty Structures at Different Price Levels




This spike in the Alberta MRF that levies higher royalties relative to the BC structure is because the Alberta rate in this situation is above the 20% flat rate on NGLs as well as the 27% cap on natural gas rates. At a high price, high production scenario in the Heritage Montney, the company is paying a royalty rate of 36% on its rents. If the government was charging 24% in this scenario, then the BC and Alberta structures would create equivalent government revenues.

### 4.3 Northern Montney

Table 9: Northern Montney Natural Gas and NGL Production

| Northern Montney | Low production | Base production | High production |
|---|---|---|---|
| Gas Production (mmcf) | 1.52 | 2.40 | 4.63 |
| Propane (bbl/mmcf) | 1 | 3 | 6 |
| Butane (bbl/mmcf) | 1 | 2 | 4 |
| Condensate (bbl/mmcf) | 5 | 25 | 50 |
| Propane * 1.52 mmcf | 1.52 | 4.56 | 9.12 |
| Propane * 2.40 mmcf | 2.4 | 7.2 | 14.4 |
| Propane * 4.63 mmcf | 4.63 | 13.89 | 27.78 |
| Butane * 1.52 mmcf | 1.52 | 3.04 | 6.08 |
| Butane * 2.40 mmcf | 2.4 | 4.8 | 9.6 |
| Butane * 4.63 mmcf | 4.63 | 9.26 | 18.52 |
| Condensate * 1.52 mmcf | 7.6 | 38 | 76 |
| Condensate * 2.40 mmcf | 12 | 60 | 120 |
| Condensate * 4.63 mmcf | 23.15 | 115.75 | 231.5 |

Sources: Government of British Columbia, *British Columbia's Oil and Gas Reserves and Production Report*, (Victoria: BC Oil and Gas Commission, 2015): 14. / Government of British Columbia, *Montney Formation Play Atlas NEBC,* (Victoria, BC Oil and Gas Commission, 2012):31-32.

The Northern Montney is smallest field in the Montney Play, but has roughly the same number of producing wells as the Doig Phosphate.[72] The Northern Montney has the lowest gas production of the three areas, and produces the same amount of propane and butane per well as

[72] Government of British Columbia, *Montney Formation Play Atlas NEBC,* 8.

the Doig Phosphate. However, the Northern Montney is a higher producer of condensate than the other two fields. While the Heritage Montney may have some wells with the potential to produce 100 bbl/mmcf, the Northern Montney will produce more condensate at low and base production levels, with 5 bbl/mmcf and 25 bbl/mmcf respectively. Since condensate is the most valuable hydrocarbon BC, there can be an expectation that there will be increased drilling and exploration in the Northern Montney.

Based on these characteristics, the revenue generated for the company from any well has a high dependence on condensate. If condensate production does not materialize, it is likely that company will not want to invest in the well any longer. If the government is taking too large of a percentage of the rents from condensate production, there will be little incentive to drill wells in the Northern Montney.

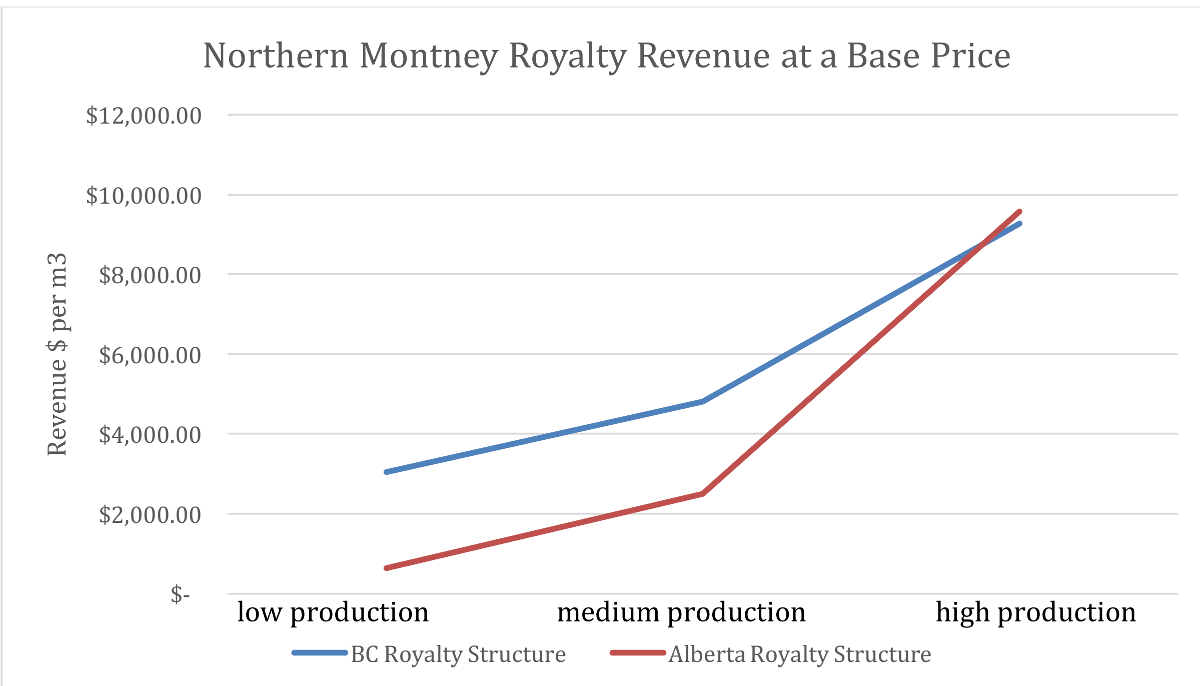
While the BC structure forces the company to pay a 20% fixed rate on all condensate produced, the Alberta MRF would only expect the company to pay a royalty between 3% and 40% on condensate (if it was the only hydrocarbon produced).[73] The company would need to pay up to 17% more than what is considered efficient under the Alberta structure if the well does not produce enough gas to bring up the maximum amount of condensate. However, if the well is working in a high price, high production environment, then the Alberta MRF charges 20% more than the BC system.

The BC structure fails to levy royalties on the proper producers. Low production companies pay too much, while the high production companies do not pay enough to the government. Thus, the BC royalty discourages any investment into the Northern Montney as it

[73] The individual royalty rates on NGLs from the Alberta MRF in the Northern Montney can be found in Appendix C, Table 17, Table 18, and Table 19.

fails to invite companies that do not hit the condensate 'jackpot.' Figure 6 shows how the Alberta MRF revenue generation spikes as condensate production grows at a base price. This is because the Alberta MRF royalty rate for condensate is now higher (29%) than the 20% flat rate from BC. However, the low rates for the other natural gas hydrocarbons keeps the total royalty rate equivalent to the BC royalty structure. The growth from the BC royalty structure is also tied to condensate, but as we can see it is more inelastic to the change in production than the Alberta MRF.

Figure 6: Northern Montney Revenue Generation: Absolute Difference between BC and Alberta Structures




In relative terms, the Alberta MRF structure continues to act the same as it did in the Doig Phosphate and the Heritage Montney. In a low price, low production scenario companies know that with the MRF they do not need to hit the condensate 'jackpot' to avoid being hit with high royalty rates. Instead, if one company does hit a high producing condensate well, they will only need to pay a higher rate than the BC system if the prices are at or above the 2026 forecasted prices. In all, the BC royalty regime is less industry-friendly and deters investment.

Table 10 is the numerical visualization of what was presented in Figure 3 and Figure 5. The negative numbers represent the BC royalty system having a higher royalty rate and generation of more revenue relative to Alberta. Therefore, the Alberta MRF charges more than the BC royalty system when the relative difference is positive. In Table 10 you can see that the BC royalty structure charges a much higher royalty rate in seven of the nine scenarios. Only once does the Alberta MRF charge a significantly higher royalty, in the high price, high production level. Thus, hitting the condensate 'jackpot' means higher relative royalties in the Alberta MRF, while anything less than high production will cause a company to be charged unnecessarily high royalty rates in the BC system.

Table 10: Northern Montney Relative Difference between BC and Alberta Royalty Regime

| Relative Change | Low Price | Base Price | High Price |
|---|---|---|---|
| Low Production | -73.78 | -78.85 | -79.49 |
| Medium Production | -73.73 | -48.26 | -10.84 |
| High Production | -44.47 | 3.16 | 43.32 |

## 5.0 Conclusion

The BC government charges higher royalties per well in almost every case as compared to what would be charged under the Alberta MRF. Only wells that have a moderate price with high production, or high price with medium to high production would pay more under the Alberta MRF. Thus, the BC royalty structure places a higher burden on wells operating in a poor oil and gas market. For this reason, a large company like Encana could easily move its investments to avoid paying the BC royalty rate when the economy is poor and prices are low. This suggests that the elasticity of oil and gas markets is high, and that if royalty rates are fixed at a higher than optimal rate, as are the BC NGL rates, then companies will react and investment is deterred.

In general, it would appear that the BC royalty structure will lead to less than optimal returns for the government from upstream oil and gas companies operating in BC. It is argued that the provincial government can significantly improve the royalty structure by incorporating key features of the Alberta MRF. This can help to increase the number of companies operating in the BC resource industry, which would maximize the total government revenues. Currently the 20% fixed rate on NGLs overcharges companies for production that should be charged at a much lower rate. Making such a change would reduce overall costs to a company, and increase the opportunities to invest into BC.

## 6.0 Recommendation

It is recommended that BC move away from their current royalty structure that separates gas and NGLs and imposes different royalty rates. It is recommended that the BC government remove the 20% fixed rate on NGLs, as it creates a large part of the excessive burden on producers in less favorable price and productivity environments, particularly as it is the NGLs that are currently the most valuable hydrocarbon that can be produced. Under the current system, there is only a strong incentive for investments in BC when the oil and gas economy is flourishing.

It is recommended that he BC government implement a royalty regime that is similar to the new Alberta MRF. This regime treats all hydrocarbons as similar and thus, it allows for companies to produce the highest valued hydrocarbons, no matter how well the oil and gas market is operating at a point in time. This allows investment decisions to be more naturally based on market fundamentals and less on differential royalty burdens depending on the type of production.   Lowering these burdens and reducing increasing their responsiveness to the price and productivity environment will spur investment and will allow for the BC government to enjoy a larger return on resource rents over the long term.

Finally, it is also recommended that the BC government replace its drilling credit system with a DCCA program. This will also eliminate economic distortions and allow for increased investment into drilling and completions which will bring increased revenues in the post-payout period.

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## Appendix A: Doig Phosphate

The relative difference between the BC royalty structure and Alberta MRF decreases as there is an increase in production. The matrix for this change is outlined below. When the numbers are negative, this represents that a company operating in the Doig Phosphate will pay more in the BC royalty system than in the Alberta system. The larger the negative number, the higher the burden is on a company in the BC system. When the number is positive, this means that a company in the Doig Phosphate will pay more under the Alberta system. As we can see, there are only two instances when a company pays more under the Alberta system. It also happens when the economy is operating at its best, as prices are at the highest levels forecast in 2026, and only when the company has a medium to high producing well. This is when a company should be paying the most in resource taxes, since the company is at its most successful. The BC royalty system charges companies more when the natural gas market is not at its most successful, thus placing a larger burden on companies that are working in a less than desirable market, and who are producing less gas and NGLs than they would prefer.

Table 11: Doig Phosphate: Relative Change between BC Royalty Structure and Alberta MRF

| Relative Change | Low Price | Base Price | High Price |
|---|---|---|---|
| Low Production | -73.67 | -79.46 | -79.49 |
| Medium Production | -73.62 | -62.45 | 17.67 |
| High Production | -47.16 | -36.68 | 49.35 |

Let’s compare the actual rates that will be paid by a Doig Phosphate company under both the Alberta MRF and the BC royalty structure. In the BC royalty structure, without accounting for the 20% flat rate for NGLs, the rates are already quite high, between 18% and 27%. By adding the 20% flat rate for propane, butane, and condensate, the rates under the low price scenario increase to levels above 18%, while lowering the rates at to below 25% and 27% under the base and high price scenarios as seen in Table 12.

Table 12: Doig Phosphate: BC Natural Gas Royalty Rates

| BC Government Royalty Rate | | | |
|---|---|---|---|
| | Low Price | Base Price | High Price |
| Low Production | 18.933% | 25.184% | 27% |
| Medium Production | 18.893% | 25.156% | 27% |
| High Production | 18.879% | 25.147% | 27% |

Sources: Government of British Columbia, *Oil and Gas Royalty Handbook, (*Victoria: Ministry of Finance, 2014). / Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 14. / Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.

This is opposed to the Alberta MRF, where the royalty rates that include all of the hydrocarbons being processed are much lower for the majority of the price and production levels. Only at the high price, with medium to high well production do we see the Alberta MRF charge more than the BC royalty structure. So, the BC flat rate on NGLs makes it worse for companies in poor economic condition when the prices are low, but helps when the economy is at a forecasted high. This copies the argument from the relative difference between the Alberta and BC royalty structures, that the BC structure charges companies more in poor economic situations, but is lenient in a strong oil and gas economy. The BC system fails to share risk with companies, and only has a competitive advantage when the economy is in excellent condition. The Alberta MRF is better at creating investor stability, and creates a profitable economic environment no matter how well the market is doing at a point in time.

Table 13: Doig Phosphate: Alberta MRF Royalty Rates

| Alberta MRF Royalty Rates | | | |
|---|---|---|---|
| | Low Price | Base Price | High Price |
| Low Production | 5% | 5% | 16% |
| Medium Production | 5% | 9% | 29% |
| High Production | 10% | 15% | 36% |

Sources: Government of Alberta, *Mines and Minerals Act, Natural Gas Royalty Regulation, 2017,* https://www.canlii.org/en/ab/laws/regu/alta-reg-211-2016/latest/alta-reg-211-2016.html. / Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 14. / Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.

## Appendix B: Heritage Montney

The difference between the Alberta MRF and the BC royalty structure is similar to what occurs in the Doig Phosphate and the Northern Montney. The BC structure charges companies working in poor economic conditions a larger percentage of their economic rents than companies working in a strong oil and gas economy. The fixed rate on NGLs in BC makes the economic conditions for companies worse when the prices are low for natural gas and NGLs. However, the fixed rate is better for companies when the economy has prices that are at or above the forecasted base price for 2026 with high and medium production levels. Table 14 and Table 15 show the royalty rates paid in the Alberta MRF and the rates paid in the BC royalty structure. As we can see, the BC royalty structure charges rates higher than Alberta's MRF in six of nine scenarios.

Table 14: Heritage Montney: Alberta MRF Royalty Rates

| Alberta MRF Royalty Rates | | | |
|---|---|---|---|
| | Low Price | Base Price | High Price |
| Low Production | 5% | 7% | 24% |
| Medium Production | 5% | 16% | 36% |
| High Production | 9% | 29% | 36% |

Sources: Government of Alberta, *Mines and Minerals Act, Natural Gas Royalty Regulation, 2017,* https://www.canlii.org/en/ab/laws/regu/alta-reg-211-2016/latest/alta-reg-211-2016.html. / Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 14. / Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.

Table 15: Heritage Montney: BC Natural Gas Royalty Rates

| BC Government Royalty Rate | | | |
|---|---|---|---|
| | Low Price | Base Price | High Price |
| Low Production | 18.963% | 25.205% | 27% |
| Medium Production | 20.365% | 25.901% | 27% |
| High Production | 20.345% | 25.886% | 27% |

Sources: Government of British Columbia, *Oil and Gas Royalty Handbook, (*Victoria: Ministry of Finance, 2014). / Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 14. / Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.

Even when we break down the Alberta MRF and look at only the propane royalty rate for example, and compare it with the BC 20% fixed rate, we can see that in most cases the Alberta MRF rate is lower. In all but three cases, if propane was the only hydrocarbon to come out of the well, the Alberta MRF would charge a lower rate than the 20% fixed rate, as seen in Table 16. Again, as we have seen in every case, the Alberta MRF only charges a rate above 20% when the company will be making more economic rent because of high prices and higher production profiles. By eliminating the fixed rate, the BC government would make it economical for companies to drill for NGLs even when prices are lower than the forecasted base price.

Table 16: Heritage Montney: Alberta MRF Royalty Rates only on Propane

| Alberta MRF Royalty Rates on Propane | | | |
|---|---|---|---|
| | Low Price | Base Price | High Price |
| Low Production | 13.56% | 14.99% | 18.19% |
| Medium Production | 14.46% | 17.68% | 24.94% |
| High Production | 15.74% | 21.51% | 34.49% |

Sources: Government of Alberta, *Mines and Minerals Act, Natural Gas Royalty Regulation, 2017,* https://www.canlii.org/en/ab/laws/regu/alta-reg-211-2016/latest/alta-reg-211-2016.html. / Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 14. / Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.

## Appendix C: Northern Montney

The Northern Montney has an abundance of NGLs that are necessary for successful production revenues since natural gas production is lower than both the Doig Phosphate and Heritage Montney (refer to Table 9). However, propane, butane and condensate royalty percentages in the MRF are, for the most part, below the 20% fixed rate in the BC system. Starting with propane in Table 17, at no point does propane in the MRF exceed the 20% rate in BC. For that reason, the Alberta MRF is more competitive for propane production at all levels of production in the Northern Montney.

Table 17: Northern Montney: Alberta MRF Royalty Rates only on Propane

| Alberta MRF Royalty Rate on Propane | | | |
|---|---|---|---|
| | Low Price | Base Price | High Price |
| Low Propane Production | 13.21% | 13.95% | 15.05% |
| Medium Propane Production | 13.43% | 14.58% | 16.31% |
| High Propane Production | 13.97% | 16.19% | 19.53% |

Sources: Government of Alberta, *Mines and Minerals Act, Natural Gas Royalty Regulation, 2017,* https://www.canlii.org/en/ab/laws/regu/alta-reg-211-2016/latest/alta-reg-211-2016.html. / Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 14. / Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.

Because of the low butane potential in the Northern Montney, there is no point where the economic rent is large enough on butane production that the MRF royalty rate should be above the 5% posted minimum, as shown in Table 18. In the BC system, a company would need to pay 4 times as much as the MRF for producing an NGL that is not worth a lot to a company operating in the Northern Montney.

Table 18: Northern Montney: Alberta MRF Royalty Rates only on Butane

| Alberta MRF Royalty Rate on Butane | | | |
|---|---|---|---|
| | Low Price | Base Price | High Price |
| Low Butane Production | 5% | 5% | 5% |
| Medium Butane Production | 5% | 5% | 5% |
| High Butane Production | 5% | 5% | 5% |

Sources: Government of Alberta, *Mines and Minerals Act, Natural Gas Royalty Regulation, 2017,* https://www.canlii.org/en/ab/laws/regu/alta-reg-211-2016/latest/alta-reg-211-2016.html. / Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 14. / Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.

The last, and most profitable NGL in the Northern Montney is condensate. Not only is it the most valuable in price terms, where it is worth $92.80 a barrel, but it is also the most abundant NGL in the Northern Montney. For this reason, the royalty rates from the Alberta MRF are much higher for condensate than for propane or for butane (see Table 19). However, compared to the BC 20% fixed rate, the Alberta MRF only charges a company a high amount on royalties when prices are high and production is medium to high. It is at these subsidiary levels, where the natural gas hydrocarbons are separated from the total MRF royalty rate, that we can understand why it allows for companies to drill for the highest value natural gas hydrocarbons. While a company may be paying most of their royalty revenues because of condensate production, they do not need to worry about paying too much in royalty levies for butane which does not have as high of a value. These counteractions allow for the government and company to risk-share, as companies look to capture the largest economic rents by reducing costs and increasing revenues through high value natural gas hydrocarbon extraction.

Table 19: Northern Montney: Alberta MRF Royalty Rates only on Condensate

| Alberta MRF Royalty Rate on Condensate | | | |
|---|---|---|---|
| | Low Price | Base Price | High Price |
| Low Condensate Production | 5% | 10.78% | 19.92% |
| Medium Condensate Production | 5% | 16.07% | 30.50% |
| High Condensate Production | 7.21% | 29.48% | 40% |

Sources: Government of Alberta, *Mines and Minerals Act, Natural Gas Royalty Regulation, 2017,* https://www.canlii.org/en/ab/laws/regu/alta-reg-211-2016/latest/alta-reg-211-2016.html. / Deloitte, *Price Forecast, March 31, 2017*, (Deloitte Resource Evaluation &Advisory, 2017), 14. / Government of Alberta, *ST98: 2017 Alberta's Energy Reserves & Supply/Demand Outlook*, (Edmonton: Alberta Energy Regulator, 2017): 3.