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The Hotelling Valuation Principle: Does User Cost and Reserve Differentials Improve Validity?

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Does User Cost and Reserve Differentials Improve Validity?

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ABSTRACT

The Hotelling Valuation Principal (HVP) implies that the value per unit of an in-ground exhaustible natural resource is equal to the current price less the cost of production. The assumptions required for this principle include a certain and homogenous reserve stock, unconstrained extraction, and constant costs. Extensive research has empirically investigated the HVP. This paper expands the HVP framework and relaxes the theory's assumptions to account for reserve differentials. The results show that the original net price model is more closely aligned with developed reserve value, than total reserve value. In addition, this paper develops two- and three-factor net price models to incorporate user cost, extraction capacity and the risk of developing and producing oil and gas reserves.

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1. INTRODUCTION

Hotelling theory posits that in a competitive market, the net price per unit of an exhaustible natural resource (prevailing spot commodity price less its per unit marginal production cost) increases at the fair rate of return (Hotelling, 1931). Miller and Upton (1985a) build upon the Hotelling theory and convert the dynamic optimization problem into a static process. They theorize that the value per unit of an in-ground exhaustible natural resource is the current net price when the fair rate of return is equal to the interest rate or rate of discount. This "implication" is referred to as the Hotelling Valuation Principle (HVP) and offers an alternative testing method for Hotelling theory.

However, prior literature shows that the net price construct does not follow observed price trends. Similarly, the empirical framework based on HVP generally overstates in-ground reserve value. Moreover, other unrealistic assumptions such as a certain and homogeneous reserve stock and unconstrained extraction have inhibited HVP's empirical validity. This over estimation is attributable to HVP's simplified cost structure, which does not adequately account for the user costs and production constraints associated with extraction. This paper argues that the inclusion of user cost into HVP's net price construct will assist in unveiling a producing asset's true resource rent. Santopietro (1998) contends that when a natural resource is privately owned, the resource rent is part of the net worth of the owner.

This paper revisits the Hotelling Valuation Principle and develops a framework that adjusts net price for developed versus undeveloped reserve differentials. In addition, a two-factor developed reserve model is constructed using a reserve extraction rate and a risk adjustment factor that further delineates net price. For total reserve values that contain both developed and undeveloped resources, a three-factor model is built that incorporates user cost and accounts for depletion.

This research compiles a sample of 61 oil and gas companies based on Ernst & Young's annual industry survey of the largest U.S. producing firms. The company-level production, cost and reserve data are pulled from FactSet, Inc. and company annual reports. The sample period compares reserve values and net prices from 2015 to 2020, which includes a full boom and bust commodity price cycle. This paper finds that HVP's net price is more closely associated with developed reserves than undeveloped non-producing reserves. In addition, the two- and three-factor models show significant net price coefficients that approximate unity, which has been difficult to achieve empirically.

This research contributes to the literature in three main ways. First, the paper extends the HVP literature to account for reserve differentials that were not explored previously in the literature. The HVP net price framework applies to total reserves, which includes both developed and undeveloped non-producing acreage. However, it only factors in production costs, not user costs. Development costs are relevant to a firm's proved undeveloped (PUD) reserves, which require additional capital to begin extraction. PUD reserves can make up a considerable portion of total reserves, particularly in this era of rapid shale oil drilling. For example, on average, 40% of proven reserves are classified as undeveloped among the 61 firms surveyed for this paper. This paper finds that the HVP net price is more closely associated with developed reserves rather than total reserves.

Second, this paper introduces a user cost factor to Hotelling's net price framework to provide a more complete assessment of a reserve's full cost structure. This in turn, will offer an estimate of a resource owner's rent, which is also a measure of scarcity according to Devarajan and Fisher (1982). A resource owner's rent can be thought of as the opportunity cost of reinvesting profits from produced reserves, so that future generations may also benefit from the utility of the natural resource. Prior literature measures the resource rent as discovery costs, which are the total exploration and development costs necessary to bring an additional unit of nonrenewable resource to market (Adelman, 1990 Devarajan, Fisher, 1982; Lasserre, 1985). However, such measurement is problematic and difficult to observe in most cases (Lasserre, 1985). As Adelman et al (1991) outlines, resource rent is user cost or the difference between the in-ground market value and the present value of expected increases in development cost, where the present value of development cost can be approximated by the current development cost.

Third, this research develops the two- and three-factor net price models to correct for unrestricted or instantaneous extraction implied by HVP (Adelman, 1990). This modification draws from prior literature (Adelman, 1990; Davis & Cairns, 1999; Thompson, 2001) that accounts for annual extraction capacity and gradual exploitation of the reserve base. The modified net price models also adjust for uncertainty or the risk of developing and producing oil and gas reserves. This modified net price is shown to improve the explanatory power and empirical validity of HVP.

The structure of this dissertation is as follows. Section 2 provides an outline of the conceptual background of Hotelling theory and its development. Section 3 develops the hypothesis. Section 4 outlines this study's data and methodology. Section 5 presents the empirical results. In Section 6, conclusions are drawn and opportunities for future research are discussed.

2. LITERATUER REVIEW

Since Harold Hotelling published his influential work in 1931, *The Economics of Exhaustible Resources*, which become the theoretical bedrock for natural resource economics. Hotelling's theory was motivated as a response to calls for regulation as reformists and conservationists in the late nineteenth and early twentieth century felt natural resources were too important and scarce to be left to monopolists and opportunists (Gaudet, 2007). However, Hotelling believed "competitive markets could achieve the planners solution" (Slade & Thille, 2009). This led to his model of sustainable resource extraction, where he established a framework of depreciation as an asset, discounted at the value of its future return (Gaudet, 2007). This model was derived in part from his prior work involving depreciation, in a 1925 publication (Hotelling, 1925).

Hotelling's theory argues that the net price of a nonrenewable resource should rise at the rate of interest. Net price is equal to the price of the commodity net of marginal production cost (Livernois & Martin, 2001). This would optimize the behavior of resource owners to supply their commodity when the resource rent or net price is extracted at a rate equivalent to the market rate of interest. This construct is known as Hotelling's r-percent growth rule (Solow, 1974), which has been at the heart of empirical studies of the theory over the last fifty years.

The base model is as follows:

$$Net\ Price_t = Net\ Price_0 e^{rt} \tag{1}$$

Where,

Net Price$_t$ = Price - Per unit marginal production cost at time t.

Net Price$_o$ = Net price at time 0.

r = The prevailing market rate of interest

Conceptually, this framework is straight forward and would seem applicable to observed price behavior. However, for most empirical tests, the linkage between commodity price paths and the market rate of interest has had difficulty adhering to the r-percent rule. Prior literature has explored several reasons for this lack of adherence, mostly surrounding a few restrictive assumptions involving: perfect competition, a certain resource stock, and issues around durability (Adelman et al.,1991(Levhari & Pindyck, 1981); Pindyck,1978; Salant,1976). Further, Hotelling's theory "fails to capture the tendency of production costs to rise as a resource is extracted", known a resource degradation (Livernois & Martin, 2001). Similarly, real-world constraints to production have been mentioned as inhibitors to the theory's observed success, which has led to several extensions to Hotelling's general model, (Adelman et al, 1991; Anderson, Kellogg, & Salant, 2018; Davis & Cairns, 1999; and McDonald 1994).

Nevertheless, despite these real-world discrepancies, Hotelling's resource theory remains foundational and is still relevant within the literature. Moreover, from an asset pricing standpoint, Livernois (2009) maintains that the Hotelling Valuation Principle offers a practical method for valuing a stock of nonrenewable reserves. This methodology has been suitably applied at a national level, as seen in Green National Income Accounting, or with investors wanting to determine the value of a firm's in-ground assets.

Davis and Cairns (1998) argue that net price is a “sufficient statistic” and gives a good approximation of value, which is particularly useful at cutting through private sector informational asymmetry found in valuation work.

2.1 COMMODITY PRICE PATHS

Initial streams of research examined the price trend of commodities (exhaustible nonrenewable resources) over very long cycles to determine whether these price trends followed the rate of interest or perhaps even signaled scarcity. What these researchers generally found was that real prices had fallen over time and were highly volatile.

Barnett and Morse (1963) were the first to formally analyze commodity price history in a study commissioned by the “Resources for the Future” commission, which is an independent organization conducting research regarding environmental, energy and natural resources issues. The study included long run commodity price data from 1870 to 1957. They concluded that resource scarcity was not a problem given historical trends that showed a decline in real prices, which is counter to the Hotelling theory. More recently, Hart and Spiro (2011) also argue that the notion of scarcity rents making up a large share of oil prices is false and have not been prevalent historically.

Smith (1979), followed the Barnett and Morse paper using more sophisticated statistical techniques, with a data set from 1900 to 1973 covering a broad array of nonrenewable commodities. Smith (1979) found no discernable trend in commodity prices in either direction. Slade (1982) also tested long-run commodity price trends from 1870 to 1978 that showed evidence of a U-shaped pricing path; with prices declining until the 1960’s and later increasing in the 70’s for 11 of the 12 commodities tested. The study noted that technological innovation eventually offset rising costs related to resource degradation.

Heal and Barrow (1980) attempted to correlate base metal (Copper, Lead, Zinc, & Tin) price movements from July 1965 to June 1977 with the 91-Day UK Treasury Bill, but were unable to substantiate the Hotelling percent-r model. Interestingly, however, they concluded that the rate of change in interest rates was more important than the level, relative to commodity price determination.

Chari and Christiano (2014) examined the historical time series of a variety of exhaustible commodities ranging from aluminum, coal, oil and lead going back as far as the 1600's in some cases, which showed commodity prices varied greatly and cannot be explained by the path of interest rates as the Hoteling theory suggest. They deemed this inconsistency the "Hotelling Puzzle" and illustrated how commodity prices from the 19th century have increased at a rate far below the average inflation adjusted U.S. Treasury yield of 1.14 percent during the twentieth century.

Neumann and Erlei (2014) highlight that prices of resources (i.e. coal, oil and natural gas) have not followed an upward exponential trend in prices. In fact, they showed periods of extreme short-run volatility in both the up and down trends. However, in an interesting theoretical exercise, Neumann and Erlei (2014) conducted an experiment using a simulation study of 10 buyers and sellers, that showed how auction prices for resources displayed an increasing price path, and trading volume in conjunction with depleting stocks, also behaved in accordance to the theory.

Constructively, Gaudet (2007) believes that the Hotelling theory still maintains its relevance due to constraints that cause net price to rise more slowly than the market rate. These constraints when viewed in the context of market equilibrium and imply that there must be more to the return of holding non-renewable stocks than simply the rate of price appreciation. Specifically, Gaudet (2007) once again summarizes real-world complexities such as, declining long-run production costs (due to technological innovation), resource durability (storage and recycling), market structure (monopoly, oligopoly) and resource and commodity price uncertainty, which must also be considered to correctly reconcile the rate of return on resource stocks.

Notably, Ferrria da Cunha and Missemer (2020) reviewed extensive unpublished archives of Hotelling's work and determined that the lack of empirical support for Hotelling's percent-r rule was caused by the notion that it was in fact a rule. Rather they assert Hotelling thought it should be viewed as a "hypothetical stylized asset" that is finite in nature. However, Hotelling did discuss and was aware of real-world geologic constraints to producing a mineral resource, such as cost inflation due to higher cumulative production, output variations and uncertainty over resource size. They argue these real contingencies provide an opportunity for alternative models that incorporate bell and U-shaped price equilibriums.

2.2 HOTELLING VALUATION PRINCIPLE (HVP)

Miller and Upton (1985a) originally proposed an alternative testing strategy that changes the unit of analysis from commodity price paths that adhere to the r-percent rule to in-ground reserve values. This implication of Hotelling theory, captures the market value of a stock of resources that is equal to the present value of the resource's future profits (Santopietro, 1998). This stock valuation method is based on the idea that resource rent is part of the net worth of private owners. Therefore, the total value of a producing firms per unit assets (net price) will equal the value of its liabilities in the form of debt and equity, or per unit enterprise value. As Santopietro (1998) mentions, the benefit of this methodology versus conventional valuation models is the low demand for information and explicit assumptions. However, market prices per unit of reserves can vary greatly because of asset quality, idiosyncratic cost differences or be clouded by other non-producing asset values that would distort per unit values.

Miller & Upton (1985a) compared in-ground valuations for publicly traded oil and gas, exploration and production (E&P) companies between 1979 and 1981. After tabulating the market value of debt and equity and netting out non-producing assets for the 39 firms in their sample, Miller and Upton (1985a) produced successful results with a net price coefficient near one and an r-squared statistic that explained forty percent of the variation of in-ground values. However, the data set for this analysis was within the highly charged Iranian Hostage crisis timeframe, and at the peak of a decade long battle with inflation, which translated into unsustainably high oil prices and correspondingly high reserve values.

Therefore, to further establish the durability of HVP, Miller and Upton (1985b) conducted a parallel study during the Reagan era of oil price moderation from August, 1981 to December, 1983. Unfortunately, this version did not prove fruitful and was deemed "noninformative" due to low price volatility. However, oil and gas royalty trusts which comprised a small 12 firm subset of their data did show promising results, which is interesting given their simple business model, which is based purely on resource exploitation and is not complicated by other assets or undeveloped acreage that can obscure reserve valuation. Moreover, Crain and Jamal (1991), (1998) also experienced empirical legitimacy applying HVP to publicly traded royalty trusts and Master Limited Partnerships (MLPs), albeit with some degree of data transformation and smaller samples.

There have been a handful of important empirical tests using the Hotelling Valuation Principle (HVP) to value in-ground oil and gas assets. Magliolo (1986) analyzes market values of producing firms' reserves relative to newly established reserve recognition accounting (RRA) rules at the time, which is similar to today's annual SEC reporting requirements and generally found that RRA data did not adequately explain market values of producing firms.

Adelman et al. (1991) analyzed user cost or depletion as a measure of resource rent. The authors argue that current development cost can be utilized as a measure to approximate user cost. After studying third party oil and gas transactions from 1979 to 1988 and third-party reserve values for firms between 1946 to 1987, Adelman et al (1991) established that in-ground oil and gas reserves generally trade a one-half of net price and one-third of the wellhead price.

Watkins (1992) applied HVP to 27 private oil and gas corporate and property transactions in Alberta, Canada, between 1989 and 1991, but the results showed no support for HVP. Later, Adelman & Watkins (1995), analyze 34 private transactions over the same 1989-91 period, and results were also decidedly against HVP. However, using a disaggregated oil and gas model and incorporating measures for production rates and a 15% discount rate, results were more constructive. Moreover, Adelman and Watkin's

(1995) modified transaction model were compared with observed per unit prices, which showed promise at implying future expectations for oil and gas commodity prices.

Davis and Cairns (1998) also showed how HVP continually overvalues in-ground oil reserves due to simplifying assumptions of the theory that ignore well specific production constraints. They compensate for these production constraints with a modification that sets net price at one half its calculated value. This method was applied to Watkins (1992) and Adelman and Watkins (1995) data, which produced better fits but yielded slope coefficients that remained significantly below one. Davis and Cairns (1999) also demonstrated how HVP provides and upper bound to reserve valuation based on previous applications of HVP in prior studies (Crain & Jamal, 1998; Magliolo, 1986; Miller & Upton, 1985a,b; Johnsen, Paxson, & Rizzuto, 1996) where most of the observations were below the HVP valuation estimate.

The valuation principle has similarly been tested in other resource categories; such as, hard-rock mining (Cairns & Davis, 1998) where the authors reformulated the basic Miller & Upton (1985a) model that returned valuation measures 40% below the original net price estimates. Further, when the base model is adjusted for remaining mine life (a mine capacity constraint), the explanatory power of their HVP model improved when compared to gold mining transactions (Cairns & Davis, 1998; Cairns & Davis, 2005).

Livernois, Thille and Zhang (2006) analyzed timber resources based on stumpage price bids made by logging firms. The authors believed stumpage prices were a more accurate measure of rent versus mineral data given that there were no new discoveries or revisions to the physical stock, and less uncertainty about the quality of the resource. The authors derive different discounts rates to approximate Hotelling's r-percent rule, including the CAPM model. In either case, their analysis produced significant results, but explanatory power was generally lower due to high price volatility.

Overall, regarding empirical tests of HVP in-ground valuation, results have had little success using Hotelling's base net price model. The Hotelling Valuation Principle has typically overestimated in-ground resource value and only been successful under very specific conditions when net price is adjusted for everyday contingencies.

2.3 EXPLORATION, DEVELOPMENT & PRODUCTION

One empirical limitation that has plagued the success of Hotelling theory is the assumption of a fixed resource stock or supply. Particularly, given that all-natural resources can be renewed through additional capital investment that are motivated in response to rising commodity prices. Adelman (1991) argues that the notion of a fixed mineral stock is "superfluous and wrong", the appropriate categorization should be framed as an inventory of proved reserves that are replaced through development.

Hotelling theory also touches on how uncertainty over resource size causes changes in the rate of extraction. If owners are uncertain about the exact size of their deposit, they will extract the commodity at a more conservative rate of production (Devarajan & Fisher, 1981). Hotelling (1931) also discusses that when a fixed resource begins to deplete, production costs will increase. Notably, however, this concept of resource degradation is not formally addressed in Hotelling's model, as costs are assumed to be constant under the theory. However, Atewamba and Nkuiya (2015) find empirical evidence that extraction costs are stock dependent after analyzing fourteen non-renewable natural resources. The researchers used a reformulated Hotelling model that incorporates technology gains and stock dependent production costs. Interestingly, they also found that the extraction rate tends to be higher in an environment of declining resource prices than a rising price environment (Atewamba & Nkuiya, 2015).

Pindyck (1978) looks beyond Hotelling's fixed supply assumption and points out the role of exploration relative to production costs. He shows that additional resource accumulation lowers production costs, thus allowing a producer to maximize the present value of reserves by extracting higher quality (lower cost) resources earlier in the process. This research also brings to light the delicate balance between extraction (harvesting profits) and exploration (reinvesting profits) that a resource owner must regulate optimally to replace reserves and maintain a competitive cost structure. Avoiding resource degradation motivates a firm to engage in exploration, which influences a resource owner's market power, particularly among price taking firms.

As a result of owners engaging in exploration and development, Pindyck (1978) also finds evidence of a U-shape price path of commodity price movements. Typically, commodity prices fall initially in response to successful exploration to a stabilization point and then begin to increase over time, as scarcity of the commodity grows due to depletion or outsized demand growth. Further, Slade (1982) also finds evidence of a U-shape pricing path as production costs decline in response to technological improvements, which is similar to what was experienced in response to shale oil and natural gas fracking.

In terms of expected price and production decisions, Thompson (2001) argues that the optimal answer has become a corner solution among practitioners whose strong preference is to produce at capacity, regardless of price, as marginal operating costs have historically trended well below petroleum prices. This idea is empirically tested using 53 public oil and gas producer observations over a window from Sept 1991 through June 1992. A reserve model utilizing each firm's production-to-reserves ratio as a proxy for maximum capacity showed better results than the Miller & Upton (1985a,b) method. In addition, Thompson used private transaction data from 1980 to 1998 to highlight how firms with longer reserve lives (lower production capacities) are generally less valuable. All of which, demonstrates that production at capacity accounts for a meaningful portion of reserve value in both the public and private markets.

Anderson et al., (2018) brought forth the notion that Hotelling's net price framework should not be viewed strictly as a production function. Instead, it should be reformulated as a drilling problem that replaces or increases reserves. This is due to their observation that current production is generally inelastic to price changes after examining individual well production in Texas from 1990 to 2007. Anderson et al (2018) shows that well pressure influences natural decline rates and is the primary factor governing the production function, but not prices per se.

Other literature (Davis & Cairns, 1999; McDonald, 1994) cite production constraints as a primary factors that inhibit prices from following the r-percent rule and highlight how producers do not have complete autonomy with respect to resource extraction. Regulatory limitations regarding well spacing and down-hole pressure (Anderson et al., 2018) prevent Hotelling's net price from responding in kind to changes in the market rate of interest.

Understanding that production rates are not ruled by commodity prices in the short run effectively transitions owner supply decisions away from near-term production optimization, towards capital investment decisions to acquire new reserves. Critically, producing firms must also deal with pragmatic considerations, such as mineral lease expiration and debt servicing obligations, as other ancillary factors that influence behavior of firms to maximize production despite adverse commodity price environments. This expands the cost analysis from merely extraction or production cost to finding (exploration) and development costs.

2.4 USER COST, RESOURCE RENT & SCARCITY

Economic theory has struggled with the measurement of scarcity for exhaustible resources. Hotelling addresses the issues of scarcity, user cost or resource rent only through his marginal cost net price formula (Hotelling, 1931). However, the issue of measurability has been problematic given "conceptual shortcomings" and data that is not "directly observable" (Farzin, 1992).

Alternatively, some economists have resorted to proxies of resource rent that would be readily available. Brown and Field (1978) illustrated three different measures. The first measure pertains to per unit production costs, although the data in this regard has been decidedly biased towards declining long-run costs and can be influenced by technological innovation or demand fluctuations. The second scarcity measure is real commodity prices, though the choice of price deflator has been ambiguous and has led to widely varying results. For example, if mineral prices were compared to the price of capital, real prices would have increased not declined (Jorgenson & Griliches, 1967).

Moreover, when resource prices are compared to wages, mineral prices also declined on a relative basis (Farzin, 1992). The third measure pertains to shadow prices or rental rates of the value of in situ resource and the cost of competing substitutes, which can serve as proxies for user cost (resource rent).

Adelman (1990) also states that, “oil value less development cost is discovery value, or resource rent”. More formerly, Adelman (1991) states that the difference between in-ground market value and the present value of expected increases in development cost can approximate resource rent and the current value of development cost can also be a proxy for resource rent. Despite difficulties in measuring scarcity, Livernois and Uhler (1987) and Santopietro (1998) also argue that, discovery costs, are a good approximations for resource scarcity value. Further, Lasserre (1985) and Devarajan and Fisher (1982) also make an argument for discovery costs as an adequate proxy for resource scarcity (rent). However, Adelman et al., (1991) warns that finding (or discovery) costs are not directly observable, given that these expenditures may be made over several years, not necessarily the year a discovery is added as a proved reserve. Therefore, current development costs would be preferred over the combined finding and development (F&D) cost metric to infer user cost.

2.5 RESOURCE DIFFERENTIALS

Theoretically, Ricardo (1821) discusses the impact of land differentials that create surpluses (rent) for land owners with competitive advantages within the factors of production. However, Miller & Upton (1985a,b), make no accommodations for reserve differentials. For example, Ricardian differentials are evident from the standpoint of reserve quality, where the percentage of proved undeveloped (PUDs) versus proved developed producing (PDPs) reserves can be highly idiosyncratic. The quality of PUD reserves is lower because future development capital is required to bring undeveloped reserves into production. Indeed, undeveloped reserves should be discounted due to higher financial and operational risk that is necessary to bring these barrels to market. Thus, highlighting how not all barrels in-the-ground are homogeneous.

2.6 CONCEPTS & TERMS

The following table presents the terms used for this empirical study.

Term	Explanation
Crude Oil Equivalent – Boe, Mcf.	Converting gas volumes to the oil equivalent is done based on the heating content or calorific value of the fuel. Before aggregating, the gas volumes first must be converted to the same temperature and pressure. Common industry gas conversion factors usually range between 1.0 barrel of oil equivalent (Boe) = 5.6 thousand standard cubic feet of gas (Mcf) to 1.0 Boe = 6.0 Mcf. (SPE, 2021)
E&P	Exploration & Production company.
Extraction Rate – (Production)	The percentage of a developed proved oil and gas reserves that is produced annually. Calculated as the inverse of the developed Reserve Life Index.
F&D Cost	Finding and development (F&D) refers to costs incurred when a company purchases, researches and develops properties to establish commodity reserves. (EIA, 2011)
In-Ground Value	The per barrel value of proven oil and gas reserves that have not been extracted.
Production Cost – (Lifting Cost)	Production costs (also called lifting costs) are the costs to operate and maintain wells and related equipment and facilities per barrel of oil equivalent (Boe) of oil and gas produced by those facilities after the hydrocarbons have been found, acquired, and developed for production. Direct lifting costs are total production spending minus production taxes (and minus royalties in foreign regions) divided by oil and natural gas production in Boe. Total lifting costs are the sum of direct lifting costs and production taxes. (EIA, 2011)
Oil & Gas Reserve	Reserves are those quantities of hydrocarbons which are anticipated to be commercially recovered from known accumulations from a given date forward.(SPE, 2021)

Reserve-To-Production Ratio or Reserve Life Index	The reserves-to-production ratio or R/P is a method used to assess the size of reserves. The value represents the number of years that current reserves would last if their rate of use did not change. The value of this ratio changes as the size of the reserve changes. A reserve is defined as the amount of a resource that can be extracted with current technology, at current prices. If technology improves, or prices increase, the reserves increase.(Univ. of Calgary, 2015)
Resource Rent	The economic rent of a natural resource equals the value of capital services flows rendered by the natural resources, or their share in the gross operating surplus; its value is given by the value of extraction. Resource rent may be divided between depletion and return to natural capital.(OECD, 2001a)
Risk Adjustment Factor	Applying a risk-adjustment factor reduces a property's volumes or cash flows to capture uncertainties linked with realizing less-than-proved reserve categories. As reserve reports for O&G properties commonly reflect gross-production volumes, it's typical to apply adjustments based on the degree of certainty. (Burgess, 2016)
Standard Measure for Oil & Gas (SMOG)	The FASB's ASC 932 requires a similar standardized measure for the value of proved reserves called SMOG (standardized measure of oil and gas). SMOG is calculated with the same methodology as PV-10 but deducts income taxes whereas PV-10 does not. Both PV-10 and SMOG require (1): reserve estimates (2): a sales price and (3): an estimate of cost. (Burgess, 2016)
User Cost	Depletion cost or the cost incurred over a period by the owner of a fixed asset or consumer durable because of using it to provide a flow of capital or consumption of services. User cost consists of the depreciation on the asset or durable plus the capital, or interest, cost. (OECD, 2001b)

3. HYPOTHESES

Empirically capturing the market value of in-ground resources using the Hotelling Valuation Principle has been elusive. HVP tends to overshoot its estimate of reserve value in virtually all but the first Miller and Upton (1985a) paper, which examined a period of very high oil prices and anxiety over supply scarcity. Adelman et al (1991) states that the market value of an in-ground undeveloped reserve is a good measure of mineral scarcity. HVP's net price, however, consistently assigns an equal value to both proven reserve categories, despite undeveloped reserves lower quality due to its additional capital requirements. Accordingly, this is paper posits that HVP is more closely aligned with developed producing reserves, rather than undeveloped reserves, which appear to be heavily discounted accept during periods of upward price shocks.

Indeed, production costs, the second component of HVP's net price (Price – marginal production cost) , are simply not applicable to undeveloped reserves, as those resources are not in production. HVP's mispricing of undeveloped reserves can be particularly acute in this era of shale development where producing firms increased their total proven reserves by nearly double from 2008 to 2014, while undeveloped reserves increased by roughly twofold (DeSantis, 2018).

Prior literature (Adelman & Watkins, 1995), mention a stylized fact among industry practitioners that one-half of net price is a better approximation to explain reserve value.

Likewise, additional studies find evidence to support the use of one-half net price (Davis & Cairns, 1999). However, these studies used private transactions or third party reserve valuations and in some cases regional rather than firm specific cost data (Adelman & Watkins, 1995);(Davis & Cairns, 1999). This paper looks beyond the one-half net price discount with an examination of the relationship between net price and developed in-ground reserve value. This study also incorporates company specific costs, reserve, and market value data after the introduction of shale technology, which should add further insight to the Hotelling Valuation Principle.

To empirically establish the linkage between developed reserves and HVP's net price, this paper proposes the following analysis:

HYPOTHESIS (1): *A Net Price structure is more closely associated with values of proven developed in-ground reserves, than total (developed and undeveloped) in-ground reserves.*

A key assumption of Hotelling's theory is that the stock of inventory is fixed and there is no limit placed on the rate of extraction. However, real-world experience shows firms continually look to replace produced reserves and operate in an environment where production is regulated by geologic and regulatory constraints. Prior literature argues that these constraints are the as reasons why net price has not risen with the rate of interest (Adelman, 1993); (Adelman et al., 1991);(Cairns & Davis, 1998).

To account for these observed well economics, this paper adopts a net price factor methodology. Specifically, a two-factor model is applied for developed reserves. The first factor involves an extraction rate formula representing the time in years until proven developed reserves are fully exploited, which offsets HVP's assumption of instantaneous extraction. The second factor is a discount rate or risk adjustment factor that incorporates the execution risk involved with the production of developed reserves. The risk factor is particularly important regarding the sub-set of reserves that are categorized as proved developed non-producing (PDNP) reserves. These PDNP reserves are slightly riskier, as they may require minor well completions or involve reserves behind the casing of existing wells ("behind pipe") that are expected to be produced in the predictable future (SPE, 2021). Notably, the practice of discounting reserves for varying degrees of reserve risk is widely implemented among practitioners (Burgess, 2016).

The application of the factors is once again drawn from Adelman (1990) and Adelman et al (1991) who present a formula that is appropriate for a developed reserves, given the assumption of no additional capital requirements to produce these reserves. As shown in eq. 2, net price converges towards the wellhead value per barrel as the pace of extraction increases.

$$V/P = a/(a+i) \tag{2}$$

V_{it} = Value per barrel for firm i at time t.

P_{it} = Price less costs and taxes for firm i at time t.

a_{it} = Extraction rate for firm i at time t.

i_{it} = Discount rate for firm i at time t.

A firm's recent production-to-reserves ratio is employed as a proxy for the reserve extraction rate. This paper extends the literature with the use of developed reserves in the calculation of the extraction measure, which is a more accurate metric given that undeveloped reserves are not available to be exploited without further investment. In addition, a measure for risk is applied to the two-factor developed reserve model. This discount rate is also aligned with industry surveys regarding developed and undeveloped reserve valuation.

To better quantify the associated risks of hydrocarbon extraction, this paper proposes a modified HVP model and the following hypothesis:

HYPOTHESIS (2): *A Two-Factor net price structure adjusted for extraction and risk factors, has higher explanatory power than the base HVP net price structure.*

As Santopietro (1998) explains, the theoretical price for a depletable natural resource includes two parts, production cost and user cost. El-Serafy states, that surplus value is derived from true income, which can be consumed, and a separate measure for depletion cost or the amount that is needed to be reinvested for future consumption (Santopietro, 1998). However, Miller and Upton's (1985a) net price framework only considers production cost. This simplified cost structure is perhaps a key reason why HVP has continually overestimated in-ground reserve values. A more complete structure should include user cost, that would account for the development capital needed for undeveloped reserves. After including this user cost, true resource rent can be approximated. Hence, the user cost factor is incorporated into the prior two-factor model to form a three-factor model for total (developed and undeveloped) reserve valuation.

The risk adjustment factor also increases from the two-factor model given the higher risk profile associated with proven undeveloped reserves. This risk discount is even more important with the adoption of a reporting rule after 2008 that requires aging undeveloped reserves to be removed from the proven category if those barrels are not developed after five years (Burgess, 2016).

To incorporate the user cost factor, this paper proposes a three-factor HVP model and the following hypothesis.

HYPOTHESIS (3): *A Three-Factor net price structure incorporating extraction, risk and user cost factors is expected to have a significantly positive correlation with total in-ground reserve values.*

4. METHODOLOGY

4.1 DATA SAMPLE

The data for this study is constructed based on Ernst & Young's annual industry survey, which covers the 50 largest oil and gas producers in the U.S. Ernst & Young is an independent third-party accounting and consulting firm with an established presence in the upstream oil and gas industry. Companies with a disproportionate amount of non-upstream oil and gas assets, such as integrated energy companies in the mold of Exxon or Chevron that engage in downstream oil refining were omitted. Also, sample firms that maintain significant operations offshore or outside the U.S. and Western Canada were also excluded.

However, eight more firms were added to the sample, due in part to their consistent operations over the test period and their data availability. The final sample size consists of 273 observations representing 61 oil and gas companies. Note: The company count increased slightly, as firms engaged in mergers where company A and B in the early years of the test period would merge to form company C in the subsequent years. In comparison, the first Miller & Upton (1985a) study used 94 observations.

The sample period for this study is from 2015 to 2020, near the nadir of the COVID-19 capital market price shock. This six-year dataset includes a full commodity price cycle, with oil prices at the beginning of the sample period exceeding $100 per barrel during the shale revolution, then falling to an average annual price below \$50 a barrel in 2016 and 2017 and then subsequently, a further decline to \$20 a barrel during the COVID selloff. Natural gas also experienced the same volatility, with a 62% decline over the six-year period.

This sample period is compared to Miller and Upton's (1985a,b) research that represented observations from 1979-1983, where crude oil varied on an inflation adjusted basis, between \$60 and \$132 per barrel (Macrotrends, 2021).

The data pertaining to stock prices, reserves, costs, and financial statements is provided by FactSet, Inc., which is an independent third-party financial data-base provider. This resource is also supplemented with 10k annual company reports. Importantly, all operational data related to reserves, costs and financial statement data were collected as of yearend for each respective firm. However, given the ninety-day window for public firms to report their yearend results, all stock and commodity price data is priced as of quarter end or March 31st.

4.2 EMPIRICAL MODELS

To test the Hotelling Valuation Principle, this paper addresses three constructs that should improve the empirical validity of HVP theory. Each model is evaluated for goodness of fit and the magnitude of the net price coefficient.

A. BASE MODEL

The base model attempts to illustrate that HVP's net price has a stronger association with the in-ground value of developed versus total reserves.

$$EIGV_{T,D} = \alpha + Net\ Price + C + \varepsilon \tag{3}$$

Where, $EIGV_{T,D\ it}$ = Total or developed reserve in-ground enterprise value for firm *i* at time *t*.

$Net\ Price_{\ it}$ = Price minus marginal production cost for firm i at time t.

$C_{\ it}$ = Control for firm size and leverage

$\alpha_{\ it}$ = Intercept for firm i at time t.

$\varepsilon_{\ it}$ = Error term for firm i at time t.

The enterprise in-ground value of total reserves ($EIGV_T$) is one of two dependent variables. The second, relates to the enterprise in-ground value of *developed* reserves ($EIGV_D$). Both dependent variables ($EIGV_T$ and $EIGV_D$) are oil equivalent per barrel metrics. The base model HVP net price model is tested against the market values of both reserve types to determine its empirical efficacy.

Firm market capitalization is calculated using the quarter-end common share prices and shares outstanding, which is later adjusted lower for non-upstream oil and gas producing assets. These non-upstream assets could include downstream, oil and gas refinery operations, mid-stream pipeline infrastructure or investments in other exploration and production related companies.

The enterprise value measure used in $EIGV_{T/D}$, is calculated as the market value of each firm's net long-term debt plus equity market capitalization. In those few instances where the market value of debt is not available, book value is substituted. Accordingly, cash and cash equivalents are deducted from the total to arrive at an enterprise value that is divided by each firm's total barrels of proven oil equivalent reserves, which equals the enterprise in-ground value of proven reserves on a per barrel basis.

Net price is the primary independent variable in this analysis and represents the per barrel wellhead profit for producing firms. To calculate this measure, each firm's percentage of oil versus natural gas production is weighted and applied to the oil equivalent price. Once revenue has been determined, the oil equivalent production cost is subtracted to arrive at net price. The revenue and cost breakdown for net price is presented as follows:

$$Net\ Price = (P - C) = \left\{\left(\frac{(Q_{Oil})}{(Q_{Boe})}\right)(P_{Oil}) + \left(\frac{(Q_{Gas})}{(Q_{Boe})}\right)\left(\frac{(P_{Gas})}{6}\right)\right\} - \ (EC_{Boe}) \qquad (4)$$

Where, $(P - C)_{it}$ = Net Price for firm *i* at time *t*.

$Q_{Oil\ it}$ = Percentage of oil production for firm *i* at time *t*.

$Q_{Gas\ it}$ = Percentage of gas production for firm *i* at time *t*.

$Q_{Boe\ it}$ = Total oil equivalent production for firm *i* at time *t*.

$P_{Oil\ it}$ = Market price of crude oil at time *t*.

$P_{Gas\ it}$ = Market price of natural gas at time *t*.

$EC_{Boe\ it}$ = Oil equivalent production cost of firm *i* at time *t*.

Notably, this net price methodology is slightly different from Miller & Upton (1985a,b) who calculated each firm's commodity weighting using reserves rather than production. This could result in a revenue differential from our model, as some firms may choose to overweight or underweight their commodity mix based on favorable pricing differentials or possibly lease or regulatory constraints.

For clarification, the crude oil price represents West Texas Intermediate (WTI) grade crude oil per barrel, as of quarter-end or March 31st for the years 2015 to 2020. The natural gas price represents Henry Hub spot pipeline quality gas quoted in U.S. dollars per million Btu or 1 Mcf of pipeline quality-gas. The price of natural gas is converted to an oil equivalent ratio of 6:1 per industry standard. Commodity prices and per unit production cost data is provided by FactSet, Inc. Production costs included lease operating expense, transportation costs and severance or non-income taxes.

CONTROLS

Given wide variances within this data set regarding firm size and leverage, control variables were utilized. Firm size is measured using common share market capitalization (shares outstanding multiplied by the common share price) and a leverage ratio, which is equivalent to the long-term debt to capital ratio (long-term debt divided by shareholders equity plus long-term debt).

As shown in Table 1, the average firm market capitalization is $9.7 billion, with a considerably lower median capitalization of $3.5 billion and a range of $19 million to $76.7 billion. This small capitalization skew is adjusted for with a large cap dummy variable, which is equal to 1 for companies with market capitalizations greater than $15 billion, 20% percent of the observations in the data set meet this criterion.

B. TWO-FACTOR MODEL – DEVELOPED RESERVES

The two-factor model for developed reserves is presented below. Equation 5 presents the baseline regression analysis that also adds controls for firm size and leverage. Additionally, to test for non-linearity between net price and the dependent variable $EIGV_D$, the net price independent variable is squared. Further, a first differencing model is employed to gauge significance while controlling for omitted variables or autocorrelation within the error terms and non-stationarity in the time series.

Two-Factor developed reserve model,

$$EIGV_D = \alpha + \{(Net\ Price) * (ER/(ER + RAF)\} + C + \varepsilon \qquad (5)$$

Where, $EIGV_{D\,it}$ = Developed reserve in-ground enterprise value for firm *i* at time *t*.

$Net\ Price_{\ it}$ = Price minus marginal production cost for firm i at time t.

$ER_{\ it}$ = Extraction rate for firm i at time t.

$RAF_{\ it}$ = 10% risk adjustment factor at time *t*.

$C_{\ it}$ = Control for firm size and leverage

$\alpha_{\ it}$ = Intercept for firm i at time t.

$\varepsilon_{\ it}$ = Error term for firm i at time t.

EXTRACTION RATE

The reserve extraction rate is the second factor in the two-factor developed and three-factor total reserve models. This is calculated as annual oil equivalent production per barrel divided by developed reserves per barrel, which represents the annual rate of extraction until all developed reserves have been fully exploited. The reserve extraction rate factor offsets one of Hotelling's implied assumptions of unconstrained production (Davis & Cairns, 1999).

The Extraction Rate factor is calculated as follows.

$$ER = \frac{Q_{Boe}}{PDP} \qquad (6)$$

$ER_{\ it}$ = Proved reserve extraction rate for firm *i* at time *t*.

$Q_{Boe\ it}$ = Annual oil equivalent extraction for firm *i* at time *t*.

$PDP_{\ it}$ = Proved developed producing reserves for firm *i* at time *t*.

RISK

In addition, to the rate of extraction and user cost, this paper also provides measures for risk that are primarily a reflection of reserve quality. Moreover, discounting for risk is also consistent among market participants and industry practitioners. The Society of Petroleum Evaluation Engineers (SPEE) in their annual 2016, 2017 and 2018 industry surveys found that producers generally apply a 10% discount rate for proved developed producing reserves (Bureau of Ocean Energy Management, 2019). The Texas Comptroller of Public Accountant also found in their 2020 market survey that corporate and property transactions were discounted within a wide range of 10.52% and 17.79% based on reserve quality and risk (Texas Comptroller, 2020). Adelman (1990) highlights a long held consensus rate of return of 9% among petroleum engineers, and that from World War II to 1973, the extraction rate has been approximately close to the discount rate.

Therefore, for developed reserves, this paper applies a 10% risk adjustment factor. For the riskier, proven undeveloped reserve category, a risk adjustment factor is applied that is also consistent with annual SPEE industry surveys of 20% (Bureau of Ocean Energy Management, 2019).

C. THREE-FACTOR MODEL – TOTAL RESERVES

User cost is the final component of the three-factor model for total reserve valuation. It is defined as the discounted future development cost that is necessary to bring proved undeveloped reserves into production. Every year producing firms are required to generate a standard measure of expected future cash flows under FASB ACS

932, which is based on a firm's proven reserves, recent commodity prices and expected production costs and development expenditures. Adelman et al. (1991) describes the difference between in-ground value and development cost as discovery value or resource rent, which can be approximated through current development cost. See equations 8 and 9 for the user cost variable derivation.

Accordingly, for this analysis, the Adelman et al., (1991) theory of rent is utilized; where the present value of development costs approximates user cost. This metric is preferred because it is a direct measure of the costs necessary to bring current PUD reserves to market; unlike historical development expenses that are problematic to allocate to annual per barrel reserve additions.

The three-factor model is also presented with control variables (eq. 7) for firm size and leverage. Net Price is also squared, and first differencing is incorporated with the main models.

Three-Factor total reserve model,

$$EIGV_T = \alpha + \left\{(Net\ Price) * \left({ER}/{(ER + RAF + UC)}\right)\right\} + C + \varepsilon \qquad (7)$$

Where, $EIGV_{T\ it}$ = Total reserve in-ground enterprise value for firm *i* at time *t*.

$Net\ Price_{it}$ = Price minus marginal production cost for firm i at time t.

ER_{it} = Extraction rate for firm i at time t.

UC_{it} = User cost factor of firm *i* at time *t*.

RAF_{it} = 20% risk adjustment factor at time *t*.

C_{it} = Control for firm size and leverage

α_{it} = Intercept for firm i at time t.

ε_{it} = Error term for firm i at time t.

Development costs are not discounted in the SEC's standard measure (only net cash flows are discounted at 10%). Therefore, this paper introduces an alternative discounting methodology. This process utilizes each firm's developed reserve life as the discount rate, and number of years necessary to exhaust the developed reserve base. Adelman (1991) discusses how the present value of expected increase in development cost approximates user cost. Once user cost is calculated, this metric is inverted to provide a discount factor, which is later applied to net price within the three-factor total reserve model.

The discounting formula is outlined as follows.

$$PVD = FVD\left(\frac{1}{\left(1+\frac{1}{RLI}\right)^{RLI}}\right) \tag{8}$$

Where, PVD_{it} = Present value of future development cost for firm *i* at time *t*.

FVD_{it} = Future value of development cost for firm *i* at time *t*.

RLI_{it} = Annual reserve life of developed reserves for firm *i* at time *t*.

PVD, provides a discounted annual development cost expenditure for each firm in the sample. *PVD* is used to determine user cost per barrel of proved undeveloped reserves.

User cost per barrel is derived with the following.

$$UC = \frac{1}{\left(^{PVD}/_{PUD}\right)} \tag{9}$$

Where,

UC_{it} = User Cost for firm *i* at time *t*.

PVD_{it} = Present value of expected development costs for firm *i* at time *t*.

PUD_{it} = Proved undeveloped reserves in equivalent barrels for firm *i* at time *t*.

ROBUSTNESS CHECK

A series of regressions were run to crosscheck $EIGV_T$ versus the SEC's standard measure of oil and gas value, two popular relative value metrics, and against the two commodity producer types. Each check is performed via a panel (or pooling) regression over the sample period, that include the two- or three-factor net price variable, and controls for firm size and leverage. The first analysis tests the accuracy of a producing firm's standard measure of reserve value based on firm fundamentals; this is essentially a discounted cash flow exercise that is required in oil and gas company reporting. This should provide a fundamental methodology consistent with financial theory to benchmark against the net price method. The standard measure is constructed according to FASB ASC 932. This methodology involves projecting each firm's net cash flows over the life of the reserve, which is discounted at a 10% rate to determine a present value. The present value is divided by each firm's proven reserve barrels to determine a per unit valuation, which is regressed against the dependent variable, $EIGV_T$ (along with net price and firm controls). This should provide a fundamental methodology consistent with financial theory to benchmark against the net price method.

In addition, the dependent variable $EIGV_T$ was regressed against the Enterprise Value to EBITDA and Price to Book ratios as a comparison to the explanatory power of net price. The denominators for each metric were taken from the prior reporting year, while market prices were tabulated at the end of the first quarter. The observations with negative book values were deleted from the price-to-book regression.

Furthermore, as a measure of total reserve replacement value, finding and development (F&D) cost per barrel is analyzed as an independent variable. This widely utilized metric among industry participants is calculated on an organic basis (ex. price revisions, acquisitions, and divestitures) over a three-year average, per industry standard (SPE, 2021). However, given the number of outliers in this distribution, the series was winsorized at the 2% level on both the upper and lower tails. The developed reserve value ($EIGV_T$) is then regressed against the two-factor model and the F&D cost metric and firm controls.

Finally, a subsample regression on the net price of oil weighted producers versus natural gas weighted producers was conducted as a robustness check. A firm is categorized as an oil (natural gas) producer if its oil (natural gas) production exceeds a two-thirds threshold of total equivalent production. On average, the firms within this sample produced 57% oil and 43% natural gas.

4.3 DATA ANALYSIS

To test HVP's net price construct, linear regressions by means of panel data were utilized and coded in the R statistical software package. Initial summary tables with descriptive statistics are provided, along with a corresponding correlation table that includes the primary variables in the regression analysis.

The first regression in equation 3, tests the original Miller & Upton (1985a) HVP net price theory with the dependent variable, $EIGV_T$ for total reserves, versus the independent variable, net price, as defined in equation (4). Once the original HVP net price model is benchmarked, a comparison regression is run that changes the dependent variable from total reserve $EIGV_T$ to the developed reserve enterprise in-ground value ($EIGV_D$). This addresses this paper's first hypothesis that compares net price to developed reserve value versus total (developed and undeveloped) reserve value.

To examine this paper's second hypothesis, the $EIGV_D$ dependent variable is regressed against the two-factor model (eq. 5). The extraction rate is accounted for with equation 6 and risk is discussed in the Risk section. In addition, two checks for non-linearity in the net price variable and a first differencing model is also run to check for autocorrelation among the residuals.

For the third and final hypothesis, the $EIGV_T$ dependent variable is regressed against the three-factor model. The three-factor model (eq. 7) incorporates user cost into the prior model to explain total in-ground reserve value. The user cost factor compensates reserve owners for the additional capital and resources needed to move a barrel of undeveloped reserves to the developed producing reserve category. The discounting methodology for future development cost, and the corresponding calculation of user cost is provided in equations 8 and 9. Similar to the testing of the two-factor model, the three-factor model will also be tested versus a non-linear and a first difference model.

5. RESULTS

This paper addresses the empirical validity of Miller and Upton's (1985a) Hotelling Valuation Principle. Previous studies of HVP generally overvalue in-ground reserves of nonrenewable natural resources. This paper incorporates a resource rent framework that adjusts the HVP net price model to account for reserve quality, the reserve extraction rate, a user cost, and a discount rate. Unlike prior empirical test that used third party consultants or brokerage research to estimate in-ground market value of firm reserves, this paper compiles and tabulates a wide-ranging dataset of public oil and gas company data.

Figure 1 shows oil and gas prices over the period of 2014-2020, which covers a full boom and bust commodity cycle. The oil price was about $100 per barrel and the natural gas price was above $4 per Mcf in 2014, which was the first year of reserve and cost data in this survey. The oil price trended in a lower range between $38 and nearly $65 per barrel between 2015-2019, and then subsequently declined as low as $20 per barrel during the onset of the COVID pandemic. Natural gas prices followed a similar trend, ranging between $1.96 and $3.19 per Mcf between 2015-2019, with an average of 2.49 (Table 1) and low of $1.64 in 2020. The price of natural gas has been depressed over this timeframe because of oversupply, due in part to associated gas production from oil shale.

Table 1 presents the summary statistics. The average *Enterprise In-Ground Value* of total reserves ($EIGV_T$) over the sample period is \$9.06 per barrel, while the average *Developed Enterprise In-Ground Value* of producing reserves ($EIGV_D$) is \$15.83 per barrel. The average *Net Price* is \$18.85 per barrel with a 25th and 75th percentile range of \$7.10 and \$29.42, respectively. This result is in line with the industry rule of thumb mentioned by Adelman (1990). In comparison, the per barrel in-ground value of developed reserves represents a discount of 16% to net price. Figure 2 shows that *Net Price* reached the peak in 2018 as oil and gas prices increased while production costs trended lower due to further industry cost cutting.

The components to estimate *Net Price* per barrel are *Realized Oil Equivalent Price* and *Production Cost.* The average *Realized Oil Equivalent Price* is \$27.08 per barrel, while the average oil price is \$47.69. This discrepancy reveals the significant price dispersion between oil and natural gas. Meanwhile, the average production cost is \$8.23 per barrel with a standard deviation of \$4.33 per barrel. Figure 3 illustrates a declining trend of production cost after 2016, caused in part by improving fracking and production efficiencies (Energy Information Agency, 2016).

Reserve replacement cost, which is approximated with the Finding and Development (F&D) cost metric averaged \$16.30 a barrel, highlighting a full replacement cycle or all-in average cost structure of \$24.53 a barrel. However, F&D cost varied widely with a standard deviation almost as large as the mean and range between \$2.59 and \$85.51 a barrel (both figures were winsorized at the 2% level).

The average development cost to convert proved undeveloped reserves to producing reserves averaged \$14.18 a barrel or 87% of the total finding and development cost measure. This contrasts Adelman et al (1991) who reported that finding costs averaged approximately one-half of development costs between 1974 and 1986. The average *Reserve Extraction Factor* or production rate is measured at 14.9% per annum with a median of 14.1%. This low variance reveals a surprisingly consistent rate of extraction for developed reserves among producing firms in the sample. In addition, the *User Cost Factor* within this dataset averaged 30.7% with a median of 22.4%, while the 25th and 75th percentile ranged between 15.1% and 30.3%, respectively. The *Two-Factor Net Price* and *Three-Factor Net Price* variables came in at \$10.95 and \$4.88 per barrel, respectively.

E&P firms within this sample carried a fair amount of debt. The average *Leverage Ratio* for the composite firms is 50% and that varied between 32% (25th percentile) and 55% (75th percentile). Moreover, conventional relative valuation ratios including the *Enterprise Value to EBITDA* and *Price to Book* ratios average 9.8x and 1.7x, respectively, over the six-year sample period. The average *SEC In-Ground value* of proven reserves per barrel is \$6.71. The average *Market Capitalization* of sample firms is in the small-to-mid-cap range, between \$1.2 billion (25th percentile) and \$12 billion (75th percentile). The average for the *Large Cap Dummy* variable is .198 with a standard deviation of .399.

Table 2 shows that *Enterprise In-Ground Value* ($EIGV_T$) and *Developed Enterprise In-Ground Value*, ($EIGV_D$) are moderately correlated and significant with *Net Price* (.42,.43), the *Realized Oil Equivalent Price* (.42,.41), the *Two-Factor Net Price* (.42,.44) and the *Three-Factor Net Price* (.39) . Unsurprisingly, both $EIGV_T$ and $EIGV_D$ are strongly correlated at 0.93. There is also a discrepancy with *Production Cost* that is significant at -.12 to $EIGV_T$ but shows no significance with $EIGV_D$. This is possibly due to the sunk cost nature of developed producing reserves versus PUD reserves, where development activities could be deferred due to cost sensitivity.

The only negatively correlated variables that show significance to $EIGV_T$ and $EIGV_D$ are the *Leverage Ratio* (-.24,-.23) and *User Cost Factor* (-0.24,-0.18), respectively. Notably, the *Reserve Extraction Factor* shows virtually no correlation at .01 and .06 to $EIGV_{T/D}$, highlighting that reserve extraction does not vary too much on an annual basis for producing reserves. Among the independent variables, there does not appear to be any notable relationships except for *Production Cost* and the *User Cost Factor*, which are -0.47 negatively correlated. This may reflect the notion that cash flows available for development (proxy for User Cost) will decline if there is an increase in production cost.

Table 3 presents the regression results for the enterprise in-ground value of total proven reserves ($EIGV_T$) against the base HVP model shown in equation 3. In addition, the HVP net price is tested versus developed enterprise in-ground reserve value ($EIGV_D$), which is subsequently tested with controls for firm size and leverage. The last two columns test the combined net price model for non-linearity (4) and for omitted variables or autocorrelation via the first differencing statistical technique (5). Model (1) shows the base HVP net price with a correlation coefficient of 0.28, which is significantly below 1, as prescribed and theorized by; Davis & Cairns (1998) and Miller and Upton (1985a). Moreover, the intercept is also significant and relatively large at 3.71, which indicates that there may be an omitted variable that is not accounted for in net price.

Importantly, Model (2) in Table 3, regresses net price versus $EIGV_D$. The results show noticeable improvement with a slope coefficient nearly twice Model (1). Also, the regression's fit improves to .189. However, the intercept remains relatively large and highly significant. This is compared to Adelman's (1991) findings, which showed that the in-ground market value of reserves usually trades at one-half of net price. The combined net price model in column (3) sees a meaningful increase in explanatory power ($R^2 = 0.26$) with the addition of control variables for firm size and leverage. Moreover, when stress tested with the regressions in column (4) and (5), the model holds up well with net price remaining significant, and quite linear (column 4). In addition, autocorrelation within the error terms is also in check as shown in model (5) via the first differencing method.

Table 4 shows regression results for the two-factor model and its ability to explain in-ground market value of developed reserves ($EIGV_D$). This two-factor model examines a discounted net price using an extraction rate factor and a risk discount rate of 10%. Model (1) reveals a net price variable that is sufficiently close to one and is significant at explaining the variation in $EIGV_D$, with an R^2 improvement to .194%. Column (2) displays the two-factor model with controls for firm size and leverage that shows a large improvement in fit with an R^2 of .278, while still maintaining a high slope coefficient of 0.95. In addition, Columns (3) and (4) yielded consistent results once again after testing for net price non-linearity and autocorrelation in the residuals that were not significant.

The regression results in Table 5 present the three-factor model, which regresses the total reserve in-ground value ($EIGV_T$) against the three-factor net price. Once again, the three-factor variable is quite good with a significant slope coefficient of 0.98. However, the explanatory power of the model appears to decline slightly from the two-factor model with an R^2 of .153. The three-factor model with controls does, however, improve its fit to .303 and maintains a robust slope estimate of .87. However, Model (3) does show the three-factor net price coefficient (-0.08) as significant, indicating that the net price relationship does weaken slightly as $EIGV_T$ increases. This is relationship is notable but does not invalidate the regression, it only qualifies the interaction. Intuitively, as net price increases, $EIGV_T$ increases at a smaller rate. This is observed in periods of upward commodity price shocks, where commodity price moves outpace related market values, which tend to adjust more slowly than commodity price at the extremes. Lastly, column (6) shows a good fit after detrending the residuals via a first difference model.

Table 6 reports the results of robustness checks. Models (1)-(3) examine the relationship between total reserve value with traditional valuation metrics, including the SEC's standard measure of proven reserve value, Enterprise Value to EBITDA Ratio and Price to Book Ratio. The results show the three-factor model remains significant when regressed with the SEC's standard measure and controls. Encouragingly, the three-factor net price also retained a significant slope coefficient near unity when combined with the Enterprise to EBITDA ratio, which was also significant, and the combined model generated the highest R_2 of any model at 0.385. Meanwhile, the Price to Book ratio was insignificant and only produced a slope coefficient of .17, while the three-factor net price variable maintained a high slope coefficient and strong significance level. Industry practitioners have generally used EV/EBITDA as their primary relative value measure, so it is not unreasonable that it fared better than Price to Book.

Model (4) in Table 6 shows the two-factor net price that is combined with the finding and development (F&D) costs per barrel metric, which is the SEC's other required measure in annual 10-k company reports. The results for model (4) show a low coefficient for both the two-factor net price and F&D measures, and only the net price metric is significant. The unresponsiveness of the F&D variable is primarily due to the industry's calculation methodology, which tabulates costs over a three-year average given the lag between exploration spending and when reserves are recognized as proved reserves.

Models (5) and (6) in Table 6 presents the sub-sample regression results. The sample is divided into oil producers versus natural gas weighted producers. If a firm produces more than two-thirds oil (natural gas) of their total production, then that firm would be deemed an oil (natural gas) focused producer. The coefficient of net price is 0.74 for the oil producer sub-sample and 0.98 for the natural gas sub-sample. The R^2 is also much higher for the natural gas sub-sample regression at 0.317 versus just 0.200 for the oil producer sub-sample regression. This higher explanatory power for natural gas producers maybe the result of higher natural gas price volatility. The annual standard deviation of natural gas prices was 44%, while the standard deviation of oil producers was 33% over the period of 2014 to 2020.

6. CONCLUSION

6.1 INTERPRETATION OF FINDINGS

This paper extends Hotelling Valuation Principle theory (Miller & Upton, 1985a,b) by developing a resource rent framework to incorporate a more realistic and complete cost structure of producing firms. The two-factor and three-factor models proposed in this paper provide an empirical footing and quantifiable measures to account for the user cost, risk, and reserve extraction constraints that resource owners must balance to optimally re-invest and exploit a nonrenewable resource.

In Table 3, results demonstrate that the explanatory power of HVP increases by differentiating between developed and undeveloped reserves (Model (1) vs. Model (2)). The coefficient of net price improved from 0.28 to 0.52 and the R^2 increased from .177 to .189. This paper empirically captures this discrepancy between developed and undeveloped reserves among conventional oil and gas companies. In addition, after controlling for wide-ranging firm heterogeneity regarding firm size and leverage, this developed reserve net price model improves its fit with an R^2 of 0.262. Overall, the models in Table 4 show higher explanatory power when net price is regressed against developed in-ground reserve values, as compared to total in-ground reserve values, which supports Hypothesis 1.

A two-factor developed reserve model is introduced to quantify the one-half price discount mentioned by Adelman et al (1991) and increase the explanatory power of net price. This model empirically applies Adelman's developed reserve formula (eq. 2) to the in-ground market value of oil and gas reserves, which shows that the value of a developed reserve changes with its rate of extraction, less its risk adjusted discount rate. Interestingly, Table 4 reveals that the two-factor net price has a coefficient 0.91, which is identical to Miller and Upton (1985a), although the two-factor model's R^2 is lower at .197 vs .408 for Miller and Upton.

Thompson (2001) applies a production capacity (extraction rate) model and the Miller and Upton model against a sample of E&P companies. The results were significant but generated very low net price coefficients using 53 observations (49 excluding non-upstream companies) over a nine-month period that utilized average versus spot oil and gas prices. However, when Thompson applied the original Miller and Upton (1985a) model that accounted for development investment, the results were noticeably improved and generated significant (but still low) coefficients versus the original HVP model that did not account for development cost.

Importantly, the two-factor model in Table 4 is superior to the original HVP net price model in Table 3 regarding developed reserves, as the former produced significantly higher coefficients (β= 0.91, 0.52) and higher R^2 (.197,.189). These results support Hypothesis 2 and effectively quantify the one-half net price discount mentioned by Adelman (1991). Prior studies (Magliolo, 1986;Adelman, 1990;Adelman et al., 1991; Adelman & Watkins, 1995; Watkins, 1992; Johnsen et al., 1996;Thompson, 2001) failed to consistently achieve a coefficient close to unity beyond Miller and Upton (1985a), with the exception of those examining royalty trusts (i.e. Crain & Jamal, 1991;Miller & Upton, 1985b). However, royalty trust's reserves are primarily within the developed category.

The three-factor model also contributes favorably to prior HVP literature. The first model in Table 6 illustrates the ability of the three-factor methodology to explain total in-ground reserve value, which produced robust regression metrics (β= 0.96, R^2=.156) that positively confirm the assertions in Hypothesis 3. This outcome is meaningful after many inconclusive attempts to extend Hotelling Valuation Principle theory (Miller & Upton,1985a). It is also noteworthy that this analysis produces significant results despite this sample's generally weak commodity price environment with WTI crude oil falling to $20 a barrel in 2020. This is counter to the strong price levels witnessed by Miller and Upton over the period of 1979 to 1981. Secondly, this study provides an apples-to-apples comparison with Miller and Upton's (1985a) study, with reserve market values that where derived from actual stock and bond market exchanges rather than market values imputed by third party research firms or from private transactions where information is limited. Lastly, the results from this study are relevant and sustainable given that the energy industry has experienced tremendous changes during the sample period. Over this time, new disruptive fracking technology and unconventional drilling techniques were introduced, which reinvigorated production. In addition, this sample period captures observations within an industry that is dealing with climate change policies and a secular transformation away from hydrocarbon fuel sources to renewable clean energy technologies.

6.2 IMPLICATIONS

From a practitioner's viewpoint, this extension of the Hotelling Valuation Principle model could provide a pragmatic valuation tool to overcome the weakness of the industry's standard DCF valuation methodology, which has consistently undervalued nonrenewable resources due to heavily discounted cash flows in the outer years of a reserve's economic life. This has also become more problematic given the large amount of undeveloped reserves and probable and possible resource categories that offer visible production profiles over decades due to the emergence of shale oil production.

For example, in Table 1, the average development cost of proved undeveloped (PUD) reserves in this dataset is $5.7 billion, which is a significant amount as compared to the market capitalization of the producing with an average of $9.7 billion. Table 1 shows that the average *Net Price* over the sample period is $18.85 per barrel, while the undiscounted development cost per PUD barrel averages $14.18 (or $5.46 per barrel on a discounted basis). The summary statistics demonstrate that PUD costs consist of a sizable portion of net price. This paper incorporates a more complete cost structure and offers a better picture of resource rent than net price in isolation. The user costs are captured through the present value of future development.

This paper illustrates the importance of differentiating reserve quality and incorporating user cost to quantify a firm's true resource rent. A fundamental weakness of HVP is the assumption of homogeneous reserve or asset quality. However, the market clearly prices assets differently based on quality. Again, this concept of resource differentials (Ricardo, 1821) shows that resource owners with higher productivity earn rent over owners with less productive land.

6.3 FUTURE RESEARCH

Slade and Thille (2009) propose to rework the theoretical assumptions of continuous and costless production into the real world where production is lumpy and managers have flexibility towards extraction and market pricing structure. Additionally, Slade and Thille (2009) posit the incorporation of real options theory into the Hotelling framework could be useful. This was first examined by Brennan and Schwartz (1985). Cairns and Davis (1998) also postulate that in addition to manager flexibility another real option factor of manager timing is not well explored. Decision rules should define optimal project investment, commissioning, shut down and abandonment choices. Empirical work on real options could prove fruitful with undeveloped reserves given the non-linear nature of decision inputs around breakeven (strike) prices, volatility, interest rates and commodity prices.

However, the area where this paper’s factor models could be applied next is directly with Miller & Upton’s (1985a,b). This provides would provide a solid comparison between this study and the original HVP research. This paper’s methodology may also improve the results of the second (Miller & Upton, 1985b) study using observations from 1981 to 1983. In addition, comparisons could also be made with other studies that utilized Miller and Upton’s data.

Private transaction valuations could also be another natural extension of the factor model proposed in this paper. Adelman and Watkins (1995), preferred the purity of private transactions over market valuations due to the noise of public markets and the difficulty of disaggregating other non-oil and gas assets. Watkins (1992) focuses on property transactions instead of corporate transactions in public markets. This data might serve as a good cross-check for this paper's factor methodology. However, one limitation of prior studies on private transactions is the lack of company specific cost and financial data, which forced prior studies to use regional cost data as a proxy.

In addition, future research could explore international oil and gas assets. Hotelling theory is widely used in national income accounting and applied to North American reserves and producing firms. As a global fungible commodity, exchange rates and real interest rates should be incorporated in HVP theory.

Akram (2009), illustrates the relationship between general commodity price levels and the inverse association with real interest rates. Akram explains that oil and metals prices "increase significantly" in response to reductions in real interest rates. Further, this research highlights the tendency for commodities to overshoot following the changes in real interest rates. Akram (2009) also concludes that declining U.S. currency exchange rates (a weak dollar) leads to higher overall commodity prices.

Sadorsky (2001) further demonstrates the explanatory power of currency movements and the real cost of money, which heavily influences Canadian oil and gas stock prices. This exchange rate and real interest rate effect is even more pronounced for international commodity producers given that their revenues are priced in U.S. Dollars and costs are priced in their local currency. Sadorsky (2001) fond that an upward move in the price of oil increases the return to the stock prices of Canadian oil and gas companies. However, an increase in domestic exchange rates decreases the return to the stock prices of Canadian oil and gas companies as much or more than the commodity price. Thus, this paper illustrates the intertwined effect and importance of currency and interest rate changes on the economic value of a resource deposit.

Regarding exchange rates, Chen and Chen (2007) find supporting evidence of a long-run cointegration between exchange rates and oil prices, or more specifically, real oil prices. In fact, Chen (2007) found significant forecasting power in real oil prices versus real exchange rates after regressing panel data from G7 countries between 1972 to 2010.

Overall, future research would involve HVP's net price construct but additional macro-economic variables for international properties and producing firms would be used. In fact, in some regions of the world, commodities are deemed hard currency where fiat money has become debased or unstable. Moreover, global demand for commodities from emerging market countries should continue to outpace already developed nations over the years to come.

This research has shown that the Hoteling Valuation Principle does have validity estimating market values of non-renewable natural resources. However, the original HVP model is too limiting in its original form to be applied to the practical contingencies of normal resource extraction. This paper has also shown how resource differentials can impact valuation by the degree of future development or user cost, which should be included into the net price framework to fully discover resource rent. This coupled with allowances for extraction and risk further improve HVP's ability to explain resource values.

TABLES

TABLE 1. SUMMARY STATISTICS

This table presents oil and gas producer statistics from 2015 to 2020. Enterprise In-Ground Value *($EIGV_T$)* is calculated as market capitalization (net of non-upstream assets) plus net long-term debt, divided by total proven oil & gas reserves per equivalent barrel. Developed Enterprise In-Ground Value *($EIGV_D$)* includes only proven developed reserves per equivalent barrel. *Net Price* is defined as the production weighted oil and natural gas equivalent price, less production cost per equivalent barrel. Crude oil and natural gas prices are linked to spot West Texas Intermediate oil and Henry Hub natural gas prices. *Crude Oil Price* is quoted in dollars per barrel and abbreviated as bbl. The *Natural Gas Price* is quoted in dollars per million Btu or 1 Mcf of pipeline-quality gas, abbreviated as Mcf. The *Realized Oil Equivalent Price* equals the production weighted oil equivalent price for each firm. *Production Costs* include lease operating expenses and taxes per equivalent barrel produced. Reserve extraction (ER) factor is equal to the annual equivalent production divided by developed reserves per equivalent barrel. The *User Cost* factor is defined as the reciprocal of the discounted development cost per proved undeveloped barrel. *PUD Development Cost* is the expected proved undeveloped (PUD) development cost per barrel. The *Two-Factor Net Price* is discounted for the reserve extraction rate and a 10% risk adjustment factor. The *Three-Factor Net Price* is discounted for the reserve extraction rate, user cost, and a 20% risk adjustment factor. *Finding & Development (F&D) Cost* per barrel is calculated on an organic basis (ex. price revisions, acquisitions, and divestitures) over a three-year average, per industry standard. F&D winsorized at the 2% level. The *SEC PV10 In-Ground Value* is equal to the present value of proven reserves discounted at 10%, plus the market value of net debt divided by proven equivalent reserves per barrel. The *Enterprise value to EBITDA* ratio over trailing 12-months. The *Large Cap Dummy* is defined as, firms with market capitalizations greater than $15B. The *Price to Book Ratio* is calculated as the common share price divided by balance sheet equity per share. The *Leverage Ratio* is calculated as long-term debt divided by long term debt plus balance sheet equity. *Market capitalization* is defined as shares outstanding multiplied by the common price per share, in millions of dollars.

(Table 1. Continuted on next page)

TABLE 1. SUMMARY STATISTICS

Variable	Mean	St. Dev.	25th Pctile.	Median	75th Pctile.	Min.	Max.
$EIGV_T$ (\$/bbl)	9.059	9.055	2.577	6.640	13.034	-0.589	54.191
$EIGV_D$ (\$/bbl)	15.830	16.000	4.590	11.220	22.856	-0.994	91.968
Net Price ($/bbl)	18.853	13.432	7.092	18.842	29.423	-8.969	50.611
Crude Oil Price ($/bbl)	47.685	14.483	38.100	50.900	60.200	20.100	64.900
Natural Gas Price ($/mcf)	2.486	0.506	1.960	2.670	2.730	1.640	3.190
Realized Oil Equivalent Price ($/bbl)	27.084	14.822	14.391	28.566	39.176	0.274	57.235
Production Cost ($/bbl)	8.231	4.330	5.595	8.140	11.000	0.610	23.380
ER Factor	0.149	0.051	0.114	0.141	0.175	0.056	0.516
UC Factor	0.307	0.324	0.151	0.224	0.303	0.029	3.857
PUD Development Cost ($/bbl)	14.179	10.194	8.732	11.768	17.415	0.685	84.993
Two-Factor Net Price ($/bbl)	10.945	7.828	4.438	10.433	17.558	-6.595	31.241
Three-Factor Net Price ($/bbl)	4.876	3.652	1.528	4.965	7.710	-3.612	15.083
Finding & Developing Cost ($/bbl)	16.301	15.899	7.168	12.095	17.667	2.585	85.508
SEC PV10 In-Ground Value ($/bbl)	6.705	3.683	3.929	6.147	8.877	0.439	24.164
Enterprise Value to EBITDA Ratio	9.784	6.819	5.247	7.464	12.363	0.414	41.683
Price to Book Ratio	1.714	5.106	0.483	1.145	1.977	-3.465	41.684
Leverage Ratio	0.499	0.367	0.320	0.410	0.550	0.000	2.800
Large Cap Dummy	0.198	0.399	0	0	0	0	1
Market Capitalization ($mm)	9,729	14,254	1,191	3,542	11,959	19	76,671

N= 273

TABLE 2. VARIABLE CORRELATIONS

This table provides correlation statistics for oil and gas producers from 2015 to 2020. Refer to Table (1) for variable definitions.

	Variables	1	2	3	4	5	6	7	8	9	10	11	12	13
1)	$EIGV_T$ ($/bbl)	-												
2)	$EIGV_D$ ($/bbl)	0.93 ***	-											
3)	Net Price ($/bbl)	0.42 ***	0.43 ***	-										
4)	Crude Oil Price ($/bbl)	0.22 ***	0.23 ***	0.63 ***	-									
5)	Natural Gas Price ($/Mcf)	0.27 ***	0.29 ***	0.50 ***	0.80 ***	-								
6)	Realized Oil Equivalent Price ($/bbl)	0.42 ***	0.41 ***	0.96 ***	0.57 ***	0.45 ***	-							
7)	Production Cost ($/bbl)	0.12 *	0.07	0.18 **	-0.01	0.00	0.45 ***	-						
8)	ER Factor	0.01	0.06	0.02	0.00	0.00	-0.03	-0.18 **	-					
9)	UC Factor	-0.23 ***	-0.18 **	-0.32 ***	-0.04	-0.07	-0.42 ***	-0.47 ***	-0.18 **	-				
10)	Two-Factor Net Price ($/bbl)	0.42 ***	0.44 ***	0.98 ***	0.63 ***	0.49 ***	0.93 ***	0.15 *	0.16 **	-0.33 ***	-			
11)	Three-Factor Net Price ($/bbl)	0.39 ***	0.39 ***	0.92 ***	0.57 ***	0.46 ***	0.90 ***	0.23 ***	0.26 ***	-0.41 ***	0.96 ***	-		
12)	Leverage Ratio	-0.24 ***	-0.26 ***	-0.07	0.02	0.02	-0.03	0.11	0.15 ***	-0.08	-0.03	0.06	-	
13)	Large Cap Dummy	0.41 ***	0.28 ***	0.13 *	0.13 *	0.15 *	0.17 *	0.18 **	-0.13 *	-0.21 ***	0.12 *	0.18 **	-0.25 ***	-

N = 273

*i) *, **, *** indicated significance at the .10, .05, and .01 level; respectively.*

TABLE 3. REGRESSION RESULTS ON NET PRICE: TOTAL VS DEVELOPED RESERVES

This table presents the regression results for total and developed reserve market values between 2015 and 2020. The dependent variable is Enterprise In-Ground Value ($EIGV_{T,D}$) of (total or developed) proven oil & gas reserves, net of non-production (upstream) assets. The variable definitions are included in Table 1. Model (1) regresses the total reserve $EIGV_T$ on net price. Model (2) regresses the developed reserve EIGV on net price. Model (3) regresses the developed reserve $EIGV_D$ on net price and controls. Model (4) includes the square of net price term to test for non-linearity in the relationship between the developed reserve $EIGV_D$ and net price. Model (5) runs the first-difference regression of $EIGV_D$ on net price and controls.

	Total Res.	Devel. Res.	Devel. Res.	Square	First Diff.
Model	(1)	(2)	(3)	(4)	(5)
Dependent Variable = Enterprise In-Ground Value ($EIGV_{T/D}$)					
Intercept	3.71 ***	6.07 ***	9.13 ***	8.27 ***	-2.60 ***
	(.859)	(1.51)	(2.01)	(1.82)	(0.428)
Net Price	0.28 ***	0.52 ***	0.48	0.65 **	0.29
	(.037)	(.065)	(.074)	(.220)	(.032)
Net Price Square				0.00	
				(.006)	
Leverage Ratio			-8.25 **	-8.38 **	-2.87
			(2.78)	(2.79)	(2.27)
Large Cap Dummy			6.10 *	5.77 *	4.29 **
			(2.35)	(2.50)	(1.36)
R-squared	0.177	0.189	0.271	0.273	0.176
Adjusted R-square	0.174	0.186	0.262	0.262	0.164
No. Observations = 273	273	273	273	273	273

i) Standard errors are reported in parentheses.

*ii) *, **, *** indicated significance at the .10, .05, and .01 level; respectively.*

iii) Model errors are corrected for autocorrelation and heteroskedaticiy.

iv) Variance inflation factors < 2 for models (4), (5) and (6)

TABLE 4. REGRESSION RESULTS ON TWO-FACTOR NET PRICE

This table presents regression results for the in-ground market value of developed oil and gas reserves versus the two-factor net price from 2015 to 2020. The dependent variable is the Enterprise in-ground value ($EIGV_D$) of proven developed oil & gas reserves, net of non-production (upstream) assets. The variable definitions are included in Table 1. Model (1) regresses the developed reserve $EIGV_D$ on two-factor net price. Model (2) regresses the developed reserve $EIGV_D$ on the two-factor net price and controls. Model (3) includes the square of the two-factor net price term to test for non-linearity in the relationship between developed reserve $EIGV_D$ and net price. Model-(4) runs the first-difference regression of developed reserves $EIGV_D$ on the two-factor net price and controls.

Model	(1)	(2)	Square (3)	First Diff. (4)
Dependent Variable = Enterprise In-Ground Value Developed Reserves ($EIGV_D$)				
Intercept	5.90 ***	9.06 ***	8.20 ***	-2.62 ***
	(1.51)	(1.99)	(.176)	(.418)
Two-Factor Net Price	0.91 ***	0.85 ***	1.16 ***	0.57 ***
	(.111)	(.126)	(.389)	(.061)
Two-Factor Net Price Square			-0.01	
			(.017)	
Leverage Ratio		-8.84 ***	-8.94 ***	-3.01
		(2.73)	(2.76)	(2.27)
Large Cap Dummy		6.11 ***	5.76 **	3.91 ***
		(2.31)	(2.49)	(1.34)
R-squared	0.197	0.286	0.288	0.207
Adjusted R-square	0.194	0.278	0.278	0.196
No. Observations = 273	273	273	273	273

i) Standard errors are reported in parentheses.

*ii) *, **, *** indicated significance at the .10, .05, and .01 level; respectively.*

iii) Model errors are corrected for autocorrelation and heteroskedaticiy via the Newey-West estimator, 1-period lag.

iv) Variance inflation factors < 2 for Models (3) and (4)

TABLE 5. REGRESSION RESULTS ON THREE-FACTOR NET PRICE

This table presents regression results for the in-ground market value of total oil and gas reserves versus the three-factor net price from 2015 to 2020. The dependent variable is the Enterprise In-Ground Value ($EIGV_T$) of total proven oil & gas reserves, net of non-production (upstream) assets. The variable definitions are included in Table 1. Model (1) regresses the $EIGV_T$ on three-factor net price. Model (2) regresses the $EIGV_T$ on the three-factor net price and controls. Model (3) includes the square of three-factor net price term to test for non-linearity in the relationship between $EIGV_T$ and three-factor net price. Model (4) runs the first-difference regression of $EIGV_T$ on three-factor net price and controls.

Model	(1)	(2)	Square (3)	First Diff. (4)
Dependent Variable = Enterprise In-Ground Value Total Reserves ($EIGV_T$)				
Intercept	4.29 ***	5.33 ***	4.00 ***	-1.19 ***
	(.842)	(1.17)	(1.03)	(.230)
Three-Factor Net Price	0.98 ***	0.87 ***	1.75 ***	0.76 ***
	(.138)	(.135)	(.400)	(.081)
Three-Factor Net Price Square			-0.08 **	
			(.036)	
Leverage Ratio		-4.68 ***	-4.34 ***	-0.94
		(1.61)	(1.66)	(1.45)
Large Cap Dummy		5.98 ***	5.75 ***	2.81 ***
		(1.34)	(1.35)	(.748)
R-squared	0.156	0.311	0.327	0.250
Adjusted R-square	0.153	0.303	0.317	0.239
No. Observations = 273	273	273	273	273

i) Standard errors are reported in parentheses.

*ii) *, **, *** indicated significance at the .10, .05, and .01 level; respectively.*

iii) Model errors are corrected for autocorrelation and heteroskedaticiy via the Newey-West estimator, 1-period lag.

iv) Variance inflation factors < 2 for Models (3) and (4)

TABLE 6. ROBUSTNESS CHECK

This table presents the regression results of robustness tests. The variable definitions are included in Table 1. Model (1), $EIGV_T$ is regressed on the Three-Factor net price and the per barrel SEC present value of reserves, discounted at 10%, with controls. In Model (2) $EIGV_T$ is regressed on the Three-Factor net price and the enterprise value to EBITDA multiple with controls. In model (3), $EIGV_T$ is regressed on the three-factor net price and the Price to book ratio with controls. In Model (4), the total reserve ($EIGV_T$) variable is regressed on the two-factor net price and finding & developing cost per barrel variables, with controls. In Model (5), $EIGV_T$ is regressed on firms with greater than 66% crude oil vs natural production and controls. In Model (6), $EIGV_T$ is regressed on firms with greater than 66% natural gas vs crude oil production and controls.

	Three-Factor	Three-Factor	Three-Factor	Two-Factor	Oil Producers	N.Gas Producers
Model	(1)	(2)	(3)	(4)	(5)	(6)
Dependent Variable = Enterprise In-Ground Value Total Reserves ($EIGV_T$)						
Intercept	3.41 **	1.63	5.20 ***	4.48 ***	8.81 ***	5.64 **
	(1.38)	(1.22)	(1.44)	(1.41)	(3.22)	(2.50)
Factor Net Price ($/bbl)	0.72 ***	0.97 ***	0.85 ***	0.43 ***	0.74 ***	0.98 ***
	(.152)	(.177)	(.159)	(.079)	(.211)	(.178)
SEC PV10 In-Ground Value ($/bbl)	0.40 *					
	(.237)					
Enterprise Value to EBITDA Ratio		0.38 ***				
		(.072)				
Price to Book Ratio			0.17			
			(.132)			
Finding & Development Cost ($/bbl)				-0.03		
				(.028)		
Leverage Ratio	-4.74 ***	-4.55 **	-4.71 **	-3.40	-8.94 **	-5.01
	(2.07)	(2.16)	(2.20)	(2.22)	(3.67)	(3.89)
Large Cap Dummy	6.11 ***	5.01 ***	5.90 ***	6.75 ***	4.44 *	3.91 *
	(1.57)	(1.55)	(1.64)	(1.56)	(2.45)	(1.99)
R-squared	0.333	0.390	0.319	0.333	0.215	0.351
Adjusted R-square	0.323	0.385	0.309	0.322	0.200	0.317
No. Observations = 273	273	253	273	64	124	61

i) Standard errors reported in parentheses.

*ii) *, **, *** indicated significance at the .10, .05, and .01 level; respectively.*

iii) Model errors are corrected for autocorrelation and heteroskedaticiy.

FIGURES

FIGURE 1. COMMODITY PRICE TRENDS

This figure presents the trend of annual commodity prices over the period 2014-2020. The blue bars represent West Texas Intermediate crude oil price per barrel. The orange line represents Henry Hub Natural Gas price per Mcf. All prices are as of March 31 of each respective year.

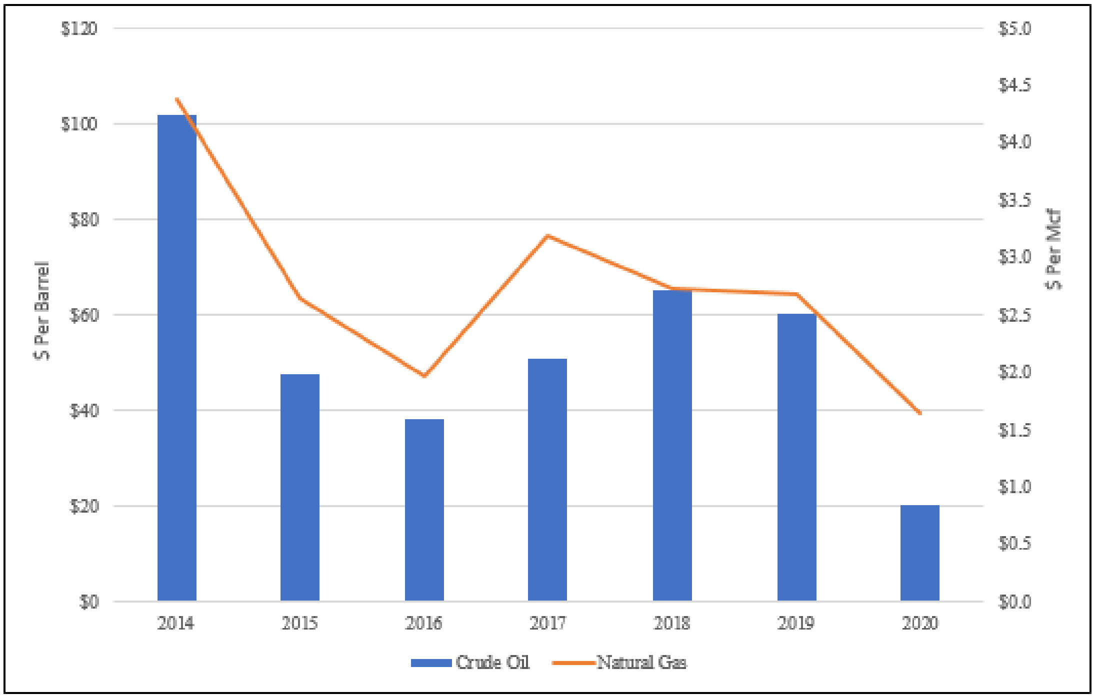


FIGURE 2. NET PRICE TRENDS

Net price is the difference between the realized oil equivalent price per barrel and the production cost per equivalent barrel. Commodity prices are as of March 31st of each respective year. Reserve and cost data are as of December 31 of the prior year.

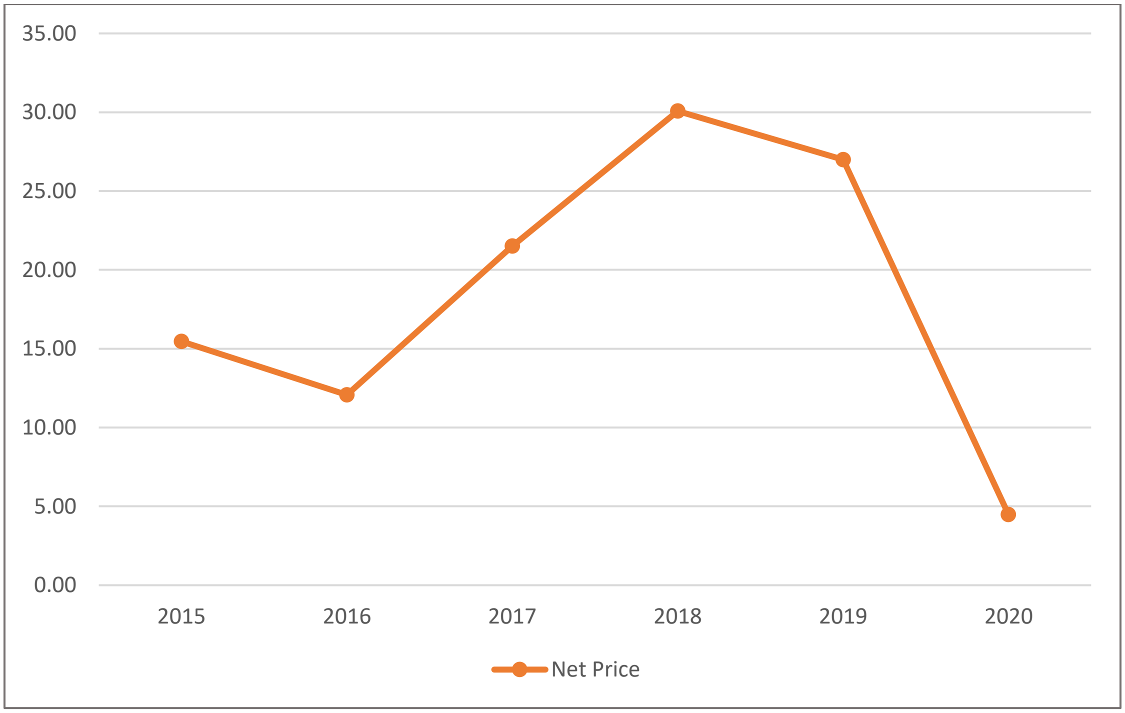
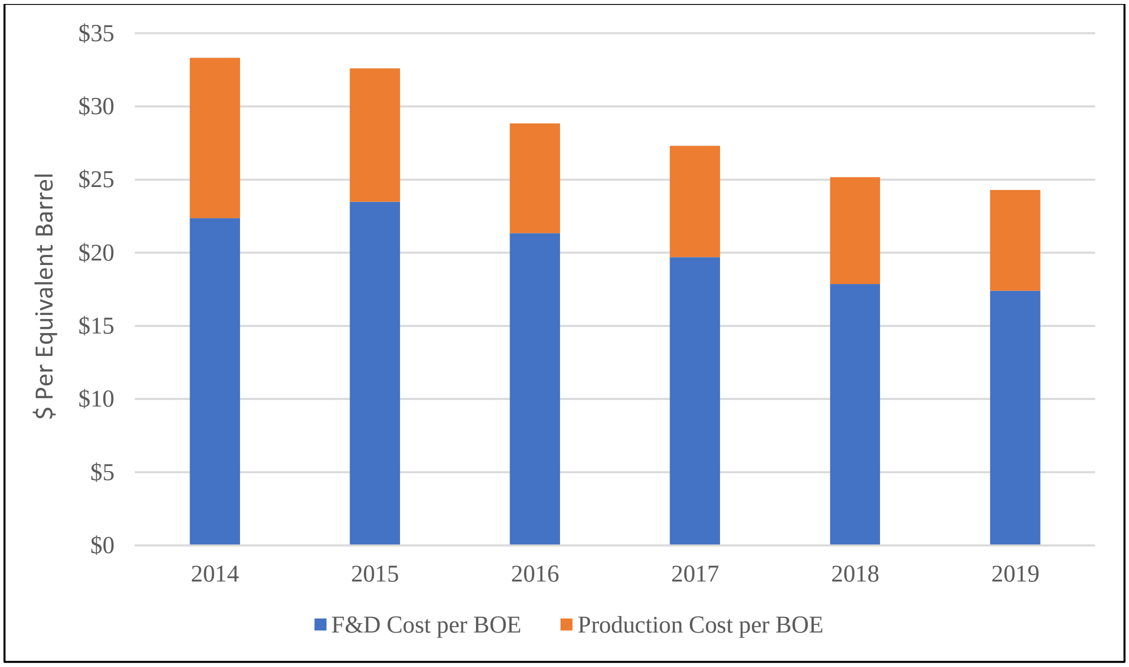


FIGURE 3. TOTAL COST TRENDS

The orange bars represent production costs and include lease operating expenses, transportation costs and non-income taxes per equivalent barrel. The blue bars represent finding and development costs per equivalent barrel and are tabulated over a three-year average, per industry standard. All cost data is as of December 31 of each respective year.



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APPENDIX

1.1 Cost Structure

The lifeblood of any oil producer is the efficiency with which it replaces its production. Bridge and Wood (2010) discuss how the two most important issues for an upstream producer of hydrocarbons is the profitability balance between production replacement and the ability to sustain market share within the industry. These indicators of market competitiveness. Further, in this era of shale oil exploration and development, high quality resource accumulation is of extreme importance for upstream companies who wish to remain relevant among other firms, particularly with the emergence of dominant new resource plays with game changing well economics and very long reserve life drilling inventories.

Upstream costs for onshore oil and gas exploration and production companies fall into one of four capital or operating categories; drilling, completion, facilities and operating. These costs can be capitalized or expensed (operating). Total capital costs to bring a well into production usually run between $5 and $8 million for the typical shale oil well (Energy Information Agency, 2016). Though, within the last few year costs have continued their downward trajectory as completion technology continues to advance.

Fore shale oil, actual drilling costs typically include 30 to 40 percent of total well costs. These costs are associated with contracting a rig, drilling a well to total depth and involve specific costs allocated to day rates to lease the rig and its crew, drill-bits, casing, cement and drilling fluids and fuel costs.

Completion activities consist of 55 to 70 percent of the total cost to bring a well online and have increased meaningfully during the era of shale technology[1]. This is primary due to the intensity of drilling fluids (water, proppant, and sand) that must be injected into the wellbore to permit hydraulic fracturing of highly impermeable sedimentary rock, that ultimately unlocks or releases hydrocarbons from the high-pressure formation. Shale oil wells are generally drilled horizontally through the shale bedrock, often as deep as 1,000 feet and another 5,000 feet laterally (Energy Information Agency, 2016). This type of unconventional drilling requires superior technology and skill to complete effectively and is crucial to the well's future productivity and economic ultimate recovery (EUR). However, once the science and technological processes are in place, exploitation of the unconventional resource play becomes more of a manufacturing process of infill drilling relative to conventional drilling where the geology is not as well defined or contained.

There are also some residual facilities construction costs for roads, storage tanks and water handling and gathering systems infrastructure that typically make up less than 10 percent of the total well outlay.

The process of drilling and completing are capital costs that are captured in a company's reported finding and developing costs, which is measured as F&D cost per barrel of new reserves. Conversely, production costs are expensed as operating costs.

These variable costs are associated with lease operating expenses, transportation costs and royalty taxes that are directly attributable to oil and gas extraction.