AN ATTEMPT TO VALUE CANADIAN OIL AND NATURAL GAS RESERVES: AN EXTENSION OF THE HOTELLING VALUATION PRINCIPLE

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ABSTRACT

The importance of the Hotelling Valuation Principle (HVP) in economic study lies in its ability to examine and drive the decision of how much of a non-renewable natural resource to produce now versus how much to conserve for future generations - the root of natural resource policy, conservation, regulation, and taxation. Hotelling (1931) assumes that net price (selling price less cost per unit of production) will grow at the discount rate, which in a deterministic setting implies that reserve value is equal to current net price. However, the application of this ideal theory to the oil and gas industry may be difficult.

The oil and gas industry is influenced by government regulation, potential monopolistic forces, and well production characteristics - each of which violate the assumptions of Hotelling's (1931) basic theory. How these violations affect the HVP is an open question. Most have the effect of limiting current supply, and thus driving prices higher than they would be in a perfectly competitive market. On the other hand, at least in the Canadian context, government regulation tends to increase costs, whereas technological advancement tends to reduce costs. The net result of these effects on future net prices and their discounted value, and therefore the effect on the HVP, is not clear a priori.

Another problem relating Hotelling's (1931) basic theory to the oil and gas industry lies in the stochastic nature of a firm's future net prices and extraction quantities, the product of which gives the firm's future cash flows. Correlation between quantity and net price may result from expanding production when prices are high and reducing production when prices are low. Of course such correlation will affect the expected cash flows, and therefore firm value. Or, in other words, the ability to adjust production quantity provides "real options" for oil and gas firms which may add value.

Previous tests of the HVP on oil and gas reserves have utilized data that may contain confounding information that results in unreliable conclusions. The two major deficiencies include using (1) acquisition values, which utilize basin-average rather than firm specific net price data, and (2) conventional oil and gas company market valuations, which incorporate additional "management exploration expertise" value beyond the reserve's value.

This study contributes to the literature by providing a more definitive test of the HVP through the use of Canadian oil and gas royalty trusts. These "pure play" publicly traded entities are focused on production rather than exploration and essentially remediate the deficiencies found in previous literature. Additionally, I include an ancillary variable to proxy real option value and control variables for firm characteristics such as oil weighting (proportion of oil relative to natural gas reserves), reserve quality (proportion of proven producing reserves relative to proven non-producing reserves), and firm size (based on enterprise value). This gives the reader a better understanding of value drivers in the Canadian oil and gas royalty trust sector and how they relate to the HVP.

My study generally fails to find support for the HVP. In particular, the results indicate that the HVP overestimates reserve value. This suggests that market participants expect net prices to grow at a rate significantly lower then the fair cost of capital, and production constraints limiting the extraction rate are binding. I do find that the real option proxy explains a significant amount of the difference between the value observed and the value predicted by the HVP. This differs markedly from what previous literature on the HVP applied to market data for the oil and gas industry documents. Each of these papers fails to reject the HVP. The fact that I generally

find the value to be lower than that predicted by the HVP is not surprising given the previous literature using market data to test it. Since these studies use conventional oil and gas companies, which likely overvalue reserves because of an exploration premium, finding support for the HVP likely means that royalty trusts will likely correspond to a value lower than that predicted. The difference could account for the exploration premium. On the other hand, when I use the log-linear specification over the second, more volatile sub-sample, I also fail to reject Hotelling's theoretical value, which is consistent with previous literature using market data.

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DEDICATION

To My Parents,
Bernice and Bronislaw Shumlich

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CHAPTER 1 INTRODUCTION

The importance of the Hotelling (1931) theory in economic study lies in its ability to examine and drive the decision of how much of an exhaustible natural resource to produce now versus how much to conserve for future generations. This discussion has been the root of theoretical and practical discussion regarding natural resource policy, conservation, regulation, and taxation.

Hotelling (1931) proposed that based on the overall market, the value per unit of a reserve of an exhaustible natural resource is equal to the current net price (selling price per unit minus the cost of extracting the unit). This simple and straightforward proposal is based on the assumption that in a deterministic setting, net prices will rise at the prevailing discount rate in a market consisting of completely free competition. He based this assumption on the profit maximizing motives of the resource owners. In this scenario prices will adjust so that the projected return of the assets will be in line with other comparable capital assets. More specifically, a net price that is forecasted to rise at a rate higher than the discount rate will induce investment. This leads to higher supply and subsequent downward price pressure. The opposite is also true. If net price is forecasted to rise at a rate lower than the discount rate, capital investment will be steered away and supply will eventually fall. When supply falls, the price will experience upward pressure back to the equilibrium level. This equilibrium balance of net prices rising at the discount rate provided Hotelling (1931) with the basis for his conclusion.

However, the application of this ideal theory to the oil and gas industry may be difficult. The oil and gas industry is influenced by government regulation, potential monopolistic forces, and well production characteristics - each of which violate the assumptions of Hotelling's (1931) basic theory. How these violations affect the theory is debatable. Government regulation and monopolistic forces will likely have the effect of limiting supply, and thus driving selling prices higher than they otherwise would be in a perfectly competitive market. Conversely, at least in a Canadian context, government regulation tends to increase costs and technological advancements tend to reduce costs. The net result of these effects on future net prices and their discounted value, and therefore the effect on Hotelling's (1931) assumptions, is not clear a priori.

Another problem with relating Hotelling's (1931) basic theory to the oil and gas industry lies in the stochastic nature of a firm's future net prices and extraction quantities - the product of which produces the firm's future cash flows. Correlation between quantity and net price may result from expanding production when prices are high and reducing production when prices are low. Of course, such correlation will affect the expected cash flows, and therefore the firm value. Or, in other words, the ability to adjust production quantity provides "real options" for oil and gas firms, which may add value. This stochastic characteristic is not captured under Hotelling's (1931) deterministic theory.

Due to the aforementioned characteristics of the oil and gas industry, previous studies finding support for Hotelling (1931) must be scrutinized carefully to conclude that either the violations are not serious, or there are factors that create coincidental support for the theory. Due to the outcomes of the previous studies it makes sense to retest Hotelling's (1931) theory using a more appropriate data sample.

The application of Hotelling's (1931) theory to oil and gas reserves has been empirically tested several times over the years using the Hotelling Valuation Principle (HVP) created by Miller and Upton (1985a). These studies used a variety of methods to test the principle. Some of the studies found support for Hotelling (1931) while others have not.

1.1 MOTIVATION

Previous studies of Hotelling (1931) on the oil and gas industry have relied on either acquisition transactions or market values. Upon reviewing these studies I suspected deficiencies for testing the HVP in both of these data samples. Using acquisition values does not allow for a precise test because accurate data for the net price of the specific properties purchased is not published. These authors applied averages for the entire basin which do not compensate for high or low net price properties. The unanimous conclusion from studies using acquisition values is that the HVP does not hold and using net price overvalues the reserves.

Although many of the previous studies used market values, their focus was on conventional oil and gas companies. These companies are also involved in the exploration for oil and gas and hence have a built in "management exploration expertise" premium over and above the value based on the reserves they currently possess. The unanimous conclusion from these studies is that the HVP does hold. However, their conclusion may be due to the extra value added by the "management exploration expertise" premium that is inherent in the value for these entities, not because the HVP holds.

This study contributes to the literature by providing a more definitive test of the HVP through the use of Canadian oil and gas royalty trusts. These "pure play" publicly traded entities are focused on production rather than exploration and essentially remediate the noted deficiencies found in previous literature. Additionally, I include ancillary variables to proxy real option value, and control variables for firm characteristics such as oil weighting (proportion of oil relative to natural gas reserves), reserve quality (proportion of proven producing reserves relative to proven non-producing reserves), and firm size (based on enterprise value). This gives the reader a better understanding of value drivers in the Canadian oil and gas royalty trust sector and how they relate to the HVP.

Although three previous studies (Miller and Upton, 1985b, and Crain and Jamal, 1991 and 1996) have used U.S. oil and gas royalty trusts (or similarly, master limited partnerships) in their samples, this study provides a unique and more precise test of the HVP for the following reasons:

1. Canadian oil and gas royalty trusts are used in this study instead of U.S. royalty trusts. The Canadian oil and gas royalty trust market has proliferated and some of these trusts are even included in the Toronto Stock Exchange's top index, the S&P/TSX Composite Index. This increase in popularity may indicate increased pricing efficiency and fewer pricing anomalies which allows for a more accurate estimation of reserve value.
2. The sample period used in this study is longer and is characterized as having more volatile energy prices and since costs for each firm remain relatively flat, this implies more volatile net prices, potentially resulting in a more powerful test. (Note that accepting the HVP is equivalent to failing to reject two linear restrictions, so clearly the power of the test is critical to the decision.)
3. To see if factors other than net price have an affect on value, the study examines the significance of other potential value drivers or control variables including real option value, oil versus gas weighting, reserve quality, and size. These factors are left out of the HVP, so finding significant effects provides evidence against it.

1.2 SUMMARY OF FINDINGS

My study generally fails to find support for the HVP. In particular, the results indicate that the HVP overestimates reserve value. This suggests that market participants expect net prices to grow at a rate significantly lower then the fair cost of capital, and production constraints limiting the extraction rate are binding. I do find that the real option proxy explains a significant amount of the difference between the value observed and the value predicted by the HVP. This differs markedly from what previous literature on the HVP applied to market data for the oil and gas industry documents. Each of these papers fails to reject the HVP. The fact that I generally find the value to be lower than that predicted by the HVP is not surprising given the previous literature using market data to test it. Since these studies use conventional oil and gas companies, which likely overvalue reserves because of an exploration premium, finding support for the HVP likely means that royalty trusts will likely correspond to a value lower than that predicted. The difference would account for the exploration premium. On the other hand, when I use the log-linear specification over the second, more volatile sub-sample, I also fail to reject Hotelling's theoretical value, which is consistent with previous literature.

The study is outlined as follows. Chapter 2 provides a review of previous literature concerning the HVP as it relates to oil and gas reserve valuation, examines the deficiencies in the previous literature, and reviews how this study mitigates the mentioned deficiencies. Chapter 3 describes the data used in this study and the process of collection. Chapter 4 reviews previous tests of the HVP, explains the current test, as well as additional tests used in this study. Chapter 5 provides the results of the main study and the ancillary studies and attempts to explain the results. Chapter 6 provides a conclusion to the study.

CHAPTER 2 LITERATURE REVIEW

Previous papers on the HVP can be primarily categorized into a two-by-two matrix: those studies that either reinforce the principle or disagree with it and those studies that tested the theory using market valuation data or acquisition data. It turns out that these categories are not as distinct as they appear to be, since all of the studies that found support for the HVP use market data and all of the studies that reject it use acquisition data. I analyse the previous literature primarily along the criteria as to whether or not they find support for the HVP.

2.1 PREVIOUS LITERATURE

2.1.1 THE INITIAL THEORY

Hotelling (1931) modeled the valuation of exhaustible resources by examining value in both the economic sense and social sense. He investigated how the owners, current consumers, and future consumers of the disappearing natural resource affect its price. He claimed that the rate of extraction in a competitive industry should be such that the net price (selling price less cost to extract) of the resource grows at a rate equal to the fair discount rate, which is the risk-free interest rate in his deterministic setting. Indeed, if net price grows faster than the fair discount rate, then resource owners will have the incentive to delay extraction, which will create an excess supply in the future, pushing future net prices down in equilibrium. Contrarily, if net price grows more slowly than the fair discount rate resource owners will have the incentive to expand current extraction. Since the stock of reserves is fixed, this is equivalent to reducing future extraction, which will create an excess demand in the future, pushing future net prices up in equilibrium. The invisible hand of the competitive resource market acts to guide net price growth toward the fair discount rate.

In other words, a resource owner should be indifferent between accepting a current price per unit now and accepting a price per unit in the future that incorporates an acceptable time-compensation component. If the price per unit of a resource is expected to rise at a rate higher than the discount rate, why extract the resource now? If it is expected to rise at a rate lower than the discount rate, why wait to extract? This implies that marginal present value of profits is constant over all periods in a market consisting of completely free competition. Consequently, according to Hotelling (1931), net prices must rise at a rate equal to the discount rate. Therefore, for all t,

$$\left(p_t - c_t\right) = \left(p_0 - c_0\right)\left(1 + r_t\right)^t, \tag{2.1}$$

where t is the time of extraction, p is the selling price per unit, c is the extraction cost per unit, and r is the fair discount rate.

One shortcoming of the above argument is how it applies to multiple firms or multiple reserves. In particular, some reserves may have better quality resources than others, and some may require lower extraction costs. Therefore, it is unreasonable for prices and costs to be equal for every reserve, and equally unreasonable for price and cost growth to be equal for every reserve. This makes it impossible for net price growth to be equal for every reserve, let alone equal to some common discount rate. This suggests that the equilibrium argument implies that an industry wide average net price should grow at the fair discount rate, but individual firms or reserves should extract resources according to the growth rates of their own individual net prices. Those with low growth will want to extract as quickly as possible and those with high growth will want to wait. Although not necessarily, these will often be reserves with low and high extraction costs respectively.

Another shortcoming has to do with the stochastic nature of future prices and costs. Since future demand and supply of the resource is stochastic, future prices will exhibit randomness. Therefore, growth in the above arguments should be replaced by expected growth and the fair discount rate may involve a risk premium. Moreover, different reserves may have different risk characteristics, so the fair discount rate may be reserve specific.

To further complicate the issue, the expected growth rate in net price - hence the extraction rate - may be affected by the net price level outcome. This implies that net price and quantity may be correlated, so the expected cash flow for a given time, which is the expected value of the product of net price and quantity, will generally not be the product of the expected net price and the expected extraction quantity. In particular, if the reserve's net price growth rate decreases with net price level, then ideal extraction quantity will be positively correlated with net price level, and the expected cash flows will be greater than the product of the expected price levels and expected extraction quantity.

The main conclusion to be drawn from this argument is that for a competitive reserve, the decision about whether to extract resources now or later depends on the (reserve specific) rate of growth of the (reserve specific) net price, *and* on the stochastic nature of that rate of growth. For a particular reserve, the current net price growth rate may be low enough to warrant immediate extraction, but doing so eliminates the possibility of extracting resources in the future should the value turn out to be even higher. Thus extracting the resources is equivalent to exercising a "real option" and the optimal exercise region depends on the entire distribution of the underlying asset, and not just the expected value. These arguments suggest that the value of a reserve should be no less than the current extraction value (the current net price times the quantity of reserves), and may be greater, especially for those reserves having a relatively low current extraction value.

Hotelling (1931) also discusses the case in which the reserve owner has market power, which is quite relevant to the oil industry. In this case he shows that the net price is higher and extraction occurs more slowly than the perfectly competitive case. Furthermore, the optimal growth rate of net price, which depends on the demand function, is higher than the fair discount rate (when demand is decreasing in price). This also implies that the value of a reserve should be higher than the current extraction value.

Another issue with the theory involves the extraction rate - Hotelling (1931) based his equilibrium assumption on producers increasing production if the discount rate is higher than the net price growth rate and decreasing it in the opposite scenario. In the oil and gas industry it is extremely difficult, if not impossible, to produce all the reserves in a pool immediately without negatively affecting the total recoverable reserves in a pool. This physical production constraint specific to the oil and gas industry means the equilibrium is harder to achieve and, as a result, implies that the value of reserves should be lower than the current extraction value.

2.1.2 STUDIES FINDING EVIDENCE FOR HOTELLING (1931)

Miller and Upton (1985a) brought forward a method to empirically test Hotelling's (1931) theory applied to the oil and gas industry. They reiterated that the value of an exhaustible resource price-taking company with profit maximization intentions can be stated as a function of the present value of cash flows generated by the reserve base. If net price grows at the rate of discount, then the value of a reserve is equal to the current net price per unit times the number of units currently in the reserve. In their test, observed market values per reserve unit for each company at a given point in time were regressed on the current net price. If the assumptions of Hotelling (1931) hold, the regression equation should have an intercept of zero and a slope coefficient of one under constant returns to scale. Based on their sample of 94 observations, 39 U.S. based companies over a period that ranged from December 1979 to August 1981, they failed to reject these restrictions and concluded that the HVP does hold true.

In a follow up study, Miller and Upton (1985b) completed a similar test based on 98 observations of U.S. based companies ranging from August 1981 to December 1983. They concluded that a relationship still exists and the HVP still holds, however the R^2 dropped significantly from the first study. They attributed this to the difference in oil and gas prices over the two periods. The first period, which contained the Iranian Revolution and the commencement of the Iran-Iraq war, encompassed relatively volatile energy price movements while the second period experienced low volatility in energy prices.

In addition to their main study, Miller and Upton (1985b) also did an additional test on oil and gas royalty trusts. They purported that royalty trusts are a good vehicle for testing due to the fact that they are usually pure play oil and gas producers with a less risky, more mature base of reserves. The supplemental oil and gas royalty trust study again fell in line with their expectations that the HVP does hold, however the authors warned that the results must be taken with caution as only 12 observations were used.

Crain and Jamal (1991) continued upon Miller and Upton's (1985b) work by examining the HVP using oil and gas royalty trusts and master limited partnerships. They too argued that royalty trusts and master limited partnerships would provide a better vehicle for testing the HVP because they are solely involved in oil and gas production and do not participate in other related businesses such as pipelines or refining and the trusts were without any significant liabilities. They altered Miller and Upton's (1985a) regression test specification by incorporating a double log transformation. Using 91 pooled observations of U.S. based entities spanning a period from 1981 through to 1986 they confirmed a relationship between market value and current net price.

The authors concluded that their study reinforced support for the HVP and suggests that the log model may do a better job of explaining variation in value.

Thompson (1996) denounced the Crain and Jamal (1991) study on three bases: (1) Profit maximization may not be met as all of the reserves may not be produced due to the way the authors specified the test, (2) The zero point estimates used for the intercept will result in the slope coefficient being removed from unity, and (3) The log-linear test specification is not in agreement with the HVP put forth by Miller and Upton (1985a) because it does not follow the assumption of constant returns to scale. He reinterpreted the data using the Miller and Upton (1985a) specification and did not find support for the HVP. He concluded his argument by stating that Crain and Jamal (1991) do not provide satisfactory evidence for the validity of the HVP.

Crain and Jamal (1996) provided a reply to Thompson's (1996) criticisms. They retested their original data using the same linear specification put forth by Miller and Upton (1985a), and found an intercept that is not significantly different from zero and a slope coefficient that is close to one, validating the HVP for oil and gas pure plays.

2.1.3 STUDIES FINDING EVIDENCE AGAINST HOTELLING (1931)

Watkins (1992) argued that there is fundamental theoretical insight from the HVP but that it does not hold up particularly well in explaining the realities of energy reserve valuations. In the review of previous work, Watkins (1992) stated that several problems occurred in Miller and Upton (1985a, 1985b). First, the market value can only be an approximation since estimated liabilities and non-reserve assets must be netted out. Second, the degree of fit, R^2, is not particularly good. Third, the prices of transactions could be a better indicator of pure reserve value than market-based values. His study used actual transaction values on 27 Canadian oil and gas reserve transactions spanning a period from February 1989 to March 1991. The data for net oil and gas prices was based on average selling prices and an average of costs for gathering, operating, royalties, and income taxes. He performed a ratio test on the data used in the study. The aggregate transaction value was placed in the numerator and the denominator consisted of the quantity of reserves times the net price of each reserve unit. If the HVP held, the ratio should approximate one. He observed that 25 of the transactions departed from the theoretical unity ratio while only two transactions approximated unity, and the average ratio was significantly different from one. Additionally, in order to make the transaction test comparable, he transformed the data so that it could be tested using the Miller and Upton (1985a) HVP regression equation with natural gas converted to an oil equivalent at 12 million Btu per barrel of oil equivalent, based on the economic pricing of the commodities at the time of the study. The results rejected the HVP.

McDonald (1994) reiterated the findings of Watkins (1992) and emphasized that the HVP over predicts reserve value by a factor of approximately two. He reasoned that the overvaluation can be attributed to two main assumptions that may not be unrealistic in industry practice. First, producers may not have the flexibility to control extraction so that net prices rise at the discount rate and secondly, the regulation of well spacing and extraction in common pools also hinders the producers' ability to control extraction over time. He argued that the compromised spacing enforced by the regulators results in operators not functioning at the profit maximizing extraction rate and consequently the conditions of the HVP will not be met.

Adelman and Watkins (1995) reemphasized the notion that the HVP overestimates the value of in-ground reserves. The data utilized in their study consisted of 34 purchase and sale transactions of Alberta based oil and gas reserves. 27 of the transactions were used in the previous study by Watkins (1992) and an additional seven observations were added. Again, only average (not property specific) selling price and cost data was used as many of the transactions did not publish this information. They found that the HVP overstated the actual reserve value of a barrel of oil by approximately 2.5 times. Secondly, the value of gas was overstated by approximately 1.6 times. On average, the HVP overstated the value by two times on a total oil equivalent basis. Since oil and gas reserves are subject to declines in pressure as the reserve is emptied (known as the decline rate) the entire pool cannot be instantaneously extracted. Instead the production level declines over time as well pressure declines. They claimed that the slope coefficient should approximate [a/(a + i)], where a is the production/reserves ratio that represents the decline rate and i is the discount rate. They argued that this adjustment accounts for the physical production constraint of declining pressure inherent in oil and gas production. Since some production will take place in one year, two years, etc. the net revenue that is expected to be generated in the future must be discounted at the discount rate in order to get today's true value.

Cairns and Davis (1998) reached the same conclusion that the HVP overstated the value of reserves by approximately double. The reasons for this include physical production constraints due to declining well pressure, less than optimal well spacing regulations, and the possibility of incremental unit costs that increase with extraction. They obtained an intercept that was not significantly different from zero, however the slope coefficient was significantly different from one. In order to avoid any gas conversion issues, the authors also performed the test using two explanatory variables, oil and gas. The estimate for oil remained below one but the coefficient for gas was not significantly different from one.

In another study, Cairns and Davis (1999) focused on creating a value range that essentially encompasses the actual values of energy reserves. The HVP essentially creates an upper bound for oil and gas reserve value due to two main factors. Well pressure limits make it impossible for an operator to realize full profit maximizing value and net prices are not expected to increase at the discount rate. The lower bound is calculated using Adelman's Rule which is based on a modified HVP. Instead of assuming a coefficient of one, the slope was calculated using a formula that incorporated the decline rate, discount rate, and expected change in net price. The authors used pessimistic assumptions for these added variables. This low case scenario resulted in a lower band of valuation. The authors also brought up the potential value add of real options in the oil and gas production industry. However, they concluded that option value does not have a major consequence on the value of producing reserves. To test the validity of their bands, Cairns and Davis (1999) applied their upper and lower limits to data used in three previous studies. 89% of the observations in Watkins (1992) fell within the boundary while 85% and 77% of the observations fell within the boundary for Miller and Upton (1985b) and Miller and Upton (1985a), respectively.

The authors came out with another article, Cairns and Davis (2001), which focused on both the HVP and Adelman's Rule. It reiterated that the HVP overvalues or provides an upper limit for the value of in-ground energy reserves due to production of oil and gas being physically constrained (cannot be produced instantaneously) and the net price does not grow at the discount rate. The authors argued that reserve values fall more in-line with Adelman's Rule where an adjustment for decline rates is included. By incorporating well pressure effects, output regulation and other production profiles, Cairns and Davis (2001) confirm that Adelman's Rule is more appropriate than the HVP for in-ground energy reserve valuations.

Lin and Wagner (2007) re-examined the Hotelling (1931) theory by focusing on the impact of stock volumes and technology. They argued that the costs to extract a resource do not remain constant over time. Rather, since the process of resource depletion usually commences with removing the most accessible reserves first, extraction costs increase as fields are depleted.

Offsetting the stock effects is the improvement of technological processes. As technology improves the methods and techniques of extraction, costs decrease. They examined 14 subsoil assets from 1970 to 2004 to test the Hotelling (1931) assumption of net price rising at the discount rate. They concluded that, over the 35 year period, only one mineral, gold, exhibited a negative growth rate with the remaining 13 exhibiting zero growth rates. They argued that the technology effect was able to offset the depleting assets stock effect and concluded that the assumption of an increasing net price within the Hotelling (1931) model is incorrect over the time period studied.

2.1.4 OTHER RELEVANT ARTICLES

McCardle and Smith (1999) focused on the techniques utilized by oil and gas entities to valuate oil and gas projects. These techniques can be applied on a larger scale, beyond single projects, to provide value estimates for entire entities. The study looked at two main valuation models: decision analysis and option pricing. The authors argued that option pricing is often ignored in evaluating decision problems even though they may more appropriately incorporate downstream decisions and can better account for market risk. However, decision analysis modeling can better value private risks such as project-specific production rates. As such, the authors recommend an integrated approach of decision analytic techniques and option valuation.

McCormack and Sick (2001) argued that the value of oil and gas companies is greater than the theoretical value obtained through a standard discounted cash flow valuation. This valuation delta can be corrected through the use of real options by adding in a component to account for potential "upside" due to the firm's ability to adjust the extraction rate of proven reserves or, to develop unproved reserves in the future. As with all value maximization transactions, the owner will only decide to develop the resource if there is positive net present value. Their modeling process for real option value in oil and gas companies is similar to a financial option and uses the Black-Scholes option pricing model as a template, with inputs that apply directly to the resource base and not an underlying financial asset. Interestingly, they find that although the option value is real, many management teams fail to use this valuation methodology when implementing their corporate strategy. Additionally, the majority of incentive plans penalize managers for delaying a project even though the economics may be improved in the future.

Boyer and Filion (2007) studied the Canadian oil and gas industry focusing on what drives the industry's market returns. Their study used data for 105 Canadian oil and gas companies but did not include Canadian oil and gas royalty trusts. They utilized five macroeconomic factors (interest rates, exchange rates, market returns, oil prices, and natural gas prices) and five company specific factors (proven reserves, production volume, debt level, operations cash flows, and drilling success) to explain what impacts the value of these entities. My study of the HVP using Canadian oil and gas royalty trusts also inherently incorporates many of the same drivers including macroeconomic factors such as interest rates, exchange rates, oil prices, and natural gas prices and company specific factors such as reserves, debt level, and operating cash flow.

The articles covered in this literature review have created a wide spectrum of thought on the HVP - some authors find agreement with the simple model's explanatory power while many others find a lack of evidence for it. While this literature review covers a variety of methods to test the HVP, their conclusions can hardly be considered decisive due to certain deficiencies.

2.2 DEFICIENCIES IN PREVIOUS LITERATURE

With the exception of Miller and Upton (1985b) and Crain and Jamal (1991, 1996), each of the previous studies on the HVP have included utilizing acquisition values and basin average costs, or utilizing conventional oil and gas company market valuations, both of which are deficient samples to test the HVP.

Some of the previous studies utilized acquisition values as the proxy for valuation of oil and gas reserves. Acquisition values are given in a press release announcing the transaction and other data given in the press release usually includes current production and an estimate for reserves and land. However, one of the key inputs that goes into the HVP, net price, is not given in the press release. Instead, the authors apply a "basin average" as the input which may lead to a major misspecification. For instance, the time period studied may have been during a period where high cost assets where popular to buy. In this case, the authors using averages would have overstated the net price and the study would have skewed the results and conclusions. Not being able to utilize net price data that is specific to the particular assets acquired is a major deficiency of the studies that used acquisition values.

The other previous studies used the market values of conventional oil and gas companies. Although this type of data sample removes the issue of not obtaining specific net prices, it does create another issue. In order to see why conventional oil and gas companies are not a good sample for the HVP we must look at the activities they are involved in. Typically, they are involved in exploration and production. Simply by examining their activities we can see a problem - the HVP values reserves (and, if you have reserves you typically have production) but it does not account for exploration. Thus, by using conventional companies, the previous authors are not providing a pure test for the HVP (in particular, they overstate value). Figure 2.1 compares the composition of the enterprise value for conventional oil and gas companies against both acquisition values (as above) and oil and gas royalty trusts.

It is apparent that a "management exploration expertise" premium can count for a large part of the value of a conventional oil and gas company. To illustrate this further, I consider a “pure” exploration company that has no reserves. The value of such a company is based entirely on exploration potential, which presumably depends on management exploration expertise that has no relation to the amount of current reserves the company currently possesses. It is quite apparent that using conventional oil and gas companies do not provide a pure test of the HVP.

As is shown in the literature review, the articles that used acquisition values did not find support for the HVP (value was about half the net price) whereas those that used conventional oil and gas company market valuations did find support. In these studies it may be possible that the additional value was attributable to the “management exploration expertise” premium and had little to do with the current reserves. Therefore, this method is not a pure test of the principle and the affirmative results they have reached should be questioned.

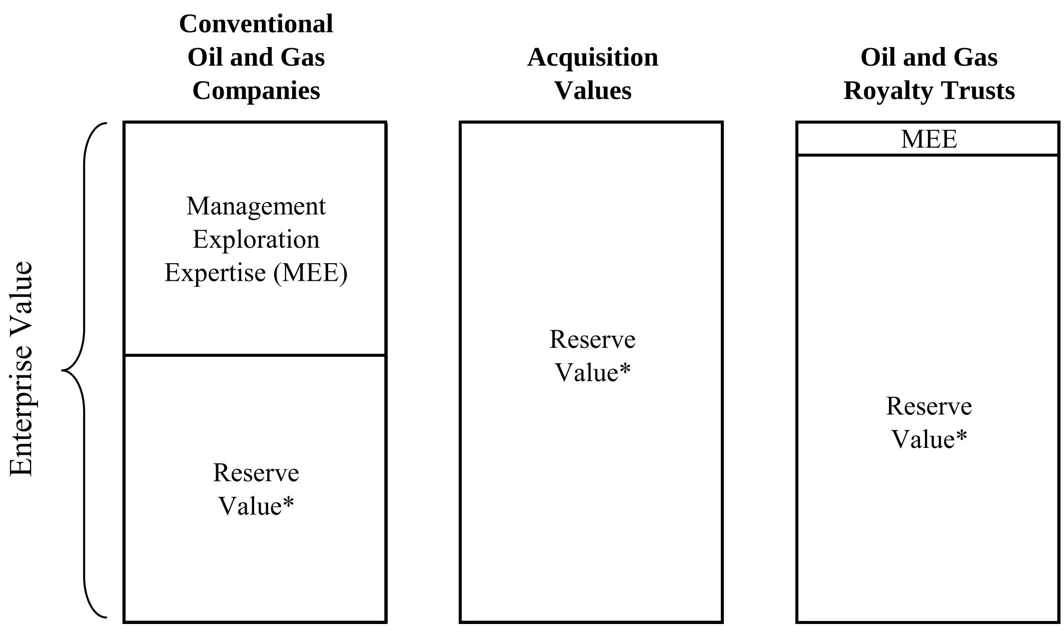


Figure 2.1 Enterprise Value Breakdown Comparison
This figure illustrates the differences in value composition among conventional oil and gas companies, acquisition values, and oil and gas royalty trusts. Value for these entities primarily consists of two sources: management exploration expertise value and reserve value. Conventional companies typically have a large portion of their value coming from its management exploration expertise. Acquisition values have zero value to management exploration expertise as only the assets are sold and purchased, not the management teams. Oil and gas royalty trusts only have a small portion of their value come from management exploration expertise since these entities are focused on producing already-found reserves, not discovering new pools of oil and gas.
* Note: Reserve value also reflects production value.

Both Miller and Upton (1985b) and Crain and Jamal (1991, 1996) did look at the U.S. royalty trust equivalent, master limited partnerships, but these did not incorporate other potential value drivers and these entities have all but dried up in the U.S.

2.3 REMEDIATING THE DEFICIENCIES

The deficiencies in the previous studies have created an opportunity for further study. My main contributions are an attempt to reduce the contamination in the previous studies by:

1. using pure play entities (oil and gas royalty trusts) that have a limited "management exploration expertise" premium factored into their value;
2. using specific extraction cost information that is specific to each trust in each time period;
3. using market trading values based on the efficient and liquid trading characteristics of Canadian oil and gas royalty trusts;
4. using reserve estimates that are based on the most strict set of rules to date;
5. using a time frame that contains the most commodity volatility; and
6. testing for other potential value impacting drivers such as real options, oil weighting, quality of reserves, and size.

By reducing the deficiencies in the previous studies this study should offer a more definitive conclusion on the HVP and its application to valuing oil and gas reserves.

CHAPTER 3 DATA

My study of the HVP focuses on Canadian oil and gas royalty trusts over the period 2000 to 2006. 22 Canadian oil and gas royalty trusts are included which results in 107 observations. The breakdown of trusts and their respective years of data are as follows:

Table 3.1 Observations by Trusts and Years of Data

Years of Data		Number of Trusts		Total Observations
7	x	6	=	42
6	x	2	=	12
5	x	4	=	20
4	x	7	=	28
3	x	0	=	0
2	x	2	=	4
1	x	1	=	1
TOTAL		22		107

Table 3.1 displays the distribution of observations sorted in ascending order by years of data. The vast majority of trusts had at least four years of data. The years of data for each trust varies due to some trusts coming into inception after the start of the observation period, some trusts being acquired prior to the end of the observation period, and other trusts diversifying their revenue streams into non-oil and gas assets. In this case, the trust was omitted from the observations when a material portion of their cash flow was obtained from non-oil and gas sources.

Canadian oil and gas trusts are chosen as the subject of the study for two main reasons. First, oil and gas royalty trusts are described as “pure play” oil and gas production firms. Typically, these entities are more focused on producing reserves out of mature, less risky development properties than participating in high-risk exploration plays that require extensive capital. This “pure play” characteristic makes them an ideal asset to focus on in this HVP study. Secondly, no previous HVP papers have used Canadian oil and gas royalty trusts as the basis for their study. Canadian oil and gas royalty trusts have experienced considerable trading volume and analyst coverage over this period, which makes them appealing candidates for accurate market valuation.

The oil and gas industry provides some interesting challenges from an economic point of view. This stems from the fact that nearly all companies that participate in the industry are involved in both oil and gas extraction. Although somewhat similar, they both have different measurement units due to their different states of matter. Oil is typically presented in barrel units and gas is presented in cubic feet units. When attempting to perform financial analysis on the industry it is most preferred to have the pricing and costing of both commodities separated out. However, oil and gas entities tend to aggregate the two units into one variable, *barrels of oil equivalent*, in order to facilitate their reporting requirements.

Previous studies of the HVP have contained both types of analysis, oil and gas metrics separated and oil and gas aggregated into a single unit. In the studies where oil and gas were separated, only proxy selling prices and costs were applied to the observations as actual net price data was not published. In previous studies where oil and gas were aggregated (gas converted to an oil equivalent) the authors used varying conversion factors. Miller and Upton (1985a) used 5,700 cubic feet (5.7 Mcf) equal to one barrel of oil based on the British thermal unit energy conversion factor. Watkins (1992) used 12 Mcf equal to one barrel of oil based on economic value at the time. During the sample time, the price for 12 Mcf was approximately equal to the value of one barrel of oil.

For the time period of this study, the conversion process has become more straightforward. Industry has adopted a 6 Mcf equal to one barrel of oil equivalent conversion factor that has been in place over the time period used in this study and all trusts have adhered to this convention.[1] Since all trusts in the sample use this convention, the test is comparable among all of the observations. Their selling price, royalties, operating costs, general and administrative costs, interest costs and capital taxes are all presented on a barrel of oil equivalent basis. (Note that all prices and costs are reported in Canadian dollars.) There is no allocation or split between the two commodities. Because all trusts present this way and there is no public information that is broken down between oil and gas, the study was performed using a barrel of oil equivalent convention. This obviously poses a limitation to performing more specific tests on oil and gas separately.

The particular time period for the analysis is chosen because of the proliferation of oil and gas royalty trusts combined with the volatile energy prices over the period. Figure 3.1 reveals extensive variability in both oil and gas prices over the sample period. The volatility in commodity prices seen below provides this study with the ability to obtain robust results as net price is a major driver in the regression test. Since costs for each firm are relatively static through time, selling price is the biggest factor in varying net price over time. Therefore, having a period of higher price volatility allows for a more powerful test of the HVP. In a supplemental test I divide my observation period into two groups: limited volatility (2000 - 2002) and large volatility (2003 - 2006) in order to verify if volatility does indeed contribute to the robustness of the analysis.

In the last year of this time period, specifically October 31, 2006, the Government of Canada proposed to change the tax treatment of income trusts to level the playing field with corporate Canada. The proposed changes would take place in 2011. This announcement seemed to have a negative impact on oil and gas royalty trust valuations as the S&P/TSX Capped Energy Trust Index declined 13.1% between the close on October 31, 2006 and the close on November

[1] National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, page 12.

1, 2006. The announcement does affect the last year of my sample since I use the year-end reserves as at December 31, 2006 and the trading prices from the beginning of April to the end of May 2007. However, I retested the data omitting the affected year and the announcement does not have a material impact to the conclusions reached in my study.

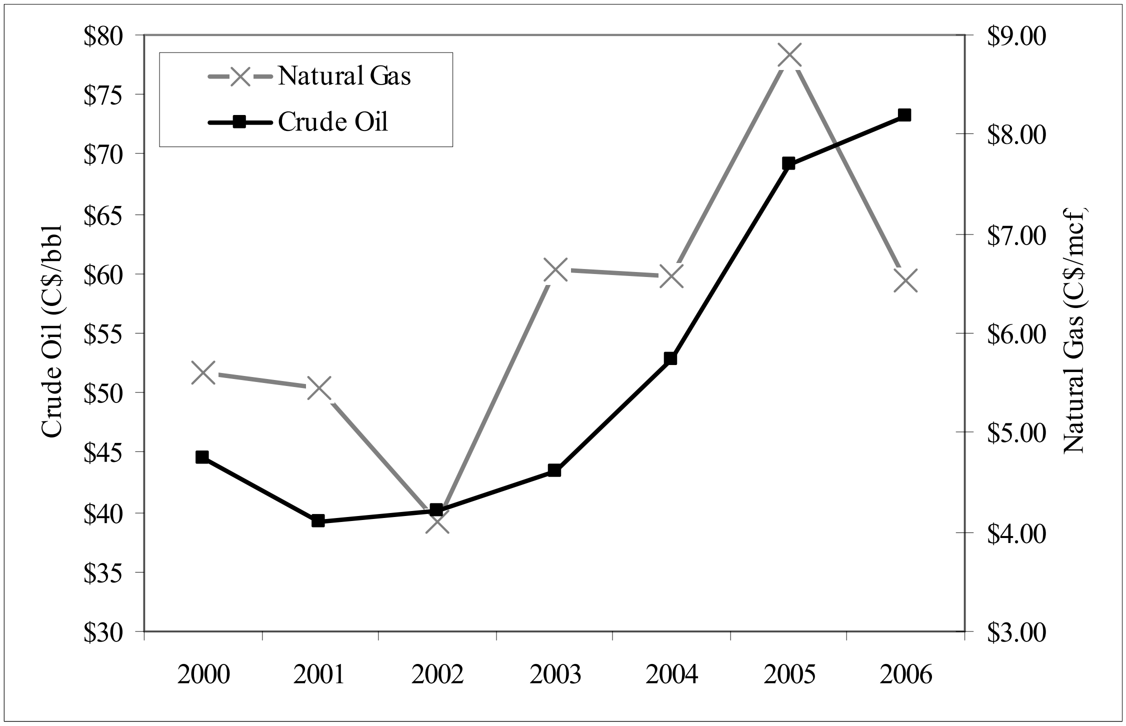


Figure 3.1 Historical Oil and Natural Gas Prices
This figure illustrates the yearly average price for crude oil (based on Edmonton Light Crude) and natural gas (based on AECO) over the observation period.

3.1 DESCRIPTION

3.1.1 RESERVES

As publicly traded entities, oil and gas royalty trusts must publish at least annually an estimate of their oil and gas reserve assets. These reserve estimates must be prepared by an independent qualified reserve evaluator or auditor. Usually the effective date of these reserve estimate reports coincide with each trusts' fiscal year end. In this sample, every trust has a fiscal year end of December 31 and all of the reserve reports are as at December 31. Each entity publishes a detailed breakout of their reserve estimates in their Annual Information Form. This document is used as the source of information for reserves for the study.

Although there are some subtle differences among the format each trust used to present their reserve estimates, they all contain the information needed to perform the appropriate analysis. Each trust presents the reserves of both oil and gas. However, some disaggregate the oil grouping into light and medium oil, heavy oil and natural gas liquids. Natural gas liquids are categorized under oil, not natural gas, and consist of the petroleum by-products that come out of natural gas extraction. In this study, I aggregate all of the oil products and natural gas liquids into the oil category and present them in units of barrels. The natural gas in the reserve reports are presented in units of cubic feet.

Each trust presents their reserves on a “gross” and a “net” basis. The definition of gross means the trusts’ interests (operated and non-operated) before deduction of royalties and without including any royalty interest. The term “net” refers to the trust’s interests (operated and non-operated) after deduction of royalties plus any deduction for royalty interest. For this study, I utilize the “net” interest of reserves classification and do not adjust for royalties in the net price calculation. If “gross” reserves are used the net price calculation would be adjusted for royalties.

Another specification used in the presentation of reserves is pricing. Because reserve estimates are based on the concept that they are economically recoverable, a set of pricing and cost assumptions are incorporated. If pricing structure is more favourable, more reserves will be economically recoverable and a higher number of estimated reserves may be attributed to the entity.

Trusts present their reserves using two pricing schedules: forecasted pricing and costs, and current pricing and costs. Forecasted pricing and costs are generated by a qualified reserve engineering firm and span out a number of years. Their forecast is based on their best estimate of pricing and costs given their knowledge of the energy industry. Constant pricing and cost forecasts hold the current profit structure throughout the estimated lives of the properties to which the estimate applies. As an example, if the reserve engineer's price forecast is higher than the constant prices, and costs remain the same in both cases, then the reserve estimate may be higher since more of the entity's reserves may be economically recoverable.

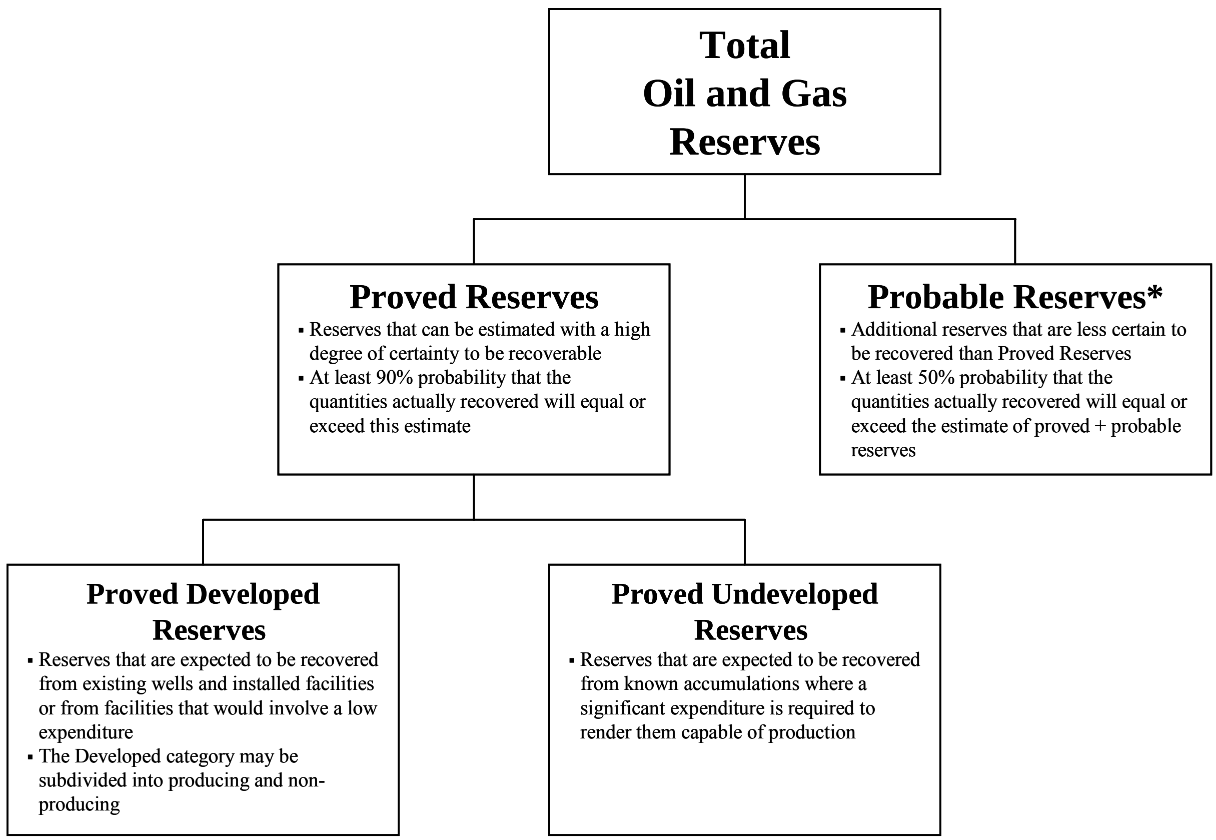
The reserve categories presented by entities are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). Currently, reserves are separated into two major categories, proved and probable, which are based on the likelihood of recovery. Each of these reserve categories is further divided into developed and undeveloped reserves, which indicate whether or not the reserve has existing wells and infrastructure for production. Developed reserves may be further divided into developed producing and developed non-producing categories depending on the production status.[2] A summary of the reserve categorizations as defined by the COGE Handbook is broken out in Figure 3.2.

One of the major differences in reserve reporting prior to the adoption of National Instrument 51-101 was in the presentation of probable reserves. Some of the trusts presented Probable reserves on a "risked" basis which adjusted the probable reserves by 50%. This is similar to the new definition. However, some of the trusts presented probable reserves on a "non-risked" basis at 100%. In these cases the probable reserves are adjusted by 50% to make them comparable to both other trusts and over time.

This test of the HVP utilizes the proved reserves category. As per the COGE Handbook, it is likely that at least 90 percent of the quantity of reserves actually recovered will actually

[2] Canadian Oil and Gas Evaluation Handbook, (pages 5-13 to 5-15).

equal or exceed the estimate. As such, there is minimal risk that that the majority of the reserves in this category will not be recovered.



* The Probable Reserves category can also be split into the Proved Developed and Proved undeveloped categories. However, it is rare to see the Trusts in my sample split out their Probable Reserves into further categories. In this test, only the Proved Reserves category is used.

Figure 3.2 Summary of Reserve Classifications
This figure illustrates the various reserve classifications and sub-categories as defined by the COGE Handbook. The major categories are proved reserves and probable reserves. It is common to see proved reserves further divided into proved developed reserves and proved undeveloped reserves. Further, proved developed reserves can be further refined into proved developed producing and proved developed non-producing. I incorporate an ancillary test which examines the value effect of reserve quality using percentage of proved developed producing reserves as the proxy.

3.1.2 LAND

All of the trusts used in my sample own undeveloped land (or “unproved properties” under National Instrument 51-101) which has not been used by the trusts to produce oil and gas. Since undeveloped land is an asset that is not producing, I net its value out of the enterprise value calculation. The majority of trusts publish a value for this land. For the trusts that do not publish a value I allocate $100 per acre to the value, which is a conventional average amount used in the industry for land valuation. For example, Sayer Energy Advisors puts out a quarterly summary report of merger and acquisition transactions in Canada titled “Canadian Oil Industry Merger and Acquisitions Report”. The report allocates $100/acre of value for undeveloped land when there is not a specific value for land reported in the transaction information. The specific value allocated to land does not have a material impact to the results of my study since the average component of land/enterprise value is 2.7% (median 2.2%, maximum 10.2%, minimum 0.3% and standard deviation is 2.1%).

3.1.3 NET PRICE

In this study I define the term net price as selling price per unit minus the costs associated with producing and selling that unit, which include operating costs, general and administrative costs, and capital taxes. This definition is similar to the net price used in previous studies of the HVP.

More specifically, selling price is defined as the amount received by the producer for selling one barrel of oil equivalent. The selling price varies among each trust due to varying grades of the commodity produced (i.e. heavy crude receives a lower price than lighter crude) and varying combinations of oil and gas. On the cost side, operating cost is defined as all of the costs associated with extracting the resource from the ground and getting it to market. These include machinery and equipment costs such as compressors and labour costs that are directly associated with the extraction process. (However, this does not include capital costs such as the drilling of the well or the installation of pipelines to tie the reserves into main service lines.) Both fixed and variable costs are included in this data and the company reports do not differentiate or report fixed and variable costs. General and administrative operating costs are associated with the overhead of operating a business. This category can include items such as management salaries and corporate office rent. Lastly, capital taxes are the only cash tax that trusts in this sample paid over the study period. These are usually immaterial in the net price calculation and may consist of tax on interest income, property tax and other non-operating items.

There are two items that are not included in my net price calculation even though they have a cash charge. Hedging gains and losses are not included because this study of the HVP is based on a cash flow model that uses forecasts and assumptions. With hedging gains and losses it is impossible to determine whether the gain or loss in the current period (quarter one) will be replicated in future periods. Because of this uncertainty, hedging gains and losses are not included in the net price calculation. There is no mention of incorporating or not including them in the previous studies. Secondly, interest costs are not included since the net price should not be dependent on how the trust is capitalized.

The definition I use for net price revolves around a cash basis definition. Basically, everything involved in the selling of oil and gas production that is cash based is included and non-cash expenses such as depreciation, depletion and amortization are not included. The cash definition is chosen for net price because it is more suitable to be used in a discounted cash flow model, which is the foundation for the HVP theory. As noted previously, royalties payable are not taken into consideration into the net price calculation as I use the "net" reserve classification which already takes into account an adjustment for royalties.

The source of the net price information comes from the first quarter financial reports of each trust for the sample period. The first quarter financial reports are chosen as a proxy to current net price as defined in previous HVP papers. Since reserve reports are effective December 31 and released to the public in the first quarter, the quarter one financials provide the current net price that most closely coincides with the release of the reserve estimates.

3.1.4 ENTERPRISE VALUE

Another item required for this study is the enterprise value for each trust. Enterprise value is defined as market capitalization plus net debt. Net debt is defined as short-term debt plus long-term debt minus any cash or cash equivalents. By using enterprise value as the main value metric I incorporate any leverage the trust may be incorporating through the use of debt. This is because the HVP is based on overall firm value, which includes both equity and debt.

3.1.4.a MARKET CAPITALIZATION

Market capitalization in this study is defined as units outstanding multiplied by the appropriate unit price. For unit price the average daily closing price between the beginning of April to the end of May for each year is used. This time period is chosen for several reasons. First, the use of an average in the study eliminates any short-term volatility that may occur on specific days. Secondly, the March to May time frame is chosen as this period reflects both the most recent reserve reports and the first quarter net prices, which are published in the quarter one financial reports. The source of information for the units is the trusts' quarter one financial reports. The unit price data is retrieved from two sources, GlobeinvestorGOLD and Bloomberg. GlobeinvestorGOLD is used for most sources but it does not have historical unit prices for three trusts that were acquired prior to the end of the study's sample period. Therefore, Bloomberg is used to get data for these three trusts.

3.1.4.b NET DEBT

The source for the net debt data is the balance sheet for each trust found in their respective quarter one financial statements. Some of the trusts have convertible debentures as part of their capital structure. Even though there is potential for equity dilution if converted, I treat them as a debt security and include them in the net debt calculation.

Although the data is taken from pre-specified points in time (i.e. reserves at year-end, units outstanding and net debt at the end of quarter one) I adjusted the appropriate variable if there is a material change in the entity. For instance, if a trust completed an acquisition of properties in March, I would add the acquired reserves to the firm's original reserves. The balance sheet would not need to be adjusted since I use Q1 data and the source of funds for the acquisition would already be adjusted at that time point. Many of the trusts completed an acquisition, sale, or equity issue in the first quarter. Out of the 107 observations, 21 are adjusted due to a material corporate announcement.

3.2 DATA COLLECTION PROCESS

This study utilizes data that was collected piece-by-piece and adjusted where appropriate. For each observation, there were many public filings to access and many press releases to filter through in order to get an accurate reflection of the state of the company.

As an example, the collection process begins with extracting the reserve report information found in the Annual Information Form filing. This also has the land holdings data and all the information is at December 31. To be precise, reserve data based on constant pricing and net after royalties is utilized in this test and land holding are based on the land that is not currently developed into an area that is captured under a reserve report. The reserves are input in detailed categories so their composition can be studied for other effects. For instance, although the proved category is used in the study, the data is inputted in three different categories of proved reserves: proved developed producing, proved developed non-producing, and proved undeveloped. And, within each of those groups, I input the volume of oil reserves and the volume of gas reserves separately.

Obtaining information from the first quarter financial statements is the next step. From these I obtain two important components: cash flow breakdown and the capitalization of the trust. The cash flow components are broken into different categories including selling price, operating cost, overhead cost, and capital taxes, if any. Each of these items is input separately. On the capitalization side I get units outstanding, long-term debt, short-term debt, and the cash balance. All of these items are dated at the end of each first quarter. In order to calculate market capitalization, and hence enterprise value, I average the daily closing unit prices from the end of March to the end of May.

The last element of the data collection process is crucial in getting an accurate reflection of value. Many of the observations were adjusted for an event that occurred during the observation time that impacted either the reserves or capitalization. I check all the press releases that are distributed from December 31 to the end of May to verify whether there are any items that affect one or both of these categories. If so, the appropriate alteration is made to the data to accurately reflect how the market would be valuing the entity. Although time consuming, this process allows for the incorporation of the most accurately specified data for testing. A list of the adjustments made to my observations can be found in Appendix A3.

3.3 DATASET CHARACTERISTICS

Table 3.2 outlines the characteristics of the 107 observations utilized in the study. The size of the trusts studied (based on enterprise value) range from $72.8 million to $7,751.0 million with debt levels ranging from a net cash position of $28.0 million to a net debt position of $1,681.0 million. Leverage levels average 16% with maximum leverage being 32%. Reserve volumes range from a low of 11 million BOE's to a maximum 335 million BOE's with an average of 97 million BOEs. The reserve composition is fairly balanced with natural gas as a percentage of reserves averaging 47%. This ranges from a minimum of 1% to a maximum of 86% natural gas. The most interesting component of the table compares the trading value versus the current net price. This comparison looks at the two components that make up the HVP: value per reserve unit and net price. The ratio in the far right column reveals an average of 65% which means trading value understates net price by 35% on average. If the HVP held true this ratio should be close to 100%. Variability on all of the columns is somewhat limited, especially examining the ratios on the right part of the table. Standard deviation is in the $8 range for both trading value per reserve unit and net price.

Table 3.2 Dataset Descriptive Statistics

	Total Capitalization			Debt	Reserves		Value	HOTEL	Ratio
	Market Cap.	Net Debt	Enterprise Value (EV)	Debt/ EV	BOE Reserves	Gas	EV/ Reserves	Cash Flow Net Price	Value/ HOTEL
	($mm)	($mm)	($mm)	(%)	(mBOE)	(%)	($/boe)	($/boe)	(%)
Mean	$ 1,428.0	$ 251.3	$ 1,679.3	16%	96,852	47%	$21.54	$34.08	65%
Median	$ 1,046.0	$ 216.6	$ 1,303.0	17%	80,853	45%	$20.48	$35.56	68%
Standard Deviation	$ 1,344.3	$ 230.5	$ 1,520.1	8%	75,660	20%	$8.83	$8.87	22%
Minimum	$ 66.9	$ (28.0)	$ 72.8	-9%	11,135	1%	$5.14	$12.79	18%
Maximum	$ 7,225.1	$ 1,681.0	$ 7,751.0	32%	335,580	86%	$43.58	$56.21	125%

Table 3.2 provides descriptive statistics for the sample used in the study. The statistics are specific to each column and not on an entity basis. The three columns at the right represent the market value per reserve unit, the current net price per unit, and the ratio of the former, respectively.

In addition to examining the dataset characteristics, I also review the value and net price growth rates over the period of my study. The results show that both the average value and net price grow at 16% which would typically be at or higher than the discount rate for oil and gas royalty trusts. This would typically mean that a higher value should be reflected in the market for these entities. It is interesting to note that value actually seems to be catching up to net price in the later years however, the results presented in Table 3.3 must be taken with caution due to the short time frame.

Table 3.3 Value and Net Price Growth Rates

	Enterprise Value (EV)		Net Price		Ratio
Year	Weighted Average	Growth Rate	Weighted Average	Growth Rate	EV/ Net Price
	($/boe)	(%)	($/boe)	(%)	(%)
2000	$12.17		$37.40		33%
2001	$12.13	0%	$14.87	-60%	82%
2002	$13.86	14%	$37.31	151%	37%
2003	$18.91	36%	$30.43	-18%	62%
2004	$22.45	19%	$35.62	17%	63%
2005	$31.26	39%	$42.30	19%	74%
2006	$27.62	-12%	$38.35	-9%	72%
Average		**16%**		**16%**	**60%**

Table 3.3 shows the average enterprise value per boe and average net prices weighted by quantity of Proved Reserves for each year in my study. Both the value and net price rise 16% on average over the period and value as a percent of net price is 60% on average. However, due to the short time frame studied and the high volatility, the average growth rates must be taken with caution.

3.4 INCOME TRUST OVERVIEW

An income trust, although publicly traded, differs from a regular public corporation with common shares in two distinct ways. First, the structure of an income trust makes it conducive to disbursing much of its generated cash flow into the hands of its investors. Conversely, regular public corporations tend to retain the majority of their generated cash flow to fund further capital projects and reinvestment opportunities. Income trusts, with their usual steady cash distribution (although by no means fixed), are comparable to a debt instrument that pays out a regular distribution (interest payment). This feature makes income trusts popular among income-oriented investors. The second major characteristic that sets them apart is their taxation structures. Holders of typical common shares face a double taxation regime. First, companies are taxed at a corporate level and then the common share holder is taxed on a personal level. Income trusts, on the other hand, are structured to allow taxation to occur only at the unit holder level, and at this level, distributions are taxed as ordinary income. The Royalty Trust structure, although similar to income trusts, is limited to domestic Canadian resource properties under Canadian legislation. Income trusts on the other hand have no specific restrictions on the assets they hold.

As indicated earlier, a common theme among income trusts and royalty trusts is the distribution of nearly 100% of cash flow. Only minimal amounts are retained to reinvest in depleting assets. As an example, capital required for maintenance and development projects is usually paid with debt and then replaced with a follow-on equity issue. This payout of cash flow is similar and can be compared to the payout of an annuity since both have a limited life and a declining capital base.

Another characteristic of oil and gas royalty trusts is their declining asset base. Each day, as oil and gas units are pumped out of the ground, the reserve declines. This is in contrast to real estate investment trusts where the asset base is characterized by a much longer useful life. The declining asset base of oil and gas royalty trusts complemented with high cash flow payout ratios implies that cash flow would decline over time. However, oil and gas royalty trusts have historically reversed this trend through acquisitions.

Figure 3.3 shows the two primary components of the royalty trust structure, the trust and the operating company. The process for creating a royalty trust still begins with the formation of a corporation; however, the subsequent steps are very different. First, an operating corporation ("OPCO") is created that will take ownership of the assets (mainly oil and gas reserves). Then, a trust ("TRUST") is created and an offering of trust units is carried out through an initial public offering. Proceeds from the offering are used to buy a royalty of income from OPCO. OPCO uses the proceeds from the royalty purchase (plus debt financing, if any) to purchase the oil and gas assets. The price paid for the royalty interest by TRUST to OPCO is substantially the same amount as the price paid for the assets less any debt. Finally, the purchase of the royalty by the TRUST results in the TRUST receiving 99% of OPCO's net cash flow (with 1% being retained by OPCO to qualify as a business). To summarize, the trust units own a 99% interest in the assets.

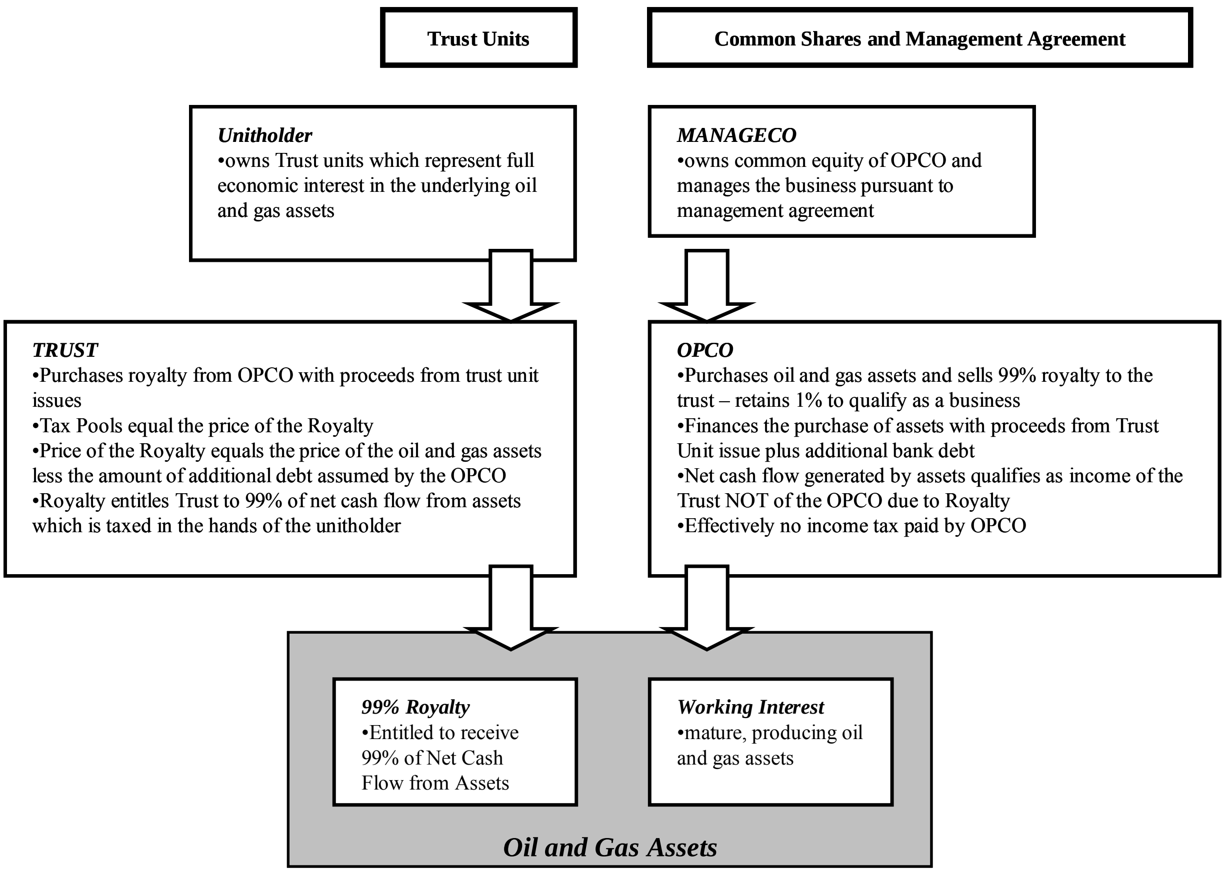


Figure 3.3 Oil and Gas Royalty Trust Structure[3]
This figure illustrates the two primary components of the royalty trust structure: the trust and the operating company.

OPCO and the TRUST are managed by a separate entity ("MANAGECO"). The compensation of MANAGECO is usually paid through a combination of management fees based on

[3] Panarites (2000)

operating metrics, acquisition and disposition fees, incentive fees and general and administrative costs reimbursement. More recently, MANAGECOs have been “internalized” into the trusts and operate within the trust rather than through a separate entity.

Tax implications from a trust structure occur at both the corporate and the personal level. At a corporate level, the income generated by the assets (99% of the income) is received by the TRUST, not OPCO. This occurs as OPCO passes through the income generated to the TRUST and is effectively a tax deductible expense of OPCO. Debt is used by OPCO to maximize royalty income. A significant portion of OPCO capital expenditures are financed with debt (rather than retained earnings) and the debt proceeds offset the capital spending in calculating royalty income. Therefore, if capital expenditures are 100% debt financed, the cash flow of OPCO is essentially equal to the royalty income. Over time, debt is replaced with new equity issues usually in conjunction with an acquisition in order to keep unit holder dilution to a minimum.

At the personal level, a tax pool is created at the TRUST level when the TRUST purchases the 99% royalty interest from OPCO. These pools allow for the sheltering of the distribution paid to unit holders from personal income tax. The sheltered component is categorized as a return of capital which in turn reduces the unit holders’ asset base. This allows for a tax deferral as tax is applied to the capital gain, if any, when the unit is sold. If the investor’s cost base goes to zero, the distribution will qualify as regular income. In order to offset the potential of investors facing a zero cost base, the TRUST, through OPCO, can continually make acquisitions to refill the tax pool.

In an attempt to give a better understanding of royalty trusts I expose some of the major differences between a conventional oil and gas production company and an oil and gas royalty trust through Figure 3.4. Although the diagram is highly simplified, it does provide the major taxation and operating differences between the two structures. It also shows that the major advantages of the royalty trust structure are single taxation and stable return of investment through (somewhat) predictable distributions, although these distributions are not fixed. On the other hand the advantages of the corporate structure are the potential for a big payoff and share appreciation. The federal government has legislated that only resource properties can be held under the royalty trust structure while there are no restrictions on the type of assets that can be placed in income trusts.

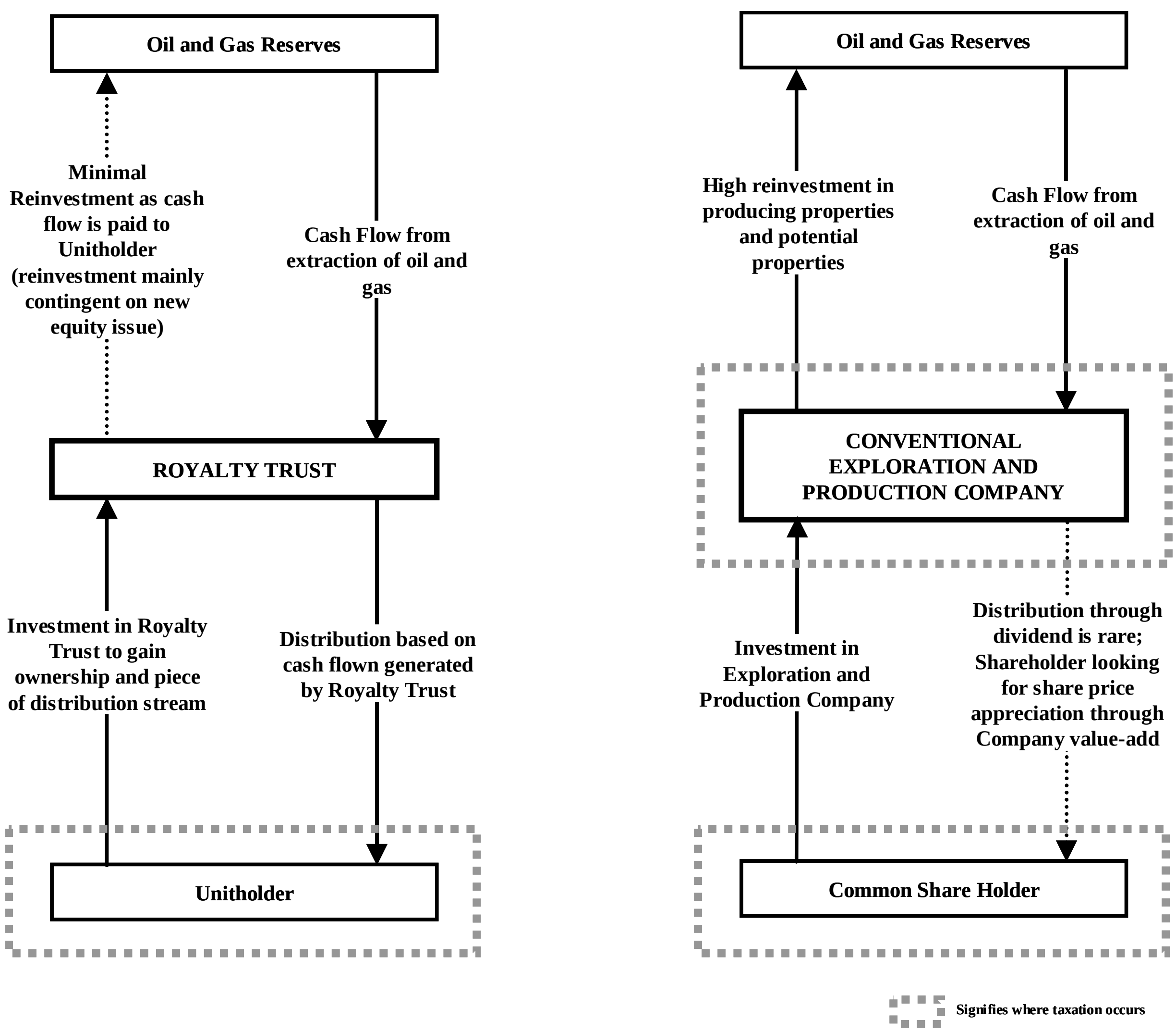


Figure 3.4 Royalty Trust Structure versus Conventional Corporate Structure
This figure illustrates the major corporate structure differences between a conventional company with common shareholders versus an oil and gas royalty trust with unit holders.

The main difference between the two structures is the process of transferring net cash flow from OPCO to the TRUST in a tax efficient manner. Under the royalty trust structure, net cash flow in the form of royalty income is earned by the TRUST's 99% net cash flow royalty and the royalties are essentially a tax deductible expense of OPCO. On the other hand, under an income trust structure where the TRUST owns all of the debt and equity of OPCO, cash travels from OPCO to the TRUST in the form of interest and dividends. Since equity is usually minimized and debt maximized, most of the transfer occurs in tax deductible interest payments.

The creation of the royalty trust structure breathed new life into mature, stable assets that may have been on the edge of being uneconomical. Previously, these assets did not garner near the amount of attention that they do now with the royalty trust structure. This royalty trust structure brought attention to these assets on two fronts:

1. The tax advantage of putting these types of assets in the royalty trust structure made these assets more economically viable.
2. These assets, when put in a royalty trust structure, created an investment vehicle that attracted income oriented investors who also wanted to participate in an equity play.

The above reasons opened up a new world of capital for these assets which in turn allowed the assets to be efficiently exploited.

From an investor standpoint, the benefits of the royalty trust structure are straightforward. The tax advantage is the main benefit as taxation only occurs at the personal level and not at the corporate level. Secondly, the regular disbursement of cash flows generated by the business allows for income oriented investors to receive a regular payment. Furthermore, non-income oriented investors always have the option of reinvesting the distribution back into the royalty trust.

CHAPTER 4 METHODOLOGY

The methodology used to test the HVP must incorporate a proxy for value along with data for the current net price. This test utilizes market value of equity plus book value of debt as the proxy for reserve value. The market value is regressed onto the net price to test the net price's ability to explain value. In addition to including net price as an independent factor, I also run additional tests incorporating other potential drivers of value including real option value, oil weighting, reserve quality, and size to see their impact, if any. Also, other test specifications are examined to further test for robustness of the HVP.

4.1 BACKGROUND

Fundamental valuation is based on the cash flow generation abilities of an asset or entity. Hotelling (1931) applied cash flow methodology to the valuation of exhaustible natural resources. The derivation process of Hotelling's (1931) theory is as follows.

The value of an exhaustible natural resource reserve can be calculated by taking the expected cash generated in each year into the future and discounting each year back at the appropriate rate,

$$V_0 = \sum_{t=0}^{\infty} \frac{(p_t - c_t)q_t}{(1+r_t)^t}, \tag{4.1}$$

where V_0 is the current value, t is the time of cash flow, p is the selling price per unit, c is the extraction cost per unit, q is the quantity extracted and sold at time t, and r is the fair discount rate.

A resource owner will want to maximize the value but is obviously constrained by the overall quantity of reserves (R) they have in their possession. Therefore,

$$\sum_{t=0}^{\infty} q_t \leq R_0 \,, \tag{4.2}$$

where R is the total reserve quantity.

The Hotelling (1931) Equation 2.1 states that in equilibrium, the net price is expected to grow at the discount rate. Put another way, the present value of the net price at any future time must equal the current net price,

$$\frac{(p_t - c_t)}{(1+r_t)^t} = p_0 - c_0 \,. \tag{4.3}$$

Substituting this into Equation 4.1 gives

$$V_0 = (p_0 - c_0)\sum_{t=0}^{\infty} q_t \,. \tag{4.4}$$

Assuming that all of the reserves are eventually extracted, or equivalently by considering only economically viable reserves, Equation 4.2 will hold with equality. This implies

$$V_0 = (p_0 - c_0)R_0 \,. \tag{4.5}$$

There are a number of issues that could lead to the failure of Equation 4.5 for a particular firm. The first is Hotelling's (1931) theory itself. Since the argument for its validity hinges upon economic equilibrium, it applies more naturally to a global setting rather than firm specific cases. This implies that the extraction cost that the principle applies should be considered an industry average, or rather a threshold. Firms with a cost advantage should extract more quickly, and those with a cost disadvantage should defer extraction.

Other issues involve the derivation of Equation 4.3. These involve the independence between price, cost, and quantity extracted. The independence of price and quantity results from the perfectly competitive market assumption. However, even in that case it seems likely that a firm's extraction costs would depend on the quantity extracted. Furthermore, even if price and cost do not depend directly on the quantity, the stochastic nature of the problem implies that Equation 4.3 requires the future variables to be stochastically uncorrelated with each other. Intuitively, this suggests that the firm makes its extraction decision independently of the net price it faces, which seems unreasonable. Any of these issues will cause Equation 4.5 to fail.

4.2 TEST OF THE HOTELLING VALUATION PRINCIPLE

For this study I perform a test of the HVP and also further the study by incorporating other potentially value impacting variables and completing ancillary tests.

Rearranging Equation 4.5 gives value per unit of reserves,

$$\frac{V_0}{R_0} = \left(p_0 - c_0\right). \tag{4.6}$$

Miller and Upton (1985a) adapt this equation into the linear regression model

$$\frac{V_0}{R_0} = \alpha + \beta\left(p_0 - c_0\right) + u \;. \tag{4.7}$$

If the HVP is valid, the intercept should be $\alpha = 0$ and the slope should be $\beta = 1$. My study of the HVP using Canadian oil and gas royalty trusts uses a slightly modified version of the above regression equation. The modification allows me to test whether $\beta = 0$ rather than $\beta = 1$ and is specified as

$$\frac{V_0^{it}}{R_0^{it}} - \left(p_0^{it} - c_0^{it}\right) = \alpha + \beta\left(p_0^{it} - c_0^{it}\right) + u^{it}, \tag{4.8}$$

where i represents cross section and t represents time series.

In order to run the regression, each trust's current net price is used as the independent variable and enterprise value per unit of reserve less the net price as the dependant variable. The dependant variable is a product of taking each trust's total enterprise value (adjusted for any un-developed land value), dividing it by the total proved reserves outstanding for each entity and then subtracting the net price.

In order to improve on the estimation efficiency in my testing I also utilize the generalized least squares (GLS) method in addition to the ordinary least squares (OLS) method since my dataset consists of a cross sectional times series of unbalanced panel data with the potential for unequal variances and/or correlation. The GLS method attempts to adjust for autocorrelation in the time series and missing factors that have a common effect on the dependent variable in the panel data. It does this by utilizing a different weighting matrix on the error term.

In particular, I assume that the covariance between residuals is

$$\operatorname{cov}\left[u^{is}, u^{jt}\right] = \begin{cases} 0 & if \quad s \neq t \\ \sigma^2 \rho & if \quad s = t \quad and \quad i \neq j \\ \sigma^2 & if \quad s = t \quad and \quad i = j \end{cases}. \tag{4.9}$$

The regression is estimated using a two-stage least squares procedure, in which the correlation ρ is the estimated correlation of the appropriate residuals obtained through OLS. The second stage uses this estimate for the GLS covariance matrix.

This process is performed for all 22 Canadian oil and gas royalty trusts in the sample over the years in which they operated since 2000 for a total of 107 observations. This process of testing for a one-to-one relationship between net price and reserve value will determine whether the HVP holds for Canadian oil and gas royalty trusts.

4.3 ADDITIONAL POTENTIAL VALUE DRIVERS

In addition to performing the main regression, additional variables are included in ancillary tests to see if they have any impact. I include variables relating to real options, as well as variables controlling for commodity mix, reserve quality, and firm size. These additional independent variables are layered in to the regression model and both the individual independent variables and the equations are tested for significance.

4.3.1 REAL OPTIONS

The management of oil and gas companies are always being faced with capital planning decisions. For example, after finding a new discovery, they can produce the newly found pool immediately or they can choose to delay to take advantage of improving economics in the future. This ability to choose the timing of extraction has inherent value - real option value. For instance, the more volatility there is in the selling price of oil and gas the more "potential" value there is in reserves held by a company. In particular, when prices are high, the firm can expand production. I account for this by incorporating a call option proxy. As stated earlier in McCormack and Sick (2001), real option value has not been implemented widely into practice and many companies lack incentive to management to focus on this value. However, I do test for this inherent value in this study using the Black-Scholes model for option valuation. The model utilizes an at-the-money call option and is specified in Table 4.1. I transform the estimated option price using the natural logarithm, which helps linearize an otherwise strictly positive variable. The specification for the real option test included in this study is:

$$LN\ (Black\text{-}Scholes\ Option\ Value). \tag{4.10}$$

If the HVP holds, the real option variable should not be significant. Conversely, since the HVP only captures the deterministic elements, the real option will allow me to test for the stochastic factors which I believe are present in the oil and gas industry.

Table 4.1 Real Option Specification

Call Option of Common Share	**Option Value on Oil and Gas Reserves**	**Variable Utilized**
Underlying Share Price	Net Price	Specific Net Price for each Trust
Strike Price	Net Price	Specific Net Price for each Trust
Time to Expiry	Period of Volatility Test	62 trading days (90 calendar days)
Risk Free Rate	Risk Free Rate	90 day Government of Canada Bond
Share Price Return Volatility	Oil/Gas Net Price* Return Volatility	Standard Deviation of the Natural Log of the daily Oil/Gas Net Price* Returns (Weighted for each Trust) for the First Quarter of Each Year

Table 4.1 is a comparison of the assumptions used in the valuation of a call option on a common share using the Black-Scholes model and the assumption used in the valuation of a real call option for oil and gas reserves. The table also includes the assumptions used for each input.
* The Net Price volatility calculation is based on posted sales prices as costs are assumed constant over the three month period.

4.3.2 ISOLATING OTHER DATA CHARACTERISTICS

Although quantity of reserves and net price received for those reserves should be the major driver in value for oil and gas companies, I suspect there may be some other factors that also have an influence on value. I include oil versus gas weighting, quality of reserves, and size in my ancillary test to determine their impact on value.

1. Oil and Gas Weighting

   One of the major issues brought up repeatedly when studying the HVP is the issue of gas conversion factors for equating gas into an oil equivalent. By adding a proxy for the oil weight I am able to determine whether there is an impact to value based on what commodity, oil or gas, the trust possesses. A logarithmic transformation is used to linearize the variable, so the proxy variable used is calculated as

$$LN\left[p/(1-p)\right], \tag{4.11}$$

where p = proportion of oil in each trust's proved reserves. The proportion is calculated using the contemporaneous conversion factor (based on average first quarter selling prices of oil and gas) and not the industry convention of 6:1 in order to more accurately reflect the current pricing environment.[4] If gas is less valuable than what the 6:1 ratio warrants (such as 7:1 or 8:1 as appears in Figure 3.1), then the coefficient should be positive.

2. Proved Developed Producing Reserves as a Percentage of Total Reserves

The classification of reserves into categories required by regulators provides a unique opportunity to examine the effects of reserve quality on the regression equation. Although the HVP uses quantity of reserves as one of its variables, it is not known what category of reserves best reflects this quantity. Similar to this test, previous studies have also used the proved reserves category for their tests. However, there may be potential positive value impact if a greater proportion of the reserves in the proved category are classified as proved developed producing as opposed to proved developed non-producing or proved undeveloped. My test for this is similar to the oil weighting proportion test,

$$LN\left[p/(1-p)\right], \tag{4.12}$$

where p = proportion of proved developed producing reserves in each trust's proved reserves. If the HVP holds and costs are accurately reflected, then the proved developed producing weighting variable should not be significant. However, if fixed costs are mistakenly amortized into variable extraction costs, then the coefficient should be positive.

[4] I repeated the analysis using the conventional 6:1 conversion factor and the results were similar.

3. Size (Enterprise Value)

There is a general understanding that entity size plays a part in valuation. It is believed that larger companies demand a premium valuation over their smaller peers due to the fact their shares may have more trading liquidity, they have improved access to capital, and they are seen as a more stable investment. In order to test for size effects in this study, I include the variable

$$LN(size), \tag{4.13}$$

where size is represented by enterprise value. If the HVP holds, the size variable should not be significant.

To summarize the relationships among the variables included in the tests I include Table 4.2 which shows the correlation among the added variables, in their form included in the test, for the full time period. The table shows that the real option variable shows the most correlation with net price.

Table 4.2 Correlation between the Independent Variable Proxies

	Net Price ($/boe) X1	**Real Call Option Value X2**	**Oil Weighting X3**	**PDP Weighting X4**	**Size X5**
X1	1.0000				
X2	0.7275	1.0000			
X3	-0.2893	-0.3876	1.0000		
X4	-0.1159	0.1219	-0.1377	1.0000	
X5	0.3544	-0.0294	-0.0974	-0.1776	1.0000

Table 4.2 shows the correlations between the independent variable proxies utilized in the study. The results show that the real option proxy is highly correlated with net price.

4.4 ADDITIONAL ROBUSTNESS TESTS

Further tests are run on the data to obtain a better understanding of the dynamics among the data and the model and to test for robustness. Specifically, I test for the impact of commodity price volatility, the impact of price and cost separately on value rather than combined into net price, the impact of any nonlinearities through the addition of a squared net price term, and also look at a log transformation test to verify if Miller and Upton's (1985a) specification remains robust.

4.4.1 COMMODITY PRICE VOLATILITY

Miller and Upton (1985b) put partial blame on their weakened test results on lack of commodity price volatility. The period I use in my study contains volatile oil and gas prices as can be seen in Figure 3.1. Oil price nearly doubles over the time period while natural gas more than doubles over the period. However, upon closer examination of Figure 3.1, you can see that the period can be divided into a period of relatively flat pricing (2000 - 2002) and extremely volatile pricing (2003 - 2006). These two periods give me an ideal structure to test the impact of flat versus volatile prices on the test results.

4.4.2 SEPARATING NET PRICE INTO STAND-ALONE PRICE AND COST

I run an ancillary test on the data to test the significance of selling price and extraction cost separately to see if this provides a better explanation of value than using them combined in one variable, net price. Reiterating Equation (4.6), the HVP states

$$\frac{V_0}{R_0} = p_0 - c_0 \,. \tag{4.14}$$

Rather than considering net price to be a single variable and arriving at regression equation (4.7), one could argue that both price and cost could be considered separate variables, which leads to the regression equation

$$\frac{V_0}{R_0} = \alpha + \beta_1 p_0 + \beta_2 c_0 + u \;. \tag{4.15}$$

In this case the HVP would require $\alpha = 0$, $\beta_1 = 1$, and $\beta_2 = -1$. If either of the variables are significantly different on their own, then support for the HVP would further be weakened.

4.4.3 TESTING FOR NONLINEARITIES IN THE RELATIONSHIP

In order to test for nonlinearities in the original Hotelling relationship I include a squared net price term. Potential nonlinearities may arise from two main sources: real options, which increase value when net price is low, so value should be higher than net price when it is low; and extraction constraints, which reduce value when net price is high (and presumably not going to grow as fast), so value should be lower than net price when it is high. The regression equation to test for nonlinearities with a squared net price term is

$$\frac{V_0}{R_0} = \alpha + \beta_1 (p_0 - c_0) + \beta_2 (p_0 - c_0)^2 + u \ . \tag{4.16}$$

4.4.4 APPLYING A NATURAL LOGARITHM TEST

In order to further test the strength of Hotelling's (1931) assumptions I transform the regression test into a natural logarithm specification. Since value, reserve quantity, and net prices are positive, taking the logarithm of both sides of Equation (4.14) would still describe the HVP,

$$\ln\left(\frac{V_0}{R_0}\right) = \ln(p_0 - c_0). \tag{4.17}$$

Crain and Jamal (1991) adopt this equation into the linear regression model

$$\ln\left(\frac{V_0}{R_0}\right) = \alpha + \beta \ln(p_0 - c_0) + u \ . \tag{4.18}$$

The main effect from this transformation is to mitigate the contribution of very large or very small net price observations. It is not unreasonable to suppose that a larger net price could be associated with a more variable residual term. The logarithmic transformation helps resolve that problem.

The logarithm test is performed on all the specified tests including the main test (all observations), the real option test, the control variables test (oil weighting, reserve quality, and size), and a test on all the variables. The logarithm test is also performed on the period splits (2000 - 2002 versus 2003 - 2006) to see if there are varying results between the two periods.

CHAPTER 5 STATISTICAL RESULTS AND ANALYSIS

The statistical results and analysis of the HVP tests using Canadian oil and gas royalty trusts are presented in this section. In addition to presenting the study progression from the original Hotelling specification, I examine the results of incorporating other potential variables including real options, commodity mix, reserve quality, and size in the detailed analysis section.

5.1 STUDY PROGRESSION

The regressions ran according to the original Hotelling specification (where only net price is the explanatory variable for reserve value) do not provide affirmative results in support of the HVP. In Table 5.1 under both the linear and natural logarithm regressions, the net price coefficient is significantly less than zero, indicating that value is less than that predicted by the HVP.

Table 5.1 Original Hotelling Specification

Test	Obs	Variables	Intercept X_0		Net Price X_1	rho	R^2	F	SSRes
FULL RESTRICTION									24,391
Original (Linear)									
OLS	107	2	3.1414		-0.4599	0.0000	0.2946	167.3390	5,825
			0.2764		0.0000				
GLS	107	2	6.9315		-0.5854	0.4748	0.4160	213.0449	4,822
			0.0705		0.0000	0.0000			
Original (Natural Logarithm)									
OLS	107	2	0.5120		-0.2923	0.0000	0.2568	94.6480	15.7460
			0.2157		0.0144				
GLS	107	2	0.5859		-0.3214	0.4697	0.3911	127.0818	12.9021
			0.2997	0	0.0463	0.0000			

Table 5.1 provides a summary of the results from the original Hotelling specification regression which includes net price as the only independent variable. The net price coefficients (in the OLS and GLS versions of the linear and natural logarithm regressions) are significantly different from zero which goes against the theory. The p-values for each coefficient are directly below.

To further the understanding, I isolate price and cost into their own independent variables rather than combining them into net price. This allows me to see if each one has an impact on its own. Table 5.2 shows that only the price variables are significant and their signs are positive as expected. This may give some support for the HVP since costs are relatively constant. Overall, the regression with the variables broken out does a slightly better job of explaining value versus the original specification where net price is used.

Table 5.2 Regression Results on Price and Cost Isolated

Test		Obs	Variables	Intercept X_0	Price X_1	Cost X_2	rho	R^2	F	SSRes
FULL RESTRICTION										24,391
Price / Cost Split										
	OLS	107	3	-2.5423	0.5372	0.0675	0.0000	0.3328	118.8188	5,509
				0.4871	0.0000	0.7966				
	GLS	107	3	5.4860	0.4365	-0.3626	0.4204	0.4584	154.4089	4,472
				0.2828	0.0001	0.0562				

Table 5.2 provides a summary of the results from the regression run on price and cost separately, versus combined in a net price independent variable as per the Hotelling (1931) specification. The price coefficients are the only variables that are significant. The p-values for each coefficient are directly below.

Furthermore, I add an additional variable, squared net price, to the original Hotelling specification to test for nonlinearities in the relationship. The results in Table 5.3 show that the squared net price term is not significantly different from zero which means there is a lack of evidence for a nonlinear relationship. Also, the addition of a squared net price variable does not add any material explanatory power to value over the original Hotelling specification. This suggests that a more careful examination about the failure of the HPV is warranted.

Table 5.3 Regression Results of including a Squared Net Price Term

Test	Obs	Variables	Intercept X_0	Net Price X_1	Net Price^2 X_2	rho	R^2	F	SSRes
FULL RESTRICTION									24,391
Net Price + Net Price^2									
OLS	107	3	9.5751	0.0793	0.0075	0.0000	0.3021	112.0538	5,763
			0.1580	0.8586	0.2933				
GLS	107	3	-0.4639	0.8730	-0.0066	0.4462	0.4438	149.4492	4,592
			0.9581	0.0882	0.3624				

Table 5.3 provides a summary of the results from the regression which tests for nonlinearity in the relationship. The squared net price term is not significantly different from zero signifying that a nonlinear relationship does not exist. The p-values for each coefficient are directly below.

5.2 DETAILED ANALYSIS

Table 5.4 presents the statistical results of the HVP regression run on a sample of 22 Canadian oil and gas royalty trusts spanning a period from 2000 to 2006 with 107 observations in total. The regression test results of the original Hotelling specification study do not show support for the HVP using both the OLS and the GLS regression methods. Although the intercept is not statistically different from zero based on p-value, the slope coefficient is negative, and significantly different from zero. (Recall that I adjusted the dependent variable so that the appropriate restricted value for the HVP would be zero, so the negative coefficient implies that reserve value is less than current extraction value. However, because the coefficient is greater than –1, reserve value is increasing with the net price as expected.) The study shows that the independent variable (net price) explains just over 29% of the movement in the dependent variable (market value) based on OLS and over 41% based on GLS (together with the estimate of the contemporaneous correlation, rho).

Table 5.4 - Full Period Test Statistics

Test		Obs	Variables	Intercept X_0	Main: Net Price X_1	Option: Real Call Option X_2	Other Variables: Oil Weight Proxy X_3	Other Variables: PDP Weight Proxy X_4	Other Variables: Size Proxy X_5	rho	R^2	F	SSRes
FULL RESTRICTION													24,391
Original Hotelling Specification													
	OLS	107	2	3.1414	-0.4599					0.0000	0.2946	167.3390	5,825
				0.2764	0.0000								
	GLS	107	2	6.9315	-0.5854					0.4748	0.4160	213.0449	4,822
				0.0705	0.0000					0.0000			
With Real Call Option													
	OLS	107	3	-2.8306	0.0632	-11.8594				0.0000	0.5119	175.1415	4,030
				0.2704	0.5398	0.0000							
	GLS	107	3	1.7482	-0.2429	-6.3088				0.1713	0.5574	196.7184	3,654
				0.6188	0.0981	0.0123				0.0015			
With Other													
	OLS	107	5	-11.5714	-0.6010		-0.3072	-2.5004	2.9908	0.0000	0.4134	82.3258	4,844
				0.0363	0.0000		0.6240	0.1341	0.0001				
	GLS	107	5	7.6826	-0.6478		-0.9857	1.5028	0.1148	0.2301	0.5552	115.0618	3,673
				0.1873	0.0000		0.0562	0.2779	0.8649	0.0000			
With All Variables													
	OLS	107	6	-7.2712	-0.0400	-11.7995	-1.3929	-0.3823	1.2061	0.0000	0.5565	95.2801	3,662
				0.1349	0.7453	0.0000	0.0178	0.7985	0.0982				
	GLS	107	6	4.3970	-0.1761	-10.5783	-1.7712	1.1389	-0.1195	0.1528	0.6049	109.0137	3,263
				0.4128	0.2265	0.0002	0.0019	0.4013	0.8608	0.0007			

Table 5.4 presents the results of the OLS and GLS regression variations based on $Y = X_0 + B_1 X_1 + \ldots + B_5 X_5$ where X_0 represent the intercept, X_1 represents net price per unit (the main test variable for Hotelling theory), X_2 represents the logarithmic real call option proxy, X_3 represents the oil weighting proxy, X_4 represents the reserve quality proxy and X_5 represents the size proxy. The regressions are run on the Canadian oil and gas royalty trust data for the period 2000 - 2006 and the p-values are directly below the coefficients. Although the original Hotelling specification does not show support for the Hotelling theory, the regressions with the real call option proxy and with all variables do show support for the theory.

Potential reasons for the lower than expected slope coefficient may be that market participants generally believe that net prices will rise at less than the fair discount rate and the decline rate limits the maximum rate of extraction so that a significant amount of the reserve cannot be quickly extracted. Or perhaps it may be due to the market not believing that the independent engineers are providing an accurate estimate of reserves and are instead over estimating the quantity (as in the captured auditor agency problem). Although, since I use proved reserves, which is the most conservative estimate of reserves available, this potential problem should not be too great. The rho in the GLS specification is significantly different from zero, so the contemporaneous correlation among residuals does seem to be an issue for the basic model.

5.2.1 ADDITIONAL POTENTIAL VALUE DRIVERS

5.2.1.a REAL OPTIONS

The inclusion of the real call option variable increases the overall explanatory power R^2 of the regression to over 51% based on the OLS method and over 55% based on the GLS method. In this study, the OLS and GLS methods result in the same conclusion - both the intercept and the net price coefficients agree with the HVP and the real option coefficients are significant. These results appear to be supportive of the HVP in the fact that both the net price coefficients and the intercepts are not significantly different from zero. In particular, the real option variable significantly captures the value loss observed in the initial HPV test. The negative sign of the coefficient suggests that the option to reduce production given a drop in resource prices may be more important than the option to expand, (according to put-call parity). The inclusion of the significant real option variable may be capturing the stochastic nature of the oil and gas industry where production quantity is influenced by net price. The rho for the GLS regression is significant potentially due to correlated error terms but the additional explanatory power, 4% on an R^2 basis, is relatively small.

5.2.1.b ISOLATING OTHER DATA CHARACTERISTICS

The regression run using the control variables (oil weighting, proved developed producing reserves weighting, and size), does add explanatory value to the original Hotelling (1931) equation though not as much as adding the real option variable. However, the coefficient on the net price is different from zero which does not support the HVP. Out of the three additional independent variables added to the regression only one, size in the OLS specification, is significant. The sign on the size coefficient is as expected; size translates into higher value potentially due to liquidity and access to capital. All of the other variables do not show a significant impact to value. The significant GLS rho of 0.23 has a material impact to the explanatory impact bringing the R^2 from 41% in the OLS regression to over 55% in the GLS specification. The high GLS may mean there is still correlated error terms even when these additional variables are added.

5.2.1.c INCLUDING ALL VARIABLES

An inclusion of the control variables provides a marginal effect over the basic real option specification. As in the real option specification, both the intercept and net price coefficient are not significantly different from zero and the real options coefficient is significantly negative. However, the oil weighting variable is also significant in both OLS and GLS specifications. The negative signs on the oil weighting variables may mean that the market attributes more value to natural gas reserves versus oil reserves. (Or rather the conversion ratio of 6 Mcf per barrel may understate natural gas reserve value.)

The inclusion of the other variables did increase the explanatory power of the equation to 55% using the OLS method and 60% using the GLS method. In each case the rho used in the GLS specification is significantly different from zero, so it may be important to consider contemporaneous correlation of the residuals when analysing the panel data, although in this case the main conclusions are not affected.

Overall, each incremental test version where additional independent variables are added, or further unrestricted cases, are statistically significant using an F-test. This means that the parsimonious restricted models can be rejected in favour of the full model.

5.2.2 ADDITIONAL ROBUSTNESS TESTS

5.2.2.a COMMODITY PRICE VOLATILITY

Breaking the observation period into two categories leaves 39 observations occurring in the 2000 - 2002 group and 68 observations occurring in the 2003 - 2006 group. The regression results of the 2000 - 2002 group can be seen in Table 5.5 while the 2003 - 2006 results can be seen in Table 5.6.

The results of the 2000 - 2002 time period study do not show support for the HVP. None of the regressions have a net price coefficient that is not significantly different from zero and the only regressions that have an intercept that is not significantly different from zero is the regressions with the other variables included. The explanatory power of the original Hotelling (1931) specification regression is approximately 7% which is significantly lower than the full period R^2 of 29% for the OLS regression and almost 42% for the GLS regression. Additionally, the real option variable is significant under the OLS real option specification and the coefficient is positive, which suggests that the option to expand is still relevant for this period, (as resource prices are still relatively low, and production may still have some slack). However, the real option coefficient is not significant when the other variables are added.

Table 5.5 - 2000 to 2002 Test Statistics

Test		Obs	Variables	Intercept	Main	Option	Other Variables						
					Net Price	Real Call Option	Oil Weight Proxy	PDP Weight Proxy	Size Proxy				
				X_0	X_1	X_2	X_3	X_4	X_5	rho	R^2	F	SSRes
FULL RESTRICTION													14,726
Original Hotelling Specification													
	OLS	39	2	10.5990	-0.9071					0.0000	0.0686	504.5410	521
				0.0000	0.0000								
	GLS	39	2	9.6879	-0.8788					0.0555	0.0764	508.9381	517
				0.0000	0.0000					0.5805			
With Real Call Option													
	OLS	39	3	15.4550	-1.2700	5.2903				0.0000	0.1832	374.8361	457
				0.0000	0.0000	0.0268							
	GLS												
With Other													
	OLS	39	5	6.3445	-0.9728		-1.1945	4.2516	0.4550	0.0000	0.3512	269.1937	363
				0.1810	0.0000		0.0423	0.0287	0.4700				
	GLS	39	5	7.5028	-0.9610		-1.3214	4.3692	0.1857	0.1083	0.3660	275.6474	355
				0.1253	0.0000		0.0209	0.0163	0.7574	0.3790			
With All													
	OLS	39	6	10.9168	-1.2594	4.2943	-0.9856	4.6242	0.2658	0.0000	0.4195	244.0021	325
				0.0340	0.0000	0.0513	0.0854	0.0139	0.6639				
	GLS												

Table 5.5 presents the results of the OLS and GLS regression variations based on $Y = X_0 + B_1 X_1 + \ldots + B_5 X_5$ where X_0 represent the intercept, X_1 represents net price per unit (the main test variable for Hotelling theory), X_2 represents the logarithmic real call option proxy, X_3 represents the oil weighting proxy, X_4 represents the reserve quality proxy and X_5 represents the size proxy. The regressions are run on the Canadian oil and gas royalty trust data for the period 2000 - 2002 and the p-values are directly below the coefficients. None of the specified regressions show support for Hotelling theory. The GLS results for the Real Call Option and All specifications above are not included due to positive definiteness of the covariance matrix that arises from the two-stage regression.

Table 5.6 - 2003 to 2006 Test Statistics

Test		Obs	Variables	Intercept X_0	Main: Net Price X_1	Option: Real Call Option X_2	Other Variables: Oil Weight Proxy X_3	Other Variables: PDP Weight Proxy X_4	Other Variables: Size Proxy X_5	rho	R^2	F	SSRes
FULL RESTRICTION													9,665
Original Hotelling Specification													
	OLS	68	2	0.5564	-0.2969					0.0000	0.3816	110.4241	2,224
				0.8919	0.0082								
	GLS	68	2	3.1585	-0.3661					0.0276	0.3850	111.2119	2,212
				0.4771	0.0026					0.5492			
With Real Call Option													
	OLS	68	3	0.6271	-0.3019	0.1583				0.0000	0.3816	72.5021	2,224
				0.8938	0.1226	0.9748							
	GLS	68	3	3.5413	-0.3921	0.7939				0.0274	0.3852	73.0536	2,211
				0.4912	0.0604	0.8765				0.5394			
With Other													
	OLS	68	5	5.5126	-0.3098		-0.5740	2.0401	-0.6918	0.0000	0.4064	44.4479	2,135
				0.4664	0.0155		0.3858	0.2435	0.5089				
	GLS	68	5	22.3099	-0.5417		-1.0530	3.1733	-1.8163	0.0826	0.4494	48.9098	1,980
				0.0118	0.0001		0.0959	0.0581	0.0820	0.0301			
With All													
	OLS	68	6	5.5444	-0.2241	-2.8143	-0.7211	1.9666	-0.8356	0.0000	0.4086	36.6314	2,126
				0.4666	0.3029	0.6268	0.3246	0.2654	0.4453				
	GLS	68	6	22.1645	-0.4571	-2.7602	-1.1959	3.0664	-1.9352	0.0829	0.4516	40.3143	1,972
				0.0130	0.0418	0.6253	0.0876	0.0711	0.0726	0.0312			

Table 5.6 presents the results of the OLS and GLS regression variations based on $Y = X_0 + B_1 X_1 + \ldots + B_5 X_5$ where X_0 represent the intercept, X_1 represents net price per unit (the main test variable for Hotelling theory), X_2 represents the logarithmic real call option proxy, X_3 represents the oil weighting proxy, X_4 represents the reserve quality proxy and X_5 represents the size proxy. The regressions are run on the Canadian oil and gas royalty trust data for the period 2003 - 2006 and the p-values are directly below the coefficients. Although the original Hotelling specification does not show support for the Hotelling theory, the OLS regressions with the real call option proxy and with all variables do show support for the theory.

The 2003 - 2006 period results still fail to support the HVP, since the net price coefficients are significantly different from zero. For the basic model and the real option specification, rho is not significantly different from zero, which suggests the OLS specification is adequate. However, with the inclusion of the control variables, rho becomes significant, so GLS is the relevant technique. In this case, the other regressions in the 2003 - 2006 period contain a net price coefficient that is significantly different from zero, which provides evidence against the HVP. Again, the real option variable is not significant in this period even when conditioning on the control variables. This is puzzling given the results from the full and early periods, since I would expect a strong negative coefficient would be needed to counter the positive effect observed in the early period and still arrive at a negative coefficient for the full period sample.

A major difference between the flat commodity price period versus this period is the explanatory power of the original Hotelling (1931) specification model. The regression of the 2000 - 2002 period has an R^2 of 7% while this period has an R^2 of 38%. This supports the theory that higher commodity price volatility will result in a more robust model.

5.2.2.b NATURAL LOGARITHM TEST

The natural logarithm test further attempts to search out a relationship between reserve value and net price. Since value is a positive quantity, the linear specification may not accurately represent the true relationship. The natural logarithm tests are carried out in a similar manner to the linear test: the full period from 2000 to 2006 can be seen in Table 5.7, the low volatility period from 2000 to 2002 can be seen in Table 5.8, and the high volatility period from 2003 to 2006 can be seen in Table 5.9. Also, each period contains the ancillary tests of including the real option proxy and the other control variables.

Table 5.7 - Full Period Test Statistics (Natural Logarithm Specification)

Test		Obs	Variables	Intercept X_0	Main: Net Price X_1	Option: Real Call Option X_2	Other Variables: Oil Weight Proxy X_3	Other Variables: PDP Weight Proxy X_4	Other Variables: Size Proxy X_5	rho	R^2	F	SSRes
FULL RESTRICTION													44.1331
Original Hotelling Specification													
	OLS	107	2	0.5120	-0.2923					0.0000	0.2568	94.6480	15.7460
				0.2157	0.0144								
	GLS	107	2	0.5859	-0.3214					0.4697	0.3911	127.0818	12.9021
				0.2997	0.0463					0.0000			
With Real Call Option													
	OLS	107	3	-1.2369	0.0095	-0.5615				0.0000	0.4441	95.2206	11.7790
				0.0089	0.9336	0.0000							
	GLS	107	3	-0.1749	-0.1753	-0.2089				0.2205	0.5186	115.3452	10.1988
				0.8032	0.3069	0.1222				0.0001			
With Other													
	OLS	107	5	0.0375	-0.5353		-0.0338	-0.0831	0.1960	0.0000	0.4382	55.2295	11.9043
				0.9284	0.0000		0.2707	0.3139	0.0000				
	GLS	107	5	0.7806	-0.5068		-0.0602	0.1091	0.0581	0.2144	0.5664	77.5938	9.1875
				0.1601	0.0009		0.0178	0.1189	0.0890	0.0000			
With All Variables													
	OLS	107	6	-1.3352	-0.1867	-0.5586	-0.0947	0.0170	0.1140	0.0000	0.5556	62.0594	9.4167
				0.0043	0.1286	0.0000	0.0019	0.8232	0.0023				
	GLS	107	6	-0.6301	-0.2311	-0.5205	-0.1108	0.1063	0.0333	0.1810	0.6144	74.1055	8.1693
				0.3116	0.1376	0.0004	0.0002	0.1145	0.3264	0.0002			

Table 5.7 presents the results of the OLS and GLS regression variations based on $Y = X_0 + B_1 X_1 + \ldots + B_5 X_5$ where X_0 represent the intercept, X_1 represents net price per unit (the main test variable for Hotelling theory), X_2 represents the logarithmic real call option proxy, X_3 represents the oil weighting proxy, X_4 represents the reserve quality proxy and X_5 represents the size proxy. The regressions are run on the Canadian oil and gas royalty trust data for the period 2000 - 2006 and the p-values are directly below the coefficients. Although the original Hotelling specification does not show support for the Hotelling theory, the GLS regressions with the real call option proxy and with all variables do show support for the theory.

Table 5.8 - 2000 to 2002 Test Statistics (Natural Logarithm Specification)

				Main	Option	Other Variables						
Test	Obs	Variables	Intercept X_0	Net Price X_1	Real Call Option X_2	Oil Weight Proxy X_3	PDP Weight Proxy X_4	Size Proxy X_5	rho	R^2	F	SSRes
FULL RESTRICTION												31.4126
Original Hotelling Specification												
OLS	39	2	2.0853	-0.8599					0.0000	0.0377	149.6078	3.4569
			0.0000	0.0000								
GLS	39	2	1.9205	-0.8120					0.0608	0.0443	150.7708	3.4332
			0.0002	0.0000					0.6160			
With Real Call Option												
OLS	39	3	4.5053	-1.4274	0.5393				0.0000	0.2331	124.8228	2.7550
			0.0000	0.0000	0.0031							
GLS	39	3	4.7375	-1.4936	0.5517				-0.0646	0.2727	132.2705	2.6128
			0.0000	0.0000	0.0000				0.1704			
With Other												
OLS	39	5	1.7677	-0.9767		-0.0940	0.3561	0.0672	0.0000	0.3934	91.2191	2.1792
			0.0005	0.0000		0.0350	0.0184	0.1702				
GLS	39	5	1.8531	-0.9625		-0.1066	0.3663	0.0436	0.1257	0.4101	94.0010	2.1191
			0.0029	0.0000		0.0121	0.0088	0.3456	0.3331			
With All												
OLS	39	6	3.5516	-1.3693	0.3988	-0.0563	0.4057	0.0468	0.0000	0.4743	85.9937	1.8883
			0.0002	0.0000	0.0263	0.2114	0.0052	0.3205				
GLS	39	6	3.9220	-1.4619	0.4803	-0.0457	0.4134	0.0489	-0.0444	0.4882	88.4669	1.8386
			0.0000	0.0000	0.0005	0.2730	0.0047	0.3015	0.3520			

Table 5.8 presents the results of the OLS and GLS regression variations based on $Y = X_0 + B_1 X_1 + \ldots + B_5 X_5$ where X_0 represent the intercept, X_1 represents net price per unit (the main test variable for Hotelling theory), X_2 represents the logarithmic real call option proxy, X_3 represents the oil weighting proxy, X_4 represents the reserve quality proxy and X_5 represents the size proxy. The regressions are run on the Canadian oil and gas royalty trust data for the period 2000 - 2002 and the p-values are directly below the coefficients. None of the specified regressions show support for Hotelling theory.

Table 5.9 - 2003 to 2006 Test Statistics (Natural Logarithm Specification)

				Main	Option	Other Variables						
Test	Obs	Variables	Intercept X_0	Net Price X_1	Real Call Option X_2	Oil Weight Proxy X_3	PDP Weight Proxy X_4	Size Proxy X_5	rho	R^2	F	SSRes
FULL RESTRICTION												12.7205
Original Hotelling Specification												
OLS	68	2	-0.4555	0.0272					0.0000	0.3678	71.9159	4.0011
			0.4453	0.8699								
GLS	68	2	-0.1944	-0.0450					0.0199	0.3695	72.2082	3.9900
			0.7581	0.7979					0.6695			
With Real Call Option												
OLS	68	3	-0.4618	0.0282	-0.0020				0.0000	0.3678	47.2176	4.0011
			0.6017	0.8858	0.9924							
GLS	68	3	-0.1482	-0.0520	0.0152				0.0195	0.3696	47.4158	3.9896
			0.8746	0.8041	0.9419				0.6669			
With Other												
OLS	68	5	-0.1779	-0.0468		-0.0297	0.1204	-0.0071	0.0000	0.4062	30.0531	3.7577
			0.7827	0.8052		0.2885	0.1015	0.8725				
GLS	68	5	1.2710	-0.3605		-0.0486	0.1697	-0.0512	0.0764	0.4433	32.8970	3.5228
			0.0991	0.0814		0.0720	0.0174	0.2433	0.0447			
With All												
OLS	68	6	-0.5101	0.0130	-0.1353	-0.0385	0.1167	-0.0157	0.0000	0.4091	24.8139	3.7398
			0.5675	0.9529	0.5874	0.2364	0.1161	0.7385				
GLS	68	6	0.8821	-0.2936	-0.1722	-0.0603	0.1641	-0.0623	0.0795	0.4483	27.3125	3.4916
			0.3779	0.2130	0.4942	0.0572	0.0231	0.1791	0.0399			

Table 5.9 presents the results of the OLS and GLS regression variations based on $Y = X_0 + B_1 X_1 + \ldots + B_5 X_5$ where X_0 represent the intercept, X_1 represents net price per unit (the main test variable for Hotelling theory), X_2 represents the logarithmic real call option proxy, X_3 represents the oil weighting proxy, X_4 represents the reserve quality proxy and X_5 represents the size proxy. The regressions are run on the Canadian oil and gas royalty trust data for the period 2003 - 2006 and the p-values are directly below the coefficients. All of the regressions show support for the Hotelling theory.

The full period results found in Table 5.7 using the natural logarithm specification produce a similar conclusion to the linear specification: there is no support for the original Hotelling specification. Furthermore, both the intercept and the net price coefficient are not statistically different from zero, and the real option coefficient is significantly negative. Also, the explanatory powers of the regression are similar to those of the linear specified model.

The results of the flat commodity price volatility period from 2000 to 2002 can be seen in Table 5.8. The results are similar to the linear specification, but generally stronger: all variables are significant and the GLS method is well specified in this case. Furthermore, the signs of the net price and real option coefficients are the same as in the linear case.

The natural logarithm results from the volatile period 2003 to 2006 can be found in Table 5.9. This time period, using the natural logarithm transformation, provides the most support for the HVP among all of the other analysis. Every regression shows the intercept and net price coefficients not significantly different from zero, even the original Hotelling specification. Additionally, all of the other variables, with the exception of reserve quality in the GLS regressions, are not significant which further provides support for the HVP. These results show that, in a volatile commodity price environment, the HVP may hold under the natural logarithm specification.

CHAPTER 6 CONCLUSION

The HVP states that the value of oil and gas reserves is equal to the current net price of those reserves times the quantity, or equivalently that net prices rise at the discount rate. Previous studies have found support both for, and against, the HVP, although the majority of these studies have used data that is deficient to provide an accurate test of the principle.

6.1 CONTRIBUTION OF THE STUDY

This study attempts to remedy the deficiencies in previous studies and provide the most definitive test of the HVP to date. By utilizing Canadian oil and gas royalty trusts as the sample I am able to mitigate the average cost information used in acquisition based studies and it also allows me to remove the “management exploration expertise” premium found in previous studies using conventional oil and gas exploration and production companies. For this test, I use 22 Canadian oil and gas royalty trusts spanning a period from 2000 to 2006 for a total of 107 observations.

My study generally fails to find support for the HVP. In particular, the results indicate that the HVP overestimates reserve value. This suggests that market participants expect net prices to grow at a rate significantly lower then the fair cost of capital, and production constraints limiting the extraction rate are binding. I do find that the real option proxy explains a significant amount of the difference between the value observed and the value predicted by the HVP. This differs markedly from what previous literature on the HVP applied to market data for the oil and gas industry documents. Each of these papers fails to reject the HVP. The fact that I generally find the value to be lower than that predicted by the HVP is not surprising given the previous literature using market data to test it. Since these studies use conventional oil and gas companies, which likely overvalue reserves because of an exploration premium, finding support for the HVP likely means that royalty trusts will likely correspond to a value lower than that predicted. The difference would account for the exploration premium. On the other hand, when I use the log-linear specification over the second, more volatile sub-sample, I also fail to reject Hotelling's theoretical value, which is consistent with previous literature.

6.2 LIMITATIONS OF THE STUDY

Although my study attempts to provide the most definitive test to date on the HVP's application to the oil and gas industry – there are still the factors apparent in this specific industry such as government regulation and monopolistic forces that make the application difficult. Additionally, there are other potential explanations of why the HVP does not hold in my test, although the verification of these hypotheses goes beyond the scope of this paper:

1. The market believes the independent engineer estimates are overestimated: There may be a perceived conflict of interest for the independent engineers who produce the reserve estimates. For instance, in an attempt to do repeat business with a specific trust an independent reserve engineer may try to provide the highest estimate of reserves. This overestimate may not be fully reflected in value as the market artificially haircuts the reserves to compensate for any potential conflicts of interest.
2. The study is geographically isolated. Oil and natural gas (although less so) is a worldwide commodity that is influenced by forces throughout the globe. By examining just one segment of this worldwide industry I am biased by potential factors that only affect the specific market I am looking at. For instance, government environmental regulations in Alberta or the United States may be different than those in Saudi Arabia resulting in different cost struc-

tures and leading to bias in the net price inputs.

3. The quantification of reserves in the model cannot be specified. If the Hotelling (1931) assumption holds, eventually every barrel of oil and every gas molecule will become economical to recover due to the positive net price growth rate. However, the estimates used in previous literature of HVP tests are based on reserves that are economically recoverable at today's prices. There is a big discrepancy between what is estimated as reserves now and what will be estimated as reserves if net price keeps growing indefinitely.
4. The assumption that cost remains constant regardless of quantity produced. Typically, a producer would go after reserves that are less costly to produce first.

6.3 FUTURE RESEARCH

It is hoped that this study has accomplished its intention of providing the most definitive conclusion of the HVP to date. However, I do not believe this essentially "closes the book" on the topic but rather opens it up to new avenues. For instance, future studies on this topic could potentially examine:

1. Future growth rate assessments: As the world heads toward "peak" oil (and gas) supply should be reduced forcing upward price pressure. Maybe then net price will grow at the discount rate.
2. World study: Study observations from around the world since oil and gas is a worldwide commodity and North America only makes up a small segment of the sector.
3. U.S. Master Limited Partnerships (in time): U.S. oil and gas MLPs are now starting to get rolling again and should get more popular as Canadian oil and gas royalty trusts disappear.

As we come closer to a world decline in the production of hydrocarbons the issue of conservation and allocation becomes more pronounced. The study of the Hotelling (1931) theory provides a starting point for the allocation between economic maximization for resources owners and Pareto optimal distribution among generations. However, the factors present in the oil and gas industry are too complex to be captured by the straightforward HVP. Other factors, such as real options, are needed to capture the stochastic elements existing in the oil and gas industry.

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APPENDIX A1 SCATTERPLOT OF OBSERVATIONS

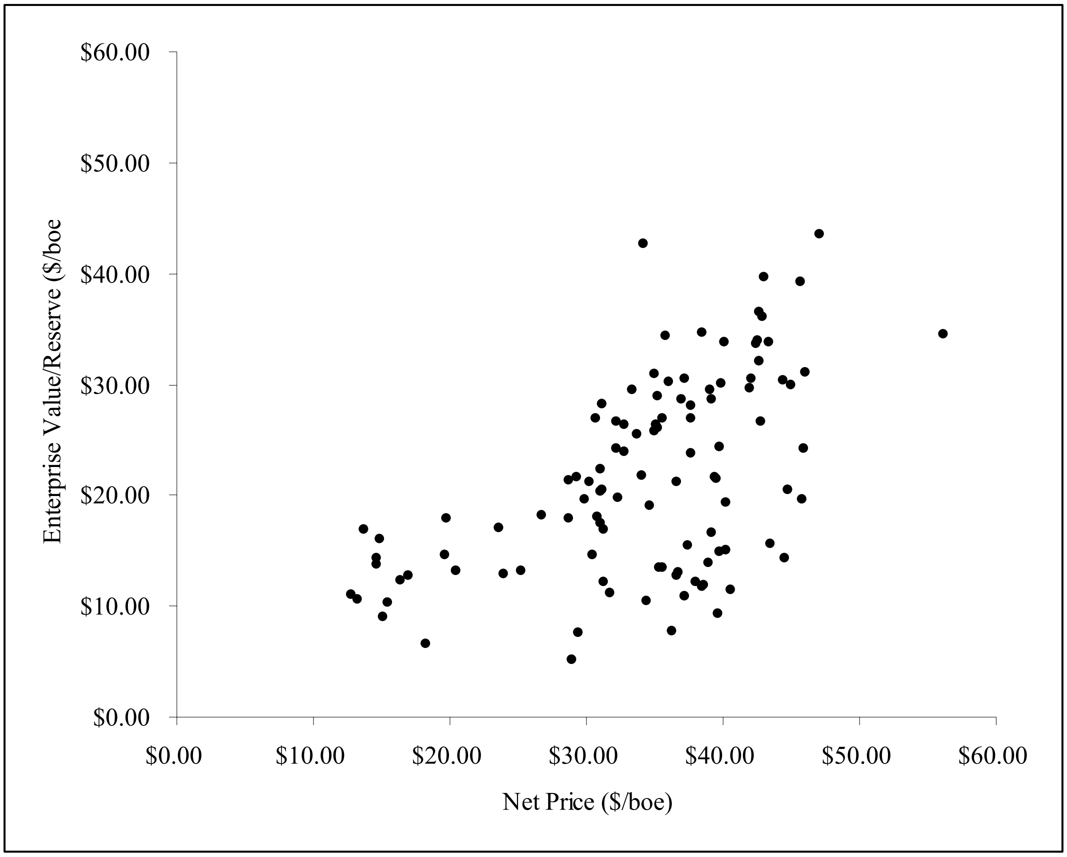

Figure A1.1 Scatterplot of Value versus Net Price

This figure shows the scattering of net price per barrel of oil equivalent on the independent (x axis) versus the market value per barrel of oil equivalent reserve on the dependent (y axis). Market value is represented through enterprise value which also includes the debt component, if any.

APPENDIX A2 OIL AND GAS DEFINITIONS

Barrels of Oil Equivalent: A standard unit of measure whereby gas is converted to an equivalent barrel of oil based on either their heat content or economic value.

Common Pool: A natural occurring underground accumulation of oil and/or natural gas (and separate from other accumulations) where two or more entities have an interest.

Decline Rate: The rate at which a well's production declines due to natural and, occasionally, man-introduced forces. Expressed in percent per year.

Economically Recoverable: An estimate of resources, including oil and/or natural gas, both proved and undiscovered, that would be economically extractable under specified price-cost relationships and technological conditions.

In-situ: Confined to the site of origin. "In the earth" when referring to oil and natural gas reserves.

Net Price: The selling price (revenue) received for a reserve unit less the costs of extracting and selling the unit. Also known as Netback.

Reserve Life: Remaining reserves divided by annual production.

Unitization: A term denoting a common operation of separately owned producing leases in an oil and natural gas pool or reservoir. A legal process which defines operatorship, ownership, working interest, royalties, etc. and provides for more economical operation and subsequent recovery.

APPENDIX A3 REQUIRED DATA ADJUSTMENTS

Acclaim Energy Trust:

1. Closed $174 million acquisition of Elk Point Resources Inc. on January 28, 2003.
2. Closed $9 million asset divestiture in Q1 2004.

Advantage Energy Income Fund:

1. Closed $62 million acquisition of a private oil and gas company on January 8, 2002.

ARC Energy Trust:

1. Closed $485 million acquisition of Startech Energy Inc. on February 1, 2001.

Crescent Point Energy Trust:

1. Closed $81 million acquisition of Capio Petroleum Corporation on January 6, 2004.
2. Closed $257 million asset acquisition on January 9, 2006.
3. Closed $627 million acquisition of Mission Oil & Gas Inc. on February 9, 2007.

Enerplus Resources Fund:

1. Closed $123 million acquisition of Ice Energy Limited on January 7, 2004.

NAL Oil & Gas Trust:

1. Closed $18 million asset divestiture on January 1, 2001.
2. Closed $550 million asset acquisition on February 10, 2005.

Pengrowth Energy Trust

1. Closed $1,038 million asset acquisition on January 22, 2007.

Petrofund Energy Trust:

1. Closed $24 million asset acquisition on January 1, 2001.
2. Closed $40 million asset acquisition on March 5, 2002.

PrimeWest Energy Trust:

1. Closed $700 million acquisition of Cypress Energy Inc. on March 29, 2001.

2. Closed $206 million asset acquisition on January 23, 2003.

3. Closed $35 million acquisition of Seventh Energy Ltd. on March 16, 2004.

Shiningbank Energy Income Fund:

1. Closed $175 million acquisition of Birchill Resources Limited on March 8, 2004.

Vermilion Energy Trust:

1. Closed $95 million asset acquisition on March 10, 2005.

2. Closed $140 million asset acquisition on May 8, 2007.

Viking Energy Royalty Trust:

1. Closed $320 million acquisition of KeyWest Energy Corporation on February 26, 2003.

2. Closed $450 million merger with Calpine Natural Gas Trust on February 1, 2005.