JOURNAL OF PETROLEUM RESOURCES ECONOMICS

QUARTERLY JOURNAL OF THE SOCIETY OF PETROLEUM RESOURCES ECONOMISTS

ISSUE 1 - OCTOBER 1, 2018

The Society of Petroleum Resources Economists

ABOUT JPRE AND SPRE

This is the inaugural issue of the Journal of Petroleum Resources Economists (JPRE). JPRE is the quarterly journal of the Society of Petroleum Resources Economists (SPRE).

SPRE is the first professional international organization specifically dedicated to the business side of the oil and gas industry, that is "Petroleum Economics" and our focus is Exploration-Production. Our vision is to more efficiently link economics, finance, financial markets with oil and gas exploration and production to achieve better-integrated teams along the entire value chain and to attain superior stakeholder results and shareholder return maximization for the benefit of all.

The purpose of the JPRE it is to provide both high quality and innovative articles useful to the oil and gas and/or the financial industry as well as more efficiently linking economics, finance, financial markets with oil and gas exploration and production to achieve better-integrated teams along the entire upstream value chain. In other words, the JPRE shall serve the SPRE mission of (re)building creatively, connecting the dots, and forging the missing link between the following words: Society, Petroleum, Exploration, Production, Oil, Gas, Reserves, Resources, Risk, Return, Economics, Finance, Banking and Financial Markets. And maybe a few more. Each Journal issue shall contain a diversified set of relevant Petroleum Resources Economics topics of interest to professionals, regulators, academics, and students alike.

PRESIDENT'S MESSAGE

Dear 2018 SPRE members,

It is my privilege to introduce to you the first issue of our Journal of Petroleum Resources Economics (JPRE). The endeavor is the latest significant building block of our professional organization.
After sets of meetings and conferences held and planned in Houston, in Paris, in Calgary, in London and at student chapters across North America, Europe, and Asia as well as a SPRE Newsletter, it is only natural that a quarterly journal constitutes an additional move within the SPRE build up.
Our step by step approach has served us well from inception onwards and it is my sincere hope that you will enjoy an enhanced JPRE in the years to come.

May the Fourth be with you,
JC Rovillain, as 2018 SPRE President.

EDITOR'S NOTE

After showing growth and progress in its mission of serving as a society dedicated to the business side of the oil and gas sector, the SPRE has embarked on its next step that will take it further on this path: The Journal of Petroleum Resources Economics (JPRE).

The Journal of Petroleum Resources Economics will be a quarterly journal of SPRE. It is an international, multi-disciplinary journal in petroleum resources economics. It is intended to promote the advancements and circulation of new knowledge pertaining to the oil and gas industry. The articles published in the JPRE shall provide useful and innovative analysis that will be of interest to oil and gas industry professionals, academicians, students, regulators, and the financial community. We welcome contributions covering all the major areas of petroleum resources economics, not limited to: gasoline demand analysis, OPEC and oil markets, policy issues, natural gas topics, econometric modeling, regulatory economics, energy taxation, unconventional oil and gas, geology and engineering of oil and gas E&P, reserves and resources management, and oil and gas and the environment economics. It will also feature articles presented at SPRE's annual Petroleum Resources Economics Conference (PREC).

The goal of JPRE is to become a leading peer-reviewed journal and an authoritative source of information for analyses, reviews and evaluations in petroleum resources economics.

Saad Siddique
JPRE Managing Editor

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Price Forecasting: Good Judgement or Luck?

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Although the original author is unknown, many famous people from baseball player Casey Stengel to physicist Niels Bohr have been credited with the simple quotation "*Never make predictions, especially about the future*". In other words, I don't know what the price of oil is going to be, but I do know that I'll be wrong if I try and predict it. The conventional wisdom on forecasting the oil price is that you'll always be wrong. So, is good or inaccurate price forecasting the consequence of a human's ability to forecast, the fundamentals of macroeconomics, or is it oil itself, as a so-called commodity? Well, as you'd expect, it's a mixture of all three, but the exact proportions vary from individual to individual and organization to organization. While many of the factors are beyond our control, a key issue is that as human beings we are all fallible and often put the wrong emphasis on the wrong variable, but why?

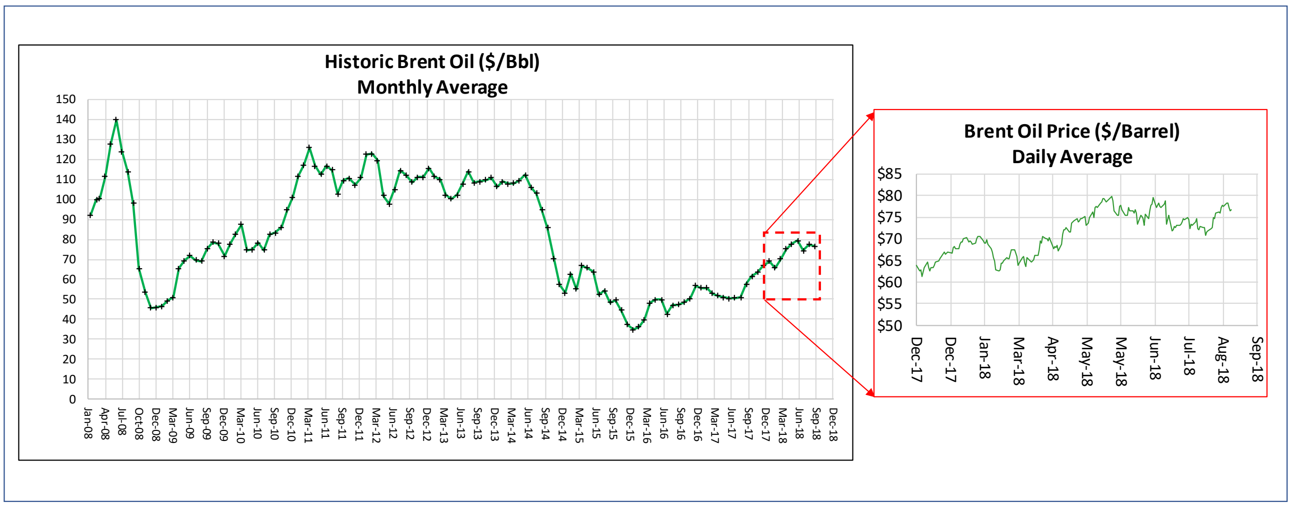

Figure 1: Low and High Frequency changes

In order to demonstrate this, we're going to borrow a couple of themes from a relatively obscure blog by Belle Beth Cooper entitled '*Eight Common Thinking Mistakes Our Brains Make Every Day'* and modify them for the oil industry:

1) We surround ourselves with information that matches our beliefs:

Humans love making order out of chaos and the fluctuations of daily oil price does at first sight look impossible to predict (figure 1). We're used to seeing similar patterns in the rise and fall of stock prices and it's commonly referred to as a '*Random Walk'*. However, the phrase implies complete disregard for the underlying value of an asset or company, and the relatively narrow band of price change day to day. Astute forecasters can differentiate between what are merely correlations of data from those that demonstrate a cause and the consequential effect. In this author's experience most oil company price forecasters look for broad data trends and continue these to the end of the dataset without questioning the assumptions.

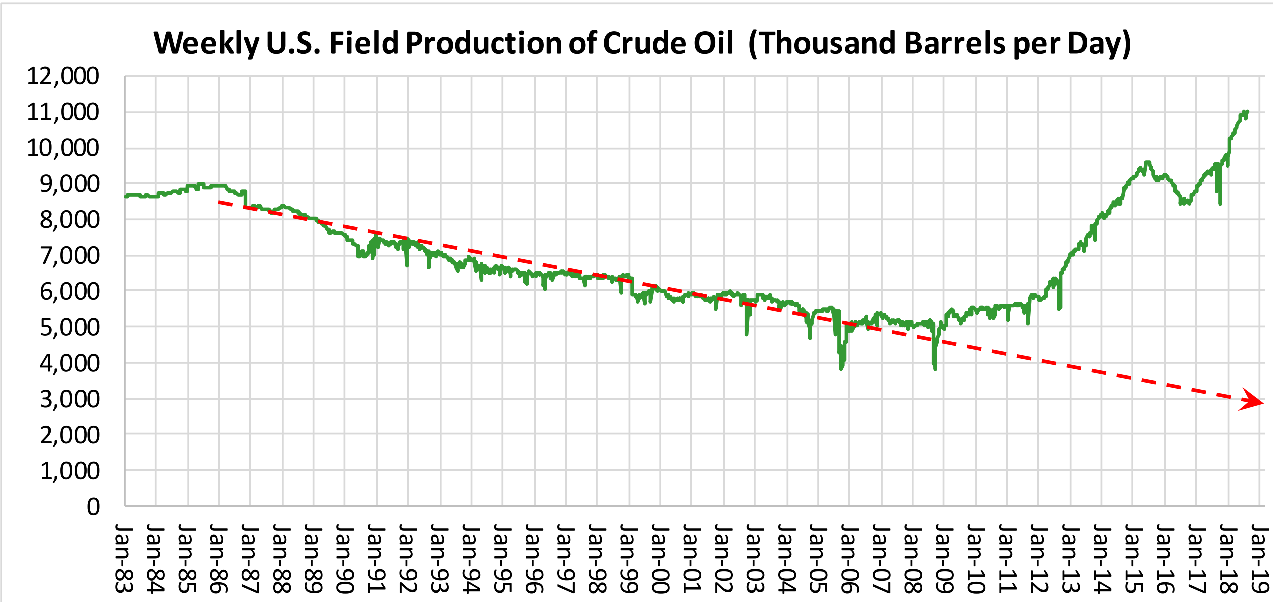

Figure 2: US Production (1983 to 2018)

If you were working in 2008, you would have seen that the US domestic oil production was in decline (figure 2). Most predictions at the time would have continued that decline until reaching zero between 2030 and 2050. The belief was that no big fields existed to halt that decline. As history shows, trends are bucked by unforeseen circumstances and the very nature of '*unforeseen'* means that you can't predict it. Similarly, for price shocks such as conflicts in major oil exporting countries or political interference.

2) We incorrectly predict odds:

In July 2008, Neil King, a journalist on the '*FiveThirtyEight*' website which focusses on opinion poll analysis, asked a wide range of energy journalists, economists and other experts to anonymously predict what the price of oil would be at the end of the year. The nearly two dozen responses ranged from $70 a barrel at the low end to $167.50 at the high end. The actual answer was $44.60.

The problem is that human beings think they know more than they actually do and usually give a single figure.

Scott Plous, professor of psychology at Wesleyan University and the author of '*The Psychology of Judgment and Decision Making'*, wrote, "*No problem in judgment and decision making is more prevalent and more potentially catastrophic than overconfidence."*. In fact, studies have shown that the ratio of confidence to accuracy is an inverse one -- that is, a lesser confidence level tends to correlate with a higher degree of accuracy, since assumptions are questioned and rechecked.

Subsurface professionals have developed sophisticated estimating techniques, learned from estimating exploration prospect volumes pre-drill and then calibrated their estimating techniques with the new information on discovery. They commonly give ranges, low to high with an associated confidence level attached to those ranges. They are taught to '*open up the ranges'* to make sure the actual figure (i.e.: after the well has been drilled) falls within the range but to also be wary that the range shouldn't be so wide as to make the estimate of little value. For example, a range of zero to $1,000 for the price of oil to the earlier question by Neil King would have a high confidence that the actual answer would lie inside the range but be so wide it doesn't help with any decision making apart to imply huge uncertainty. The key to oil industry volume prediction is to constantly calibrate your predictions with post mortems/post well reviews to keep on learning and understand the key criteria for the geographic location, play type, depth of burial etc.

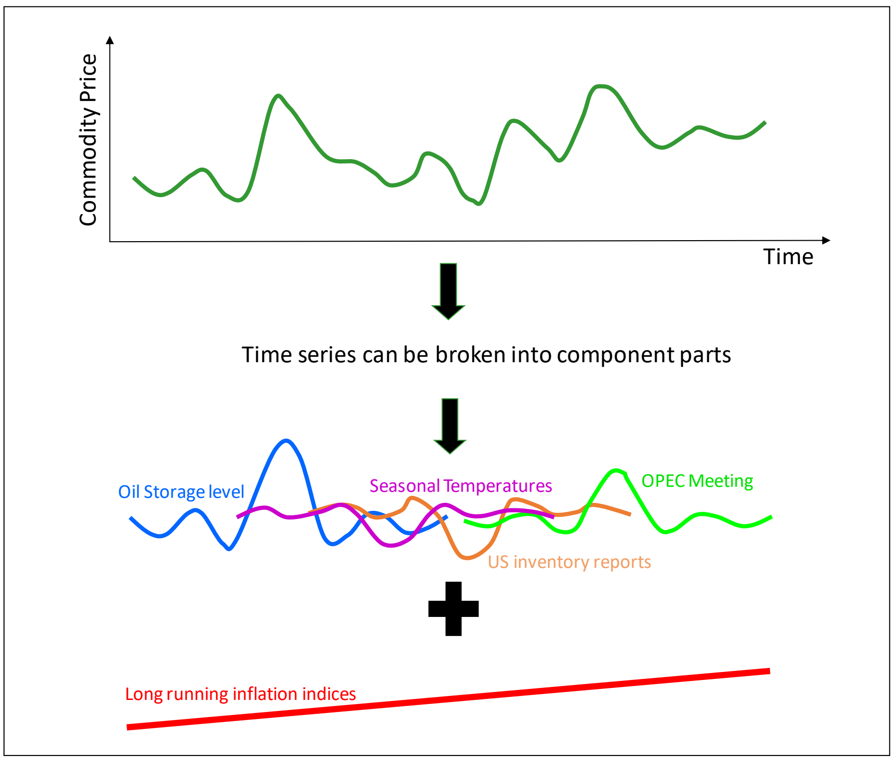

Figure 3: Components of price as a complex time series

A psychology study by Tyszka and Zielonka titled "*Expert Judgments: Financial Analysts vs. Weather Forecasters*," asked two groups of experts to "*predict corresponding events (the value of the Stock Exchange Index and the average temperature of the next month)."* The authors found that, although both groups of experts were over confident in their predictions, over confidence was significantly higher among financial analysts than among the weather forecasters. The high-level conclusion and crux of the issue was that weather forecasters deal with the events of a periodic nature such as seasons and cyclically. This world is partially predictable in that it is cyclic, but the weather forecasters are aware that they are working with a gross approximation of the underlying system and that in such an area, the uncertainty must be taken into consideration. Financial analysts, on the other hand, must deal with a world which seems to be completely unpredictable, where even weak probabilistic tendencies are rarely observed. Thus, the financial analysts behaved as if they had to demonstrate the ability of a perfect forecast of the events in question. Unless there are severe storms in the area (hurricanes, tornadoes, possible floods), most people who listen to weather forecasts are happy if the forecast is not hopelessly inaccurate. Therefore, in order not to lose their clients, financial analysts are very sensitive about their reputation and better skilled than weather forecasters in formulating excuses for their errors. Borrowing a phrase from renowned economist John Maynard Keynes, the weathermen are happy to say, "*I'd rather be vaguely right than precisely wrong*".

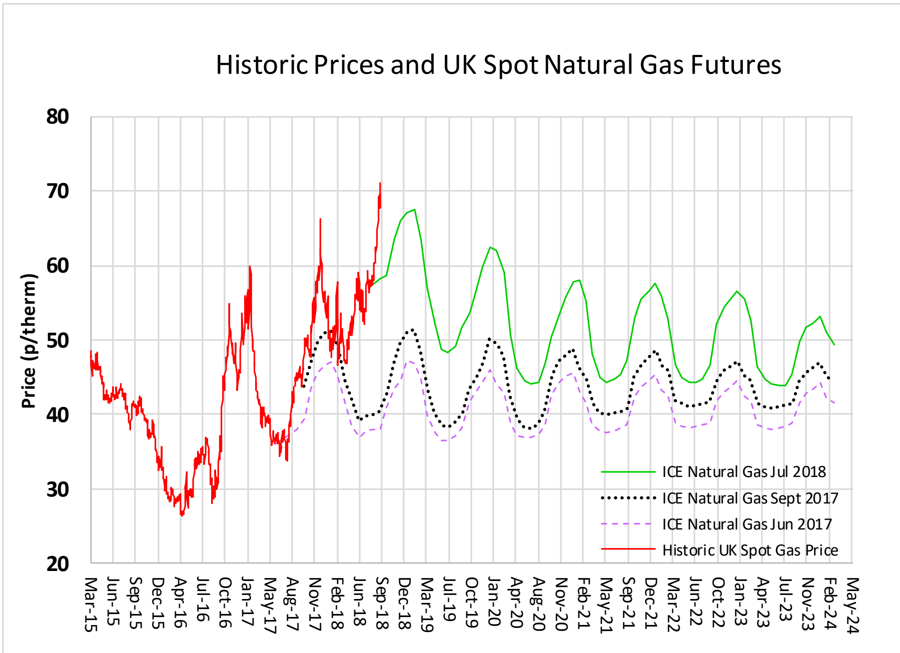

Figure 4: seasonality of gas price and change in forecast 2017 to 2018

People are always looking for patterns and relationships that are not there, or to put it succinctly, 'correlation is not causation'. For example, the decline in production from 1980s to 2000s (figure 2) was perhaps due to global political tensions easing; the Berlin wall coming down, breakup of the Soviet Union, China joining world trade, democracy spreading and perhaps therefore resulting in making the US happy to trade freely around the world for its energy supplies. This world trade view changed in 2001 for the US with the terrorist attack on the Twin Towers and resulted amongst other things, in a more inward-looking perspective on energy supply because open trade could be viewed as vulnerability. This drove the search for domestic US energy sources and the increase in unconventional shale oil. Of course, there are many variables interacting and few concrete causes.

So back to the question; does successful price forecasting result from good judgement or just good luck? The answer to this can perhaps be summed up with one very insightful quote from a former colleague who prefers to remain anonymous "*I'd rather be calibrated and 'theoretically challenged' than theoretically correct and uncalibrated*". This statement hides the complexities of solving for all the variables in a complex pattern (the calibration). Every time series can be broken down into low and high frequency events (figure 3). The moderately predictable components such as seasons and long running inflation rate are called Low

Frequency events because they change over long periods. Events such as armed conflicts, extreme cold weather events and OPEC announcements are relatively sudden, have an immediate impact on energy prices and the event itself generally does not last for long. We call these High Frequency events.

Those of us that would rather be '*theoretically correct'* will build up forecasts based on a multitude of high and low frequency components from the '*ground up'* with some knowledge that most of the errors (if random) in the individual forecasts will cancel each other like white noise. However, those of us that prefer to be '*calibrated and theoretically challenged'* will build forecasts based on the last known price point of the market (which is instantaneous) plus a relatively predictable '*trend factor'* such as inflation or the seasons (figure 4). Neither is right or wrong, and the implied precision of the '*ground up'* method is exactly that, 'implied'. Both methods are reasonable, but the calibrated method seems to be that adopted by most independents and small companies. However, the most important part of the process is setting the price envelope, or low to high boundaries (figure 5). This is where true success lies in price forecasting for acquisitions and divestments since short term pricing (day trading) is not relevant. It is the long running price that is applicable. Too many price forecasters are unwilling to allocate probabilities like P90, P50, P10 to their price scenarios and instead label them as subjective Low, Mid/Base and High or sometimes a more specific naming convention like '*Acquisition Case', 'Divestment Case',* or *'Long Range Plan Case'*.

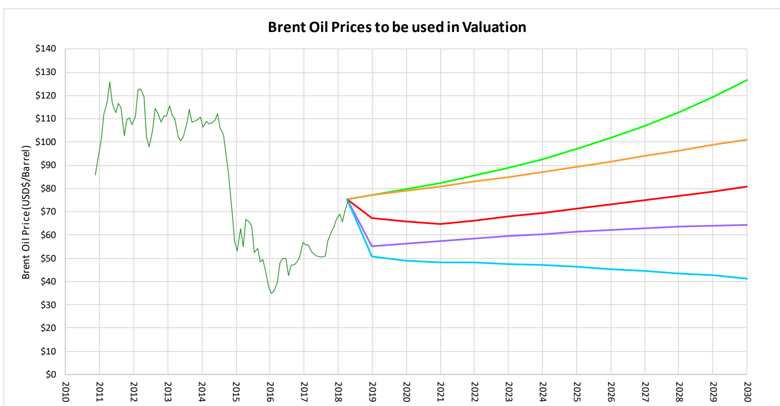

Figure 5: Boundaries of price uncertainty

Whatever, the naming, every good forecaster should recognise that uncertainty increases as you move away from your calibration point which is today's price. This is similar to what Project Managers call the Cone of Uncertainty when comparatively little is known at the beginning of a project, so estimates are subject to large uncertainty. As more work is done, more information is learned about the project, and the uncertainty then tends to decrease, reaching zero when all residual risk has been terminated or transferred i.e.: today's price which is known (figure 5). To disregard the increasing width of the cone over time as you move away from your known calibration, or to define a narrow range, is poor forecasting and that usually results in bad 'luck'. The recommendation is therefore to consider the trends of several low frequency parameters to build the low frequency model and over lay it onto a second-time series that represents the average number of high frequency events and average impact (amplitude) of these events. With that in place you can draw on your confidence lines (figure 6).

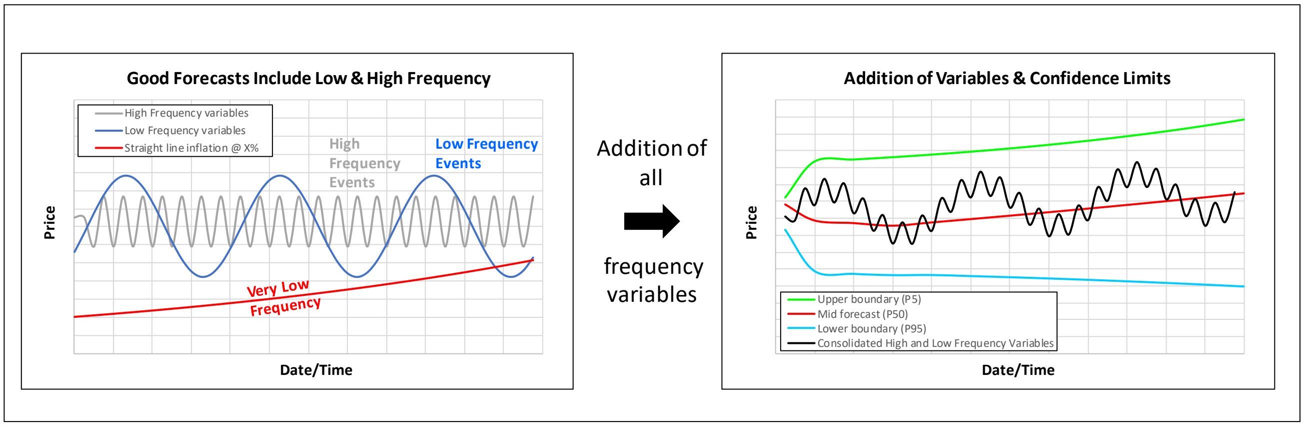

Figure 6: Elements of a good forecast

Petroleum Exploration and Production Risk Assessment

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Risk assessment and analysis are critical phases of petroleum asset management. The methods in common use today examine the 90-10, or some other probability distribution, variance to assist in evaluating uncertainty when estimating reserves. In other words, some method of estimating a 10% vs 90% likelihood of occurrence is determined. Obviously, this method could be applied at the 80-20, or any other points, on the probability curve. The values chosen are typically based on perceived risk tolerance.

This method can be used to evaluate size of reserve/reservoir expectations under "normal" conditions and are based on statistical treatment of current data. They perform poorly when unexpected, or black swan, events occur. The world-wide estimate of total reserves is an example of this characteristic of the statistical methods. Prior to the "unconventional" resource plays you would have seen lower totals for reserve estimates of hydrocarbons. The development of unconventional play technologies represents a "black swan" event, and the increase in estimated world reserves since their advent is a good example of this characteristic. It is unfortunate that geopolitical strategies are frequently based on this type of analyses.
Risk assessment, for this article's purposes, is the structuring of your information and data prior to performing numerical (statistical) risk analysis. In today's interpretation world, risk analysis means estimating properties like volume, porosity, permeability, etc. This allows the analyst to estimate potential recoverable volumes of hydrocarbons (aka SEC acceptable reserve estimates). Some of the more recent software extrapolates upstream in an effort to statistically enhance the volumetric, porosity/permeability, saturation, etc. estimates at various stages of the interpretation process.

However, this approach may be insufficient to support good decision making for prospect evaluation and ranking and is definitely inadequate for portfolio management. For example, where does the quality or completeness of an interpretation workflow enter into this analysis? It does not. In some ways we can consider the real estate initiated financial crisis, circa 2008, to fall in this same category of poorly structured information management during risk assessment. Consider that Moody (1909, "Moody's Analyses of Railroad Investments") came up with a new means of evaluating the relative investment risk in railroad bonds. This ranking of assets (railroad investment bonds) was accomplished by the simple expedient of classifying each bond as A, B, or C based on a set of defined criteria. This was such an effective approach relative to prior methods that it caught on quickly and spread to other investment assets rapidly. The system, originally simple, is still used today but has become very complex. There are many new categories of information and data to differentiate, so the classes A, B and C have become a complex aggradation of AABB, AbBc, etc. with long lists of definitions and criteria.

It should be clear in overview that the complexity of modern information and assets far exceeds Moody's originally simple model for a single and limited asset class. The failure of the method to alert banks and other financial institutions to the true variability within their asset portfolios prior to the recent crisis provides clear proof as well. Potential reserve estimates are also problematic. So, how can this be resolved in an efficient, clear manner? What methods are available to us? My favorite choice is Euler plots. The nice thing about these plots is that they are three dimensional intersections of variables in the decision space. This allows for a complex and evolving understanding of the variables and their interactions. Even better, when projected to two dimensions they still provide a wealth of information in simple graphic form about the relationships of a large number of variables. The two-dimensional representations of this three-dimensional Euler space are named things like radial, starfish, or spider(web) plots.

Using a spiderweb analogy for this proposed method, each spoke of the web can be considered a data variable and each point along the spokes (the intersection of the web cross-lines with the spokes) may be defined by a quality or completeness criteria. For example, synthetic ties for wells to seismic horizons could be peer-reviewed as a completeness-criteria, and steps completed through that stage of the interpretation process could be colored green. Figure 1 demonstrates this approach using a few arbitrary geophysical and geological evaluation criteria. Adding color provides a good project management tool, giving decision makers a quick glance method of the steps still needed for prospect development (the completeness of phases of the interpretation process), and the relative merit (drillable status) of different assets in a portfolio. Classification of the spokes, and criteria for points along the spokes, are flexible and may be defined on the basis of the needs and resources available.

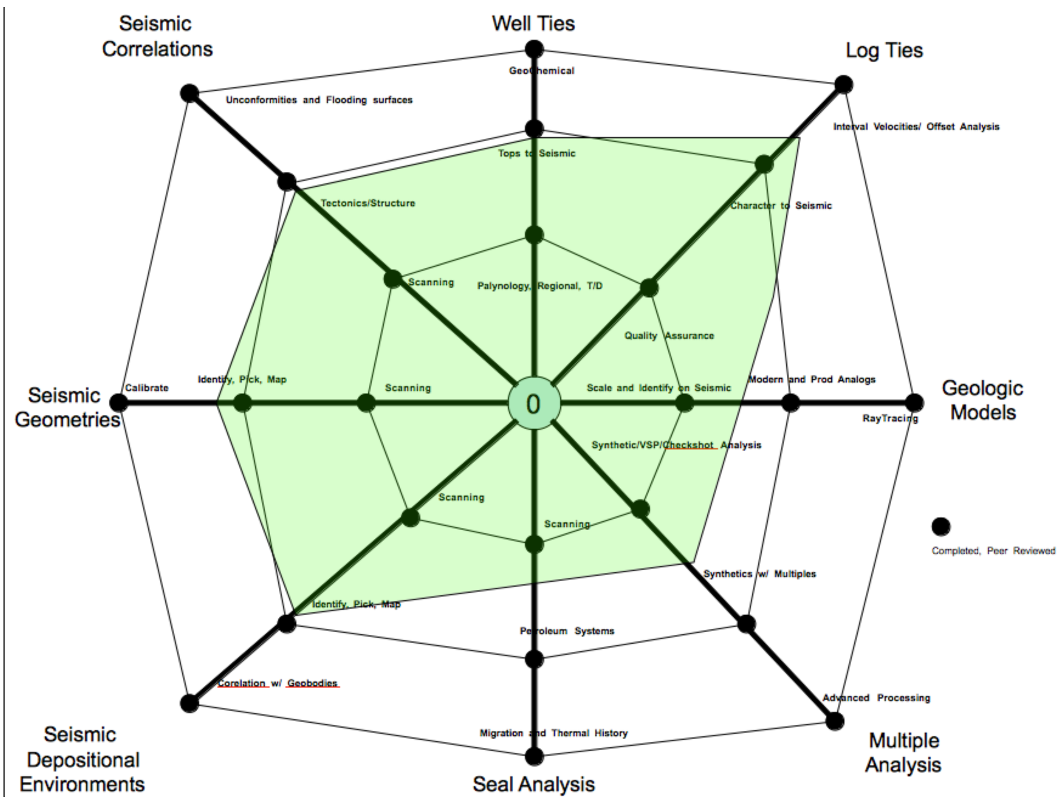

Figure 1: A simple (not recommended for use) example of a two-dimensional Euler plot of some variables in a G&G interpretation. This 'spiderweb' plot allows a user to identify the completeness of specific interpretation phases, based on completeness or peer review criteria, quickly and easily.

The Effects of Lifting the U.S. Oil Export Ban on Market Equilibrium

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Introduction

Shale resource development has affected the U.S. domestic market by dramatically reversing a decline going on since decades and turned the U.S. from an expanding sink for petroleum to a potential global source instead. This massive growth in production due to the new production from unconventional resources, however was hampered by the longstanding federal ban on most crude oil exports (Langer et al., 2016). On December 18, 2015, President Obama signed into law an act that repealed a forty-year old export ban on crude oil (H.R. 2029) and allowed American crude oil to flow around the globe again.

But what were reasons for the crude oil ban, the circumstances that led to lifting of the ban and financial effects of restarting crude oil exports on the domestic and global markets?

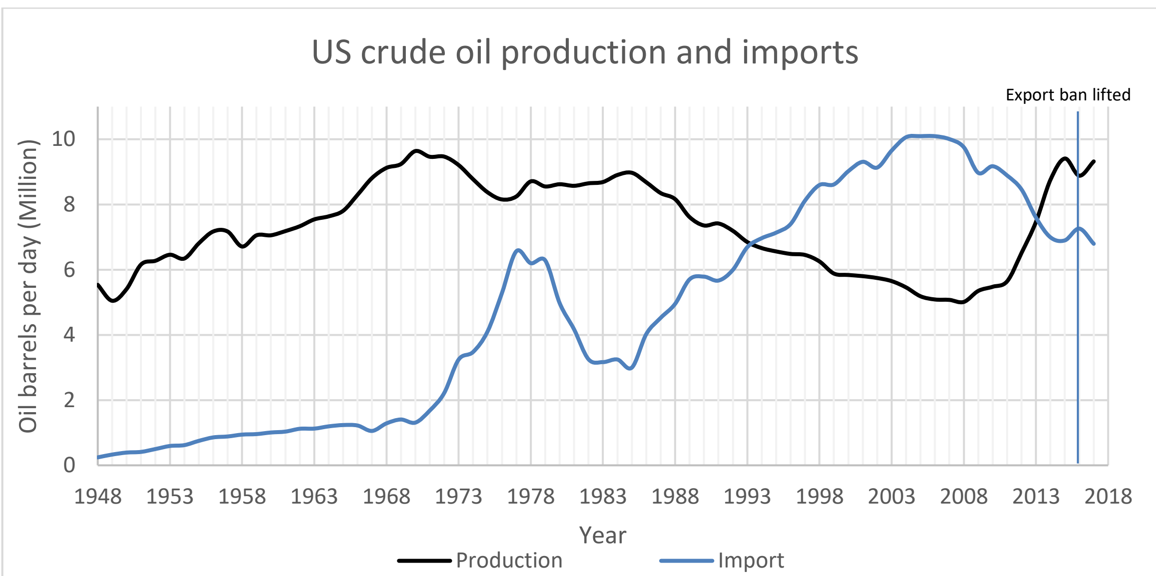

Figure 1: U.S. crude oil production & import data. (U.S. Energy Information Administration - EIA)

Origin and History of the ban

Government intervention in the U.S. oil market began long before the recent export ban repeal. As seen in Figure 1, while the U.S. crude oil production rose steadily in the 1950's, the crude oil imports also doubled due to cheap oil from the middle east. Considering growing dependence on imported oil, the U.S. Congress began the Mandatory Oil Import Quota in 1959 to restrict imports (Melek and Ojeda, 2017). This continued till 1970 when the annual oil production peaked at 9.6 million (MM) barrels per day (b/d) and began to decline. However, due to 1973 Arab oil embargo the international oil prices rose and caused an oil scarcity panic. This triggered the Nixon administration to put oil export restrictions under three laws (Colgan and Van de Graaf, 2017): the Trans-Alaska Pipeline Authorization Act, allowed pipeline construction to Valdez port with the stipulation that the oil would not be exported (Bradley, 1996); the Emergency Petroleum Allocation Act (EPAA) of 1973 exercised domestic price controls since the embargo increased the international oil prices relative to the domestic prices; the export ban under the Energy Policy and Conservation Act (EPCA) of 1975, due to fears about domestic resource depletion.

However, since then, repealing efforts were partially successful, leading to multiple exemptions in the ban such as certain exports to Canada (1985), exports from Alaska (1985) and limited exports from Californian heavy oil in 1992 (Bordoff and Houser, 2015), while the crude oil export ban stayed in place for forty years.

Equilibrium factors considered during ban repeal (For / Against)

a) Shale revolution and oil flow distortion

Figure 1 shows from 1978 to 2008, the U.S. oil production declined by half, leading to U.S. becoming the world's largest oil importer. The crude oil imports crossed 10 MM b/d in 2004, while the crude oil exports were hardly 0.1 MM b/d. Since the production was declining, the export ban was not under consideration and had a non-binding restriction on the U.S. crude exports. However, due to the shale oil revolution, from 2008, the production steadily increased by 4 MM b/d and in 2015, the annual daily production was 9.4 MM barrels, almost as high as 1970's production. This sudden increase in production brought numerous challenges as the transportation and refining system were not prepared for this influx. Moreover, as the crude oil was only allowed to be exported to Canada, it caused severe price distortions (Melek and Ojeda, 2017).

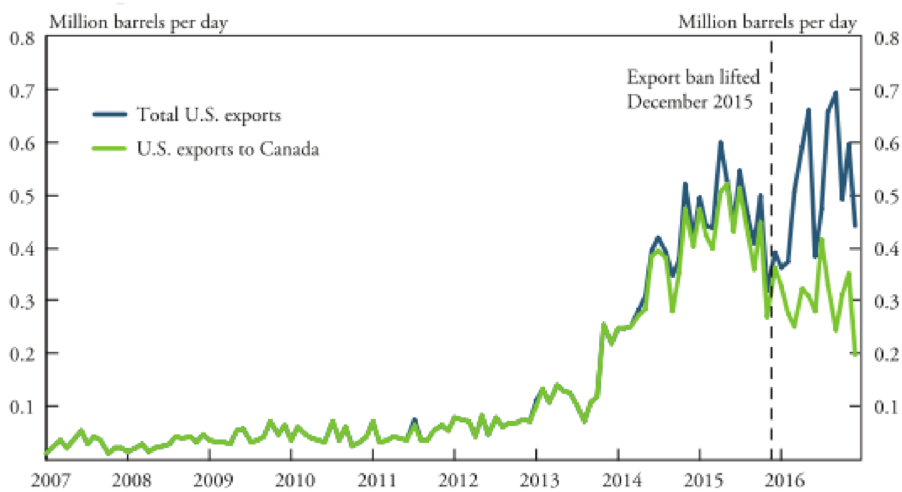

Figure 2: Comparison of U.S. Exports (Total vs Canada) (Melek and Ojeda, 2017)

Exports to Canada (Figure 2), which were exempt from the crude oil export ban, seemed to provide an outlet for some of the excess domestic supply. From 2008 to 2012, exports of U.S. crude oil increased modestly, averaging around 0.05 MM b/d over this period. As shale boom kicked in, exports rose to 0.6 MM b/d by early 2015. Although oil prices began to decline in mid-2014, both production and exports continued to increase until April 2015 before decreasing. The export ban appeared to have distorted both U.S. and Canadian oil flows and contributed to price distortions by sustaining domestic oversupply.

However, this was not sufficient when the oil prices plummeted in mid-2014 when there was oversupply of U.S. oil in the domestic market resulting in U.S. commercial crude oil inventories rising by 106 million barrels during 2015 alone (Delaney, 2017). Consequently, U.S. producers pushed for a repeal of the oil export ban, arguing that allowing exports of U.S. oil would help eliminate the domestic price discounts and provide relief to the ailing oil industry by allowing access to more markets for American oil.

b) **Conflict within the oil market: Producers vs Refiners**

As crude oil is not a homogeneous commodity but differs based on its properties, light oils are preferred by refiners as they require less processing to produce larger amounts of gasoline and diesel (Melek et al., 2017). Sweet crude oils, with a lower sulfur content than sour crude oils do not need further handling to fulfill sulfur emission requirements.

Transportation factors into the cost of crude oil when it is moved to a refinery. The U.S. refinery sector has been investing in advanced refinery technology and most refineries on the U.S. Gulf Coast, in Texas and the Midwest have been retrofitted to meet the supply of predominantly heavy crude in that region. Conversely, East Coast refiners, are primarily configured to process light oil. Oil producers thus must transport their oil to its appropriate refineries. The shale boom highlighted this mismatch between refinery configuration and U.S. light oil production (Langer et al., 2016). Refiners reacted to the supply growth by substituting their imports with heavy oil. Therefore, exports of petroleum products soared, as the export ban did not apply to refined petroleum products.

In 2011, the U.S. became a net petroleum products exporter. Due to the export ban, U.S. refineries were able to buy low-priced U.S. crude oil, refine it, and then sell those products at (high) world market prices. Thus, all revenues from lower crude prices in the U.S. were collected by the refiners and not consumers or producers. The refiners were therefore against lifting the ban and argued that allowing crude exports would increase domestic refined product prices, like gasoline, and they argued that exporting crude would reduce the security of the nation’s energy supply (Agerton and Upton, 2017).

Conversely, the oil producers argued that exporting crude oil would not increase gasoline prices but would lead to a decrease in gasoline prices as oil prices dropped with expanded supply and depressed refined product prices (Yergin et al., 2014). Further, they argued that increasing domestic prices to parity with international ones would stimulate new investment and oil production, creating thousands of domestic jobs. Therefore, there resulted a political contest that put different parts of the oil industry against one another, each offering a different policy solution: lifting restrictions on oil exports (producers) or investing in more refinery and transport capacity at home (refiners) (Colgan and Van de Graaf, 2017).

Table 1 (Modified from Colgan and Van de Graaf, 2017) summarizes the positions of the key interest groups at low and high oil prices respectively.

Time	**Factor**	**Oil Producers**	**Refiners**	**Consumers**
2011-2014: High oil prices	Position	Pro Repeal	Against Repeal	Against Repeal
	Motive	Foregone revenue	Profit from price differential	Keep fuel prices in check
	Preference intensity	Medium: Already high profits	High: Due to WTI-Brent spread	High: Fuel prices high
	Result	**Ban maintained**		
2014-2015: Low oil prices	Position	Pro Repeal	Against Repeal	No position
	Motive	Averting crisis in industry	Profit from price differential	Low fuel prices so no issue
	Preference intensity	High: Question about survival and saving jobs	Medium: Low spread and crude prices low	None
	Result	**Ban repealed**		

Table 1: Positions of primary stakeholders in export ban debate (Modified from Colgan and Van de Graaf, 2017)

At the end of 2015, the low oil prices spurred a furious campaign from the oil producers to end the ban and allow them new markets for the produced oil which will help them stay afloat in the adverse economic conditions.

c) Impact studies of repealing the ban

There were several studies summarized by Medlock (2015) which examined and predicted the consequences of the ban repeal. Regardless of the policy stance, all studies generally recognized that lifting the restriction would result in increased domestic crude oil production, as U.S. oil producers could access international markets. The studies differed significantly, however depending on the inbuilt assumptions, in their assessment of how large the increase in production would be. Projections ranged from just 100,000 b/d according to the consulting firm ICF (Vidas et al., 2014) to as much as 2.3 MM b/d according to the consulting firm IHS (Rosenfield et al., 2014) but all studies concluded that when ban is lifted, the discount on the U.S. crude oil prices will dissipate and increasing hydrocarbon production will become commercially attractive.

These studies were partially instrumental in providing evidence for advantages of repealing the ban and helped provide the policy-makers empirical evidence to repeal the ban.

Results of repealing the ban

The combination of the factors discussed above finally gave a result and the crude oil export ban was repealed on December 18, 2015.

As seen in Figure 3, the monthly oil exports increased from 0.39 million b/d in December 2015 to 0.44 million b/d in December 2016, accounting for 5 percent of December U.S. oil production. In 2016, U.S. oil exports were 12 percent higher than their 2015 average, despite global oversupply and falling U.S. oil production in 2016. Then in 2017, oil exports increased by 300,000 b/d to a total average of 900,000 b/d in the first half of 2017 and in late September even hit a record of about two million b/d (Siliciano, 2017). But the U.S. is still producing crude oil at monthly levels not seen since the 1970s – roughly 9.7 million b/d and EIA expects that annual U.S. production will reach a record high this year. Since lifting the ban, U.S. crude oil exports have grown by roughly 1.3 million b/d (as of October 2017), while imports of crude oil have dropped by nearly 23 percent since 2005 (Mandel, 2018).

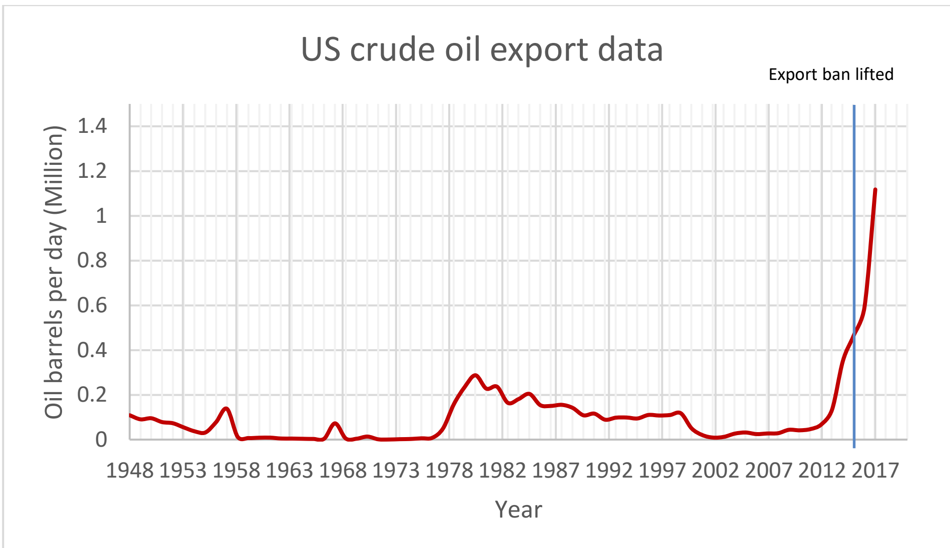

Figure 3: U.S. Exports of crude oil (EIA)

The increase in oil exports after the ban was lifted, even during a period of falling U.S. oil production and excess global supply is evidence that the export ban distorted oil trade flows. Its removal increased efficiency by eliminating these distortions. Additional evidence for fewer distortions and increased efficiency is that while total U.S. oil exports increased after the ban was lifted, exports to Canada decreased (Melek and Ojeda, 2017). Moreover, the multi-year declining trend in Canadian imports from the rest of the world reversed in 2016, and total imports excluding the U.S. increased significantly. According to the EIA, the U.S. exported oil to 26 countries including Canada in 2016, more than triple the number of destinations in 2014 and almost triple the number of destinations in 2015.

Together, these developments suggest the oil market became more efficient after the removal of the U.S. export ban.

Conclusion

Thus, it was seen that the export ban presented a binding constraint on the domestic market and the benefits of lifting the ban extended beyond the price uplift it could provide to the upstream. Once the ban was lifted, it immediately allowed the sale of domestic crude oils into the international market where prices reflected differences in crude quality and therefore was higher for the light crude oils being produced from domestic shale plays. This, in turn, incentivized investment in the midstream aimed at moving domestic crude oils to the coast – through pipelines and other means – for export through port facilities, where additional investment is required. Therefore, the ban on crude oil exports had also left investment in infrastructure unrealized (Medlock et al., 2015).

Moreover, exporting oil had a geopolitical effect that is starting to take effect by displacing oil from OPEC, the international cartel that includes a number of the world's largest nationalized oil companies, such as Saudi Aramco (Siliciano, 2017). According to a few projections, the U.S. may even overtake Russia to become the world’s largest oil producer by 2023, accounting for most of the global growth in petroleum supplies with U.S. crude production expected to reach a record of 12.1 million b/d surging past Russia, currently the world’s largest crude producer at roughly 11 million b/d (Kent and Puko, 2018). Hence, we can conclude the economic benefits to the U.S. economy by lifting the crude oil export ban were manifold and the ban played a major role in influencing the hydrocarbon markets, both domestically and worldwide.

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Canadian Upstream Sector in Brief - Outsized Resources Looking for New Markets

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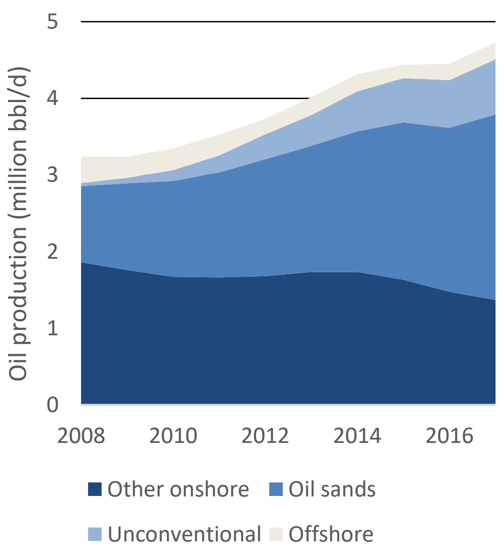
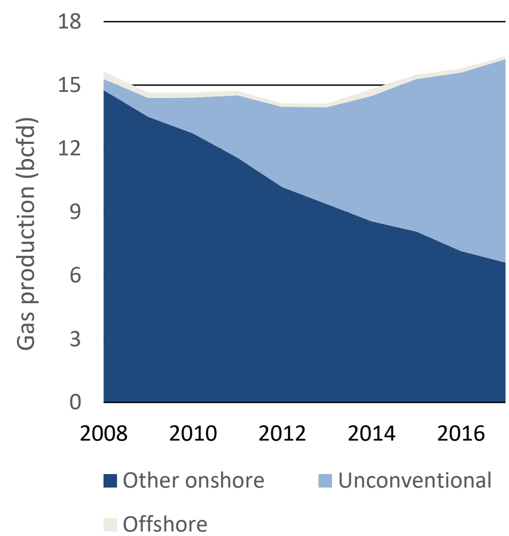
Despite relative abundance of oil and gas resources, Canadian producers face challenging commercial conditions. In 2018, Albertan natural gas prices traded at negative values at multiple points[1] and Western Canadian Select (WCS) sold at a fifteen-dollar discount to the US benchmark.[2] [3]In both cases, there is an interplay of geology, geography and policy. While Canada contains the largest oil reserves in North America and ranks third globally after Venezuela and Saudi Arabia,[4] its population is less than the state of California's[5] and its biggest buyer, the United States, has rapidly increased its own production.[6] To grow sustainably, Canada's exploration and production (E&P) sector may need to not only grow production, but also overcome regulatory hurdles to build infrastructure like pipelines and liquefied natural gas (LNG) facilities.

The size of the prize

Canada's E&P companies produce from several key resource themes such as shale (e.g. Bakken, Cardium, Duvernay, and Montney), the oil sands (both mining and in-situ), offshore in basins off the Atlantic East Coast as well as a number of more mature conventional and unconventional plays. In total, Canada produces almost five million barrels per day (b/d) of liquids, including oil and condensate as well as roughly sixteen billion cubic feet per day (bcfd) of natural gas (figures 1 and 2). Much of the liquids are in the form of bitumen and similar from oil sands, while unconventionals ranging from more recent shale to developments to legacy coal bed methane produce a little over half of the nation's gas supply.





Source: Rystad Energy UCube Database[7]

While Canada produces significant volumes of oil and gas, its reserves are broadly indicative of unmet potential. The country contains 173 billion barrels (bbls) and 67 trillion cubic feet (tcf) of proven reserves[8] and with its extensive shale plays, the US Energy Information estimates that Canada contains 8.8 billion bbls and 573 tcf of technically recoverable shale resources, potentially with wellhead economics similar to the United States.[9] In other words, there appears to be significant running room with potential production upsides that may not be fully realized at this time.

Few barriers to entry, but domestic demand is a challenge

Unlike much of the Americas outside of the United States, there appear to be few barriers to entry for E&P companies in Canada. Large producers in the country include US majors like ExxonMobil and Chevron, regional integrated companies like Husky and Suncor, and independents and pure-play E&Ps (figure 3). The largest producers typically have significant oil sands exposure, but this does not apply across the board. For example, Crescent Point Energy focuses on the Viking and Bakken plays among others in Saskatchewan.[10] Similarly, Husky has invested in a number of offshore oil and gas projects. This means that industry activity (and future interest) is not driven by a single play or basin. This variety, along with the established industry footprint and business and regulatory standards, opens up opportunities for smaller firms to compete.

Figure 3. Canadian companies represent the majority of top domestic producers

Company	Oil production (bbl/d)	Gas production (mmcfd)	Natural gas liquids production (bbl/d)	Combined production (BOE/d)
Canadian Natural Resource	641,475	1,601	-	908,308
Suncor Energy	617,400	-	-	617,400
Imperial Oil	354,000	120	1,000	375,000
Cenovus Energy	296,401	326	16,928	367,662
Husky Energy	209,600	378	10,500	283,133
Tourmaline Oil	18,778	1,222	19,959	242,325
Seven Generations Energy		493	115,100	197,333
Crescent Point Energy	139,996	107	18,250	176,013
Encana	400	838	29,100	169,167
Devon Canada	128,000	17		130,833

Sources: Company annual reports, SEDAR database[11]

But even though Canada is a large producer of oil and gas, its domestic demand is limited. The country exports roughly 3.3 million barrels a day of liquids and imports only 600,000 barrels per day, mainly from the United States.[12] This means the country's net exports are equivalent to half of its production. Similarly, Canadian net natural gas exports to the United States averaged 6 billion cubic feet per day over the last year, more than a third of total production.[13] These export levels seem to indicate that companies active in the region are focused heavily on the export market and midstream infrastructure could be key to project development. It also likely means that there is large demand for condensate and natural gas liquids for diluent, allowing for export of bitumen produced from the oil sands.

Tapping the export markets

The country produces significant quantities of oil and gas, but as mentioned, the United States is its single largest importer. As the United States' production has also risen, this has squeezed Canadian E&Ps and due in part to stretched infrastructure, with low realized prices for the country's exports. There appear to be three hurdles that companies need to overcome to grow production sustainably (and profitably).

First is lowering domestic costs of production. For example, oil sands have relatively high ongoing operating costs, sometimes exceeding $20 per barrel despite significant reductions since the oil price decline post-2014.[14] While other plays may not prove as costly, the dramatic decline in US shale capital and operating expenditures means that Canadian operators may need to move down the cost curve to remain competitive.[15]
Secondly, as a major exporter to the United States, Canada may need to tread carefully in light of recent tariff discussions. To a degree this is in the hands of the federal government, not private companies, but their voice could play a role in the discussion. The country exports roughly 80 percent of crude production, 50 percent of its natural gas production, and 25 percent of its refined products to the United States,[16] so Canadian E&Ps potentially face high costs in a trade dispute.

Lastly, while Canadian E&Ps cannot change geography, the oil and gas industry (and the government), may need to build-out pipeline and shipping infrastructure to lower the transport costs and reduce price differential and at the same expand access international markets. Recent disputes over pipelines and the longer-standing debates over LNG have stalled projects that might ease the reliance on saturated US markets. This could require more investment and more in-depth discussions with regulators, but the effort appears worthwhile. Addressing all three obstacles to growth, E&Ps could be on the path to better compete in increasingly global oil and gas markets for the long term.

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Quantifying Socially Responsible Investing in the Oil and Gas Sector

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1. Introduction

At the 2018 San Francisco Barron's Investment Summit the message was overwhelming; sustainable investments are here to stay. Morgan Stanley's Audrey Choi stated that the annual growth of assets invested under an ESG (Environmental, Social and Fair Governance) mandate was 23% between 2014 and 2016. It therefore seems apparent that the market wants ESG integration. And it wants it as soon as possible. This is of course problematic for companies and industries that do not conventionally fit the ESG mandate, including the oil and gas industry. However, the majority of long-term energy outlooks identify a clear need for natural gas as part of the energy transition towards a more environmentally sustainable future. Consequently, there is a clear need for oil and gas companies to integrate ESG criteria into their operations. While simultaneously providing shareholders with competitive returns. Oil and gas companies must generate the necessary capital in order to pursue exploration opportunities, which in turn will meet the future demand for fossil fuels, in a market which does not consider these activities as truly ESG compatible. Therefore, this article proposes one method of quantifying ESG progress in the oil and gas sector in order to allow investors to better assess investment opportunities. This method is intended to allow shareholders to better make socially responsible investments while also accounting for investment in the oil and gas sector. Therefore, this paper will outline a tentative method for quantifying ESG progress in the oil and gas sector and relate this progress to portfolios, and their expected returns, which include oil and gas securities.

2. ESG Investing and the Oil and Gas Sector

The ESG criteria defined by Goldman Sachs, JPMorgan, and other key firms reflect the transition of ESG from an esoteric concept to a relatively well-defined mandate with profound implications on the market (Goldman Sachs, 2018; JPMorgan Chase & Co., 2018). These criteria incorporate the environmental and social progress made by companies, in addition to their integrity and corporate image, into their appeal to investors. Coincident with the emergence of ESG as a mainstream investment practice over the last five years, the oil and gas industry has experienced one of its most challenging periods in recent history. Exploration expenditure declined over the course of the same period for supermajor and large-cap companies (see Fig.1). With a similar trend reflected in the return on equity (ROE) (see Fig.2). However, as the ROE in this sector looks set to recover over the course of 2018, investors are relatively bullish on the oil and gas industry. However, it is unclear how the uptake of ESG criteria will affect companies in this sector.

3. Utilizing an ESG Premium

The proposed methodology provides a quantitative method of comparing oil and gas companies via ESG criteria (however this methodology can be applied to any industry which publishes annual data on performance indicators).This is accomplished through the inclusion of an ESG Premium, added to shareholders' expected market return for any given portfolio. This ESG Premium is comprised of an ESG Metric, an ESG Multiplier, and the proportion of the portfolio that these companies represent.

3.1 The ESG Metric

The ESG Metric reflects the annual progress made by a company in ESG criteria. This progress is recorded through three indicators, with their weightings also listed below:

1. Direct Greenhouse Gas Emissions (Million Tonnes of CO_2 Equivalent) (0.4)
2. Fresh Water Withdrawn (Million Cubic Meters) (0.2)
3. Acid Gases and Volatile Organic Compounds Emitted (Thousand Tonnes) (0.2)
4. Gender Diversity (% Professional Women Up to 50% of the Workforce) (0.2)

The weighted average of the annual percentage change in these indicators is referred to as the ESG Metric. This Metric will decrease with a decrease in indicators one through three and an increase in indicator four up to fifty percent. Selection of these indicators was based upon their availability for major oil and gas companies and their relevance to ESG as a concept. However, there is scope for further inclusion of indicators should oil and gas companies prove more consistent in their publication of environmental and social data.

3.2 The Proportion of the Portfolio Under Consideration

This factor reflects the current proportion of the portfolio under consideration that the relevant company represents. For example, a portfolio which is comprised of 20% Shell would see the most recent Shell ESG Metric multiplied by 0.2 to reflect this proportion.

3.3 The ESG Multiplier

The ESG Multiplier is intended to reflect shareholders' preference for incorporating ESG into their investments. Consequently, it remains consistent for all companies considered within the same portfolio. However, shareholders may have a differing ESG preference across their portfolios. For instance, a shareholder may have one portfolio with an ESG Multiplier of 0.25 and another with a Multiplier of 0.65 but for all companies within each of these portfolios the same Multiplier will apply. This Multiplier is on a linear scale from zero to one with zero reflecting no interest in ESG criteria and one reflecting a strong emphasis on ESG criteria. Based upon the research conducted during this study, an ESG Multiplier of 0.5 is recommended for the best results. However, individuals with an extreme aversion to, or preference for, the inclusion of ESG criteria in a portfolio may prefer values closer to the lower and upper limits of this linear distribution. The product of the factors described in Section 3.1 and 3.2 is multiplied by the ESG Multiplier to produce a final value for the ESG Premium.

4. Applying ESG Premiums to Varied Portfolios

Given the calculation of appropriate ESG Premiums for oil and gas companies, ESG Premiums must be applied to portfolios which hold shares in the relevant companies. In order to effectively convey the role of an ESG Premium, what follows is worked examples of applying an ESG Premium to two portfolios. Due to the data available, and the market capacity of their stock, each of the portfolios has 25% of its value invested in four oil and gas companies; BP, Chevron, ConocoPhillips, and Shell with 75% of the portfolio comprised of non-ESG investments (see Fig.3). In one case, the portfolio remains constant and the ESG Multiplier is varied. While in the other it is the Multiplier that remains constant and the portfolio varies. In both cases, the initial expected return from the portfolio is 5% with the ESG Premium added to this.

4.1 Calculating Company ESG Metrics

As described in Section 3.1, the ESG Metric is calculated via a weighted average of the annual percentage change in four indicators. In the examples which follow, the most recent data available has been utilized to calculate the ESG Metrics for four supermajor oil and gas companies for the year 2016 to 2017 (see Appendix). With these Metrics then applied to either a consistent portfolio and varied ESG Multiplier (Section 4.2) or a consistent Multiplier and varied portfolios (Section 4.3).

4.2 The ESG Multiplier and Expected Return

The ESG Multiplier is intended to reflect the emphasis that the investor places upon ESG with regards to the relevant portfolio. It is therefore intended to have a significant impact on the ESG Premium and consequently the portfolio owner's expected return. In this case, Portfolio A is owned by an investor with a low emphasis on ESG investing, represented by an ESG Multiplier of 0.25. While Portfolio B is owned by an investor with a high emphasis, represented by an ESG Multiplier of 0.75. Both Portfolio A and B mirror Figure 3, thus the proportion of the portfolio under ESG consideration remains constant. However, the adjusted expected return from each of the portfolios differs relative to the investor's ESG preference. Portfolio A sees an adjusted expected return of 4.7% compared to Portfolio Bs adjusted return of 4.2%. Therefore, by utilizing an ESG Multiplier the expected return from each of these portfolios has been tailored to more accurately reflect how strongly the investor values the ESG Metric of the oil and gas companies incorporated in the portfolio.

4.3 The Impact of ESG Performance on Expected Return

In the case of the ESG Premium described in this article, positive ESG performance by an oil and gas company over the course of a year will see investors who are ESG preferring willing to accept a slightly lower return on their investment during that year. The adjustment to their expected return is therefore relative to three factors; how much they value ESG performance, the ESG performance of the oil and gas companies in the portfolio, and how much of the portfolio is comprised of each of these companies. Section 4.2 addressed the first of these three points while the latter two are best described through the comparison of Portfolios 1 and 2 (see Fig.4). As is evident, Portfolio 1 is comprised of 15% ConocoPhillips, a company which performed well in ESG criteria between 2016 and 2017. Consequently, the adjusted expected return of this portfolio is 4.5%. Conversely, Portfolio 2 does not include shares of ConocoPhillips. Instead holding 20% of its value in Chevron shares, a company which performed poorly in ESG criteria between 2016 and 2017. As a result, the adjusted expected return of this portfolio is 5.1% with Chevrons poor 2016/17 ESG performance resulting in an increased required rate of return to satisfy the investor. In this way, the proposed ESG Premium tailors the investor's expected return from companies relative to their ESG performance. Through this method companies which fail to improve their ESG Metric will be required to generate greater returns to keep shareholders with a preference for ESG content. The stronger the ESG preference, as defined by the ESG Multiplier, the greater the return that poorly performing companies will be expected to generate. On the other hand, companies which perform well in ESG criteria will be given more leeway by investors with a strong ESG preference while investors with less emphasis on ESG will be less willing to accept lower returns despite strong performance in the assessed indicators. Positive ESG performance for companies in the oil and gas sector would therefore result in ESG preferring investors expecting lower returns and would therefore free up more capital for oil and gas companies to pursue projects which benefit their ESG Metric and improve their environmental and social impact.

5. Why Use an ESG Premium Relative to Expected Return?

At its core, this ESG Premium is therefore intended to allow investors to adjust their expected annual return from a portfolio relative to the degree to which the portfolio under consideration meets ESG criteria. This works off the basis that a truly ESG preferring investor would be willing to see reduced return on their investment in a company if it is improving its ESG performance annually. Coincident with this assumption is that if oil and companies are required to generate lower returns they may be more willing to pursue projects which provide an opportunity to further lower their ESG Metric. And therefore, their ESG Premium for investors. In utilizing an ESG Premium which considers annual ESG performance, the emphasis of the investor on ESG, and the proportion of the considered portfolio that the assessed companies occupy the intention is to provide investors with a tool to compare companies both in regards to financial and ESG performance. Conventionally, ESG Premia have chiefly focused on the risk of ESG investments relative to the wider market; with the hypothesis being that companies which perform well in ESG criteria tend to perform better financially in the long run (McKnett and Roe, 2014). However, incorporating ESG performance into investors' expected returns marks a more direct approach in encouraging the pursuit of environmentally and socially compatible projects. The use of an ESG Premium as described in this article will help both investors and companies track their financial performance relative to ESG progress. And will consequently allow long term investors to more effectively consider their position on any company which publishes the data utilized in calculating the ESG Metric. A company which consistently fails to meet investors adjusted expected return each year has underperformed financially relative to its ESG progress and therefore investors may want to consider alternative investments. By using an ESG Premium related to an investor's expected return, and not risk, this method directly connects financial and ESG performance. A lack of progress in one must be compensated for by progress in the other. With the appropriate degree of compensation determined by investors' emphasis on ESG.

6. Conclusions

ESG Premia in general represent a potential method of quantifying socially responsible investment practices. This article has attempted to shed light on the demand that exists for such practices within the oil and gas industry, and how performance indicators could be leveraged to provide a more quantitative framework in assessing these practices relative to investors' returns. However, the framework and methodology proposed is tentative and subject to change relative to the preferences of the investor. There is considerable scope to implement additional indicators in the ESG Metric should operators record and publish data more consistently. Examples of such could be the inclusion of the proportion of minority professional professionals employed or the total paid for all HSE fines over the course of the year. This information is published by some but not all of the companies considered and would provide a more holistic ESG Metric were it more widely available. Furthermore, the scope for the use of ESG Premia is huge. Provided that comparable companies are assessed, ESG Premia could be employed across any number of sectors utilizing a variety of differently weighted performance indicators within the ESG Metric. At present, ESG Premia are occasionally applied to risk but rarely ever applied to expected market return. It is hypothesized that such a shift would allow the investor to more effectively track the performance of their investments relative to ESG. While the inclusion of the ESG Multiplier in this case ensures that investors' ESG preferences are accounted for within the premium. In this way, ESG Premia appear particularly well suited to the nuanced future of the oil and gas industry. It is clear that oil and gas companies will require public investment to fund future operations while simultaneously ensuring that they adhere to the increasingly high expectations of the public relating to ESG performance. Through the adoption of the proposed methodology, or similar, it is suggested that oil and gas companies will be given more economic flexibility in ensuring that they meet ESG standards and investors can more effectively identify oil and gas companies which suit their investment criteria; i.e. those which produce sufficient returns relative to their ESG progress and the ESG preference of the investor. Therefore, the use of such an ESG Premium would be of benefit to investors and oil and gas companies during the challenging energy transition.

Figures

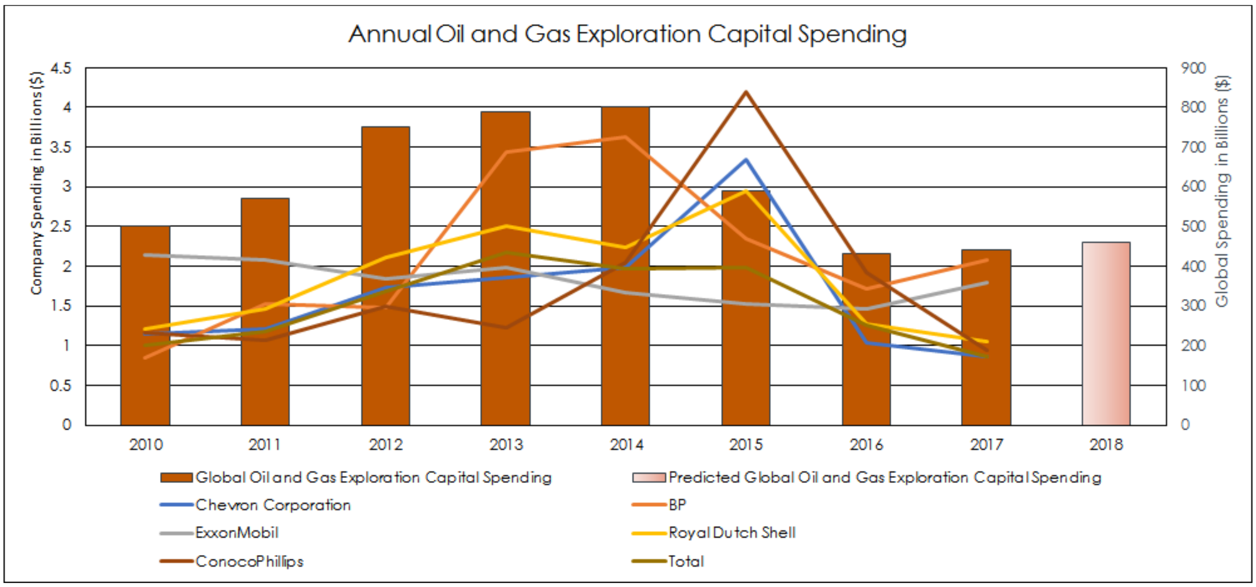

Figure 1: Annual Oil and Gas Exploration Capital Spending. Information sourced from 2018 annual reports and the International Energy Agency (2018).

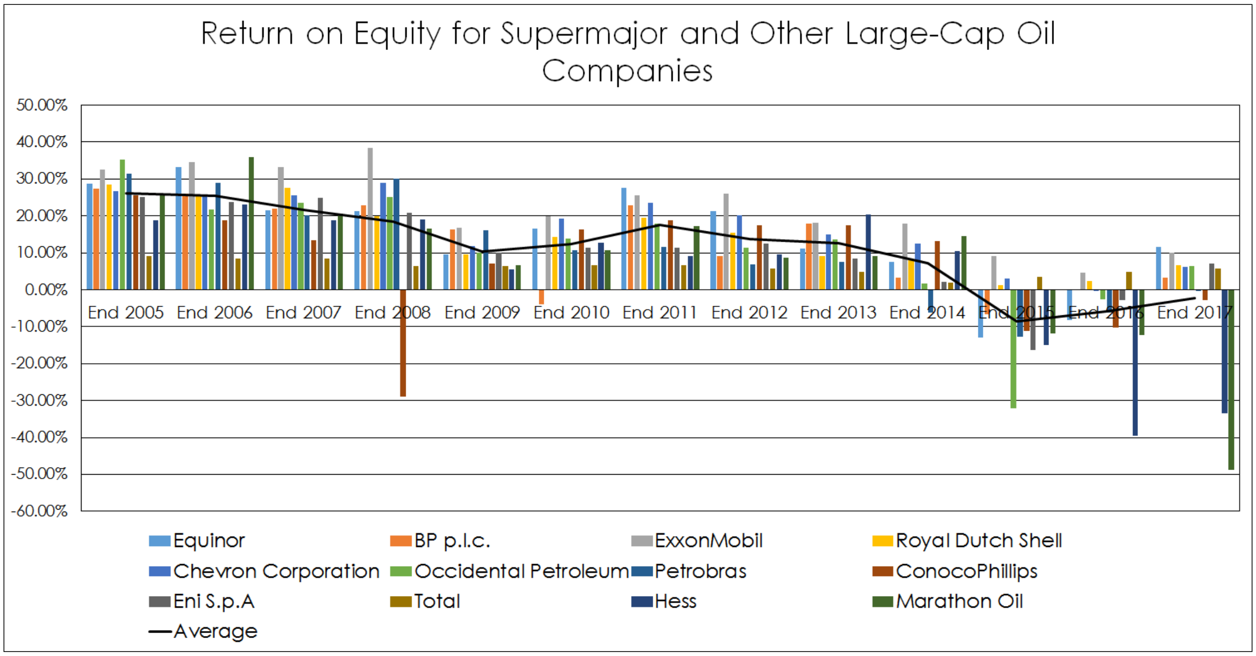

Figure 2: Change in Return on Equity Over Time for Supermajor and Large-Cap Operators. Information sourced from 2018 annual reports.

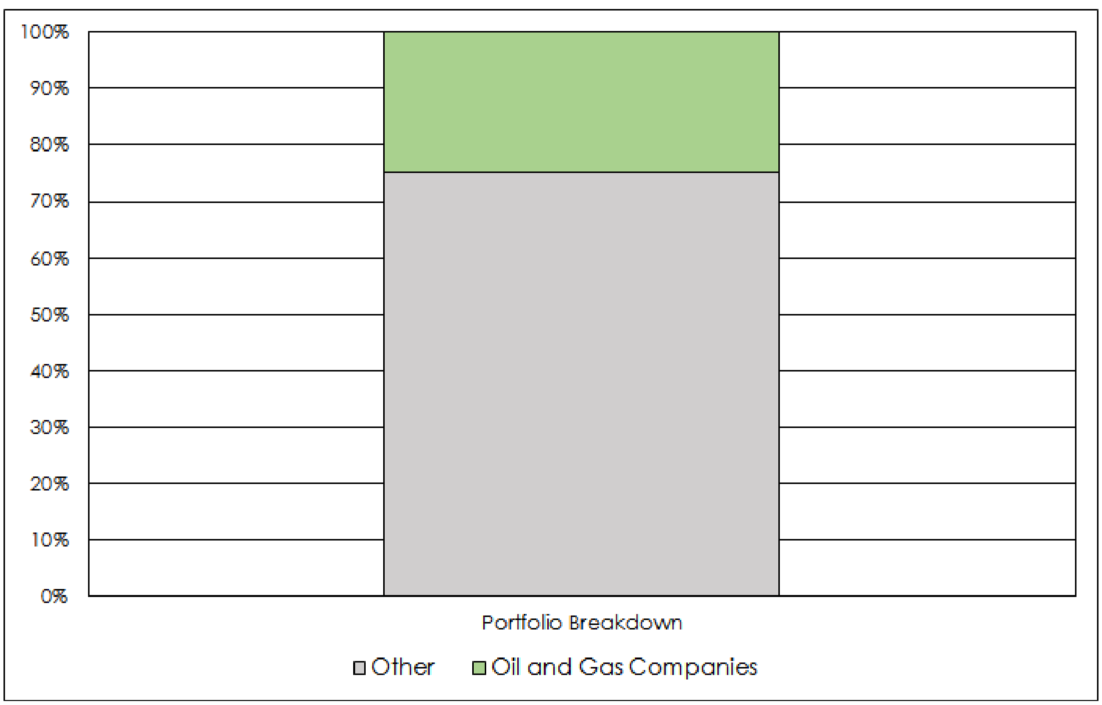

Figure 3: General Breakdown of the Modeled Portfolios Considering an ESG Premium

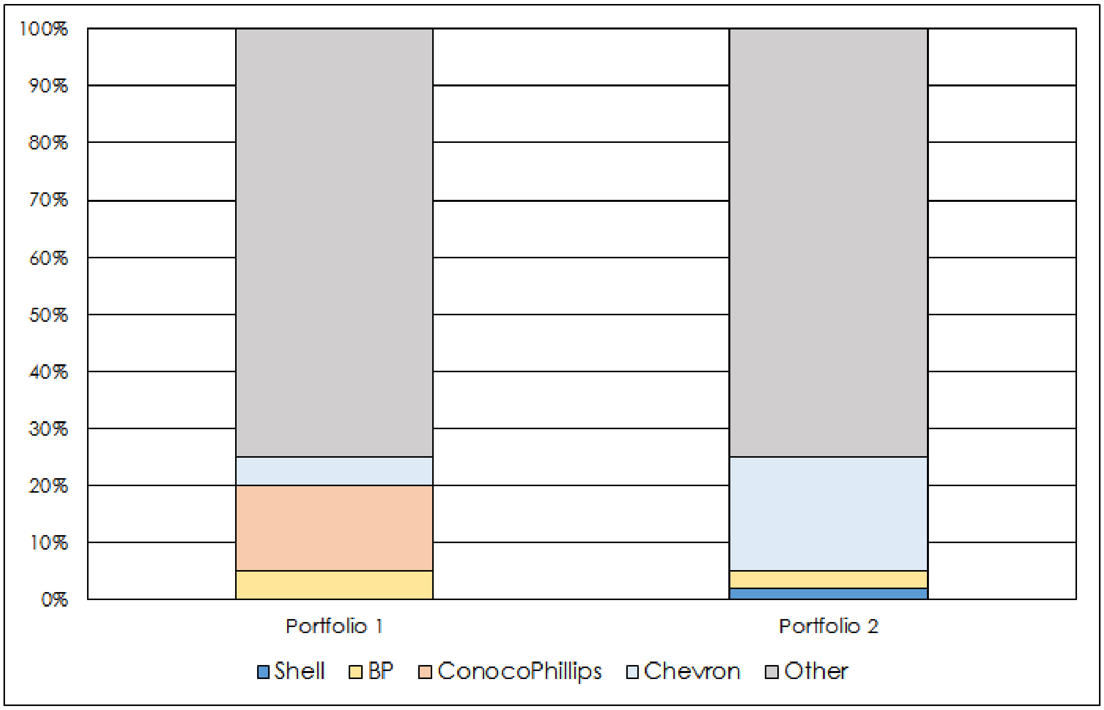

Figure 4: Breakdown of Portfolios 1 and 2 Modeled Considering an ESG Premium

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CALL FOR STUDENT POSTERS

The Society of Petroleum Resources Economics (SPRE) is dedicated to continue leading conversations regarding the flow of resources in the Oil & Gas sector. Founded on the pillars of reserves evaluation, commodity pricing, petroleum project management, and corporate financing, the SPRE Petroleum Resources Economics Conference (PREC), to be held in Houston TX on 10th May 2019, aims to be the leading forum for discussion regarding the economic and financial aspects of the industry.

Recognizing the quality work of the students & future thinkers behind the Oil & Gas industry is a core element to SPRE's mission. SPRE encourages the submission of any and all high-quality abstracts to present posters during the student poster session at the upcoming SPRE 2019 PREC. In particular, we welcome economics-focused contributions covering the entire Oil & Gas value chain, including but not limited to the following:

- Reserves and resources management
- Hydrocarbon prices outlooks, product supply and/or demand
- Natural gas & LNG markets
- Unconventional geosciences or engineering economics
- Offshore project finance and resource assessments
- Dollars and cents company resources allocation
- OPEC & international oil markets
- Policy issues, regulatory economics, and geopolitical impacts
- Oil and gas sustainability & ESG

Abstract Submission Details:
Word limit: 300
Deadline for abstract submission: January 15, 2019
Acceptance notifications sent: March 1, 2019
Conference presentations: May 10, 2019
Submit abstracts to: 2019PRECposters@SPREconomists.org

For more information, contact: 2019PRECposters@SPREconomists.org

SPRE

Call for Articles for JPRE Issue 2: January 1, 2019

Submission Details:

Word limits: 300 / 1000 / 2500
Deadline for submission: December 1, 2018
Journal issue date: January 1, 2019
Submit articles to: jpre@spreconomists.org
More Information, contact: saad.siddique@spreconomists.org, jc.rovillain@spreconomists.org

Submissions will be judged on the following criteria:

- Clarity of definition of aim and scope of article
- Use and adequate description of scientifically relevant methodologies
- Article to not have been published elsewhere before submission
- Support of conclusions by the presented data
- Logical construction and writing of the article

JPRE Cost

For SPRE members: Free

For non-members,
Fee for one issue: $25
Annual Subscription (4 issues): $75

From your Membership Coordinator

SPRE Members, I am excited that you are reading the first Journal of Petroleum Resources Economics (JPRE), published by and for the SPRE membership and industry subscribers. I have a nice perk to offer those of you taking the time to read this today. By heading to Eventbrite between the Oil Prices Outlook on the 4th and the December networking event for members, you can renew your membership for 2019 for only $100 or $25 for students.

As you know, membership benefits include free access to regular monthly events, food and drink at quarterly members only events, and discounted access to our major events; the 2019 Petroleum Resources Economics Conference in May and next fall's Oil Prices Outlook.

Contact me at jgarland@spreconomists.org if you have any questions. We will see you at the Oil Prices Outlook on October 4th.

Jim Garland
SPRE Membership Coordinator