RE-EXAMINING THE HOTELLING VALUATION PRINCIPLE:
Empirical Evidence from Canadian Oil and Gas Royalty Trusts

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Abstract

The Hotelling Valuation Principle (HVP) implies that the in situ value of a unit of a non-renewable resource is equal to current price less the cost of extraction. The required assumptions for this principle are strongly violated in the oil and gas industry, but despite this, results from previous research are mixed, with studies based on market data supporting the principle, and those based on basin-aggregate data rejecting the principle. To address problems with the data choice in previous studies, we test the HVP using market data on Canadian oil and gas royalty trusts. Unlike previous studies using market data for conventional oil and gas companies, our results tend to reject the HVP and we generally find market value to be significantly less than that predicted by the principle. The reduced value is explained by a significantly negative response to a real option to expand (proxied by a call option on oil and gas prices). These findings are consistent with the argument that in the period of rising oil prices that we consider, (2000–06), the net extraction price is high relative to its expected future growth, but production constraints prevent firms from fully exploiting the high price.

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Introduction

The importance of Professor Hotelling's (1931) theory on resource extraction lies in its ability to reconcile 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) demonstrates that in a competitive market, the equilibrium net price per unit of an exhaustible natural resource reserve (selling price per unit less the cost of extracting the unit) should increase at the fair rate of return.

$$p_t - c_t = (p_0 - c_0)(1 + r)^t, \tag{1}$$

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. This claim is justified as the outcome of an optimal control of the production rate. If the net price grows slowly, then the resource owner would have the incentive to extract sooner, increasing current supply and therefore reducing expected future supply. This would tend to reduce current prices and increase expected future prices, which would tend to increase the expected net price growth rate. The reverse argument applies if net price grows quickly. A growth rate at the fair rate of return eliminates the incentive to modify supply. In the deterministic case he considered, the claim is justified using the calculus of variations, and the fair rate of return is the risk-free interest rate. (The fact that the benefit of extraction does not converge to the cost is known as scarcity rent.) The main result of this, which is referred to as the Hotelling Valuation Principle (HVP), is that the value per unit of an exhaustible natural resource reserve is simply the current net price.[1]

However, the application of this 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[2] – each of which violate the assumptions of Hotelling's (1931) basic theory. Monopolistic forces will likely have the effect of limiting supply, and thus driving current net prices higher than they otherwise would be in a perfectly competitive market. This results in net prices growing more slowly than the fair rate of return, and therefore reserve value per unit being lower than the current net price. (Although naturally the current net price is higher than it would be in the competitive case, and so is the value of the reserve.) For Canadian oil and gas reserves, monopolistic forces from foreign suppliers would provide an incentive to extract more quickly than they would in a competitive market. Indeed, if they could produce the reserves immediately, they would still have a per unit value equal to the net price. However, well production characteristics and government regulations have the effect of limiting the rate of extraction. Thus these forces likely have the effect of decreasing per unit reserve value below current net price.

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 of the HVP must be scrutinized carefully to determine whether or not these violations are serious or whether there are factors that create coincidental support for the theory. Previous studies of the HVP on the oil and gas industry have relied on either acquisition transactions or the market values of conventional firms that have both production and exploration interests. Using acquisition values does not allow for accurate reserve valuation because reserve specific data for the net price of the acquisitions is not published. On the other hand, previous studies that used market values usually considered conventional oil and gas companies, which are also involved in the exploration for oil and gas. The market value of such companies includes a premium over the value of the reserves they currently possess.

This study contributes to this literature in two main ways: First, we use market data from Canadian oil and gas royalty trusts to estimate the reserve value. This helps to resolve the cost estimation problems that arise from using acquisition data and the reserve value estimation problems that arise

[1] Lin and Wagner (2007) find that improved technology reduces costs, so increasing net price may involve a decrease in real resource prices.
[2] Both extraction rate limits and economically viable reserve quantity are closely linked to well pressure. This limits the ability to increase production when net prices grow slowly.

from the conventional companies' exploration premium. Second, we incorporate a variable to account for the real options that arise from having some control over the extraction rate. Both of these contributions appear to be quite important, since we find that with this market data, the value of oil and gas reserves are significantly less than what is predicted by the HVP, and that real options contribute significantly to the reserve value. Moreover, the real option variable shows up in the form of a cap on value and largely accounts for the lower reserve value. In particular, we find that per unit reserve value is equal to the net price less a call option on the oil price.

Previous Literature

We divide the literature into two components according to the type of data being used to test the HVP.

Market data. Miller and Upton (1985a) were the first to develop a framework to test the HVP in the oil and gas industry. They used market data of conventional companies to estimate reserve value, and found support for the model.

Crain and Jamal (1991, 1996) and Miller and Upton (1985b) also find support for the HVP, These studies use market data for US royalty trusts and master limited partnerships to estimate reserve value. Unfortunately, the market was thinly traded during the time period (pre 1986) and these firms generally had significant non-reserve business holdings such as pipelines and refineries, which could overestimate reserve value.

Acquisition data. Following the methodology developed by Miller and Upton (1985a), Adelman and Watkins (1995), Cairns and Davis (1998, 2001), McDonald (1994), and Watkins (1992) use acquisition data to estimate reserve value and find that the HVP fails. In particular, the reserve value estimate is found to be significantly lower than the net price estimate. Adelman and Watkins (1995) attribute this difference to well production characteristics such as a constant production to reserves ratio (production decline rate). Unfortunately, since net price is not available for acquisition data, a basin average net price is applied. It may be that the net price for acquisitions is higher on average than the basis average net price, which would underestimate net price.

Real options. Cairns and Davis (1999) incorporate reserve specific real options in a valuation model, but due to difficulties aggregating this quantity into a common variable across reserves, they don't include it to explain reserve value. McCardle and Smith (1999) also develop a model incorporating real options and decision analysis, which attempts to aggregate reserves across a firm, but not among firms.

McCormack and Sick (2001) argued that the value of oil and gas companies through a standard discounted cash flow valuation can be corrected through the use of real options due to the firm's ability to adjust the extraction rate of proven reserves or, to develop proven or unproved reserves in the future. Their model for real option value in oil and gas companies uses the Black-Scholes option pricing model with inputs that apply directly to the resource base.

Contribution. We contribute to this literature by using market data for Canadian royalty trusts, which have large trading volume and wide analyst following during our period of study between 2000 and 2006, to accurately estimate reserve value. We find that reserve value is indeed lower than that predicted by the HVP. We make use of McCormack and Sick's (2001) methodology to model real options across reserves, and we find that the reduction in value can be explained by a significantly negative relation with such real options to expand (during this period of rising oil prices). This suggests that the net extraction price is high relative to its expected future growth, but production constraints prevent firms from fully exploiting the high price by expanding production.

Data

Our 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 firm-year observations. Annual data is used because reserve estimates are provided in annual reports (with years ending December 31 of each year for each trust).

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 primarily focused on producing reserves out of mature, less risky development properties rather than participating in high-risk exploration plays that require extensive capital. Secondly, no previous HVP articles 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 an interesting valuation challenge. 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 units of millions of cubic feet (Mcf). 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 a "barrels of oil equivalent" variable (BOE) in order to facilitate their reporting requirements. For the time period of this study, industry has adopted a 6 Mcf per barrel of oil equivalent conversion factor to which all trusts in our sample have adhered.[3] In particular, 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.) This obviously poses a limitation to performing more specific tests on oil and gas separately.

On October 31, 2006, the Government of Canada announced a change to the tax treatment of income trusts to 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, 2006. The announcement affects the last year of our sample since we 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.[4]

[3] Ontario Securities Commission Rules and Policies. *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities*, page 12.

[4] For robustness, we retested the model omitting the affected year and there was no material impact to the conclusions reached in our study.

Description of variables

Reserves. As publicly traded entities, oil and gas royalty trusts must publish at least annually an estimate of their economically recoverable oil and gas reserve assets. These reserve estimates are prepared by an independent qualified reserve evaluator or auditor. In our sample, all of the reserve reports coincide with the Dec 31 year-end date. Each entity publishes a detailed breakout of their reserve estimates in their Annual Information Form, which we use as the source of reserve quantities for our study. Although there are some subtle differences among the format each trust used to present their reserve estimates, we aggregate all of the oil products and natural gas liquids into the oil category and present them in units of barrels. The natural gas is in units of cubic feet.

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. Our study of the HVP utilizes the proved reserves category, for which it is 90 percent likely that the quantity of reserves actually recovered will actually equal or exceed the estimate. [5] (As such, we use a very conservative estimate on the reserve quantity, which strengthens our finding of a significantly lower value *per unit* than the net price predicted by the HVP.)

Land. All of the trusts used in our 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, we subtract its value from the enterprise value calculation used to estimate reserve value. The majority of trusts publish a value for this land. For those that do not, we allocate $100 per acre to the value following industry practice. The specific value allocated to land does not have a material impact to the results of our 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%).

Net price. This is defined as the selling price per barrel of oil equivalent less the per unit operating costs of producing and selling. Selling price is defined as the amount received by the producer for selling one barrel of oil equivalent, which 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. 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 and labour costs that are directly associated with the extraction process. 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.

[5] Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Petroleum Society of CIM (Petroleum Society). (Volume 1: 2007, Volume 2: 2005), *Canadian Oil and Gas Evaluation Handbook*, (pages 5-13 to 5-15).

There are two items that are not included in our net price calculation even though they have a cash charge. Hedging gains and losses, which could be considered an unobservable adjustment to the selling price per unit, or simply as speculation, are not included. There is no mention of whether or not they are included in the previous studies. Secondly, interest costs are not included since the net price should not depend on how the trust is capitalized. (Debt is included in the enterprise value described below.)

The source of the net price information comes from the first quarter financial reports of each trust for the sample period. 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.

Enterprise value. Another item required for this study is the enterprise value for each trust. Enterprise value is defined as market equity capitalization plus net debt. This is because the HVP is based on overall reserve value, which being proxied by firm value includes both equity and debt.

Market capitalization in this study is defined as units outstanding (reported in each trust's first quarter financial reports) multiplied by the average daily closing price between the beginning of April to the end of May, (in order to reduce spurious or date specific prices and yet reflect first quarter reserve 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 our sample period, and Bloomberg is used to get data for these three trusts.

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, we 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) we 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, we would add the acquired reserves to the firm's original reserves. The balance sheet would not need to be adjusted since we 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.

Dataset Characteristics

Table 1 provides descriptive statistics. 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 1

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 1 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, we also review the value and net price growth rates over the period of our study in Table 2. 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. The results must be taken with caution due to the short time frame.

Table 2

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 2 shows the average enterprise value per boe and average net prices weighted by quantity of Proved Reserves for each year in our study. Both the value and net price rise 16% per year 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 should be taken with caution.

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 reserve 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, we 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.

Background

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,

$$V = \sum_{t=0}^{\infty} \frac{(p_t - c_t)q_t}{(1 + r_t)^t}, \tag{2}$$

where V 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, and r is the fair discount rate or cost of capital.

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

$$\sum_{t=0}^{\infty} q_t \leq R, \tag{3}$$

where R is the total reserve quantity.

The Hotelling (1931) Equation 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,

$$\frac{(p_t - c_t)}{(1 + r_t)^t} = p_0 - c_0. \tag{4}$$

Substituting this into Equation 2 gives

$$V = (p_0 - c_0) \sum_{t=0}^{\infty} q_t. \tag{5}$$

Assuming that all of the reserves are eventually extracted, or equivalently by considering only economically viable reserves, Equation 3 will hold with equality. This implies

$$V = (p_0 - c_0)R. \tag{6}$$

There are a number of issues that could lead to the failure of Equation 6 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 to which 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 5. 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 5 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 6 to fail.

Testing the Hotelling Valuation Principle

Rearranging Equation 6 gives value per unit of reserves,

$$\frac{V}{R} = p_0 - c_0. \tag{7}$$

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

$$\frac{V}{R} = \alpha + \beta(p_0 - c_0) + u. \tag{8}$$

If the HVP is valid, the intercept should be $\alpha = 0$ and the slope should be $\beta = 1$. Estimating this with panel data gives

$$\frac{V^{it}}{R^{it}} = \alpha + \beta\left(p^{it} - c^{it}\right) + u^{it}, \tag{9}$$

where *i* indicates cross sectional firm and *t* indicates time series date.

To mitigate the effects from common valuation shocks that could apply across trusts in each year, (and that aren't controlled by the variables we consider), we use a two-stage GLS regression that estimates this common correlation, ρ. Note that because part of the HVP test involves testing restrictions on the constant term α, we can't use the usual panel data technique of including year dummies to control this. We also use OLS regression for robustness and the results are generally similar.

Additional Variables

In addition to performing the main regression, we include a variable relating to real options, as well as variables controlling for commodity mix, reserve quality, and firm size. These additional independent variables are incorporated into the regression model and both the individual independent variables and the equations are tested for significance.

Real options. The main difficulty with implementing real options into a panel data set is relating the value of the real options between different firms. We aggregate the value of real options by estimating the Black-Scholes values of a call option on a portfolio of oil and natural gas, whose portfolio weights are the firm specific proportions of oil and gas reserves of each particular trust. The volatility of the portfolio is estimated for the previous quarter of daily prices, the options are evaluated at the money and expiring next quarter. We use the log transform of this value to implement it in the linear regression framework:

$$RO = \ln(Black - Scholes\ call\ option\ value). \tag{10}$$

If the HVP holds, the real option variable should not be significant. Conversely, finding a significant relationship with the real option value will indicate that the stochastic properties of the net price have a significant impact on reserve value in the oil and gas industry.

Control variables. Following Lin and Wagner (2007), we control for each firm's oil versus gas proportion, developed and producing proportion (versus developed and non-producing or undeveloped), and firm size. The first two control variables are proportions, so we transform them using the logistic transformation to implement them in the linear regression framework as follows:

$$OW = \ln\left(\frac{o}{g}\right), \tag{11}$$

where *o* and *g* are the proportions of oil and natural gas for the firm respectively;

$$PDP = \ln\left(\frac{p}{1-p}\right), \tag{12}$$

where *p* is the proportion of producing properties (versus developed non-producing or undeveloped) and

$$SZ = \ln(EV), \tag{13}$$

where *EV* is the enterprise value. If gas is less valuable than what the 6:1 ratio warrants, then the coefficient of *OW* should be positive. If producing reserves are more valuable than non-producing reserves (after accounting for the cost of production) the coefficient of P*DP* should be positive. And if there are economies of scale favouring larger reserves, the coefficient of *SZ* should be positive.

To summarize the relationships among the variables included in the tests we include Table 3 which shows the correlation among the added variables, in their transformed form. The table shows that the real option variable shows the most correlation with net price.

Table 3

Correlation between the Independent Variables

	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 3 shows the correlations between the independent variable used in the study. The results show that the real option proxy is highly correlated with net price.

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, we test for 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.

Separating net price into stand-alone price and cost. We 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 the one net price variable. Reiterating Equation 7, the HVP states

$$\frac{V}{R} = p_0 - c_0. \tag{14}$$

Rather than considering net price to be a single variable and arriving at regression Equation 9, both price and cost could be considered separate variables, which leads to the regression equation

$$\frac{V}{R} = \alpha + \beta_1 p_0 + \beta_2 c_0 + u. \tag{15}$$

In this case the HVP would require $\alpha = 0$, $\beta_1 = 1$, and $\beta_2 = -1$.

Testing for nonlinearities in the relationship. In order to test for nonlinearities in the original Hotelling relationship we include a squared net price term,

$$\frac{V}{R} = \alpha + \beta_1(p_0 - c_0) + \beta_2(p_0 - c_0)^2 + u. \tag{16}$$

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. If these are important, then β_1 should be positive and β_2 should be negative. The HVP requires that $\alpha = 0$, $\beta_1 = 1$, and $\beta_2 = 0$.

Applying a natural logarithm specification. In order to further test the HPV we 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 14 would still describe the HVP,

$$\ln\left(\frac{V}{R}\right) = \ln(p_0 - c_0). \tag{17}$$

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

$$\ln\left(\frac{V}{R}\right) = \alpha + \beta \ln(p_0 - c_0) + u. \tag{18}$$

The main effect from this transformation is to mitigate the contribution of very large and accentuate the contribution of 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.

Statistical Results and Analysis

The statistical results and analysis of the HVP tests are presented in this section. In addition to presenting the study progression from the original univariate specification, we examine the results of incorporating other variables including real options, commodity mix, reserve quality, and size in the detailed analysis section.

Basic Specifications

The univariate regressions (where net price is the only explanatory variable for reserve value) provide evidence against the HVP. In Table 4 under both the linear and natural logarithm regressions, the net price coefficient is significantly less than one (the p-values test the restriction $\beta = 1$ for the net price variable), indicating that value is less than that predicted by the HVP.

Table 4

Original HVP Specification

Test		Obs	Variables	Intercept X_0		Net Price X_1	rho	R^2	F	SSRes
FULL RESTRICTION										24,391
Univariate (Linear)										
	OLS	107	2	3.1414		0.5401	0.0000	0.2946	167.3390	5,825
				0.2764		0.0000				
	GLS	107	2	6.9315		0.4146	0.4748	0.4160	213.0449	4,822
				0.0705		0.0000	0.0000			
Univariate (Natural Logarithm)										
	OLS	107	2	0.5120		0.7077	0.0000	0.2568	94.6480	15.7460
				0.2157		0.0144				
	GLS	107	2	0.5859		0.6786	0.4697	0.3911	127.0818	12.9021
				0.2997	0	0.0463	0.0000			

Table 4 provides a summary of the results from the univariate regression specification 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 less than one, contrary to the theory. The p-values for each coefficient are directly below.

In another specification, we isolate price and cost into independent variables rather than combining them into net price, as per Miller and Upton (1985a). This allows us to see if each one has an impact on its own. Table 5 shows that the coefficients on the price variables are significantly less than one and the coefficients on the cost variables are significantly greater than negative one. This also provides evidence against the HVP. Overall, the regression with the variables broken out does only a slightly better job of explaining value compared to the original specification where net price is used (according to the R^2 statistics).

Furthermore, we add an additional variable, squared net price, to the original specification to test for nonlinearities in the relationship. The results in Table 6 show that the squared net price term is not significantly different from zero which suggests 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 specification. However, the inclusion of a squared term does have a significant effect on the net price coefficient, which is no longer significantly different from one. This suggests that a more careful examination about the failure of the HPV is warranted, and it motivates us to examine other ways in which non-linearities could be incorporated, such as through the inclusion of a real option proxy variable.

Table 5

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	0.0000				
	GLS	107	3	5.4860	0.4365	-0.3626	0.4204	0.4584	154.4089	4,472
				0.2828	0.0001	0.0000				

Table 5 provides a summary of the results from the regression run on price and cost separately. The price coefficients are significantly less than one and the cost coefficients are significantly greater than negative one, contrary to the theory. The p-values for each coefficient are directly below.

Table 6

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	0.0000	0.2933				
	GLS	107	3	-0.4639	0.8730	-0.0066	0.4462	0.4438	149.4492	4,592
				0.9581	0.2882	0.3624				

Table 6 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 seem to exist. However, it does seem to affect the net price term, which is no longer significantly different from one. The p-values for each coefficient are directly below.

Detailed Analysis

Table 7 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 specification reject 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 significantly less than one. However, because the coefficient is positive, reserve value is increasing with the net price as expected. The study shows that net price explains just over 29% of the movement in reserve value based on OLS and over 41% based on GLS (together with the estimate of the contemporaneous correlation, rho).

Table 7 - Linear 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												24,391
Original Hotelling Specification												
OLS	107	2	3.1414	0.5401					0.0000	0.2946	167.3390	5,825
			0.2764	0.0000								
GLS	107	2	6.9315	0.4146					0.4748	0.4160	213.0449	4,822
			0.0705	0.0000					0.0000			
With Real Call Option												
OLS	107	3	-2.8306	1.0632	-11.8594				0.0000	0.5119	175.1415	4,030
			0.2704	0.5398	0.0000							
GLS	107	3	1.7482	0.7571	-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	0.3939		-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	0.3522		-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	0.9600	-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	0.8239	-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 7 presents the results of the OLS and GLS regression variations based on $Y = B_0 + B_1X_1 + \ldots + B_5X_5$ 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 seem to substantially explain the reduced value.

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 overestimating the quantity (as in the captured auditor agency problem). Although, since we use proved reserves, which is the most conservative estimate of reserves available, this potential problem should not be too great. The coefficient 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.

Real options. The inclusion of the real call option variable increases the overall explanatory power 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 provide the same conclusion – both the intercept and the net price coefficients agree with the HVP and the real option coefficients are significantly negative. 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), and it is also consistent with the notion that reserve value is partially capped because of production constraints. The inclusion of the significant real option variable may be capturing the stochastic nature of the oil and gas prices where production quantity is influenced by net price. The rho for the GLS regression is significant potentially due to correlated residuals but the additional explanatory power, 4% on an R^2 basis, is relatively small.

Control variables. The regression run using the control variables (oil weighting, proved developed producing reserves weighting, and size), does add explanatory value to the original HVP equation though not as much as adding the real option variable. However, the coefficient on the net price is different from one, which does not support the HVP. Out of the three additional independent variables added to the regression only size in the OLS specification and possibly oil weighting in the GLS specification, are significant. The sign on the size coefficient is as expected: larger 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 rho estimate may mean there is still correlated error terms even when these additional control variables are added.

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 one respectively, and the real options coefficient is significantly negative. However, the oil weighting variable is also significantly negative in both 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 including controls.

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 specification results are outlined in Table 8. These results support a similar conclusion to the linear specification: the original HVP specification is rejected. Furthermore, when including our real option proxy in the regression, both the intercept and the net price coefficient are not statistically different from zero and one respectively, and the real option coefficient is significantly negative. Also, the explanatory powers of the regression are similar to those of the linear specified model.

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 for or against the HVP, although the majority of these studies have used data that may be deficient in it's ability to provide an accurate test of the principle.

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 we are able to mitigate the average cost information used in acquisition based studies and it also allows us to avoid the "management exploration expertise" premium associated with the market value of conventional oil and gas exploration and production companies. For this test, we use 22 Canadian oil and gas royalty trusts spanning a period from 2000 to 2006 for a total of 107 observations.

Our study generally rejects the HVP. In particular, the results indicate that the HVP overestimates reserve value. This could suggest 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. We 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 we 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, it's likely that royalty trusts will correspond to a value lower than that predicted. The difference would account for the exploration premium.

Table 8 - 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	 PDP Weight Proxy X_4	 Size Proxy X_5	rho	R^2	F	SSRes
FULL RESTRICTION													44.1331
Original Hotelling Specification													
	OLS	107	2	0.5120	0.7177					0.0000	0.2568	94.6480	15.7460
				0.2157	0.0144								
	GLS	107	2	0.5859	0.6786					0.4697	0.3911	127.0818	12.9021
				0.2997	0.0463					0.0000			
With Real Call Option													
	OLS	107	3	-1.2369	1.0095	-0.5615				0.0000	0.4441	95.2206	11.7790
				0.0089	0.9336	0.0000							
	GLS	107	3	-0.1749	0.8247	-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	0.4647		-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	0.4932		-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	0.8133	-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	0.7689	-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 8 presents the results of the OLS and GLS regression variations based on $Y = B_0 + B_1 X_1 + \ldots + B_5 X_5$ 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 seem to substantially explain the reduced value..

Limitations of the Study

Although our 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 our 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 discounts 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 we are biased by potential factors that only affect the specific market we are 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 structures and leading to biasness 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 is not a function of quantity produced. Typically, a producer would go after reserves that are less costly to produce first.

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