JPRE

JOURNAL OF PETROLEUM RESOURCES ECONOMICS

QUARTERLY JOURNAL OF THE SOCIETY OF PETROLEUM RESOURCES ECONOMISTS

ISSUE 3 – 2019 Quarter 2

SPRE

The Society of Petroleum Resources Economists

ABOUT JPRE AND SPRE

This is the third 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. SPRE has been active in the USA, Canada, UK, France, China, Pakistan, and might soon have student chapters in Algeria, India, Middle East, and beyond.

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

Mission Impossible? MISSION ACCOMPLISHED!

0. Yes, "from absolutely zero" our own SPRE have pulled off a quantum leap.
1. Absolutely, our step by step approach has paid off in an era of instant gratification, "thanks to the sheer determination of our leaders." In other words, it is my privilege and my honor to introduce to you our latest and third Journal of Petroleum Resources Economics. 100+ pages mind you.
2. Additionally, we were fortunate enough to somehow craft a SPRE 2019 Petroleum Resources Economics Conference lineup "to be reckoned with" too, as soon as our first annual Conference. Including but not limited to past and future SPE Presidents.
3. Last but not least, couldn't have pulled it off myself without you: grateful to the handful of professionals and students alike that have made it possible.
4. May the Fourth be with you too: we have managed to forge the missing link.

JC Rovillain
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). With three successful issues, each one improving significantly than its previous issue, SPRE has set its feet firm as a professional society.

The Journal of Petroleum Resources Economics is the 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 shall also feature seminars/posters presented at SPRE's annual Petroleum Resources Economics Conference (PREC).

This issue showcases eight articles from professionals, researchers, and students from USA, Canada, Australia, UK, Hungary, and Pakistan. Two articles are from 2019 PREC distinguished speakers. This issue also includes highlights of SPRE chapter meetings in USA, Pakistan, and Canada. The PRE Conference highlights, speaker bios, and agenda are also presented here.

In these three issues, we have received articles from students, researchers, and professionals hailing from the Americas, Europe, Australia, and Asia. The articles have covered issues ranging from energy markets, price forecasting, valuation, influence of policies on the commodity prices and markets, to unconventional resources, and inclusion of social responsibility in decision making. The journal strives to publish articles from across the globe and on topics covering interdisciplinary issues in oil and gas. 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
May 09, 2019

CONTENTS

COMMON PITFALLS IN OIL AND GAS VALUATIONS

Gavin Ward, Partner, RISC Advisory, London, UK
Stephen Newman, Principal Advisor, RISC Advisory, Perth, Australia
Geoff Salter, Partner, RISC Advisory, Perth, Australia

A stark statistic is that most mergers and acquisitions (M&A) fail to generate value. According to collated research[1] and a 2016/2017 Harvard Business Review report, the failure rate for mergers and acquisitions sits between 70% and 90%. A similar article[2] from 2018, reported that nearly half of some 90 M&A professionals surveyed, believed the deals they manage would "*increase in transaction value*" over the next three years. Respondents expressed great interest in using M&A to move beyond existing lines of business into new strategic areas, but this still resulted in core business M&A failure rates of between 66% and 75% according to the McKinsey article. However, since very little to no post-acquisition review has been published, it is impossible to know whether these are failure rates which should be applied to the oil and gas industry, or whether they are just average failure rates across multiple sectors.

There are many reasons for the poor performance quoted in reports on acquisitions by the big accountancy and advisory firms, but they tend to focus on the non-technical reasons and sometimes use general explanations like *'inadequate due diligence'* and '*it's important to understand the value added',* or, in other words, over-valuing new growth opportunities which might arise from the acquisition.

This JPRE article digs into the '*inadequate due diligence'* explanation, since it's authored by subsurface, technical professionals who have led due diligence valuation teams through hundreds of data rooms; from the sale of Petrobras Nigeria's multi-billion-barrel producing oil fields, to high capex field developments in the North Sea, and much smaller and less costly Yegua plays in the Gulf of Mexico. The technical due diligence and economic valuations always use assumptions and estimates, and, as we will show, are statistically accurate only when a significant number of samples (wells and fields) are used. After decades of reviewing the value of oil and gas asset acquisitions, we have noted the following six critical factors in acquisition valuations:

1) Consider the appropriate valuation metrics;
2) Assess the uncertainty on a portfolio of assets; take a probabilistic approach and validate with a deterministic methodology;
3) Question your assumptions e.g. will the new owner use the same investment plan?
4) Focus on the dominant assets in the portfolio;

[1]http://lakeletcapital.com/blog/2017/3/15/success-and-fail-rate-of-acquisitions
[2]https://www.mckinsey.com/~/media/McKinsey/Business%20Functions/Organization/Our%20Insights/Merger%20Manager%20Compendium/A%20McKinsey%20perspective%20on%20the%20opportunities%20and%20challenges.ashx

5) Consider 'Black Swan' events i.e. the unexpected;
6) Treat contingent resources with extra care; not all convert to production and cash flow.

Most economists in the oil and gas industry use discounted cash flow methods to calculate a net present value (NPV). A measure of a company's total value is the sum of the NPV's for all assets minus debt and is referred to as the '*Enterprise Value'*. However, there are other useful metrics, such as:

- Multiples of EBITDA (Earnings Before Interest, Tax, Depreciation and Amortisation), which is most commonly used for service industries where Intellectual Property dominates, and few capitalised fixed assets exist;
- Capitalised Accounting Book value;
- Historic or benchmarked $value/Boe;
- Market Capitalisation.

Market Capitalisation is a valid metric as it is the current value of a company on the stock market. It is the share price multiplied by the number of shares, but it also includes short-term debt, long-term debt and any cash on the company's balance sheet. It is often the starting point for an acquiring company looking to buy all the shares in the market at this price but requires the shareholders to be willing to sell. More often than not, a premium on this price is offered to get the shareholders to sell rather than hold and is known as the Acquisition Premium. Eighty three percent of global M&A deals in 2016 had premiums between 10% and 50%, according to Bloomberg[3].

Our analysis of the sale of the Santos Limited[4] Southeast Asian production assets to Ophir Energy in 2018 makes the comparison of market capitalisation with an enterprise value approach. Ophir bought Santos' Southeast Asian production assets for an aggregate cash consideration of USD$ 205 million pre-working capital adjustments. An independent Competent Person's Report[5] issued as part of the shareholder circular gave a wide range of values for the assets based on long-term oil price (Table 1).

NPV USD$ million	**$54/Barrel Long Term**			**$60/Barrel Long Term**			**$70/Barrel Long Term**		
	1P	**2P**	**3P**	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**
Total NPV	$132	$182	$226	$182	$237	$306	$198	$259	$342

Table 1: Valuation of Santos Southeast Asian assets

The acquisition of the producing assets was structured to have an effective date of 1 January 2018, with cash flows generated by the producing assets post the effective date (but pre-completion) netted off against the final amount payable. The cash flows generated by the

[3] https://www.wallstreetprep.com/knowledge/premiums-in-ma/
[4] Santos is a predominantly Australian energy company and Australia's second-largest independent oil and gas producer.
[5] https://www.ophir-energy.com/wp-content/uploads/2018/08/Jaguar-Class-1-Circular.pdf

producing assets in 2018 have in fact been better than Ophir's expectations, owing to higher than expected commodity prices over the period, and production from the Chim Sáo field in Vietnam outperforming most forecasts. The net cash payable to Santos by Ophir on completion was therefore USD$ 144 million. An analysis of the stock market valuation over time highlights a critical factor in acquisition valuation, that of timing and pricing:

- On 2 January 2018, Ophir Market Capitalisation[6] = GBP £477 million (Value A), when share price = 67.4 UK pence per share.
- On 2 May 2018, Ophir Market Capitalisation = GBP £421 million pre-Santos asset acquisition, when share price = 59.4 UK pence per share.
- On 3 May 2018, Santos announced the sale of its non-core Asian portfolio to Ophir Energy plc.
- On 31 Dec 2018, Ophir Market Capitalisation = GBP £252 million (circa USD$ 328 million) post Santos asset acquisition (Value B), when share price = 35.7 UK pence per share at the close.

In January 2019, Ophir Energy agreed to accept a cash offer from Indonesia's Medco for GBP£ 391 million (approximately USD$ 511 million) to acquire the entire share capital of Ophir (which includes approximately 55% Acquisition Premium). Given some simple assumptions, one might be tempted to assign a value (X) to the Santos assets of X = B - A, i.e.: Value of Ophir prior to offer from Medco minus value of Ophir prior to acquisition of Santos assets. This figure is negative so is this clearly wrong? The most notable variable in this X = B – A approach is the change in oil price over the period since most of the gas volumes were contracted at fixed prices (Figure 1).

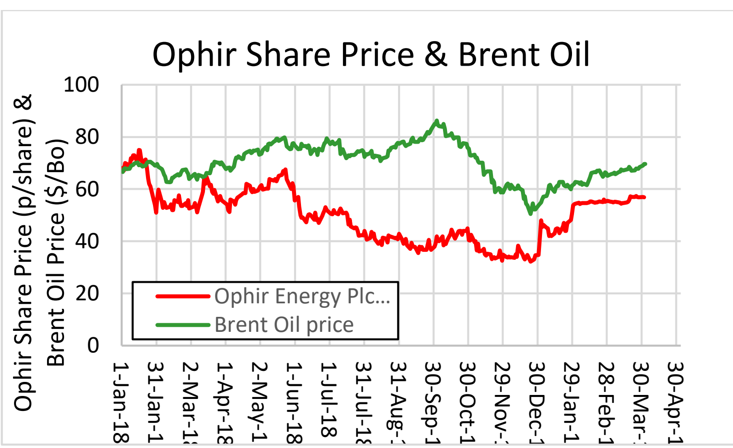


Figure 1: Change in valuation of Ophir Energy with time

This example highlights the difference between market capitalization (with Acquisition Premium) and enterprise value. Enterprise value is the theoretical takeover price if a company were to be bought and includes debt. However, the market will consider how the debt will be used by the company's management, which will be reflected in the share price. This also means

[6] Shares in issue 708,137,080

that the market capitalization value can be influenced by market sentiment, that may be unrelated to the underlying value of the assets. The oil and gas industry is capital-intensive and typically carries significant amounts of debt relative to other industries, thus creating more divergence between market capitalization and enterprise value assessments.

With M&A failure rates of between 66% and 75%, it seems reasonable to compare transaction success with oil industry exploration well success rates, which have a similar risk profile. When we consider exploration portfolios, we acknowledge that they only generate value when a statistically significant portfolio of exploration wells will be drilled, and an investor can start to rely on the portfolio '*averaging effect'*.

Before we jump into oil industry examples, we need to take a step back and look at how portfolio theory in the oil industry started. In 1952, the American economist, Harry Markowitz (who was awarded the Nobel Memorial Prize in Economic Sciences in 1990), derived a theory about how stock market investors can construct portfolios of shares to optimize or maximize expected return based on a given level of market risk, emphasizing that risk is an inherent part of higher reward (i.e.: the classic Risk v Reward trade-off). He demonstrated that it's possible to construct an "*Efficient Frontier*" of optimal portfolios of shares, which offered the maximum possible expected return for a given level of risk. This theory was published in his paper "*Portfolio Selection*" by the Journal of Finance.

Modern oil industry portfolio work combines the Markowitz work with the oil field statistical work carried out by Ed Capen in his paper[7] '*The difficulty of assessing uncertainty'*, and one other of his papers[8] published jointly with Peter Rose '*Why lognormal?*'. The result is compelling in theory but frequently fails in data-room exercises in practice, because the fundamentals are mis-used by many small to midsized companies, since they fail to test the basic assumption that predictability depends upon a statistically significant sample size. Markowitz's theory works for portfolios of stocks because there are many stocks to choose from and frequent options to trade and substitute one stock for another, one value for another and one risk for another. This is less true for transactions in the oil and gas industry where there is limited ability to substitute/swap out assets with different risks or value. The market for oil and gas assets is far less liquid than the stock market. However, the use of portfolio theory and Efficient Frontiers (Figure 2) in the oil and gas industry is a better investment selection method than simple ranking based on one or two metrics.

---

[7] Journal of Petroleum Technology, v. 28, p. 843-850
[8] Prospect Evaluation: AAPG Course Notes: Tulsa, OK, AAPG, 8 p.

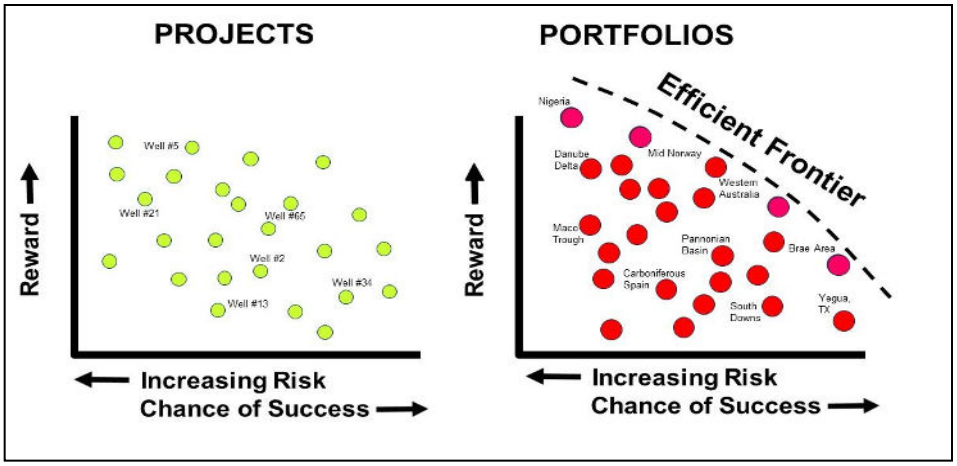


Figure 2: Efficient Frontier represents the optimal trade-off between risk and value.

A simple review[9] of the drilling portfolio of US independent operator Noble Energy (Figure 3) demonstrates forecasts at portfolio versus individual business unit level. Although at a corporate level, the post-drill well capex met the forecast pre-drill estimates within a few percentage points (and without too much on-going management), the Offshore Shelf, Gulf of Mexico business unit underestimated the final well cost and the International business unit largely over-estimated well costs. However, the net effect of the two is to offset the over-estimate with the under-estimate and balance them out on a corporate and portfolio level.

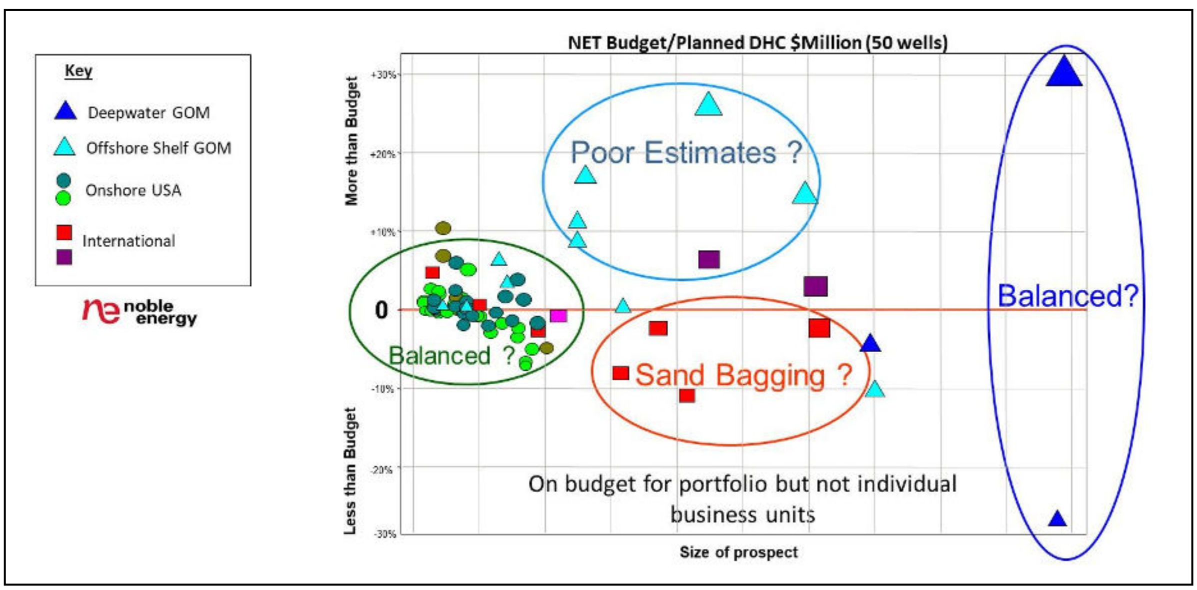


Figure 3: Predicted versus actual well costs

The example (Figure 3) shows that although individual business units may not contain statistically significant numbers of wells or fields (i.e.: investment opportunities) to have high confidence in the outcome, when we consolidate them at the corporate level and get a

[9] The Essentials of Good Portfolio Management at Independent Oil and Gas Companies, AAPG Annual Convention, Houston, TX 2006

statistically significant number of samples, then the portfolio effect can average out the over-estimates and under-estimates. Putting this another way, valuations of single assets may provide focus for a due diligence team in a data-room, but usually result in wide ranges of estimates. Conversely, a portfolio with many assets can average itself out and the estimation of the range of total values should be narrower and therefore more accurate in most circumstances. This is also known as Portfolio Diversification (Figure 4).

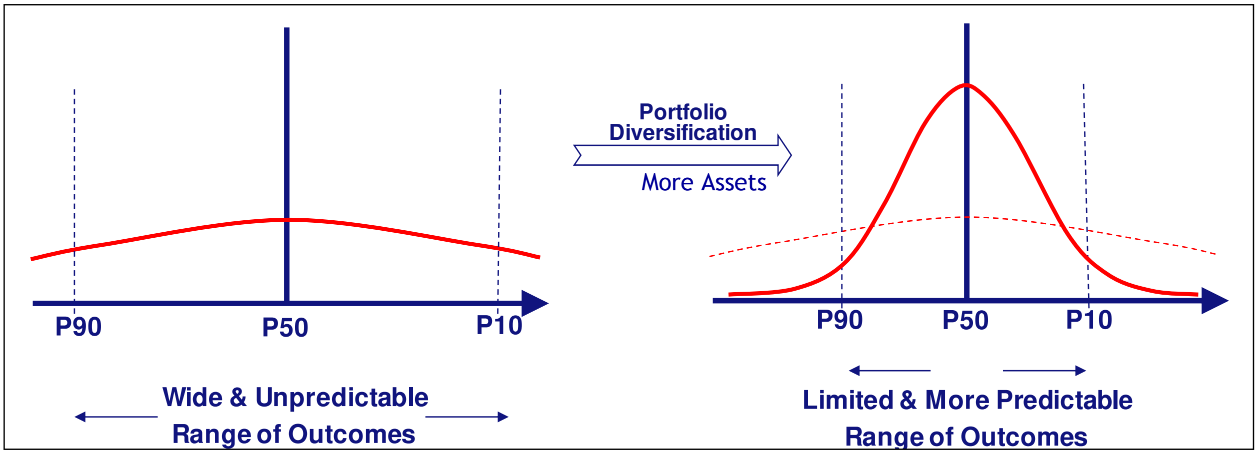


Figure 4: Portfolio Diversification leads to more predictable outcomes

Andy Wood, when he was Head of Global Exploration, Shell International Exploration & Production, said in his presentation at the European Association of Geoscientists and Engineers in 2001 that "*One of the great advantages of having a large portfolio is the ability to be increasingly selective about which prospects to drill. It's about choice*". The same is true for all asset types and recognizes one final key factor in acquisition valuation; that the production, development and exploration plan, (collectively known as the post-acquisition investment plan), in our experience is most likely to change after acquisition. The due diligence economist has no control over this, but it is rare to see any of these scenarios modelled as part of the valuation.

The statistical portfolio effect and assumptions start to break down with small portfolios/groups of assets and particularly when a single asset dominates. An example of this is when UK utility Centrica Energy acquired the North Sea operator Venture Production plc (Venture) in August 2009. Centrica made an aggressive take-over of Venture, which finally conceded and accepted the £1.3 billion (circa[10] USD$ 2.5 billion) offer (Figure 5). The portfolio of assets held by Venture comprised twenty producing fields, twenty-six discovered non-producing fields and more than fifty prospects and leads. This portfolio under most definitions would be classified as containing a statistically significant number of assets/investment opportunities.

[10] Exchange rate in August 2009 approx. GBP£1 = USD$1.9

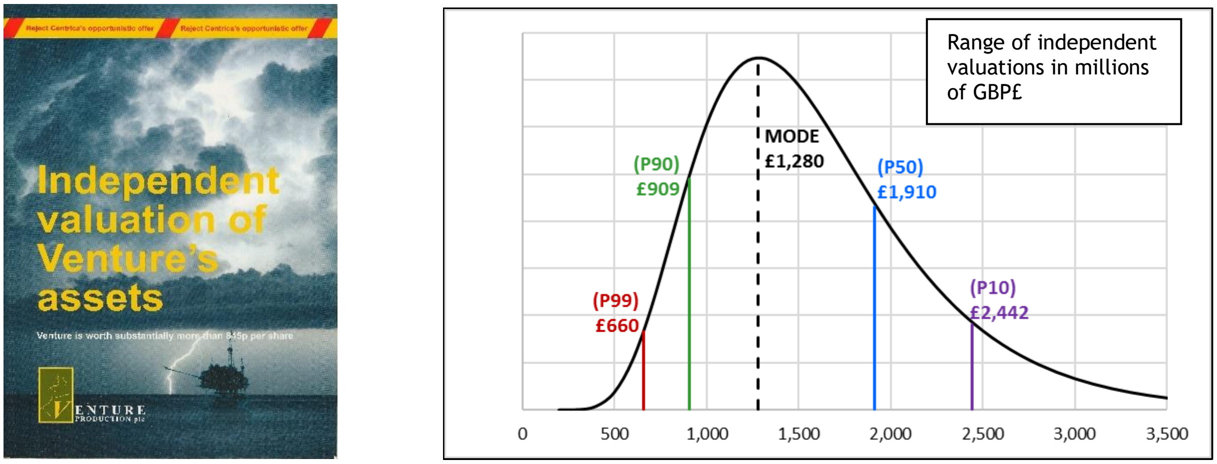


Figure 5: Range of Valuations of Venture Production by Independent Expert

A review[11] of the forecast production made at the time of the Venture take-over showed a range of scenarios. However, when the portfolio was reviewed in 2018 after nine years of ownership by Centrica, it showed that the assets had significantly underperformed (Figure 6). The significant short fall in production could be attributed to the undeveloped Cygnus field which dominated the portfolio. The Cygnus gas field was assessed to have a P50 gross recoverable resource of approximately 630 Bcf which represented 17% of the total portfolio resource volume, with Venture/Centrica holding 49% Working Interest and Net Revenue Interest in the field. However, it was the date of Cygnus first gas which caused the portfolio production shortfall. At the date of the pre-acquisition valuation in 2009, the operator of the field (GdF Suez), had made the financial investment decision to develop the field, with an expected date of first production in late 2011 (which creates the ramp-up in production in Figure 6). However, first production was delayed by five years to December 2016 (represented by the uptick in the red line in Figure 6). This delay accounted for an estimated loss of £160 million (circa USD$ 304 million at 2009 exchange rates) due to the discounting effect in the NPV calculation.

[11] https://riscadvisory.com/wp-content/uploads/2019/04/Venture-Production-shareholder-circular-4-Aug-2009.pdf

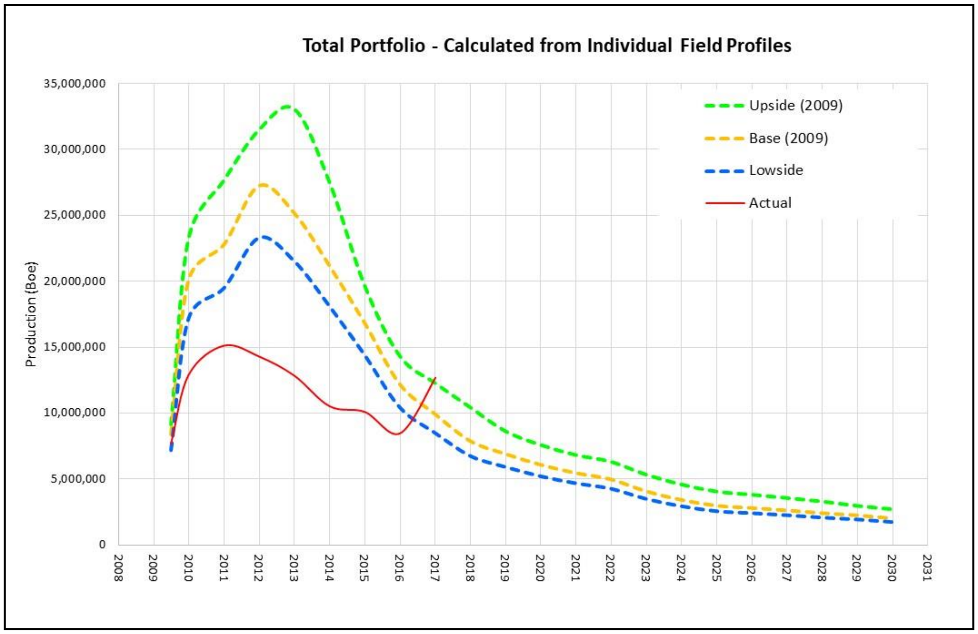


Figure 6: Forecast production from portfolio in 2009 versus realized production in 2018

Our post-acquisition review of value (using a discounted cash flow analysis) showed that after nine years the portfolio of assets delivered the statistical Mode of the NPV distribution and not the P50. Although the significant production delay in the Cygnus field created an 8.4% drop in portfolio value and significant production shortfall, this was compounded by some contingent resources not being developed, a drop in gas prices and lower production from the rest of the portfolio of fields. However, this estimated loss was partially offset by an increase in realized oil price over the period and an increase in actual production from Cygnus when it did come on-line. Some changes in the forecast versus actual economic variables were not analyzed in our post-acquisition review (table 2):

Revenue/Cost not re-estimated	Comment
Change in costs	Data not publicly available
Increase in Cygnus field Base case recoverable volume from 560 Bcf to 635 Bcf (13%)	Announcement made after review completed
Change in taxation 2009-2018 • Small Fields Allowance (2010, 2012) • Shallow Water Allowance (2012) • Supplementary Charge (2011, 2016) • Decommissioning Relief (2017) • Investment & Cluster Allowance (2014, 2015)	Out of scope

Table 2: Factors not included in assessment

The critical factor in the Venture acquisition, which we can apply to all acquisition valuations, is that the economist and due diligence team need to focus on the big assets as they can skew the distribution of outcomes. It sounds obvious, but all too frequently the due diligence team tries to cover all bases when it's only really the largest asset(s) which can skew the portfolio modelling. The inaccuracies in estimation of the smaller and often more numerous assets tend to average out, so the net effect is a narrow and more accurate range of values.

We listed the six Common Pitfalls in Oil and Gas Valuations at the start of this article and we encourage the reader to go back and review these again. Despite these being reasonably obvious in hind sight, they continue to be repeated by many companies because post-acquisition reviews of valuation rarely occur. The authors encourage Resource Economists to learn from this article and post-acquisition reviews so that future valuations are better calibrated.

BUILDING A MORE RESILIENT STRATEGY FOR DIVERSIFIED INDEPENDENTS IN AN INCREASINGLY VOLATILE OIL AND GAS PRICE ENVIRONMENT

Thomas Shattuck
Deloitte, Houston, USA

Following the 2016 nadir in oil prices, the industry outlook has improved thanks to rising prices, with Brent reaching $85 per barrel in October 2018, the first time since 2014. However, volatility has more recently come back, and global oil prices declined sharply to under $60. [12] Despite this volatility, it appears that we might be past the period of lower for longer, setting the stage for a new period of growth for the industry. Moreover, the downturn led to an increase in industry bankruptcies and low spend on exploration and field development, creating an upside price risk in the medium to long term. Perhaps then, this is a good point to take stock and assess strategic options for upstream oil and gas companies as they focus on growing production to meet future demand while sustainably generating value. To identify strategic options, we have segmented the sector into six main peer groups that have distinct characteristics:

1) **Resource-rich NOCs:** National oil companies with access to extensive domestic oil and gas resources, often producing large volumes from conventional onshore or shallow water projects
2) **Resource-limited NOCs:** Lacking the direct access to sizeable resources in their home countries, these operators typically focus not just on domestic projects, but also invest internationally
3) **The majors and large integrated international oil companies (IOCs):** These are companies who span the entire value chain, including supply and trading as well as petrochemicals, and work across the globe
4) **Internationally focused independents:** These operators usually focus on high impact international exploration, with some exposure to development and production, as well as midstream or downstream operations
5) **US-focused independents:** These are often focused solely on upstream shale developments, with limited spend focused on other resource types, geographies, or business segments
6) **Diversified independents:** Diversified independents often focus on multiple regions and resource themes, with some midstream or downstream exposure to balance out their upstream portfolios

Each peer group faces distinct challenges compared to the others and their portfolios should be viewed differently. However, they can all be assessed using a common framework that identifies how their portfolios perform against four key criteria: **Scale**, **Scope**, **Cost**, and **Running Room**. These four characteristics determine what options are on the table, the various tradeoffs available, and the risks of any potential strategic choices.

[12] "Europe Brent spot price FOB," US Energy Information Administration, https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm, accessed January 10, 2018.

Each company and peer group will differ significantly across these factors. For example, a major might produce several million barrels of oil equivalent per day from shale, conventional onshore, offshore, and deep-water fields as well as from oil sands, while also operating midstream, downstream, and trading assets that diversify its overall portfolio. However, a small international independent would likely be the opposite, with a handful of high-impact upstream exploration investments in a single resource theme (with commensurately high risk) and limited if any exposure in midstream or downstream operations.

Considering these differences, how can a company make the right choices to navigate the markets in the current environment? To answer that question, we can look at a specific peer group. The **Diversified Independents** and assess what lever these types of companies can pull to improve their strategic position in the current, more volatile oil and gas price environment. Other companies' strategies will differ, but the framework will be equally applicable.

Diversified independents – Balancing a diverse portfolio in challenging times

Diversified independents often focus on multiple regions and resource themes, with some midstream or downstream exposure. They lack the focused portfolios of their US and International cousins, and they do not have the scale of the majors or many NOCs. These companies have varied legacies, with some companies like ConocoPhillips and Hess splitting off their refining and retailing arms, whereas others outgrowing their original focus on a region or basin. For example, many diversified independents have heavy US investment. Anadarko operates in US shale, and in the US Gulf of Mexico, as well as internationally in both East and West Africa. Similarly, Apache's operations are split between Egypt, the United Kingdom, and the United States, and include both shale as well as conventional onshore and offshore production. No matter the specifics, diversified independents should pursue a goldilocks approach, balancing their scope and scale along with costs and running room.

How can a diversified oil and gas company thread the needle and maintain balance even as the markets shift? There are three concrete steps they should consider:

Firstly, these operators should focus on narrowing scope and increasing scale. Operating several fields and integrating their upstream and midstream assets in one region would likely be preferable to spreading their operations more thinly. Reducing total operating costs can be difficult, particularly for older facilities and infrastructure in challenging environments. Boosting throughput is one way to reduce unit costs that can improve both the top and bottom lines simultaneously.

Secondly, they should manage not just physical or financial scope, but also temporal scope. Refineries, pipelines, deep-water upstream, and shale take different amounts of time to develop from first concept to FID to startup; and they all have different operable lives. A mid-size company needs to balance its cash and project cycle for the short, medium, and long term. Letting their portfolio drift to one side or another through a rapid investment in a single resource like shale can risk the company losing balance and exposing itself to risk that its diversification is supposed to mitigate.

Lastly, divesting noncore assets can help, as maintaining a long tail of smaller projects could prove distracting. Creating synergies elsewhere in a portfolio can work as well. For example, investing in LNG can kill two birds with one stone by extending the portfolio's production life while providing an outlet for produced natural gas. Similarly, they should plan to leverage infrastructure in mature producing areas like the Alaska North Slope, Gulf of Mexico, or North

Sea, as that could reduce project lead times and boost commerciality of any discoveries. Moreover, older assets can generate opportunities for enhanced oil recovery through the deployment of advanced analytics combined with marginal increases in capital spend. Leveraging physical and digital assets holistically could generate more value than using each independently.

By rebalancing and streamlining their business, diversified independents will likely be better positioned to take advantage of the current upswing in crude prices and weather the next downturn. Long-term assets can provide cash flow through leaner periods, while maintaining a hopper of exploration leads and short-term projects allows for sustainable growth. The trick is to keep investments balanced as the portfolio expands.

ON THE NATURE OF WIDESPREAD SHALE PRODUCTION SHORTFALLS REPORTED BY THE WALL STREET JOURNAL

Scott Lapierre
Founder, Shale Specialists LLC, Houston, USA

Introduction

On January 2, 2019, the Wall Street Journal (WSJ) published *Fracking's Secret Problem—Oil Wells Aren't Producing as Much as Forecast*[1]; the first in a series of articles[2,3,4] critical of the *Great American Oil Shale Revolution*. The authors employed a third-party energy consulting firm to re-forecast "16,000 wells operated by 29 of the biggest producers in oil basins in Texas and North Dakota[1]", and then compared the updated forecasts to original corporate projections published to justify drilling campaigns and lure in investors. The WSJ authors claim that "two-thirds of projections made by the fracking companies between 2014 and 2017 in America's four hottest drilling regions appear to have been overly optimistic[1]". The authors further single out Pioneer Natural Resources (PXD) and Parsley Energy (PE) where the WSJ's newly generated projections pointed to 25% less recovery than what "their owners projected to investors".

Since the WSJ articles were published, the industry has undergone dramatic change as evidenced by the announcements of reorganizations and layoffs in an effort to boost profits by reducing costs[5, 8,9,10]. Also worth noting, for the first time in the 10-year history of the shale oil revolution, capital budgets are being reduced not as a direct response to structural changes in commodity prices but rather in response to investors who no longer seem willing to tolerate value destruction from unprofitable development spending. Together, the widespread layoffs[8,10], executive retirements[5] and capital budget reductions[9] suggest there is a yet-to-be-identified, or yet-to-be-disclosed, fundamental obstacle hindering the commercial production of oil from fracked shale reservoirs.

The present article explores public data from key operators in major basins for evidence of the shortfalls reported by the WSJ to independently confirm their existence and determine their severity and regularity. The present article further attempts to characterize the common nature of the shortfalls and provide a context for comparison with original projections. While covering such a topic necessitates delving into technical aspects of reservoir engineering, an attempt is made to keep the discussion friendly to the layperson by keying in on just two types of production data plots. A typical *rate-versus-time* plot is described and used to introduce a new *rate-versus-cumulative oil produced* plot format. The new plot format will provide for very quick, visual comprehension of the nature, severity and regularity of the reported deviations. Becoming comfortable with the new plot format will greatly assist the reader with visually identifying the problem and quickly approximating the implied reduction to ultimate oil recoveries.

A Minor, Preparatory Dive into Technical Aspects

Production data is commonly displayed in Investor Relation slide decks via one of the two formats shown in Figure 1. Figure 1-A shows a typical *rate-versus-time* plot where [barrels of oil equivalent per day (BOEPD)] are plotted against [time]. Figure 1-B shows a plot where [cumulative oil equivalent produced (BOE)] is plotted against [time on production]. Corporate projections for ultimate recovery by the end of a well's life are overlain as 'type curves' and provide an important scale for translating early-time production data into a magnitude of estimated ultimate recovery (EUR). Production is typically presented normalized for lateral length due to the reality of developing leases supporting various wellbore length capacities. Normalization for lateral length is not a subject of controversy among industry experts.

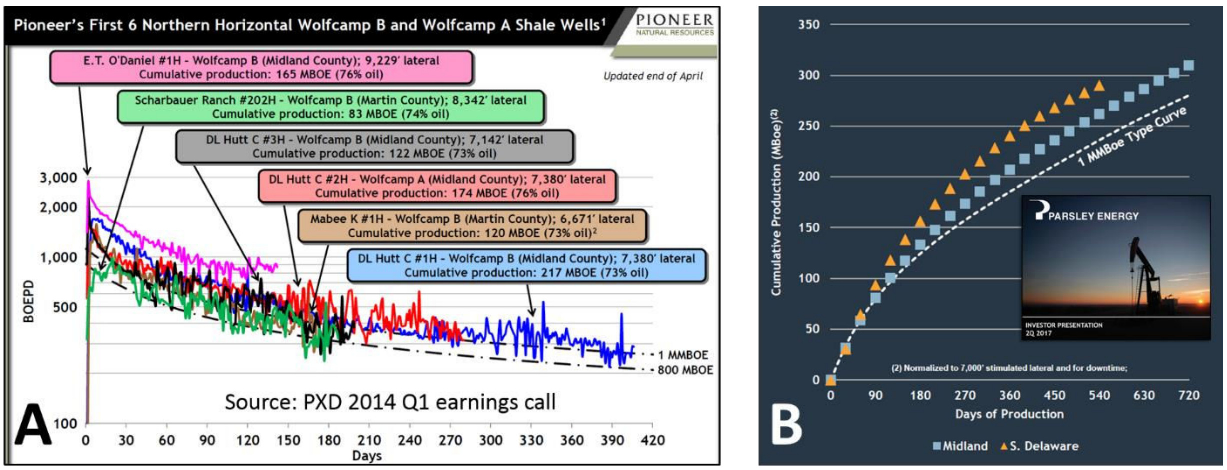


Figure 1: Common formats for displaying production relative to forecasts. (A) is an example of barrels of oil equivalent daily rate (BOEPD) plotted against time (days). (B) is an example of cumulative oil production in barrels of oil equivalent (BOE) plotted against days on production. Presenting only the first and most prolific months of production is assisted by multiple type curves being overlain to represent various projections of ultimate recovery. Typical well life, determined by assuming a terminal, constant-rate exponential decline of 3%-14% coupled with a 1-2 barrels per day minimum economic rate suggest 20-50 year well life.

Typically, engineers plot early-time oil and gas production rates versus time on a semi-log plot (Figure 2). Quite commonly, a forecasting method of decline curve analysis (DCA) first introduced by the geologist J. Arps in 1944[11] is used. Accordingly, a hyperbolic math function is 'fit' through early-time data by selecting equation parameters that optimize an empirical regression. Figure 2 illustrates the *rate-time* plot and forecast generated by fitting a hyperbolic decline function through the early-time data.

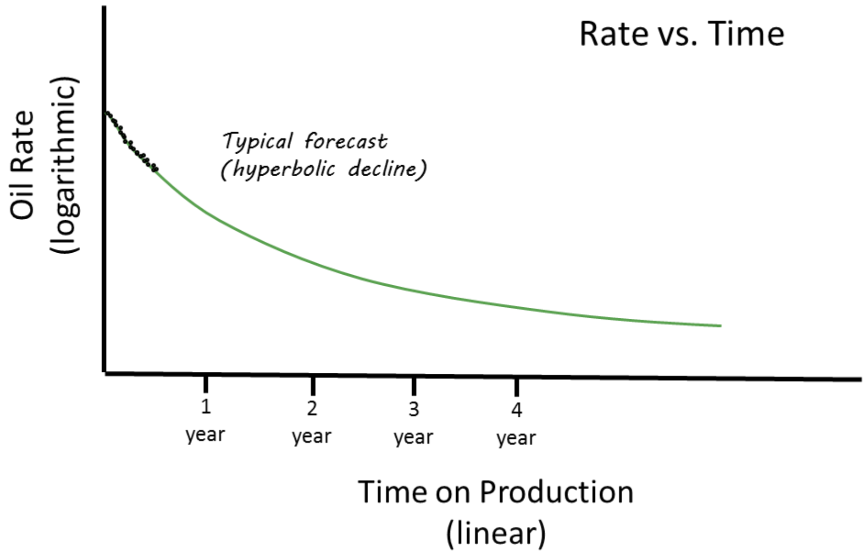


Figure 2: (Illustrative) Typical plot of oil production plotted against time illustrating a forecast generated with a hyperbolic decline function whose parameters have been selected to optimize the function's fit through early-time data

The hyperbolic decline function has specific characteristics that make it useful as a curve to fit through production data. Namely, the hyperbolic math function can reproduce natural decline profiles characterized by initial annual decline rates that lessen over time. For example, in steeply declining shale wells, the first year of production may end with an exit rate 60% to 95% of the initial oil rate. Fortunately for longevity of production, each additional year enjoys a less severe annual decline rate. Nonetheless, ultimately the life-prolonging lessening of decline severity terminates and a final, minimum, terminal constant-rate decline (D_{min}) sets in. The appearance of a brutally constant, minimum decline rate (D_{min}) marks the beginning of the end of the economic life of a well. Figure 3 illustrates the consecutive lessening of annual decline rate characterized by the hyperbolic decline function. A minimum decline rate (D_{min}) is invoked to represent a more realistic, first-principles explanation of the end of well life. D_{min} values of 3% to 14% have been in widespread use since the beginning of the shale oil revolution based largely on observations of legacy vertical production in places like the Midland Basin[12].

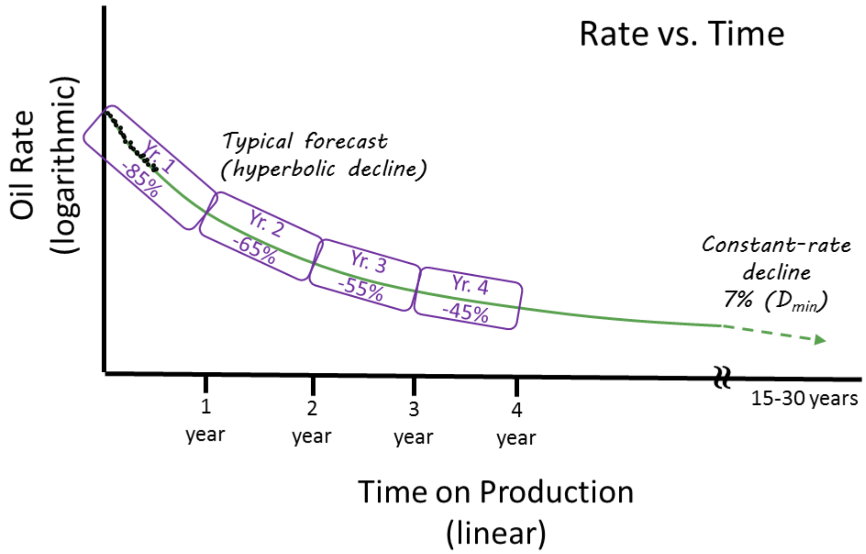


Figure 3: (Illustrative) Hyperbolic decline function fit through early-time production data as per Arps DCA illustrating year-on-year lessening of annual decline rate with an assumed constant-rate minimum decline (D_{min}) equal to 7% being reached in the distant years

The nature of the production shortfalls identified by the Wall Street Journal appear on a *rate-time plot* as a gentle shallowing of production over time relative to an original forecast. Figure 4 illustrates the subtle appearance of a typical shortfall as seen on a *rate-time* plot.

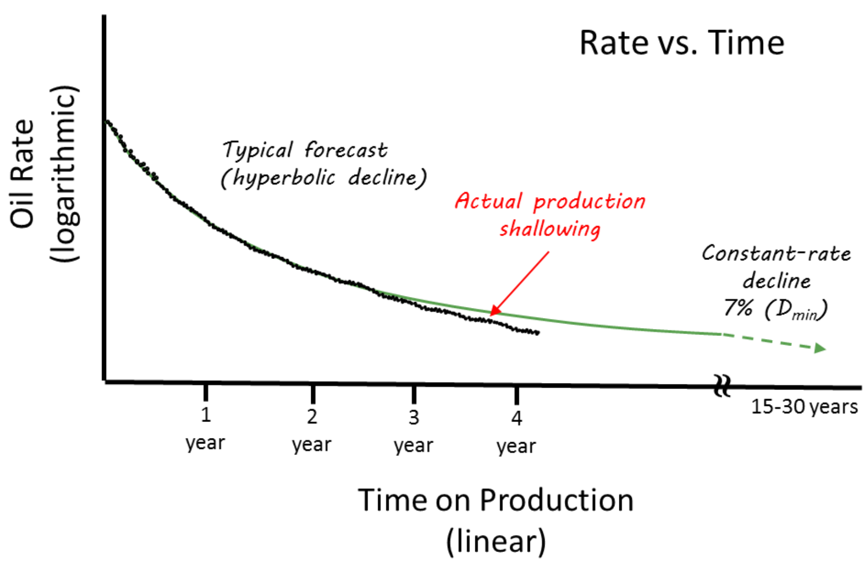


Figure 4: (Illustrative) Typical nature of the production shortfalls identified by the Wall Street Journal as viewed on a rate-time plot

Unfortunately, since the x-axis represents time, projecting the observed production data and corporate forecast forward does not immediately convey the magnitude of the shortfall nor its effects on ultimate recovery. A plot format in which the x-axis represents the *cumulative oil* *produced* is more capable of conveying both the magnitude and the nature of the reported shortfalls. With a properly scaled x-axis on a *rate-cumulative production plot*, the shallowing of production that was unremarkably subtle on a *rate-time plot*, will appear as a pronounced, marked, downward curvature from a straight line angled toward the bottom right of the plot (Figure 5).

In the *rate-cumulative production plot* space, a straight line angled toward the bottom right of the graph approximates the period of gradual lessening of annual decline characteristic of the hyperbolic decline function (with a b_{exp} of ~1). Furthermore, a straight-line angled toward the bottom right of the graph will reliably approximate the forecast methodology widely used to generate or justify published corporate forecasts. Consequently, *rate-cumulative production plots* provide a quick reference to ultimate recovery as continuation of the initial linear portion of the trend "points" to an approximation of the EUR for a traditional forecast that assume a 3% to 14% D_{min}. Downward curvature from the descending linear trend represents an unexpected transition to a minimum, constant-rate terminal decline (or a reduction in b_{exp} to below a value of 1). Such downward curvature fundamentally marks the beginning of the end for commercial well production. Once a downward curvature is established, a projection of that downward curvature reliably "points" to a new approximation of ultimate recovery for that well. Any downward curvature observed in the semi-log *rate-cumulative oil plot* represents a marked deviation from the fundamental underpinnings used to make many of the corporate projections supplied to investors over the last decade. As will be shown in the next section, a significant portion of the reported production shortfalls can be attributed to premature transitions to constant-rate terminal decline. The "***D_{min}* Problem**", to which it shall henceforth be referred, stems from widespread use of incorrect assumptions for values of D_{min} (3%-14%).

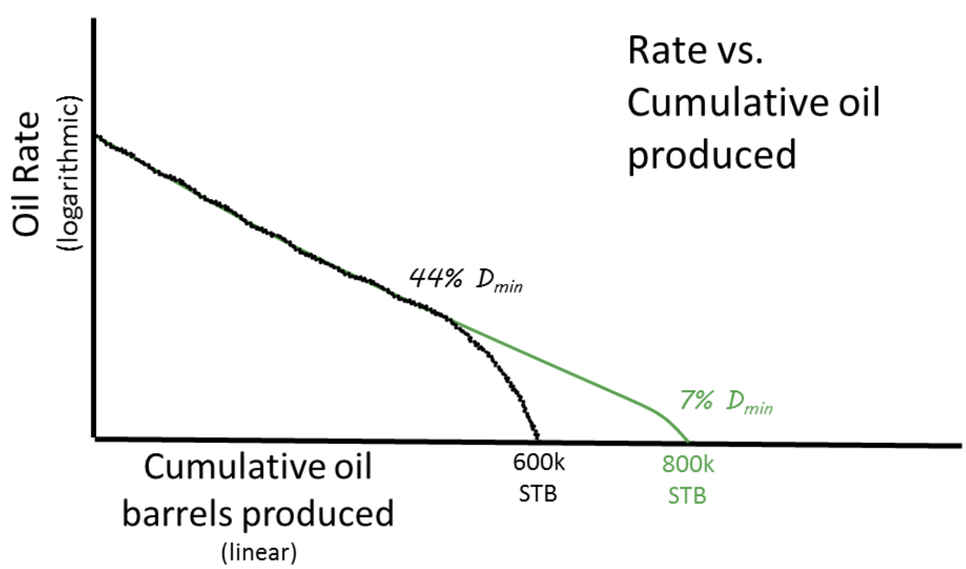


Figure 5: (Illustrative) Oil rate plotted against cumulative oil produced more handily reveals the magnitude and nature of production shortfalls

While the *rate-cumulative oil production plot* dramatically highlights visibility of the ***D_{min}***

problem; adding the ratio of gas produced per barrel of oil (GOR) reveals a reliable and potentially important precursor to the ***D_{min} problem***: exponential increases in GOR.

Figure 6-A and B illustrate how an exponential rise in GOR trends precede the ***D_{min} Problem***. Figure 6-A illustrates the seemingly benign early stage of rising GOR that has been described by some CEO's to present only positive uplift through increased NGL revenues[13]. Figure 6-B illustrates the typical evolution of a rising GOR trend wherein previous arguments of a benign nature appear to fall apart.

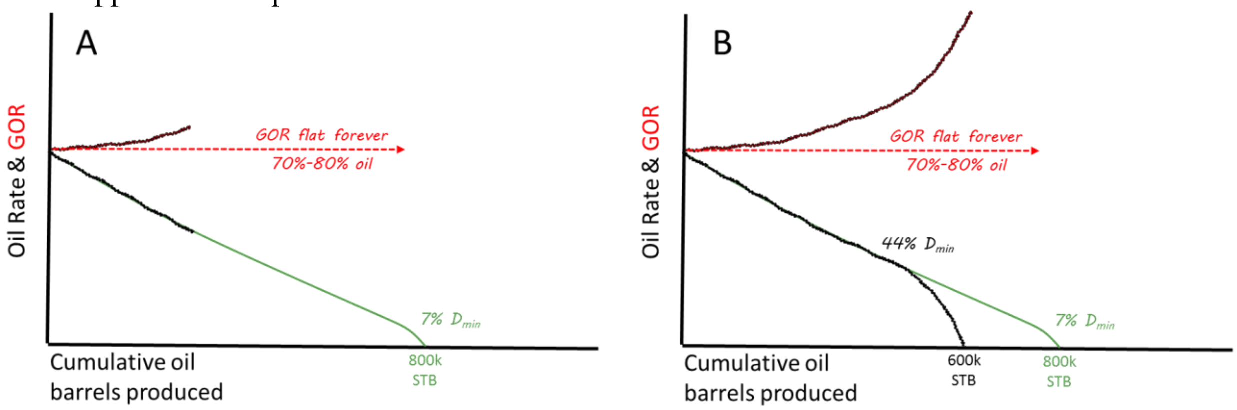


Figure 6: Illustration of exponential rise in GOR. Initially, rising GOR appears benign and presents some marginal uplift. However, as GOR trends escalate into an exponential increase they become decidedly correlated with the D_{min} Problem (B)

The "GOR Problem"

Since the beginning of the Great American Oil Shale Revolution, corporate forecasts provided by shale companies have nearly unanimously assumed GOR (and % oil) would be flat forever. It is worth noting that Percent Oil and GOR are often used interchangeably wherein Percent Oil is roughly the opposite of GOR. Only after the *Permian Stumble* of Q2 of 2017, when several key producers gassed-up unexpectedly, did the public receive the first acknowledgements by CEO's of rising GOR. At the time, CEO's claimed the un-forecast rises in GOR were an anticipated phenomenon[13]. Rising GOR's had furthermore been dismissed as benign, having no negative impact on oil production. In fact, as evidenced by continued statements by PXD, rising GOR was described entirely as a positive effect as it was said to result in higher revenues and higher ultimate recoveries than original forecasts. PXD dismissed the omission of GOR increases from their forecasts by claiming "we have a tendency to be conservative"[13]. As will be demonstrated in the following section, widespread rising GOR trends no longer appear benign despite adamant assurances from CEO's[13].

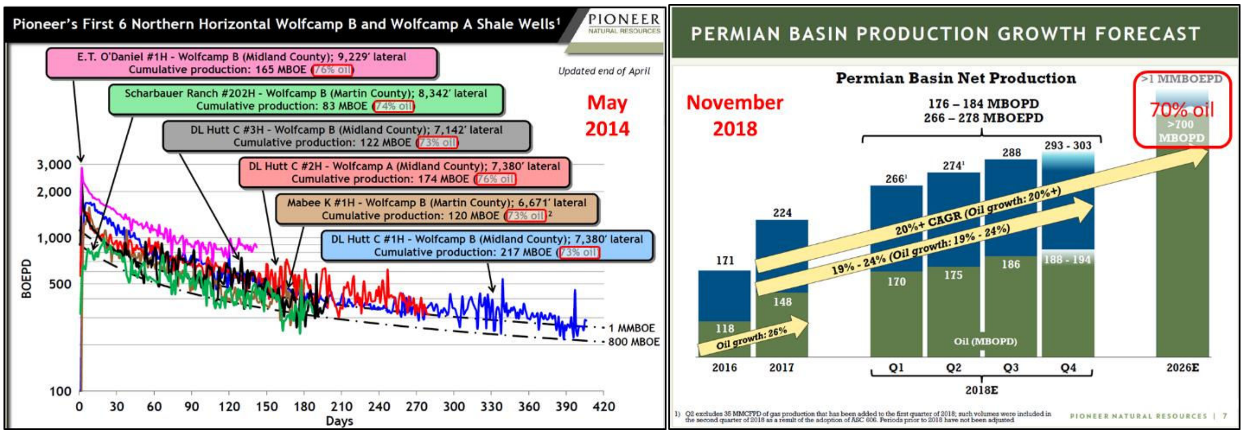


Figure 7: PXD earnings release slides from 2014 and 2018 revealing assumptions of constant GOR and % Oil

Data Review of Wells Drilled to-Date in the American Oil Shale Revolution

Leveraging an *Oil Rate & GOR versus Cumulative Oil Production* plot enables quick review of production data in the context of implied ultimate recoveries. Shale Profile Analytics Data services were used to generate a series of plots that allow quick interrogation of oil production and GOR profiles for key basins/plays within the United States (Midland Basin, Bakken, DJ-Niobrara, and Eagle Ford). Play-wide data is presented along with three individual well examples from each basin/play. Linear trends, representing DCA using common practices and parameters are overlain to represent what has traditionally been claimed as EUR's for typical wells in these plays. Taking advantage of the implications of downward curvature on a *rate-cumulative oil production plot* enables comparison of the implied production shortfalls referenced by the WSJ relative to traditional forecasting techniques. Three examples are provided for each major basin/play. The reader is expected to notice that dramatic – yet regular – deviations from traditional projections are widely manifest. Furthermore, the reader is expected to appreciate the implied magnitude of the widespread shortfalls in production relative to published projections provided by executives over the last decade. The data shown supports the observations made by the Wall Street Journal and further suggest that oil production from shales has been overestimated by approximately 50% compared to the 25% to 63% cited by the WSJ for the Midland Basin and the Eagle Ford.

Midland Basin

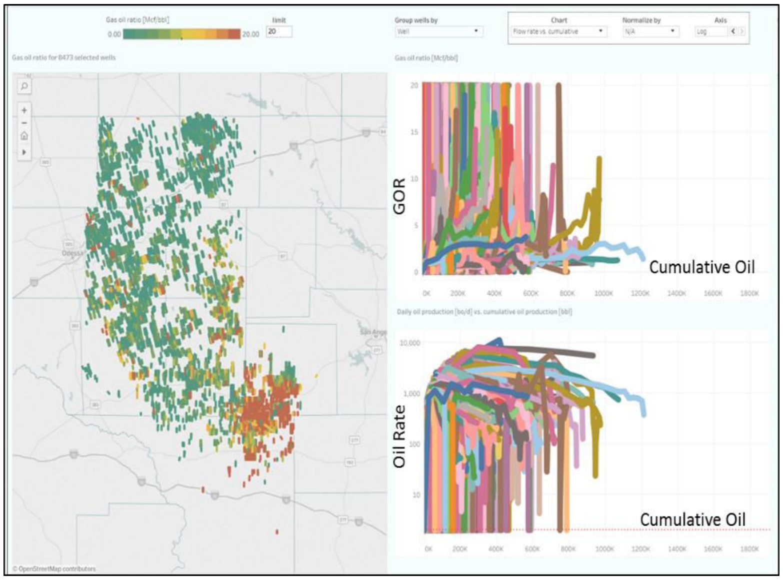


Figure 8: Shale Profile analytics data of 8,473 horizontal wells from the Midland Basin demonstrating consistent occurrence of 10- to 20-fold increases in GOR and abundant downward curvature revealing premature transition to constant-rate minimum terminal decline. Note: GOR in upper right plot scaled from 0 scf/BO to 20,000 scf/BO is equivalent to 100% oil to 23% oil.

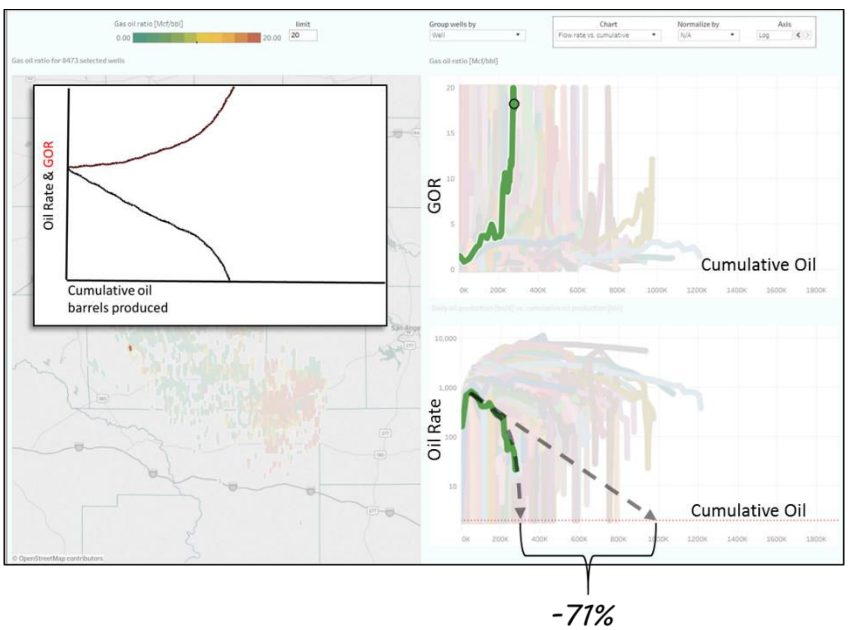


Figure 9: Shale Profile analytics data for typical horizontal well from the Midland Basin (Example #1) demonstrating correlation of the D_{min} Problem with the GOR Problem. Note: GOR in upper right plot scaled from 0 scf/BO to 20,000 scf/BO is equivalent to 100% oil to 23% oil

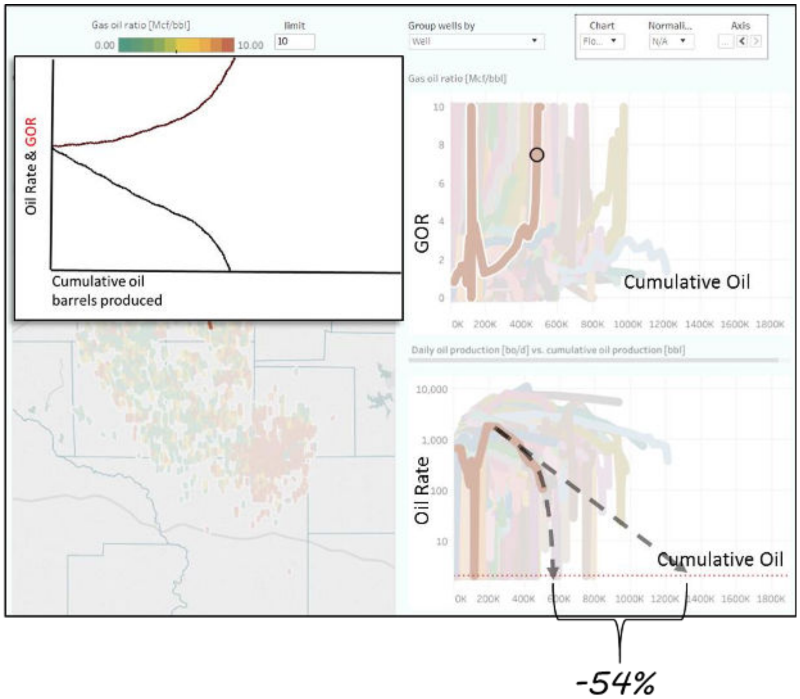


Figure 10: Shale Profile analytics data for typical horizontal well from the Midland Basin (Example #2) demonstrating correlation of the D_{min} Problem with the GOR Problem. Note: GOR in upper right plot scaled from 0 scf/BO to 10,000 scf/BO is equivalent to 100% oil to 37% oil.

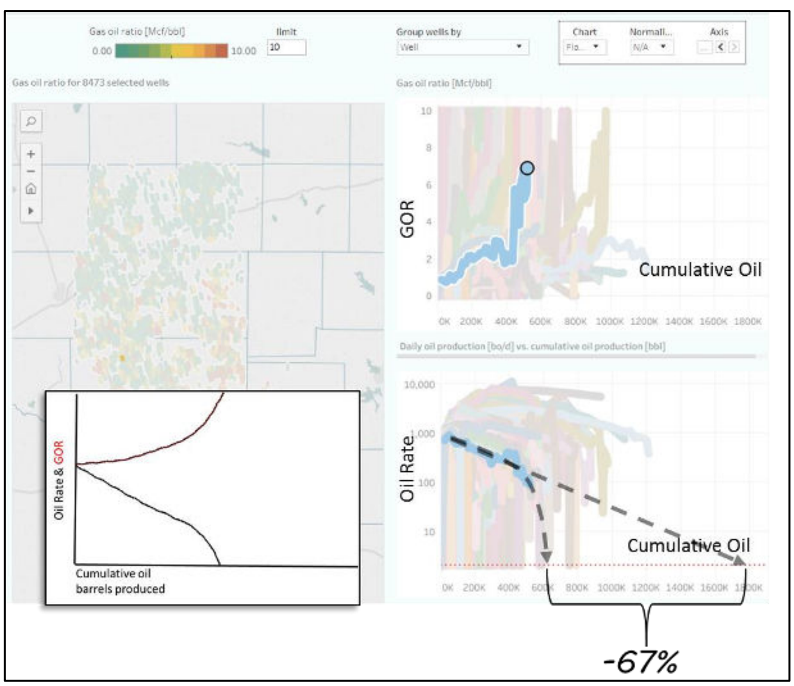


Figure 11: Shale Profile analytics data for typical horizontal well from the Midland Basin (Example #3) demonstrating correlation of the D_{min} Problem with the GOR Problem. Note: GOR in upper right plot scaled from 0 scf/BO to 10,000 scf/BO is equivalent to 100% oil to 37% oil

Bakken

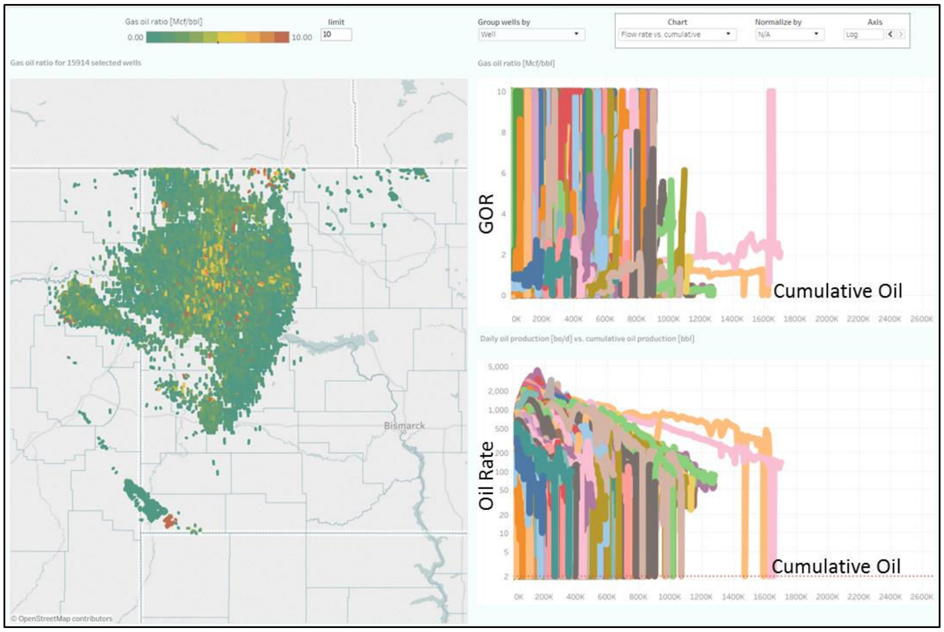


Figure 12: Shale Profile analytics data of 15,914 horizontal wells from the Williston Basin demonstrating consistent occurrence of 10-fold increases in GOR and abundant downward curvature revealing premature transition to constant-rate minimum terminal decline

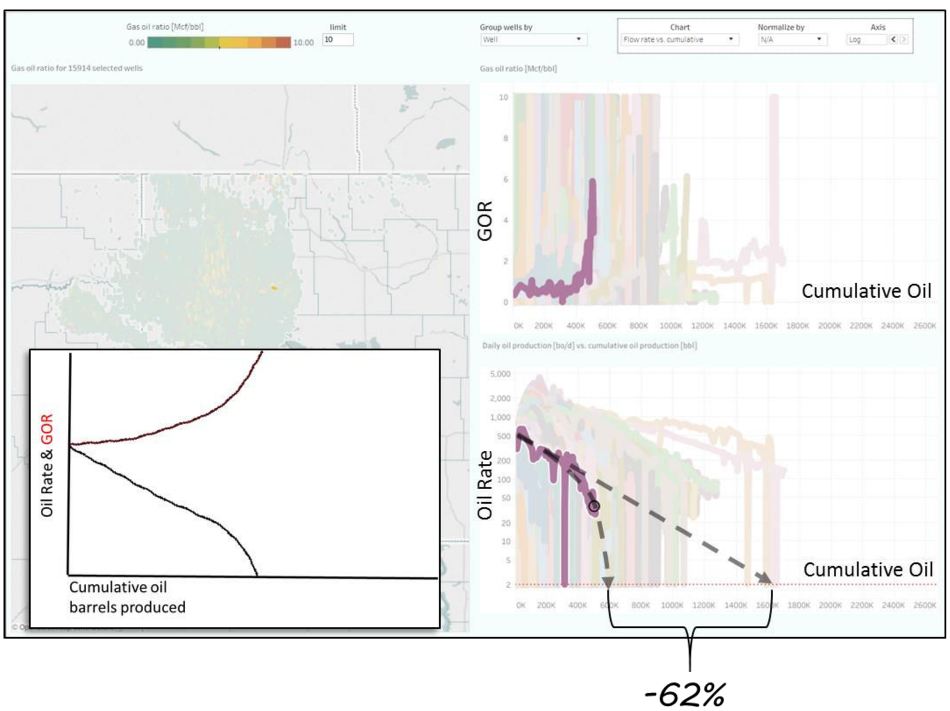


Figure 13: Shale Profile analytics data for typical horizontal well from the Williston Basin (Example #1) demonstrating correlation of the D_{min} Problem with the GOR Problem. Note: GOR in upper right plot scaled from 0 scf/BO to 10,000 scf/BO is equivalent to 100% oil to 37% oil

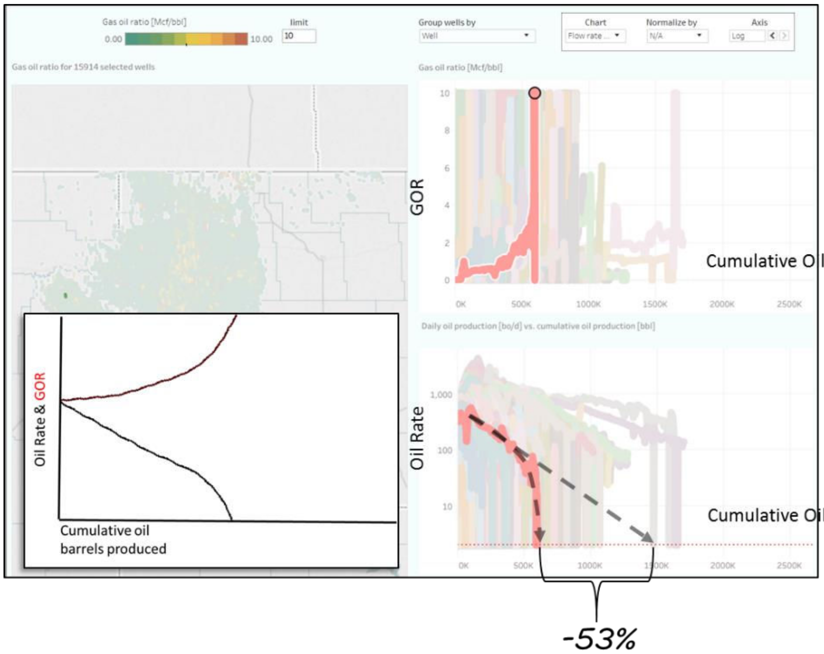


Figure 14: Shale Profile analytics data for typical horizontal well from the Williston Basin (Example #2) demonstrating correlation of the D_{min} Problem with the GOR Problem. Note: GOR in upper right plot scaled from 0 scf/BO to 10,000 scf/BO is equivalent to 100% oil to 37% oil

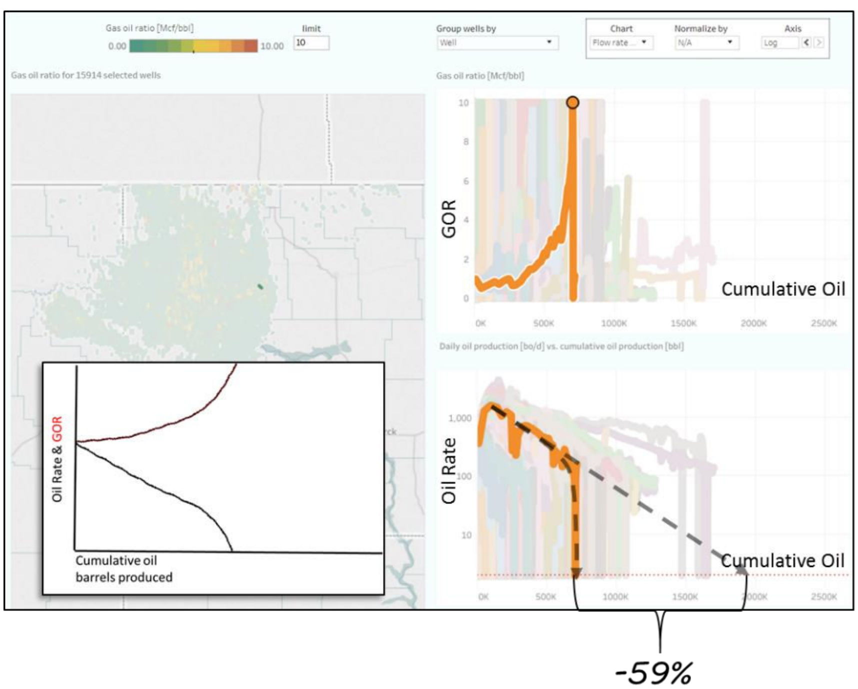


Figure 15: Shale Profile analytics data for typical horizontal well from the Williston Basin (Example #3) demonstrating correlation of the D_{min} Problem with the GOR Problem. Note: GOR in upper right plot scaled from 0 scf/BO to 10,000 scf/BO is equivalent to 100% oil to 37% oil

DJ Niobrara

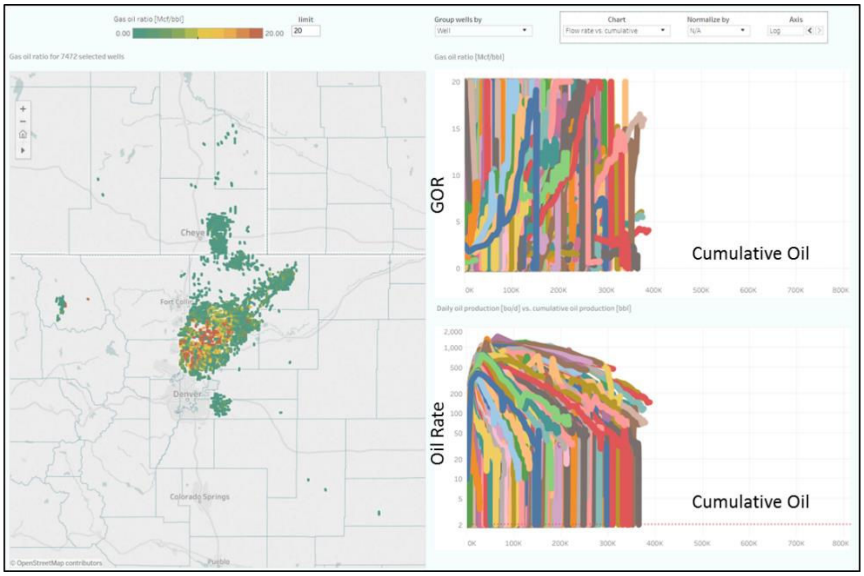


Figure 16: Shale Profile analytics data of 7,472 horizontal wells from the DJ Basin demonstrating consistent occurrence of 10- to 20-fold increases in GOR and abundant downward curvature revealing premature transition to constant-rate minimum terminal decline. Note: GOR in upper right plot scaled from 0 scf/BO to 20,000 scf/BO is equivalent to 100% oil to 23% oil

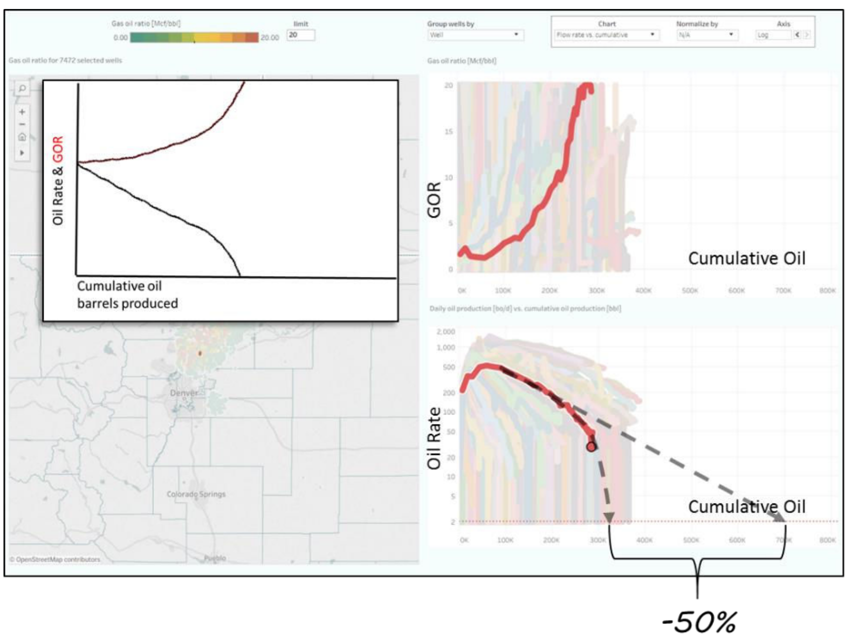


Figure 17: Shale Profile analytics data for typical horizontal well from the DJ Basin (Example #1) demonstrating correlation of the D_{min} Problem with the GOR Problem. Note: GOR in upper right plot scaled from 0 scf/BO to 20,000 scf/BO is equivalent to 100% oil to 23% oil

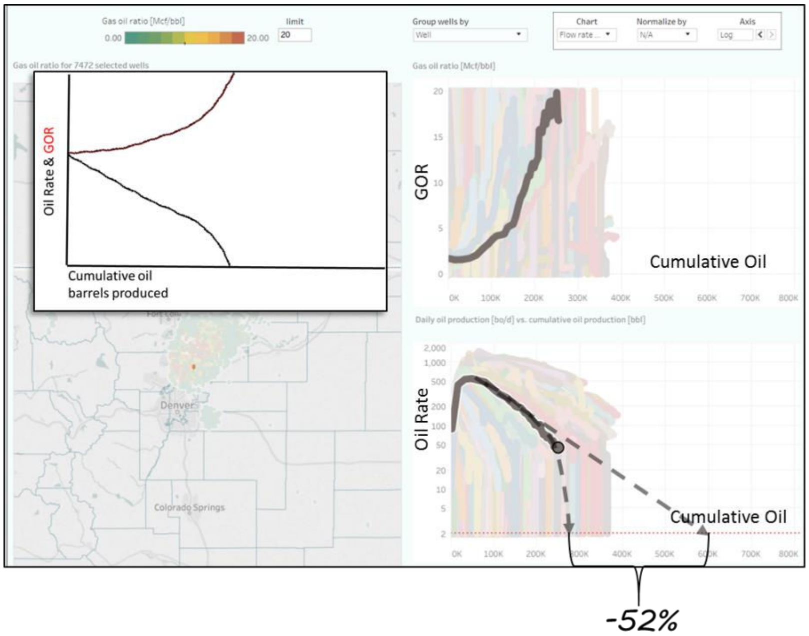


Figure 18: Shale Profile analytics data for typical horizontal well from the DJ Basin (Example #2) demonstrating correlation of the D_{min} Problem with the GOR Problem. Note: GOR in upper right plot scaled from 0 scf/BO to 20,000 scf/BO is equivalent to 100% oil to 23% oil

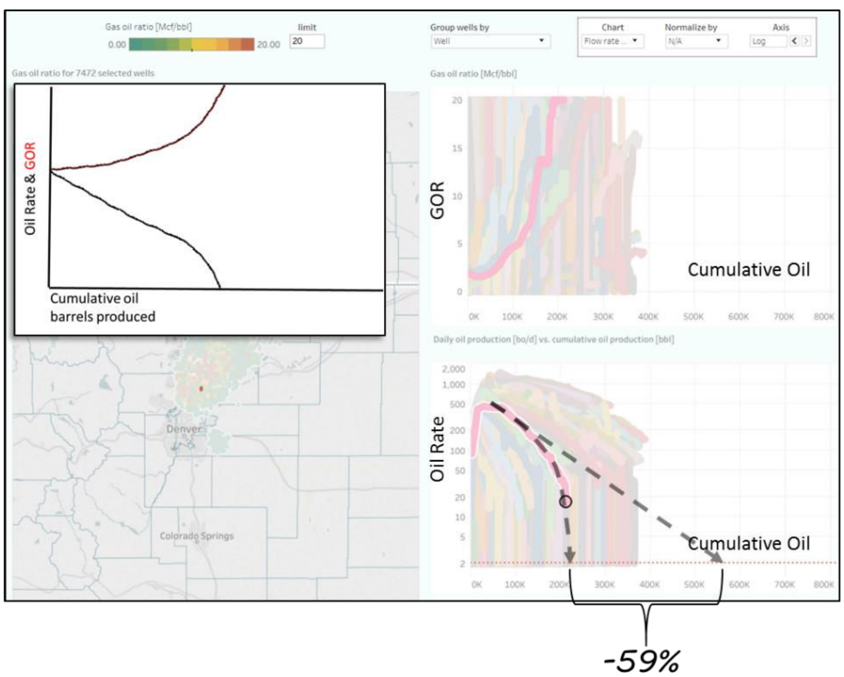


Figure 19: Shale Profile analytics data for typical horizontal well from the DJ Basin (Example #3) demonstrating correlation of the D_{min} Problem with the GOR Problem. Note: GOR in upper right plot scaled from 0 scf/BO to 20,000 scf/BO is equivalent to 100% oil to 23% oil

Eagle Ford

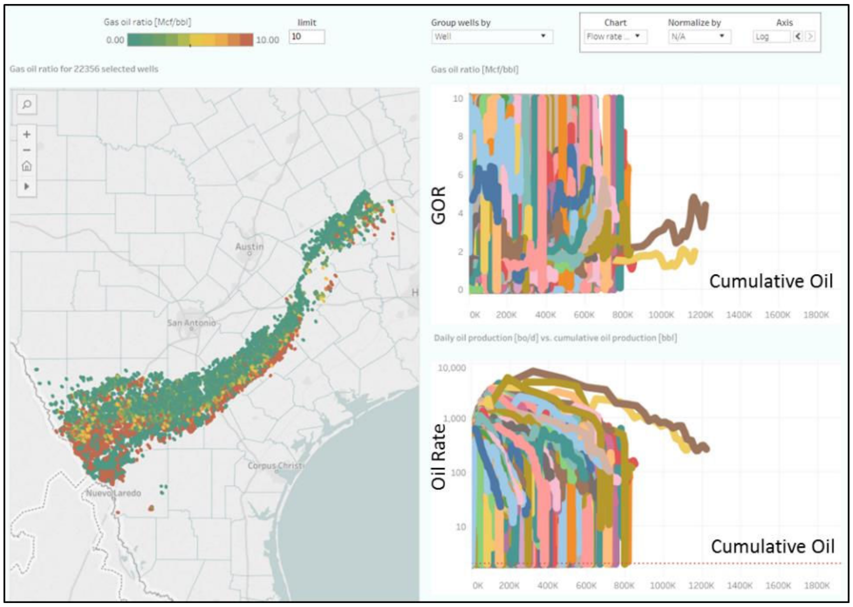


Figure 20: Shale Profile analytics data of 22,356 horizontal wells from the Eagle Ford play demonstrating consistent occurrence of 10-fold increases in GOR and abundant downward curvature revealing premature transition to constant-rate minimum terminal decline

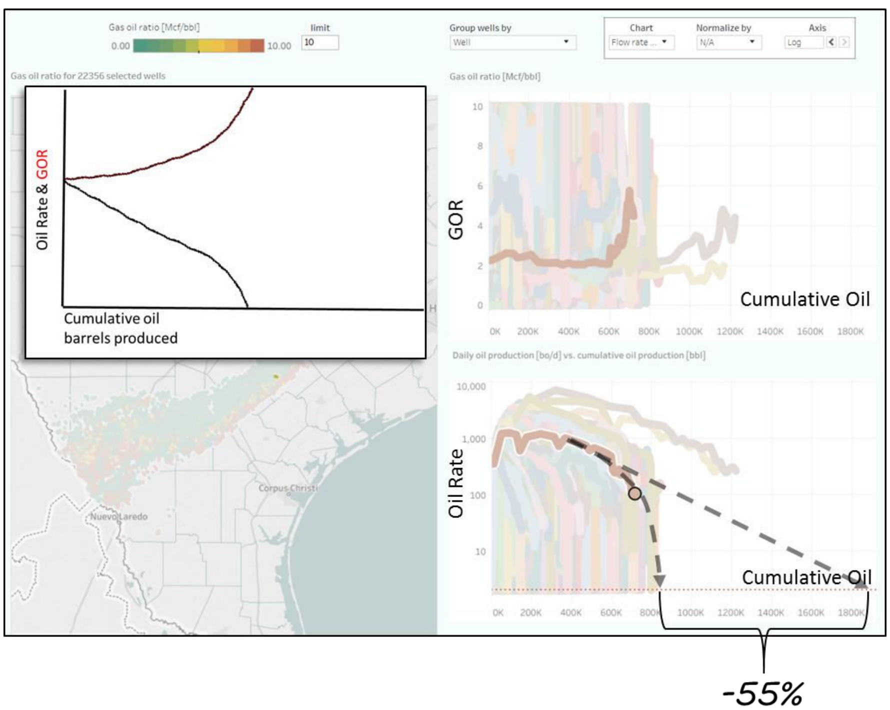


Figure 21: Shale Profile analytics data for typical horizontal well from the Eagle Ford play (Example #1) demonstrating correlation of the D_{min} Problem with the GOR Problem. Note: GOR in upper right plot scaled from 0 scf/BO to 10,000 scf/BO is equivalent to 100% oil to 37% oil

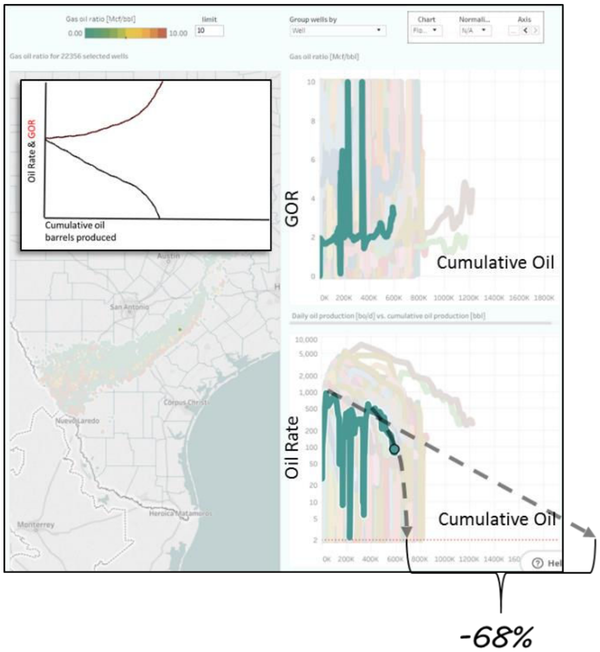


Figure 22: Shale Profile analytics data for typical horizontal well from the Eagle Ford play (Example #2) demonstrating correlation of the D_{min} Problem with the GOR Problem. Note: GOR in upper right plot scaled from 0 scf/BO to 10,000 scf/BO is equivalent to 100% oil to 37% oil

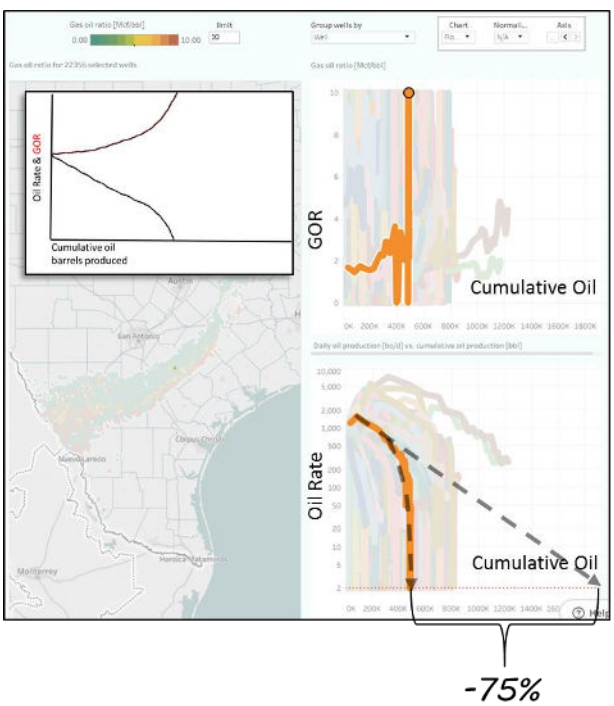


Figure 23: Shale Profile analytics data for typical horizontal well from the Eagle Ford play (Example #3) demonstrating correlation of the D_{min} Problem with the GOR Problem. Note: GOR in upper right plot scaled from 0 scf/BO to 10,000 scf/BO is equivalent to 100% oil to 37% oil

Conclusions

Review of current public data reveals that there is enough evidence to confirm the existence of the production shortfalls reported by the Wall Street Journal. Using *rate-cumulative production plots* makes it possible to quantify the implied shortfalls relative to existing forecast techniques. It has been further shown that a common nature exists in the observed shortfalls. The ***D_{min} Problem***, premature transition to constant rate decline (relative to a 3%-15% assumption), is a widespread occurrence. Additionally, the ***GOR Problem***, exponential increases in GOR, appear to correlate - and even forewarn – of imminent onset of the ***D_{min} Problem***. It is further concluded that since the Wall Street Journal compared new "re-forecasts" with original projections and assumed 30-year well life with single-digit Dmin, shortfalls as identified in the present work appear substantially more severe than with the re-forecast method employed by the WSJ. Figures provided within this work reveal at least 50% shortfalls are likely.

It is difficult for the author to pinpoint any technical justification or historical explanation for why such statistically significant and seemingly universal trends have yet to be discussed in technical papers or at conferences within the industry. Public data recently made accessible by Shale Profile clearly shows long established evidence revealing both the ***D_{min} Problem*** and the ***GOR Problem***, yet beyond the WSJ articles, the current writing appears to be the first reference to such contradictory observations. Presumably operators have abundant, proprietary daily production data that would allow early identification of the observed trends long before production data was reported to the States. The author cannot identify any peculiarity to the data trends that would have obscured them from being visible to those in possession of near-real-time production data. Therefore, no conclusion is drawn by the author as to why this writing appears to be the first reference justifying severe escalation in ***D_{min}*** values.

The Wall Street Journal's observations have clearly instigated dialogue between operators and investors on the appropriate scaling of development spending to generate positive cashflows and enable the conveyance of return on capital to investors. The WSJ authors have clearly identified a point of contention that now exists between investors and operators. The nature, magnitude and regularity of the production shortfalls identified in this writing suggest that recent failures of publicly-traded shale producers to achieve positive cashflow may not stem from changing cost basis but rather from anticipated revenues from a forecast production stream simply aren't there after the third, fourth or fifth year. Should the latter be the case, future quarterly performance following layoffs and capital budget reductions may not deliver the results that investors are looking for. Further defunding could be expected to result if, in-fact, rapidly declining production due to the ***D_{min} Problem*** is the primary cause of operators' inability to achieve positive cashflow. The next few quarters should provide key data points to confirm these suspicions given a slowdown in drilling and the corresponding lack of high-rate, high-oil-cut initial production from new wells being brought online.

References

1. Olson, B., et al, "Fracking's Secret Problem—Oil Wells Aren't Producing as Much as Forecast, *The Wall Street Journal*, January 2, 2019
2. Olson, B. and Elliott, R., "Frackers Face Harsh Reality as Wall Street Backs Away", The Wall Street Journal, February 24, 2019
3. Matthews, C., et al, "Shale Companies, Adding Ever More Wells, Threaten Future of U.S. Oil Boom", *The Wall Street Journal*, March 3, 2019
4. Elliott, R., "Frackers, Chasing Fast Oil Output, Are on a Treadmill", *The Wall Street Journal*, April 8, 2019
5. Elliott, R., "CEO of Shale Driller Pioneer Natural Resources Retires Abruptly", *The Wall Street Journal*, February 21, 2019
6. Scheyder, E., "Investors push U.S. shale firms to separate executive pay from drilling", *Reuters*, September 29, 2017
7. Scheyeder, E., "Shale firms pump up dividends as industry focus on returns grows", *Reuters*, March 25, 2018
8. O'Donnell, P., "Pioneer Natural Resources looks to cut costs with 'generous' buyout offer", *The Dallas Morning News*, April 5, 2019
9. Eaton, C., "Pioneer Natural to cut spending, slow output growth in 2019", *Reuters*, February 14, 2019
10. Hiller, J., U.S. shale producers turn to jobs cuts as investor pressures mount" *Reuters*, April 9, 2019
11. Arps, J., "Analysis of Decline Curves", Petroleum Technology, Chapter 11 pages 228-247, September 1944
12. Wood Mackenzie, "Everything is accelerating in the Permian, including decline rates", *Insight*, July 10, 2018
13. Pioneer Natural Resources Q1 2017 earnings release conference call transcripts, *Seeking Alpha*, May 5, 2018, pages 12-17
14. Pioneer Natural Resources Q2 2017 earnings release conference call transcripts, *Seeking Alpha*, August 2, 2018, Q&A page 20

UPDATE OF PETROLEUM RESOURCES MANAGEMENT SYSTEM (PRMS) IMPACTS ON RESOURCES CLASSIFICATION AND CATEGORIZATION: AMBIGUITIES REMOVED AND REMAINED

Imre Szilágyi
Petroleum Geologist and Economist, Budapest, Hungary

Recent update of SPE/AAPG/WPC/SPRE *Petroleum Resources Management System* (PRMS), the Guideline which aims to "*provide fundamental principles for the evaluation and classification of Petroleum Reserves and Resources"* came to the light in July 2018. The revision has cleared many ambiguities of the earlier version (2007), and this way has made a more robust system available for the oil and gas industry.

The study below discusses the ambiguities that has been removed and also those which apparently seem to remain. It will focus on the resource's classification and categorization framework – the discussion of other important modifications is beyond my scope.

Resources Classification and Categorization Framework in PRMS

The classification and categorization concept are demonstrated with the charts taken from PRMS below:

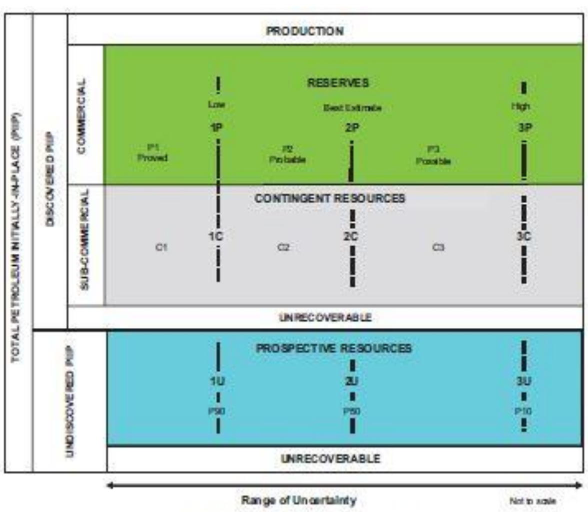


Figure 1.1—Resources classification framework

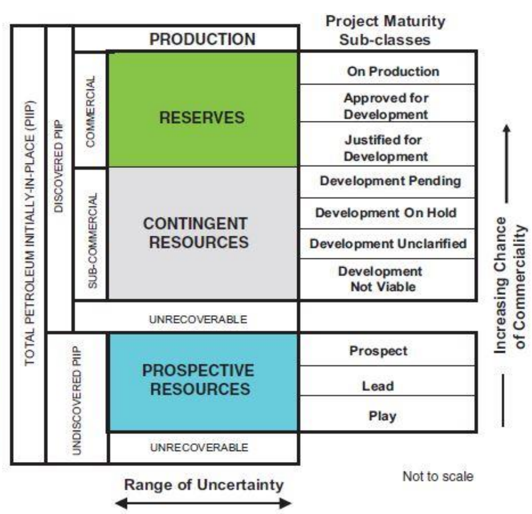


Figure 2.1—Sub-classes based on project maturity

As per PRMS Technically Recoverable Resources (TRR) associated with a Project (in PRMS: "*…a defined activity or set of activities which provides the link between the Petroleum accumulation(s)'s Resources sub-class and the decision-making process, including budget allocation*") are classified as Prospective (Undiscovered) Resources or Contingent (Discovered and Uncommercial) Resources or (Commercial) Reserves. The TRR in fact is the cumulative production forecast assigned to wells in a single Project. Note here that in PRMS the established production of already completed field developments is also considered as Project. Further sub-classification for a Project's TRR is based on Project maturity that is "*associated with the chance of reaching the commercial status"* of the actual development project. PRMS Chapter

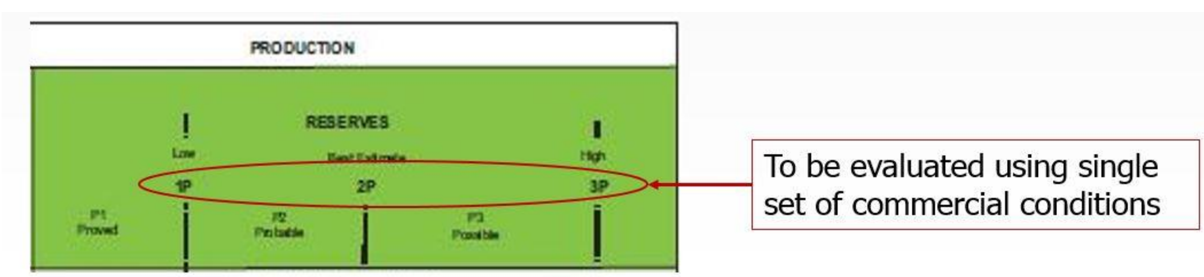
2.1.3.5 provides detailed explanations for the Project Maturity Sub-classes listed.

As of categorization PRMS suggests the consideration of the Range of the Uncertainty of TRR estimations. Primarily, resource evaluators may assess the Low, Best and High Estimates for TRR which are understood as "pessimistic", "realistic" and "optimistic" cumulative production forecast scenarios, respectively. For Reserves they are the 1P ("Proved"), 2P ("Proved and Probable") and 3P ("Proved, Probable and Possible) volumes. By the application of similar symbolic categories for Contingent Resources are 1C, 2C and 3C, while 1U, 2U and 3U for Prospective Resources.

In the Reserve Class PRMS allows for the "deterministic incremental" estimation method which is based on the assumption that physically isolated partitions of the accumulation's Gross Rock Volume might be characterized by different "certainty". In these cases – as PRMS defines – standalone estimations are made for the Proved (P1), Probable (P2) and the Possible (P3) Reserves. In this respect P1 volumes are estimated with "reasonable" certainty while P2 Reserves are less likely to be recovered than P1 but more certain than P3, and finally, P3 is less likely recoverable than P2. Important to nail it down that P1, P2 and P3 deterministic incremental volumes must be associated with a unique Project. Using similar logic incremental categories are allowed for Contingent Resources, too (C1, C2, C3).

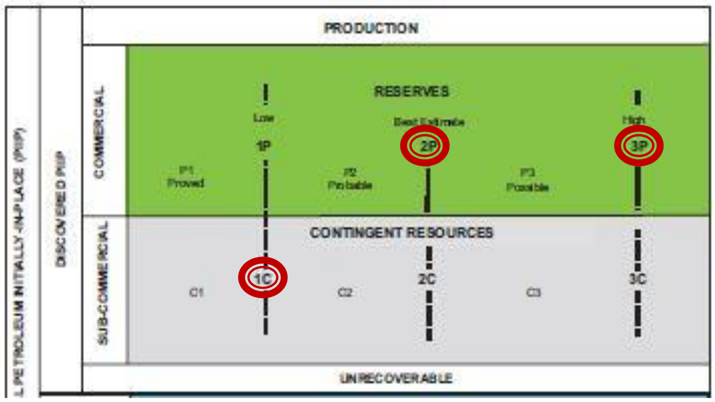
Ambiguity 1 Removed: The Split Conditions

"Split Conditions", as an estimation mistake is committed when different commercial assumptions (e.g. price) are used for Reserves categorizations i.e. 1P, 2P and 3P. At this point PRMS underlines that "*the uncertainty in a project's recoverable quantities is reflected by the… …resource categories"* and that *"the commercial chance of success is associated with Resource Classes or* (Project maturity) *Sub-classes and not with Resources Categories*" which are to reflect the range of the recoverable quantities only. Also noted that variances of commercial conditions should fall into the realm of economic sensitivity analyses. As a consequence, PRMS clarifies that recoverable resources associated with a Project must be evaluated using single set of commercial assumptions – for all the resource volume categories:



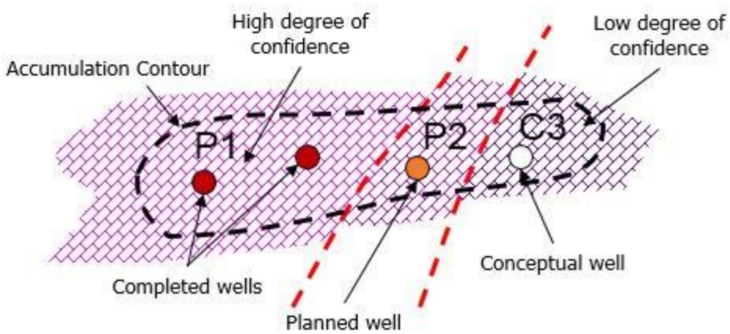
Ambiguity 2 Removed: The Split Classification

"Split Classification" may occur when recoverable quantities are "*classified in both Contingent Resources and Reserves*", for instance 1C, 2P and 3P:



Evaluators made the classification above when the NPV of the Low Estimate TRR's production forecast proved negative while at the same time the NPVs of the Best and High Estimates were found positive. The declaration however that a single Project must be uniquely assigned to a maturity sub-class disqualifies the option of categorizing recoverable quantities in different resource classes. If the case above happens the evaluator's entity should report 2P and 3P, but not 1P (actually, 1P=0).

Another (frequently seen) typical example of Split Classification is demonstrated in the cartoon of an accumulation below:



The Split Classification has been frequently connected to the mistaken application of the deterministic incremental estimation method: Reserves associated with the accumulation partition of "high degree of confidence" are thought to be proven by the completed wells and therefore categorized as P1; the Reserves of the other partition, already approved for drilling out, where our confidence in commercial recovery is weaker is categorized as P2; while the lowest confidence partition where the drilling project is in a conceptual phase only is categorized as C3.

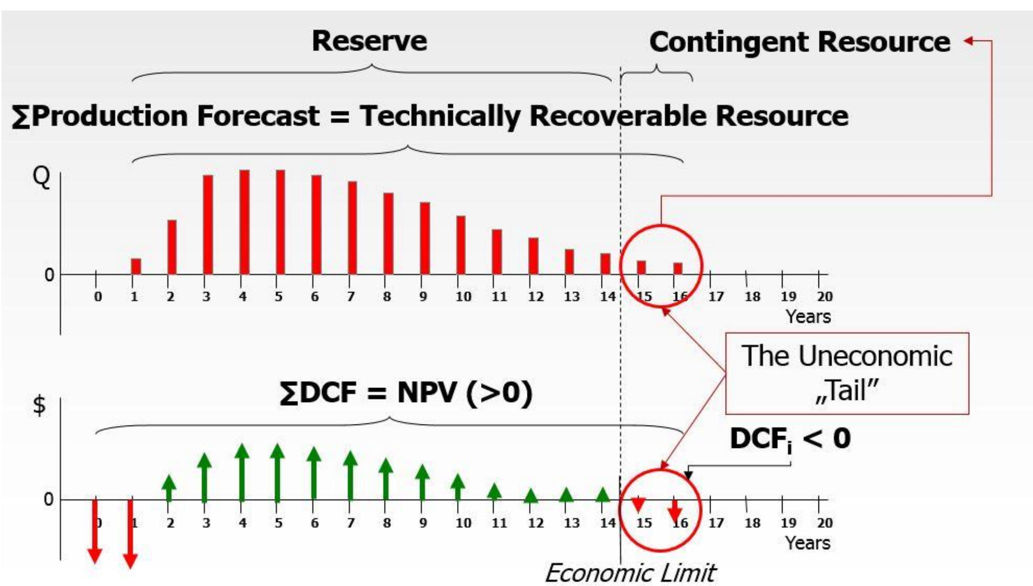
The Split Classification could be removed if the evaluator would adhere to the Project approach of PRMS saying that the TRR of a Project must be assigned to a unique maturity subclass and, at the same time all the three categories are to be given within that. Note however that several Projects may be defined for a single accumulation. The contemplations for the example above suggest that the cumulative and total production forecasts of the already completed wells are to be classified as Reserves (1P, 2P and 3P), sub-classified as "On Production" while production forecast of the "planned" well should be classified also as Reserves (1P, 2P and 3P) in sub-class "Approved for Development". Finally, the TRR of the "conceptual" well falls In the Contingent Resource Class with 1C, 2C and 3C probability based scenarios.

The very important lesson to be learnt at this point is that Technically Recoverable Resource volumes are not associated with Gross Rock Volume partitions ("blocks", "areas", etc.) of the accumulation but with cumulative production forecasts of wells – in a Project.

Ambiguity 1 Remained: Classification of the Sub-economic "Tail" Production

Economic viability is one of the commerciality criteria that differentiates between Contingent Resources and Reserves. As PRMS it describes "*production from a project is economic when the revenue attributable to the entity interest from production exceeds the cost of operation.*" With other worlds the cumulative production until the economic limit is classifiable as Reserves. How to classify however the cumulative TRR beyond the economic limit? Or is the TRR understood as the cumulative production forecast till the limit? If it is, why is it called *Technically* Recoverable Resources? For me, technically means till the technical limit e.g. the abandonment pressure… Moreover, the definition of TRR suggests that it should be understood "*regardless of commercial and accessibility considerations*". Does commerciality, in this respect, include economic viability?

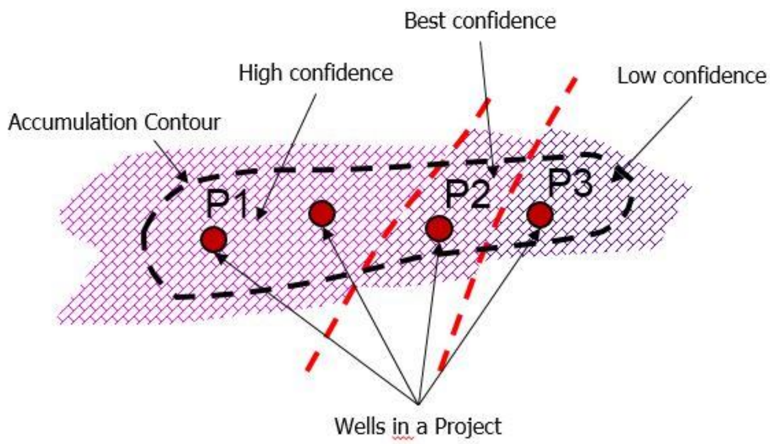
Evaluators formerly delivered a creative solution of classifying the sub-economic "tail" production as Contingent Resources illustrated in the chart below:



The solution may not be applied anymore because it is Split Classification: recoverable resources associated with a Project cannot be split into Reserves and Contingent Resources. However, the removal of the sub-economic tail from the production forecast would argue for the interpretation that TRR is cut by economics – and not by the technical limit…

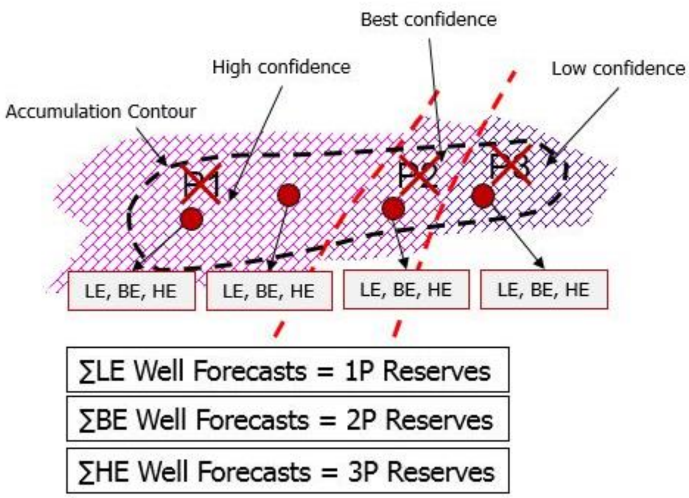
Ambiguity 2 Remained: The unviability of the Deterministic Incremental Method

As Chapter 4.2.1.2 of PRMS cited "*the deterministic incremental method is based on defining* *discrete parts or segments of the accumulation that reflect high, best and low confidence regarding the estimates of recoverable quantities under the defined development plan."* For this case PRMS suggests the "incremental" categorization: Reserves categories for the High, Best and Low confidence partitions should be P1, P2 and P3, respectively, as illustrated in the chart below:



Note that the wells (all the four) are planned to be put into production under the scheme of a single development Project (suppose that one out of the four has been already drilled in the segment of the P1 but not yet tied in; while the drilling and tying the other three are approved, and the whole Project is commercial). The Project's TRR is classified as Reserves and sub-classified as "Development Approved".

PRMS (and also common-sense logic) however suggests that TRRs are cumulative production forecasts of wells. Given that the initial production rates as well as future decline rates are uncertain before the production start (at the very moment of the development plan approval) the evaluator cannot do else with the consideration of the range of the uncertainty (of the production forecast) than elaborating a Low, Best and a High Estimate forecast scenarios. This way the aggregates of the wells' Low, Best and High Estimate forecasts will give the Project's 1P, 2P and 3P Reserves, respectively:



The deterministic incremental Reserve categories (P1, P2, P3) in fact do not exist, simply because the range of the uncertainty of the TRR cannot be solely attributed to the degree of confidence in the Gross Rock Volume. The range of the uncertainty of the TRR is defined by many other parameters controlling the recoverability – and these parameters cannot be neglected.

No well spacing is conceivable to confirm the viability of the deterministic incremental method. The unviability is also evincible once one thinks it over that it is impossible to forecast the production of the Best and Low, as well as the High and Best estimates' differences. The explanation why the ambiguity of the illogical deterministic incremental method still exist lies in tradition. Terms Proved, Possible and Probable Reserves had been born well before the actual (and very correct) Project approach of PRMS was elaborated. That time Proved meant "drilled and tested" while Possible and Probable indeed described the degree of confidence in the recoverability of the undrilled reservoir partitions. The evolution of resources classification and categorization resulting in the PRMS framework of today albeit has set aside but could not eliminate traditional terminological inveteracies. "Old schooler" industry veterans still believe and are convinced that the usage of the traditional but outdated terminology is survivable. That is the reason why the ambiguous deterministic incremental resource assessment method is still with us. The result is compromised Reserves booking and reporting.

Ambiguity 3 Remained: Project Maturity Sub-classes for Prospective Resources

PRMS defines Play, Lead and Prospect as Project Maturity Sub-classes in the Prospective Resources Class which comprehends the recoverable part of yet undiscovered recoverable resource volumes. A geologist may raise four concerns about the appropriateness of these terminologies.

First, petroleum Plays, Leads and Prospects are definitely not "projects" albeit exploration project activities including but not limited to seismic data acquisition, processing and interpretation as well as exploratory well drillings may purpose the maturation and de-risking of resource volumes assigned to Plays, Leads and Prospects. Second, the play analyses may result in the estimation of the Yet-To-Find (YTF) volumes which, by definition, includes the volumes assigned to Leads and Prospects – within the Play. Third, Prospective Resources sensu stricto, and as the terminology suggests, denote volumes in Prospects i.e. drillable geological structures which may, under the geological probability (Pg) of success, capture recoverable quantities of hydrocarbon. Fourth, if we want to be consistent with the classification concept of PRMS regarding the separation of the Contingent Resources and Reserves Classes the overall definition for the Prospective Class and the Project maturity based sub-classification thereof should reflect the maturity status of the future development Project activity, and definitely not the maturity stages of exploration that is based on geological knowledge. The alignment however could be problematic because the field development is merely conceptual in the exploration phase. A schematic development design must be elaborated for the exploration project's economics for the most likely discovery realization out of the many, but it is not to compare with the feasibility of the post-discovery development concept. The solution would be if no further sub-classification were applied to the Prospective Resources and the definition should conclude that development in this stage (exploration) is conceptual only.

Note that I neither challenge the assignability of resources to Plays, Leads and Prospects, nor the viability of the prospect maturation as described in PRMS. I just argue that the sub-classification, as it is in PRMS for the Prospective Resources, is consistent with the sub-classification of Contingent Resources and Reserves.

Conclusive remarks

As of the ambiguities removed (Split Conditions and Split Classification) from previous version of PRMS one question is flashing on one's mind: Will the removal trigger the revision of earlier bookings? The PRMS says that Split Conditions and Split Classification is advised to avoid – in the future. It is fine but what to do with 1P and 2P Reserves which had been assessed in alignment with PRMS 2007 but are not conform to PRMS 2018? Differences in categorized volumes might be significant.

Time and daily practice will decide on the ambiguities that has been remained with the industry. As of the classification of the "sub-economic tail" I would not recommend to consider these production forecasts beyond the economic limit neither as Contingent Resources nor as Reserves. The solution is far from granularity but elegantly bypasses the Split Classification conflict.

The application of the deterministic incremental method, due to its inherent ambiguity should be avoided. Although PRMS allows this estimation methodology its usage is not obligatory at all. The unviability of the method however raises concerns about the fundamental PRMS-terminologies. In case no standalone estimations for the Probable (P2) and the Possible (P3) can be given then how Proved plus Probable (2P) or Proved, Probable and Possible (3P) should be understood? After all, non-existent quantities cannot be added… The inconsistency could be removed by a terminological revolution only: "1P", "2P" and "3P" are recommended to be retired and replaced with Low Estimate (LE), Best Estimate (BE) and High Estimate (HE) Reserves, respectively. For the sake of those who like and have got used to the traditional forms we may recommend to apply Possible Reserves for Project commercial TRR in PRMS Sub-class "Justified for Development" – Status Undeveloped; Probable Reserves for Sub-class "Approved for Development" – Status Undeveloped; and finally, Proved Reserves should refer to commercial TRR in Sub-class "On Production" – Status Developed. As it is mentioned above some old fashioned or superficially informed experts and managers by the way believe that "Proved" means drilled and tested. Let them be right – albeit added that the Proved Reserves must have Low, Best and High Estimates which could be equal if the range of the uncertainty of the cumulative production forecast scenarios is insignificant.

The ambiguities around the Prospective Resources' maturity sub-class terminologies will not cause serious problems because undiscovered resources are never reported publicly and usually are not part of the company's resource-reserve tracking system. These definitions, as they are in PRMS, are just eyesores for geologists.

The PRMS updating process has just been completed and another revision is hardly expected in the near future. It means that the industry must accommodate the remaining ambiguities. However, we should not forget about them: Petroleum resources estimation and reserves evaluation is a serious business which would deserve granularity and terminological clarity.

ASPHALTENE DEPOSITION ORIGIN AND TREATMENT TECHNIQUES IN OIL AND GAS FIELDS

Abdus Saboor & Nimra Yousuf
Petroleum Engineering Students, NED University of Engineering & Technology, Karachi, Pakistan

Introduction

Flow assurance is a term that deals with the successful and economical transportation of reservoir fluid from field to oil industries. During the transportation of crude oil, the organic matters that it contains under unfavorable condition precipitate out, grow and then deposited in the pipelines and facilities causes the decrement in the flow of oil and gas. These organic compounds can also deposit in the well bore thus blocking and stopping the further flow of hydrocarbons to the subsurface and surface facilities. Many oil and gas fields are facing this kind of problem which is affecting the economy of oil industry.

Asphaltene is also one of the complex organic compounds found in crude oil. Many oil fields have to face the deposition of Asphaltene. These are deposited due to the compositional changes occur in crude oil. Asphaltene deposition is a serious and expensive problem in oil and gas fields and can take birth in wellbore, subsurface and surface facilities causing huge loss of hydrocarbon production Figure 1 and 2. The remedial methods taken to treat this problem put huge economic impact over oil companies for example in the Gulf of Mexico oil fields, cost associated with this issue to treat per well by ring intervention during well shut period has been approximately $70 M [1]. Another case is of Middle Eastern fields where cost of injecting chemical additives to cure this problem is in the range between USD $31,000 and USD $46,000[2]

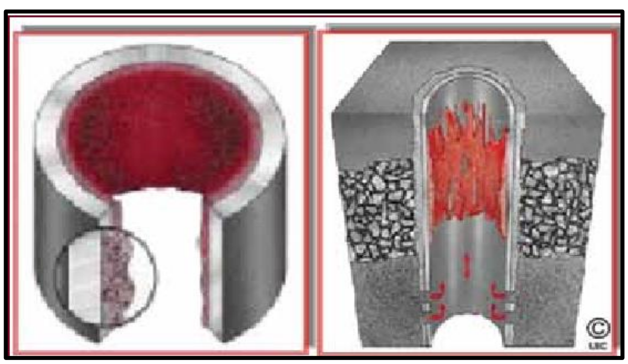


Figure 1: Deposition of Asphaltene in Wellbore [3]

Figure 2: Asphaltene deposition [4]

The main reason of Asphaltene deposition is the change of pressure and temperature in well bore and in the pipelines as well. The use of the HCL for the simulation of well can also harm the formation because of the presence of Asphaltene in formation which can damage the formation. The Asphaltene can poison the refinery catalyst and can fouling the production facilities. Also, Asphaltene can be the reason of plugging of reservoir and it alters the wettability.

Definition

Upon addition of n-pentane and n-heptane to the crude oil, it precipitates out the solids called Asphaltene. Crude oil consists of Aromatics, Resins, Saturates and Asphaltene. Asphaltene are the heaviest element in the crude oil and is the polar components as well. Asphaltene is soluble in aromatics such as xylene, toluene and benzene but insoluble in n-pentane and n-heptane. It does not exist in same weight and molecular structure [5]

Crude oil shows more instability in terms of Asphaltene deposition when interact with n pentane as compared to n-Heptane. Asphaltene precipitation decreases as the carbon atoms in n alkane increases [6]. Therefore, Asphaltene is more insoluble in lighter liquid such as the n-pentane than n-heptane which is heavier.

Structure of Asphaltene

Yen Mullins model used to predict the size, shape and mass of the Asphaltene molecule. It divides the Asphaltene molecular structure into three categories as shown in Figure 3:

a. Asphaltene molecule
b. Nano aggregates of Asphaltene molecule
c. Cluster of Nano aggregates

Yen-Mullins model explains that Asphaltene molecules can be identify at low concentration and in volatile oil, it is identified as a solution and measure about 1.5 nm. It is predicted that the Asphaltene structure is like chain in which hexagonal rings is exist and side chains of alkanes are hanging. If the concentration is high when Asphaltene molecule combine and form Nano aggregates which measured about 2 nm wide, and at very high concentration the Nano aggregates cartel to form cluster which measured about 5 nm wide and spread in heavyweight oil.

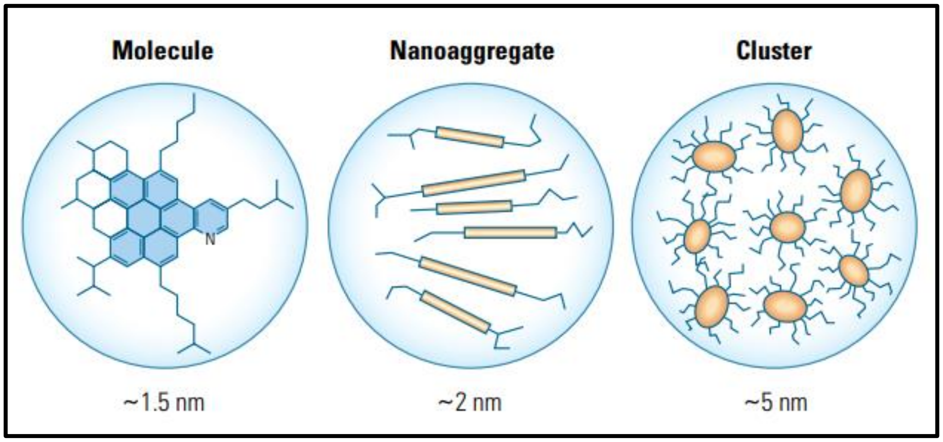


Figure 3: Structure of Asphaltene [7]

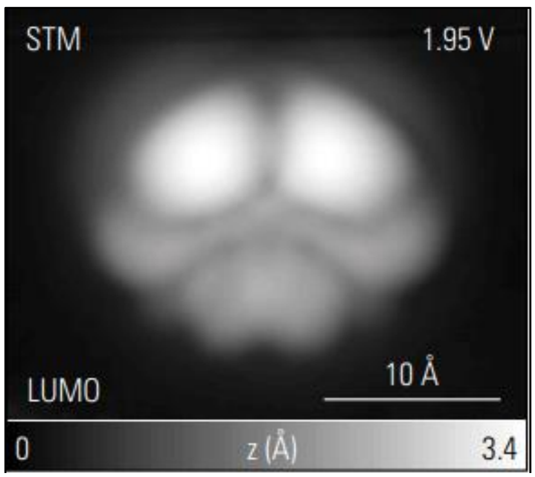


Figure 4: Scanning Tunneling Microscopy[7]

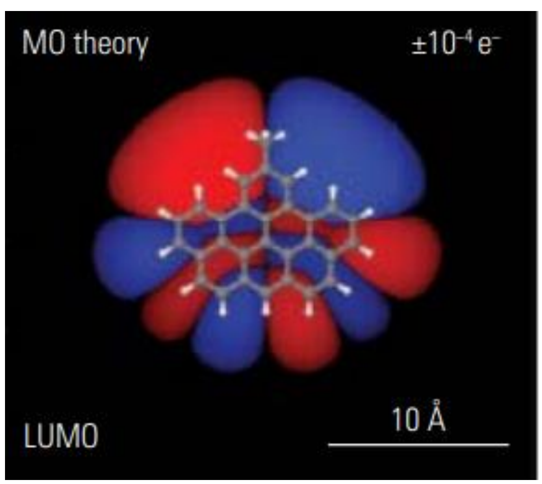


Figure 5: Colorful print of STM [7]

More images have been taken by different methods like by atomic force microscopy (AFM) image which shows the atomic structure of Asphaltene in which molecules are arranged in aromatic rings to form the polycyclic ring of aromatic. Also Scanning Tunneling Microscopy (STM) shows different electrons of Asphaltene molecule. Image has the calculation of LUMO (lower unoccupied molecular orbit) in which density functional theory is also used. The molecular structure consists of the carbon and hydrogen where carbon is shown by grey and hydrogen is shown by blue. Figure 4 and 5 showing the image of AFM and STM [7]

Asphaltene molecule

In literary context, Asphaltene molecule comprises of two structures; the continental and the archipelago models as shown in Figure 6 and 7. Continental structure consists of small alkyl chains surrounding a large central aromatic region. Whereas, archipelago contains bridging alkanes surrounding the smaller aromatic regions in the middle. Asphaltenes are prone to formation of colloidal stacks held together by π-π bonds if they have large aromatic cores.
However, if the aromatic clusters in Asphaltene molecules are small and dispersed, self-alliance is more likely to replicate polymer structures. This type of cluster may also be supported by π-π bonds and may be considered as macromolecules. These macromolecules have the ability to be freely dispersed in solution or dispersed by resin. Resins can be a part of this aggregation.

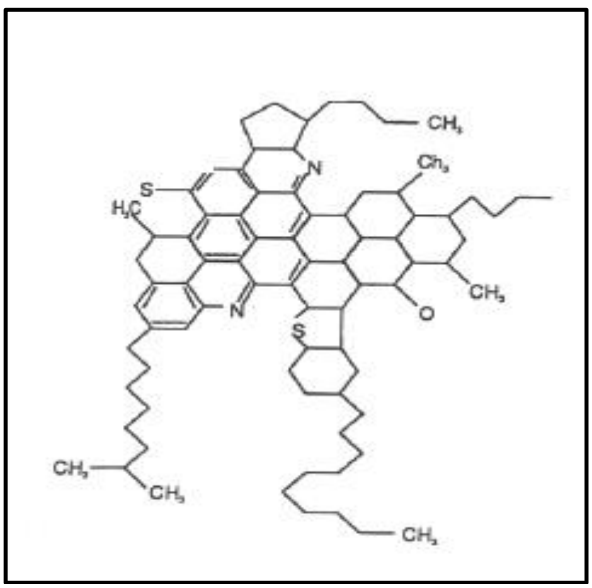


Figure 6: Continental structure of Asphaltene Molecule [8]

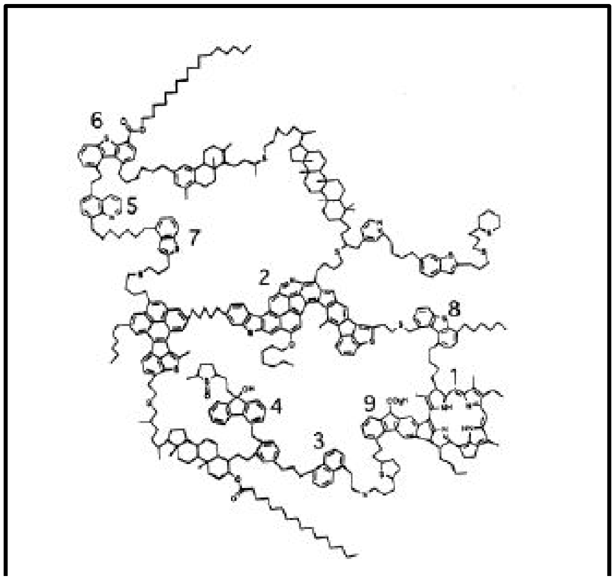


Figure 7: Archipelago structure of Asphaltene Molecule [8]

Role of SARA

Crude oil is composed of saturates, aromatics, Resins and Asphaltene as shown in Figure 8. The value of each component in a crude oil portrays a vital character towards the stability of oil in terms of Asphaltene deposition. The function of aromatics is to keep the Asphaltene molecules dissolve in the crude oil. However, it is known that resins coat the Asphaltene particle thus not allowing other molecule to come and interact with Asphaltene [9] The reason for Asphaltene precipitation is that when n-alkanes come in contact with crude oil it dissolves resins. Resins show miscibility with n-alkanes while Asphaltene are immiscible [9]. Thus, removal of resins left active space for Asphaltene to interact with other Asphaltene particles to grow and deposit.

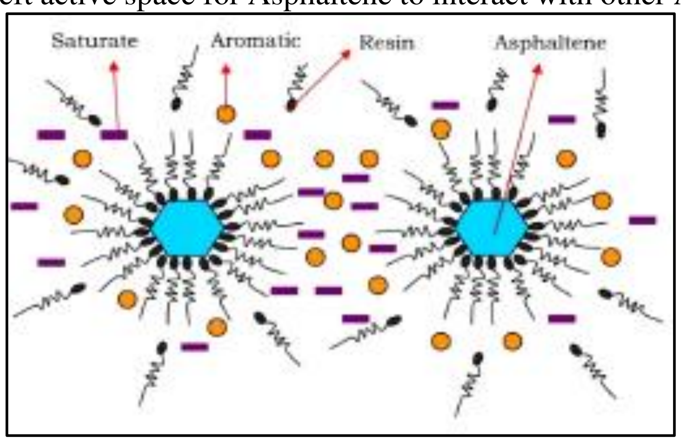


Figure 8 Illustration of Force Balance on Asphaltenes [9]

Causes of asphaltene

There can be many causes and reasons of the deposition of organic matter in well bores and in flowing pipes; it is dependent on the nature of their molecule[10]. In most oil field the deposition of Asphaltene is caused by pressure drop in pipelines and in wellbores [11]. Also, there can be many factors which becomes the main reason of the deposition of this chemical like the factor of change in temperature and pressure in the well bore and in the pipelines as well, also the variations in flow regime, composition and electro-kinetic effect [10].

Effect of temperature

The stability of Asphaltene is affected in a complex manner due to temperature. The temperature plays the vital role in deposition of heavy organic matters. As the temperature of the decompression process lessens, the Asphaltene assembly system slowly changes from limited assembly by reaction to limited aggregation by diffusion [12] After increasing the temperature, the amount of Asphaltene precipitation decreases[13]. The solubility of Asphaltene increases with increase in temperature. Another factor is that of composition of crude oil, it changes due to heat or high temperature, the solubility of Asphaltene decreases with the compositional change of oil. Due to this, the decomposition of Asphaltene becomes active and deposits in the flow lines. Another component is the viscosity; when the temperature increases, the viscosity of crude oil decreases thus promoting precipitation of Asphaltene [14]. Temperature effect is shown in Figure 9.

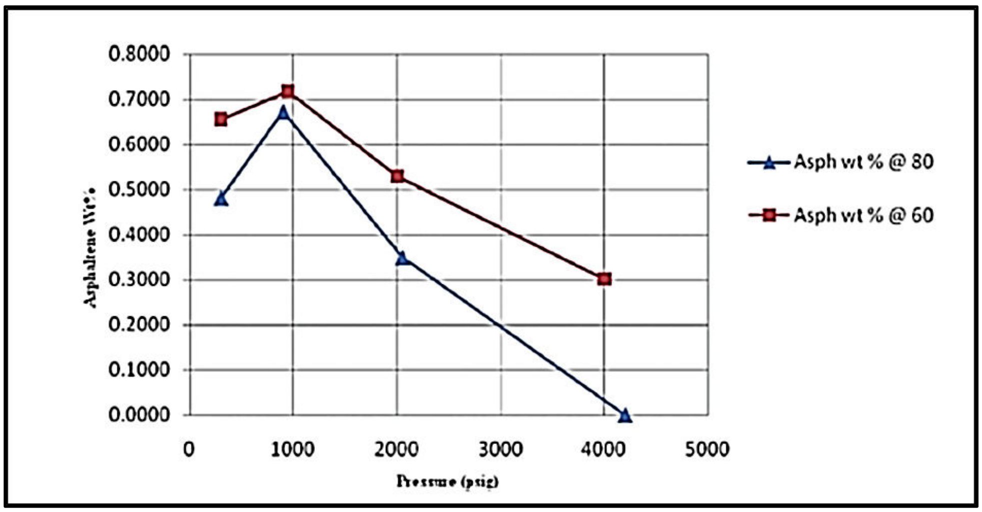


Figure 9 Effect of Temperature on Asphaltene Precipitation [14]

Effect of Pressure

When pressure drops above the bubble point the gases and oil expand causes rapid decrease in density. This lower density negatively affects the solubility of Asphaltene in crude oil, due to which the crude oil becomes the bad solvent for the Asphaltene. But when the pressure further decreases below the bubble point, the solubility of crude oil for Asphaltene improves and there is less chance of Asphaltene to precipitate. The reason for this is that: the pressure drops below bubble point causing the escape of lighter hydrocarbon molecules such as methane, ethane and other non-hydrocarbon gases from the solution. The presence of above-mentioned hydrocarbons contributes towards the Asphaltene precipitation.

The calculation of solubility and density of crude oil demonstrated that the pressure drops above the bubble point will cause decrement in the solubility of organic matters in crude oil and pressure drops below the bubble point will increase the solubility in light of the fact that the lighter particles or the dissolved gases will precipitate out which increases the density of crude oil as well. Pressure effect on asphaltene deposition is shown in Figure 10.

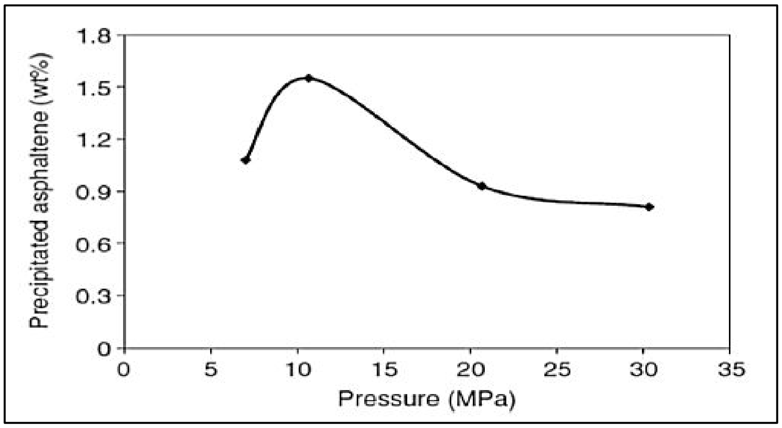


Figure 10 Amount of Asphaltene deposited by the change of pressure [15]

Effect of chemical composition

The nature of Asphaltenes is a standout amongst the most critical elements for the stability of crude oils. The structural and compositional properties of Asphaltenes significantly affect the deposition issues[16].

The constitution of the reservoir fluid changes due to natural exhaustion amid the recovery of the primary fluid that can cause the loss of lighter segments that lead to a decline in the gas/oil (GOR) and can cause increment in the fluid density. The flocculation tendency of Asphaltenes lessens due to the two things discussed.

Natural flocculation of Asphaltenes can be caused by injection of miscible fluids during secondary oil recovery because petroleum resins play a role of a peptizing agent for Asphaltenes in part or completely dissolved in the presence of an excess of low hydrocarbons molecular weight. Due to this, Asphaltenes is deposited, solidified and precipitated [15]. The composition does not play a major role in the stability of Asphaltene. [16]

Effect of Electro Kinetic

Electro kinetic is generated in fluid mostly when the oil pumped up from the reservoir to the subsurface the velocity of oil generates the electro-kinetic energy with the help of friction which is observe in the properties of produced fluids. The higher amount of Asphaltene is deposit in that part where the velocity is higher[15].

Removal methods of Asphaltene

CHEMICAL TREATMENT

Chemical methods are very common to remove the Asphaltene, because it does not require much energy as mechanical treatment requires and require less cost as compare to mechanical treatment for removing these types of organic matters. The methods are as follows;

TREATMENT BY SOLVENT

Aromatic compounds like xylene, toluene and other similar compounds are used to re-dissolve the Asphaltene precipitated in oil.

TREATMENT BY DISPERSANTS

Asphaltene dispersants prevent the growth of Asphaltene particles and keep them in suspension in oil. Dispersant done this by surrounding around Asphaltene particle thus keep other molecule away from surrounded Asphaltene molecule.

CRYSTAL MODIFIERS

Wax crystal growth is altered by polymers known as crystal modifiers using the process of disrupting nucleation, crystallization, or modification of the paraffin crystal [17]

TREATMENT BY INHIBITOR

They are the type of polymer. There function is to delay the deposition mechanism or delay the onset flocculation point.

MECHANICAL METHOD FOR REMOVING ASPHALTENE

This method is expensive and requires energy for its procedure and can take several days to fix the measure problem (deposition of Asphaltene) in the pipelines. These methods involve mechanical scraping of deposits inside the wells[18], like rod scrapers, wire-line scrapers, flow lines scrapers, free floating piston scrapers and much more[15]. Some methods are given below:

WIRELINE CUTTING:

This is the costly treatment and slow as well, it is for removing the hard deposition of Asphaltene in pipelines. It regrets due to its time taking behavior.

HYDRO-BLASTING METHOD:

In this method, the operators drilling the deposit by hydro blasting tool using the coiled tubing unit. Nonetheless, the disadvantage of this unit is that it has a limiting working pressure that makes the cleaning process inconvenient.

BY CREATING DIFFERENTIAL PRESSURE:

There is one more method of removing of the Asphaltene deposition by application of pressure to generate a differential pressure across the deposit in order to remove it [15]

DISADVANTAGES OF MECHANICAL TREATMENT:

i. Expensive treatments limited to production capacity, but not to training production,
ii. Application is limited to the equipment involved.
iii. Fishing gear can be lost in the hole. Furthermore, the mechanical treatment can plug the perforations. Aldo, it can increase the stability of oil-in-water suspensions [17]

THERMAL TREATMENT:

To remove Asphaltene by thermal treatment, there are many methods to remove Asphaltene thermally which involves many techniques,

I. HOT OILING:

In this technique there is an injection of hot oil through which the deposited Asphaltene start to dissolve in the hot oil because as we discussed earlier that the Asphaltene is soluble in oil when temperature becomes high. The disadvantage of this method is that formation can be affected by the injection of hot oil.

II. DOWN-HOLE HEATERS:

In this method the down-hole heater produces the continuous heat through which the deposited Asphaltene becomes melt and pumped with formed oil on the subsurface. But it has the disadvantage because of higher power consumption.

III. BY USING HEAT LIBERATING CHEMICALS:
Another method of removing Asphaltene from well bore is that by using the heat liberating chemicals, mixing of the ammonium chloride and sodium nitrite mixture is utilized and pumped down along with mud in the borehole to detain the exothermic reaction by which the successful inhibition takes place of Asphaltene [17]. Vegetable oils such as sweet almond, andiroba, coconut essential oil and the sandal is soluble in oil; showed a high capacity to hinder the precipitation of Asphaltenes at cheap economic price [19].

Prevention of asphaltene deposition

There are several methods to prevent the deposition of Asphaltene in pipelines the effective methods described below,

I. MANIPULATION OF PARAMETERS OF OIL PRODUCTION:

a. The effective method to reduce and prevent the deposition of Asphaltene is that by controlling the temperature and pressure, it is the most effective method for the prevention of oil because it does not require any cost but require some attention and require control on temperature and pressure.
b. Another process is that by increment of the size of orifice chock size to prevent the deposition of Asphaltene and other organic matters, due to this the ratio of oil and gas reduces which reduce the deposition of organic matters [15]
c. It is recommended that before the injection of any fluid in the reservoir for operations like acidizing, EOR, Hydraulic fracturing etc. The fluid must be tested for its compatibility with the crude oil.
d. Installation of dual completion is an effective preventive measure that allows the production of hydrocarbon fluids from one of the tubing when other is being blocked or treated. It also helps to avoid expensive workovers.

II. DISPERSANT AND INHIBITORS:
Asphaltene can be removed for some time by the use of mechanical methods like scrapping mechanically, wire-line cutting and by washing the solvents these methods are frequent and Asphaltene starts to deposit again[20]. There is one more method for the prevention, by using the chemical additives which stops the Asphaltene deposition during production of oil [21]

Conclusion

Asphaltene problem in oil and gas field is a complex phenomenon due to its intricate nature. Since, many factors are involved during its precipitation and deposition so there is no direct method sufficient enough to mitigate the problem. Before applying any method for its treatment, it needs to be screened first through lab experiments. However, it is recommended to understand the deposition mechanism which will result in the designing of the optimum conditions for the flow of reservoir fluid.

Acknowledgement
Special thanks to Dr. Javed Haneef, Mr. Imran Ali and Mr. Shane Ali for guiding and helping us in developing this article.

References

1. A, G.F., *Personal communication. Asphaltene deposition economic impact*. 2015.
2. S, A.D., *Personal communication*. 2015: Abu Dhabi, UAE: Abu Dhabi Company for Onshore Petroleum Operations Ltd.
3. Mansoori, G.A., *Remediation of Asphaltene and Other Heavy Organic Deposits in Oil Wells and in Pipelines.* Reservoir and Petroleum Engineering 2010.
4. Stavanger, *Organic flow assurance: Asphaltene dispersant/inhibitor formulation development through experimental design* 2012.
5. Mahmud, O.H.E.a.H.K.b., *asphaltene.* environmentally Freindly solvent Mix for Asphaltene Deposite Removal, dec 2015.
6. T. Jafari Behbahani, C.G., V. Taghikhania, A. Shahrabadib, *Experimental investigation and thermodynamic modeling of asphaltene precipitation.* ELSEVIER, 2012.
7. Mullins, O., Asphaltenes, 2016.
8. Kelland, M.A., *Organic flow assurance: Asphaltene dispersant/inhibitor formulation development through experimental design*. 2012, University of Stavanger.
9. Siavash Ashoori , M.S., Mohammad Masoumi , Mehdi Mohammad Salehi *The relationship between SARA fractions and crude oil stability.* ELSEVIER, 2016.
10. Mansoori, Asphaltene Deposition and its Control, 2015: p. 18.
11. *Asphaltene deposition and plugging*, in *Petrowiki*. 2015.
12. Mohammadi, S., On the effect of temperature on precipitation and aggregation of asphaltenes in light live oils, 2016.
13. Ahmadi, Y., *Petroleum Science and Technology.* The Effect of Temperature and Pressureon the Reversibility of AsphaltenePrecipitation, 2014.
14. *Advance Motor Fuel*, in *IEA-AMF*. 2005.
15. Gharbi, K., *Removal and prevention of asphaltene deposition during oil production:.* Journal of Petroleum Science and Engineering, 2017.
16. Rogel, E., *Asphaltene Stability in Crude Oils* SPE, 1999.
17. Y, A., *A new technique for treatment of permeability damage due toasphaltene deposition using laser technology.* Journal of Petroleum Science and Engineering, 2007.
18. Akbar, S.S., *A comprehensive approach to solve asphaltene deposition problem in some deep wells.* Society of Petroleum Engineers, 1989.
19. Junior, L.C.R., Ferreira, M.S., da Silva Ramos, *Inhibition of asphaltene precipitation in Brazilian crude oils using new oil soluble amphiphiles.* J. Petroleum sci, 2006.
20. Albannay, A., Masuzawa, T., Dabbouk, C.A, *Alternative methods in preventing asphaltene deposition.* Society of Petroleum Engineers., 2010.
21. Balson, T., *New methods for the selection of asphaltene inhibitors in the field.* Chem. Oil Industry, 2002.

SEMINAR ON RESUME WRITING AND TACKLING RECRUITMENT INTERVIEWS ORGANIZED BY SPRE-NED- JANUARY 21

Society of Petroleum Resources Economists (SPRE) is an international professional organization specifically dedicated to the business side of the industry or 'Petroleum Economics', having student chapters in universities all around the globe.
SPRE Chapter at NED University has the distinction of being the only one in South Asia. Team SPRE feels great pride to kickstart its activities in the varsity with a seminar organized on "Resume Writing and Tackling Recruitment Interviews", conducted by Shakeel Rauf Chief HR Manager, Pakistan Petroleum Limited on 21st January 2019 at the Department of Petroleum Engineering, NEDUET.

The guest for the seminar was Mr. Shakeel Rauf Qureshi who serves as the Chief HR Officer at Pakistan Petroleum Limited. An astonishing fact to notice was that despite graduating for the same institute as the crowd, that is NED University, he switched labels and pursued his career in Human Resources after completing MBA in Human Resource Management and then LLB furthermore. Mr. Qureshi leads the HR department in one of the most reputed E&P companies of the country and every now and then has a pile of résumés by his side, a lot of which eventually go to trash. This means that there could not have been anyone better to talk about résumé writing than him.

Shakeel R. Qureshi, Chief HR Manager, Pakistan Petroleum Limited

Proceedings

Mr. Hasnain Shabbir, also the treasurer of the SPRE Chapter at NED University, hosted. The event was started with the recitation of Holy Quran by Mr. Huzaifa Faruqui, senior at the Department of Petroleum Engineering, NEDUET.

Mr. Hassaan Chaudhry was invited to the rostrum to speak a few words to the audience regarding the newly formed SPRE Chapter at NED University. As a formal induction ceremony could not be held, the President of SPRE-NED took the opportunity to also introduce the Officer Corps of SPRE Chapter at NED University:

- Muhammad Hassaan Chaudhry - President
- Muzammil Ahmed -Vice President
- Talha Mehtab - Secretary
- Hasnain Shabbir- Treasurer

Dr. Javed Haneef, Incharge, Department of Petroleum Engineering presenting the token of appreciation to Mr. Shakeel Rauf Qureshi

Officer Corps of SPRE-NED with Dr. Javed Haneef, Mr. Faizan Ali, Faculty Advisor, and Mr. Shakeel Rauf Qureshi

Mr. Shakeel Rauf Qureshi was then invited up to the rostrum to take charge of the audience. A summary of his speech is as follows:

• An employer only spends a maximum of 45 seconds while reviewing your résumé.

• The purpose of the applicant's résumé to land him an interview, rather than a job. A résumé must be neat, well-organized, concise, error free and must have a professional appearance. Moreover, one should tailor his résumé according to the job he wishes to apply for.

• Contents of typical résumés include: Personal Information, Objective of Application, Educational Background, Professional Experience, Awards, Extra-curricular activities, Computer skills and References (if any).

Following are some the writing tips for a better résumé:

• Give yourself time and keep reviewing what you've written.

• Think like an HR professional, it will help you in arranging your information better.

• Be aware of the company, application post and requirements.

• Make your information easy to read with better fonts, color and styles.

• Make your information easy to read.

• Avoid adding unnecessary long paragraphs.

• Give your contact information early.

• Be specific while quoting facts, rather than using words, use numbers, like GPA, marks, percentage, rankings etc.

• It is better to use a reverse chronological sequence for a résumé.

While going into an interview, it was encouraged to do the following activities beforehand:

• Bring extra copies of your resume.

• Smile and give a firm handshake.

• Listen carefully – Be sure to answer the question you are asked!

• Don't cut off the interviewer and know when to stop talking.

• Maintain good eye contact, good posture, and distinct speech.

• Be self-confident and alert; stay involved and interested.

• Maintain enthusiasm throughout the interview.

• Ask your questions at the end of the interview.

Officer Corps of SPRE-NED with students from Dawood University of Engineering & Technology (left) and Department of Petroleum Technology, University of Karachi.

SPRE-NED FIELD VISIT TO OGDCL KUNNAR KPD-TAY FIELD AND LPG PLANT- MARCH 7

Team SPRE-NED feels great pride to take the lead in arranging an industrial field for the benefits of the students to Kunnar KPD-TAY Field and LPG Plant, courtesy of Oil & Gas Development Company Limited (OGDCL) on March 7th, 2019. Team SPRE-NED believes there should be a strong linkage between the industry and the academia, and that the practical knowledge is worth as much as the quality theoretical knowledge being imparted at the varsity.

Field Information

Kunnar gas/condensate field is located in the Hyderabad District at a distance of about 26 kms from Hyderabad city. First exploratory well i.e. Kunnar well No. 1 was drilled and completed in November 1987. In order to obtain reservoir data, extended production tests were conducted on Kunnar wells. Oil and Gas Development Corporation Limited (OGDCL) has a 100 percent working interest in the Kunnar Gas/Condensate Field. The field was placed on regular production in December 1991. At Kunnar field, 12 wells have been drilled so far and out of which 9 are producers, 1 is plugged & abandoned and remaining two are water disposal and gas injector wells respectively. Production from Kunnar Deep wells (Phase-I) has been started from February 2012 while from Tando Allah Yar (Phase-II) wells has been started from January 2017.

Tando Allah Yar (TAY) is a Joint Venture of OGDCL (77.5%) and Government Holding Private Limited (22.5%). The field is located at about 32 kms east of Hyderabad city and is a gas/condensate discovery. TAY is named after the nearest town, Tando Allah Yar, which is about 5 Kms away from Tando Allah Yar Well # 01. The discovery was made on 4th January 1998 in the Lower Goru formation. TAY # 01 was completed as dual producer. TAY is the integral part of KPD Project.

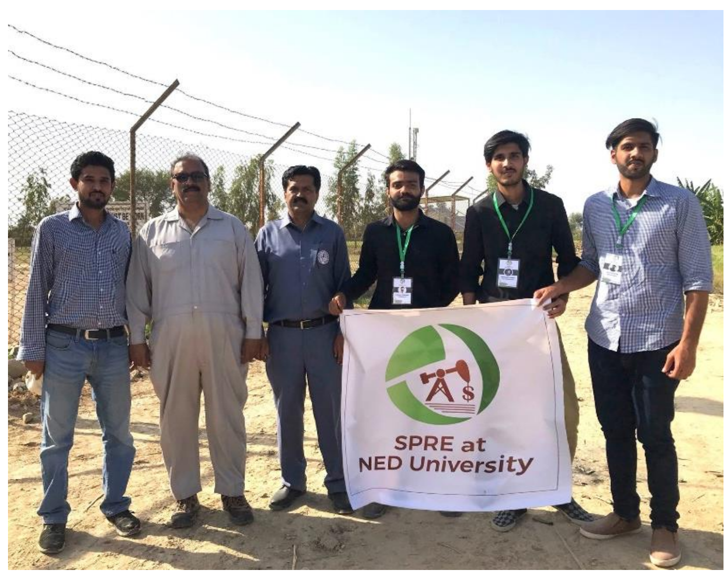
Currently 49 wells have been drilled in Kunnar Pasakhi Deep and Tando Allah Yar concession wherein 23 wells are producer, 13 wells have been abandoned and 13 wells are shut in.

Proceedings

Students of Department of Petroleum Engineering, NEDUET and faculty members pose with the officials of OGDCL outside KD-05 well.

President SPRE-NED, M. Hassaan Chaudhry and Faculty Advisor, Mr. Faizan Ali presenting the token of appreciation and souvenirs to Field Manager Kunnar, Mr. Mumtaz Ali Soomro.

QHSE Induction held by OGDCL for the Students of Department of Petroleum Engineering, NEDUET.



SPRE-NED Officer Corp poses with the officials of OGDCL outside KD-05 well.

QHSE Induction (Health Safety & Environment)

The Health and Safety Environment (HSE) department of Oil & Gas Development Corporation Limited conducted a short seminar where we were told about the safety measures and precaution that were necessary to practice at the oilfield. The combustion and fire require oxygen and fuel which is present at the oilfield, therefore one has to avoid use of Static Charge and Fire Combustion at the plant. Mobile phone signals can be an ignition source as they could result in static charge causing combustion. To extinguish the fire 3 processes are considered. The first one is cooling, second is smothering; reducing oxygen and third one is starvation where we remove the fuel. The safety department of OGDCL uses water, CO_2 gas, dry chemical powder and AFF (aqueous filling firing foam) to extinguish the fire.

The safety instructor also classified the fire based on various hazards: Paper Fire, Flammable Liquids, Electrical Fire, Metal Fire, Kitchen Fire.

The safety instructor told students about the causes of accident occurring at any place which were: I didn't think, I didn't see, I didn't know.

Gas Processing Facility (Production)

a. **Facts & Figures**

- **Capacity**: The gas processing facility have capacity to process 250 MMScf/day.
- **Production**: 286 mmcfd of gas, 387 tons of LPG, 400 tons of Liquefied Natural Gas (LNG) and 4,500 barrels of crude oil daily.
- **Processing**: The natural gas straight from the condensate reservoir is processed at the plant where the process of sweetening and dehydration occurs.
- **Separator**: Separator installed are Horizontal and Free Water Knockout (Three Phase Separator).
- **Impurities**: The gas contains 7% CO_2 and 1 ppm H_2S
- **Pipeline**: The processed natural gas is transported through pipeline.

- **Pressurized Trucks**: The LPG (Liquified Petroleum Gas) is transported through trucks where pressure of 150 psig is maintained.

- **Buyer Company**: SSGC (SUI SOUTHERN GAS PIPELINE).

- **The Field Control Unit**: The Unit contained the Plant Control Panel, the Board Control Panel and the Hardwire Communication Unit. The whole field is controlled using software provided by ABB.
    - ABB SCADA System
    - ABB Remote Telemetry System
    - ABB DCS System
    - ABB ESD/F&G System

b. Process Units

Slug Catcher: Slug Catcher is the name of a unit in the gas refinery or petroleum industry in which slugs at the outlet of pipelines are collected or caught. A slug is a large quantity of gas or liquid that exits in the pipeline.

Mercury Removal: The gas from KPD-TAY fields are mixed and then passed through mercury removal unit which consists of 2 trains with the gas flow capacity of 125*02

CO2 Removal: The CO2 Removal unit refines gas from CO2 that is hazardous for pipelines and would result in making Carbonic Acid. The CO2 concentration is 7% from KPD-TAY Condensate Reservoirs.

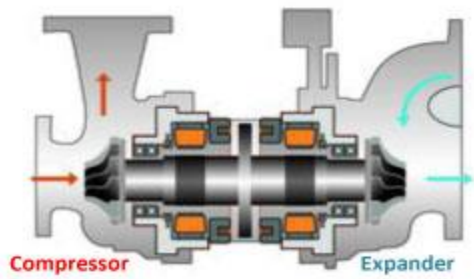
Dehydration Units: The dehydration unit consists of MDEA (Mono Di Ethanol Amine). This unit consists of 2 trains with the gas flow capacity of 117*02.

Condensate Stabilization Unit: The condensate stabilization unit consists of 2 trains with the gas flow capacity of 2789*02.
Condensate Stabilizer. Condensate Stabilizers reduce the vapor pressure of produced oil/condensate for stock tank storage and transport, increase the recoverable quantity of Natural Gas Liquids (NGLs).

LPG Recovery Unit: It recovers the LPG from natural gas and its operating temperature is -80 degree Celsius with RVP (Reid Vapor Pressure). The LPG Units consists of Turbo Expander where propane and butane are separated out. The recovery ratio is C3/C4 = 97.5/99. The LPG is transported through trucks.

Turbo Expander is the latest technology used at Processing Plant of OGDCL.

A turboexpander, also referred to as a turbo-expander or an expansion turbine, is a centrifugal or axial-flow turbine, through which a high-pressure gas is expanded to produce work that is often used to drive a compressor or generator.



Sales Gas Compressors: An air compressor is a specific type of gas compressor. Compressors are similar to pumps: both increase the pressure on a fluid, and both can transport the fluid through a pipe. The gas is transported through long pipelines.
There are 3 trains of Sales Gas Compressor.

Utilities: The utilities at production facility includes;

1. Power Generator
2. Hot Oil System
3. Cooling Water
4. RO Facility (Reverse Osmosis)
5. Water Treatment
6. Fuel Gas System

Storage:
The Processing Plant contains;
20,000 barrels of Fire Water Storage.
12580 barrels of Raw Water Storage.

Wellsite

Number of Wells: Total 36 Wells were drilled by OGDCL in which 24 are producing wells.

Oilfields: There are 3 zones at the site namely Kunnar, KPD and Tay.

Well Name: Kunnar Deep-05

First Production: The production was started in 2005.

Well Depth: The Well depth is 3000-4000m.

Producing Formation: The formation is named as Guru Formation consists of Sandstone Sedimentary Rocks.

Reservoir Pressure: The reservoir pressure is about 3000-4000 psig.

Software: All the wells are SCADA controlled.

Supervisory Control and Data Acquisition (SCADA) is a control system architecture that uses computers, networked data communications and graphical user interfaces for high-level process supervisory management.

Choke Size: The choke size of well is about 28/64 and 32/64.

Production Duration: According to expected estimate of Reservoir Engineering Department the well have producing life of about 10-15 years.

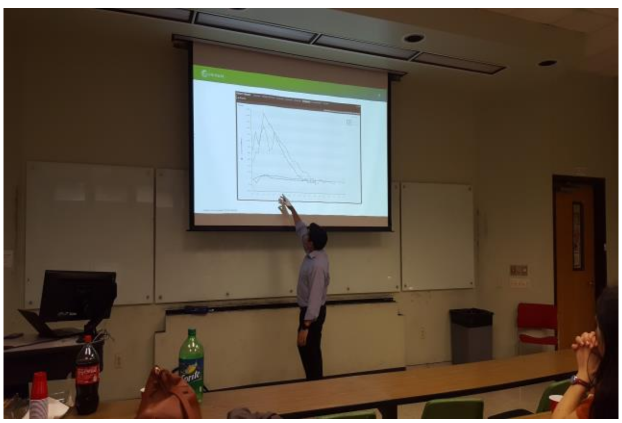
Reservoir Fluid Type: The reservoir fluid present in reservoir is Condensate.

API Gravity: The API Gravity of condensate is 50-55.

Protection System: The well uses Cathodic Protection System. The well use Cathodic protection to enhance the life of subsurface production facility where anode is dug underground at a distance of 90m.

SEMINAR ON UPSTREAM OIL AND GAS ASSET VALUATION BY SIDDHARTHA SEN AT UNIVERSITY OF TEXAS AT AUSTIN- MARCH 8

SPRE at UT-Austin was proud to host its first talk of the spring semester on March 8th. Siddhartha Sen presented a talk on the challenges facing companies wishing to make investments in the oil and gas sector and how those issues may be mitigated, along with some of the implications that valuations have for the management of a business. He explained how upstream oil and gas asset valuation not only provides an asset with a monetary value, but how it is useful for mergers and acquisitions, strategic planning, and competitive benchmarking. Mr. Sen described how reserves, production forecasts, cost estimation, commodity pricing forecasts, and fiscal regime were used to determine the asset model free cash flow to a company.



The main way in which an asset is evaluated is by creating an Asset model that accurately takes into account the ways in which the asset performs. On the output of the asset model were NPV, breakeven, and IRR, however, these values are never final. An asset needs to be revalued every three to four months to stay up to date with current market prices.

In addition to discussing the applications of asset valuation and walking through some of the steps involved in the process using the case of a previous client, Mr. Sen took a number of questions from the audience concerning subjects ranging from how to go about gathering relevant information to the implications of data for individual investors. Mr. Sen is a director and analyst at IHS Market in Houston, Texas. Pictured below from left to right are Siddhartha Sen and Christian Thomas.

INTRODUCTION TO ASSET VALUATIONS

Siddhartha Sen
Director, IHS-Markit, Houston, USA

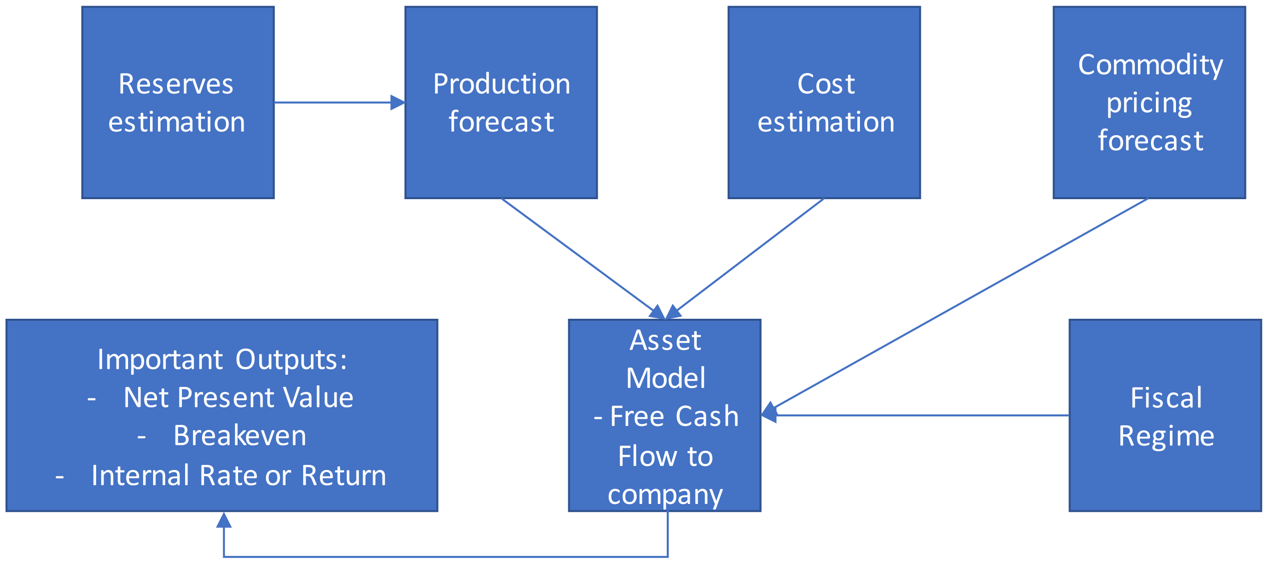
Valuation of oil and gas assets plays a vital role in the upstream oil and gas sector. It provides a quick and efficient method to screen and prioritize a group of assets for a portfolio and helps operators make key strategic decisions. However, there are several approaches to valuation. One of the main methods to effectively determine valuation of an asset is using reserves estimates, production outlooks, cost estimates, commodity price forecasts, and fiscal regimes in cohesion, thus providing valuable insight to the user. This independent approach has been quite effective and used by many valuation groups across the industry.

To conduct an asset valuation, one needs to gain fundamental clarity on how an asset has been defined. An asset could be:

- A single well for an operator drilling that well into a producing formation.
- A set of wells within an acreage position that are being analyzed together to showcase the overall value of a combination of wells for an operator.
- A producing acreage, with existing wells already online and producing; and no new activity taking place within that acreage position.
- Be defined by geographical limitations or other considerations such as depth of the wells, drilling direction – vertical, horizontal or directional, amongst other features.

The asset valuation cycle brings together the analysis and the expertise from various other functions, thus enabling concise and consistent messages to a client.

Asset Valuation cycle



Reserves estimates are usually the beginning point for any asset valuation. The reserves estimate along with the probability of success and percentage of total production that is expected out of the reserves forms the basis of the production outlook for the future.

Production forecast can be built both short term and long term, dependent on the needs of the user and the model being used. Production outlook, derived from the reserves estimate, is an important input in generating revenues from the operator activities within an asset.

Cost estimation is one of the most critical inputs to an asset valuation. Without an accurate or a reasonably accurate cost analysis, the overall asset valuation exercise is bound to fail. Costs can be categorized into capital expenditure and operating expenditure. Depending on the asset valuation cycle, whether full-cycle, acquisition forward, or point forward, other parameters such as acquisition costs or fees paid or construction of facilities can also be included into the total cost of the project.

Commodity pricing forecast is basically a forecast of the oil and gas prices into the future. This can be sourced from free online sources or from independent research and consulting firms. Either way, commodity price forecast helps build the future cash flow which in turn helps build the overall asset valuation.

Fiscal Regimes help identify the net proceed to all those who are involved in development of the asset. Fiscal regime includes corporate and state taxes, ad-valorem taxes and various other tax intricacies which help in identifying the appropriation of profits to the correct participants.

When these inputs are utilized together, the result, the free cash flows to the company can be reached. This free cash flow is usually discounted at a certain percentage (discounting factor) to come to the Net Present Value (NPV) of an asset. The NPV is one of the main outputs of the asset valuation process.

To conduct an asset valuation, an analyst must take into consideration both facts as well as use his or her experience and knowledge. Hence, an effective valuation model should be capable of incorporating both aspects. Facts would include data-driven metrics such as historical production, reserves numbers, well counts, cost per well and production type curves. An analyst's experience and knowledge would be needed to provide a view on the future – investment trends in a region, estimates of well costs and their evolution over a period of time, production type curves and their maturity as time progresses, and expected commodity price in the future. Hence there is a fair balance that needs to be maintained between facts and assumptions in an asset valuation model.

There are a few fundamentals essential to building an effective asset valuation model in my opinion:

1. ***Inputs should be clearly defined***: It is extremely important that the inputs of the model are clearly defined. This means that all the input parameters within the model should be accompanied with a definition explaining its nature and purpose. This is essential to keeping the model consistent across multiple users. Since the input section is editable, it is essential to consider various aspects involved with editing of the data in the model. All the inputs for a financial model should be showcased in a consistent color format in the model so that they are easily identifiable. In addition, if possible, the inputs section should be identifiable by either having all the inputs at the beginning of the model, or having separate excel sheet tabs for the inputs section.
2. ***Calculations should be open sourced***: An ideal asset valuation model should provide access to all the calculations to the analysts. This serves numerous purposes. Firstly, by providing the calculations and formulas to the analysts, the integrity of the model is immediately put to the test. If the calculations are accurate, the output of the model is more acceptable. Secondly, it provides the analysts the opportunity to add or edit certain aspects of the model to suit the needs of a job at hand. Thirdly, it also helps analysts follow the process to get to the outputs more accurately, thus ensuring that the models are understood by the users, and thus the usability of the model increases.
3. ***Output section should be summarized***: The output section of an asset valuation model should be summarized along with providing the granular details. The summary tables are essential to make the model effective and user friendly. The summary provides insights for the analysts and gives them important take-aways effectively and efficiently. The output section should also be protected so that changes to this section cannot be made, unless the inputs are revised or updated. By doing this, the sanctity of the model is maintained.

Asset valuations can become complicated very quickly. Hence, it is important to lay down the scope of a model at the beginning of the exercise. A complicated model might be able to capture a variety of inputs and showcase many metrics. However, they will also come with the challenges of updates and maintenance. Any changes in the calculations or input structure can involve hours or sometime days to incorporate because an analyst will need to undertake the challenging exercise of retracing all the aspects of a complex model. Laying down the scope of the model will ensure that it is built within the existing needs and requirements of the end users.

A nicely structured, simple valuation model can be more useful in practical scenarios. Upstream asset valuation models keep evolving because of the nature of the business. As upstream oil and gas companies identify new methods to reach the underground reserve and achieve production goals, efficient models must incorporate these new approaches. Being simple and nimble should enable the model to be updated immediately and effectively, thus ensuring that they are applicable and relevant.

Asset valuations are utilized by a variety of participants in the energy industry. An exploration and production (E&P) company would use this analysis to put a dollar value to reserves and ongoing production operations. This analysis can be used by E&P companies when they are engaged in the process of buying or selling assets (well or collection of wells). Within an E&P company, the strategy or competitive analysis teams would be interested in valuation of assets to compare and benchmark their asset against other competitors. Similarly, the strategy team would also be interested in using asset valuations as a screening tool to analyze their existing portfolio. By undertaking this exercise, the E&P company can identify opportunities to either buy or sells assets and thus streamline their own portfolio to align with broader company goals.

Similarly, asset valuation would also be useful to the financial institutions who are engaged in the acquisition and divestiture of the oil and gas assets. Often, E&P companies reach out to financial institutions to get a view on the valuation of their resources. These financial institutions can use the asset valuation exercise to identify opportunities to invest or divest within a certain region of activity. By looking at the cash flows generated by the assets in the analysis, a financial institution can quickly identify assets which are cash rich vis-à-vis assets which are struggling to stay profitable and thus be able to provide quantifiable and actionable suggestions to their clients on effective deployment of their available capital. Independent oil and gas consultant would use similar approaches to assist their client via asset valuations.

State governments also use asset valuations. For governments, some of which hold vast reserves of energy resources, it is critical to understand the value of those resources. As governments decide to provide exploration and drilling opportunities to oil and gas companies, they are keen to gain a good understanding of the value of the assets and build on it to launch successful bidding rounds. Thus, asset valuations play a crucial role.

There are many inputs which go into building an asset valuation. And there are several participants who contribute towards the inputs that are used in any given asset valuation model. Hence, it is extremely important that there are ample checks and balances put in place to ensure quality of inputs and that the data is validated.

Similarly, when the results are derived from these asset models, an evaluation of the results is essential, usually by an expert within the field. Some common financial metrics to look at when doing a quality check on the data include NPV, internal rate of return (IRR), breakeven prices, cost per BOE, opex. per BOE, overall reserves estimate and ultimate recovery factor. Ultimately, the inputs to the asset model drive the final outputs and conclusions derived from the same.

SPRE-NED SEMINAR ON WATER CONSERVATION- MARCH 12

Considering the importance of the noble cause of water conservation, a seminar was organized by SPRE-NED at NED University of Engineering & Technology, which was conducted by Mr. Muhammad Ali Mirza, Administrative Officer, Pakistan Petroleum Limited on 12th March 2019 at the Department of Petroleum Engineering.

Discussing the recently established strong presence of SPRE chapter at NED University, President SPRE-NED Muhammad Hassaan Chaudhry took the opportunity to quote SPRE International's President Mr. Rovillain:

"There's strong, and then there's SPRE Strong"

Mr. Muhammad Ali Mirza is a highly skilled professional with more than 10 years of work experience in Administration, Human Resources and Project management in various companies. He is now with Pakistan Petroleum Limited for the last 5 years as their administrative officer and HSE Coordinator. He had to fly from Islamabad to Karachi for holding the talk on water conservation at NED University. He now has taken the initiative to make all the necessary measures within and outside his company to conserve water as much as possible.

Proceedings

Mr. Hasnain Shabbir, also the treasurer of the SPRE Chapter at NED University, hosted. The event was started with the recitation of Holy Quran by Mr. Huzaifa Faruqui, senior at the Department of Petroleum Engineering, NEDUET.

Mr. Hassaan Chaudhry was invited to the rostrum to speak a few words to the audience regarding the newly formed SPRE Chapter at NED University. The guest. Mr. Muhammad Ali Mirza was then invited up to the rostrum to take charge of the audience. The major outtakes of the Seminar are as follows:

The whole Earth is divided into three broad categories: Atmosphere, Biosphere and Hydrosphere. And according to Google, the most important natural resource is Water. "Water is life" is such a common expression that we use it almost as a cliché. We often forget that the existence of human beings is as incomplete without water as it gets. This valuable resource is unfortunately depleting fast and it is high time that we start taking measures to conserve it. Water is so significant for humanity because according to Department of Health Australia: An average human being cannot survive without water for more than 2-7 days.

Pakistan is among the 30 countries facing acute water shortage. Government of the country is currently invested in making dams, running awareness campaigns and is collaborating with NGOs to conserve water. One of the major fallbacks for the water shortage in the country is the misdistribution of water across different sectors, 78% of the soft water is consumed for irrigation while only 22% of the water is used for domestic purposes, this results in the excessive loss of water meant for human consumption.

To tackle this, the Government of Pakistan in collaboration with USAID, initiated the Water Dripping Irrigation Project, in which water is sprinkled under controlled conditions through faucets or showers over individual plants to avoid water wastage.

PPL also took on the challenge and has installed water-saving showers across their fields which has resulted in the conservation of 40% of the water as compared to the normal showers. Mr. Mirza urges to use such showers in homes too to save water.

Moreover, water-efficient sprinklers should be used while dishwashing, rain water harvesting should be done in areas of frequent downpour and Jet wash systems should be used to wash cars than spilling buckets over the vehicles.

Officer Corps of SPRE-NED with Mr. Faizan Ali, Faculty Advisor, and Mr. Muhammad Ali Mirza.

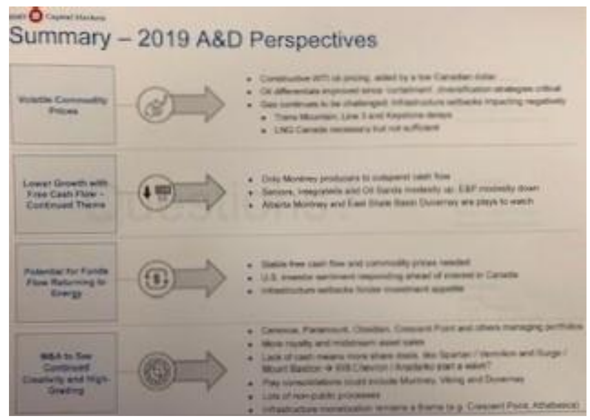
Mr. Faizan Ali, Faculty Advisor along with Dr. Javed Haneef, Incharge, Department of Petroleum Engineering presenting the token of appreciation to Mr. Muhammad Ali Mirza

CALGARY APRIL 17 MEETING ON CANADIAN ENERGY MARKET PERSPECTIVES

Seminar on "Canadian Energy Market Perspectives" was presented by Cheryl Sandercock with content provided by Morad Rizkalla of BMO Capital Markets

The presentation was well received, and the subject matter was engaging, with many insights regarding the current investment landscape. In fact, we went over-time without realizing it, due to the lively discussions. Copies of the slide deck are available upon request.

Following are snapshots from the presentation deck.



SPRE 2019 PETROLEUM RESOURCES ECONOMICS (PRE) CONFERENCE: MAY 10, 2019 IN HOUSTON, TEXAS

CONFERENCE DIRECTOR'S MESSAGE

While many professional organizations exist within the oil and gas industry, the Society of Petroleum Resources Economists was founded with the goal of bringing the various disciplines together to establish a "common language" that would be understood by the engineers and the financiers, by the geoscientists and the economists, by the executives and the rank and file. In an industry as nuanced and as expansive as ours, it can be easy to get pigeonholed within your own subject area and lose sight of the bigger picture as it affects the bottom-line and the end result.

Towards the objective of broader interconnectedness within our industry, the 2019 Petroleum Resources Economics (PRE) Conference, to be held at Station 3 in Houston TX on May 10, 2019, is the culmination of a half decade of exponential growth by SPRE and is our first attempt to connect all of the dots that have been drawn since the organization's inception. We will have talks on reserves evaluation & resources estimation, commodity pricing, unconventional & offshore projects, and risk management & uncertainty evaluation by SPRE Distinguished Speakers with well over two centuries of combined experiences and expertise within the industry, including leaders from SPE, AAPG, SPEE, HGS, SPWLA, and more.

The one-day event will include breakfast, lunch, a paid happy hour, and plenty of opportunities to network with industry decision makers for all attendees and represents one of the best values in the industry. On behalf of the full team that helped to organize the PRE Conference, I hope that you will be able to attend the event, learn something new, and expand your industry connections. For tickets or more information about the event, please visit SPREconomists.org/PREC or email me directly at Ali.Dhukka@SPREconomists.org.

I look forward to meeting you (or seeing you again) on May 10th!
Ali Dhukka, 2019 PRE Conference Director

PRE CONFERENCE ITINERARY

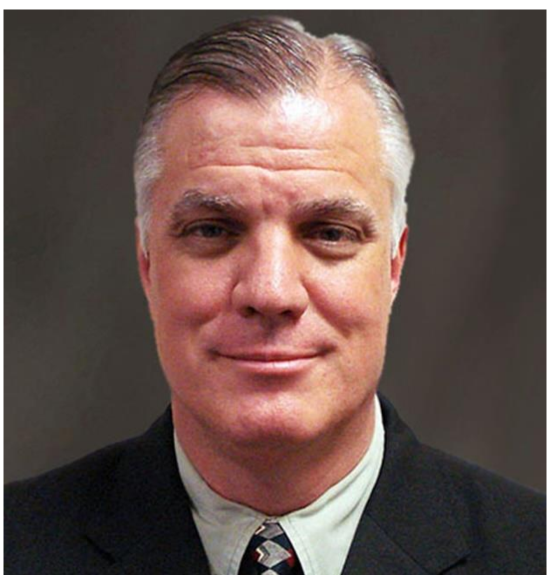
Attendees are provided breakfast, lunch, happy hour, and ample networking opportunities in between talks from our world-class Distinguished Speakers. The agenda for the day is as follows:

8:00 AM	Breakfast and Check-In
9:00 AM	Keynote with Dr. Nathan Meehan – Oil and Gas Carbon Intensity
10:00 AM	Rod Sidle – Using the SEC's "Reliable Technology" Concept for Buy/Sell Transactions
10:30 AM	Dr. Luis Quintero – Evaluating the Impact of Venezuela's Oil Production
11:00 AM	Rita Creasy-Reed – Strategies for a New Energy Future / Forward Thinking. Future Success
11:30 AM	Creties Jenkins – How to Reduce the Risk of Squandering Billions on Your Next Unconventional Project
12:00 PM	Lunch
1:00 PM	Dr. Tom Blasingame – Pressure Transient Analysis (PTA) and Rate Transient Analysis (RTA) Methods in Unconventional Reservoirs
1:30 PM	Bill DeMis – Historical Analysis of the Real Global Price of Oil
2:00 PM	Dr. Francisco Monaldi – The Shifting Politics of Oil Investment in Latin America

2:30 PM	Dr. Susan Nash – Using Artificial Intelligence and Machine Learning for Predicting Upstream Oil and Gas Risk
3:00 PM	Afternoon Break
3:15 PM	JC Rovillain – Managing Reserves & Resources. And Means.
3:45 PM	Miles Palke – Building a Dynamic Simulation Model for the Purpose of 1P, 2P, & 3P Reserves Estimation
4:15 PM	Coerte Voorhies – Risk Reduction for Reservoir Delineation Utilizing Amplitude Attribute Analysis in Visualization and Processing Software (or How to Find the Exact Reservoir to Drill in an Anastomosing Channel Sand System)
4:45 PM	Susan Howes – Toolkit for Making Better Decisions when Faced with Ethical Dilemmas
5:15 PM	Happy Hour

PRE CONFERENCE DISTINGUISHED SPEAKERS

Dr. Nathan Meehan is an American-licensed professional engineer with more than forty years of global experience in reservoir engineering, reserves estimation, arbitration, field studies, hydraulic fracturing, and horizontal well development. He is the 2016 President of the Society of Petroleum Engineers International where and has served on the Boards of several international oil and gas operating companies, service companies and software firms. He is the recipient of multiple awards- including the World Oil Lifetime Achievement Award, the SPE DeGolyer Distinguished Service Medal, and the SPE Uren Award- and has published over 70 technical articles and three books.



Pressure Transient Analysis (PTA) and Rate Transient Analysis (RTA) Methods in Unconventional Reservoirs

Dr. Tom Blasingame is the holder of the Robert Whiting Professorship in the Texas A&M University Department of Petroleum Engineering and has his Bachelors, Masters, and Ph.D. degrees in petroleum engineering from the same institute. In teaching and research activities, Blasingame focuses on petrophysics, reservoir engineering, analysis and interpretation of well performance, unconventional resources, and technical mathematics. Blasingame's research efforts deal with topics in applied reservoir engineering, reservoir modeling, and production engineering. Blasingame has made numerous contributions to the petroleum literature in well testing, production data analysis, reservoir management, and low permeability reservoir evaluation. Blasingame was recently named as the 2021 SPE International President.

Using the SEC's "Reliable Technology" Concept for Buy/Sell Transactions

Rod Sidle is an independent consultant serving software provider Aucerna, training provider PetroSkills, and other oil and gas industry clients. His industry experience, including 35 years with Shell, has primarily been in reservoir engineering and economics with a focus on reserves estimation. Rod is a member of SPEE, where he is currently the Chair of the Reserves Definition Committee, and a former member of the Board of Directors. He is also a member of SPE who has previously served as SPE Distinguished Lecturer and member of the SPE Oil and Gas Reserves Committee. Since retiring from Shell, Rod has worked as a project evaluation lecturer at Texas A&M, Director of Reserves at Oxy, and Reserves Manager for Sheridan Production Company.

Managing Reserves & Resources. And Means.

Jean-Christophe "JC" Rovillain is the founder of Enhanced Value Recovery (EVR), a private consultancy practice. Rovillain has over twenty years of financial markets experiences ranging from futures and options, equities and fixed income, investment & portfolio management, and industry communication through various media, including time with Dow Jones, publisher of the world's most trusted business news and financial information, and BARRA, the world's undisputed leader in providing risk models, strategy tools and consulting to the global institutional investor market. Rovillain is an alumnus of Prytanée Militaire, which has previously schooled and trained Descartes, Mersenne, and other military celebrities since 1604. Rovillain is a co-founder and the current SPRE President, a role he has filled since the organization's inception.

MANAGING RESERVES AND RESOURCES

JC Rovillain
Consultant, Enhanced Value Recovery, Houston and SPRE President

Efficiently overseeing a company's petroleum reserves and assets requires technical as well and economic and financial expertise

Exploration economics, this "strange mixture of engineering economics, mathematics and statistics, probability theory and the more normal sciences of exploration – geology and geophysics" has made a lot of progress since defined by Robert E. Megill in his Introduction to Petroleum Economics. The newest Petroleum Resources Management System (PRMS) reveals some of the latest improvements. However, oddly enough, some mathematics, statistics, probability theory, and finance seem to have been all but left out of the economics equation of such a management system.

The challenges faced by E&P companies in their never-ending quest for renewed reserves, not to mention their production projects, have continued to grow exponentially. All make it only natural that the US Securities and Exchange Commission would welcome the introduction of modern financial forecasting methods. Some sophisticated stakeholders and stockholders are already welcoming advocated additional disclosure.

Uncertain reserves and resources

Ultimately, the fate of oil and gas companies rest on two pillars: their ability to assess, recover, and renew their reserves as well as their ability to produce said reserves in an economically sustainable fashion.

As a super-major learned the hard way roughly 10 years ago, genuinely doing your best and accurately reporting reserves goes a long way toward managing expectations surrounding risky investments as well as mitigating investment risk and fostering investor relations. Unrelenting efforts since that time by, among others, the SPE and SPEE should be commended in terms of better reporting and assessing reserves.

Applauding its latest enforcement program, the authors believe the SEC could go even further in terms of reserves disclosures "to protect investors, maintain fair, orderly, and efficient markets, and facilitate capital formation." Consider this:

- The PRMS itself does more in terms of "economic risks" than the SEC guidelines when defining probabilistic estimates: whereas the PRMS includes critical economic data, the SEC Modernization of Oil and Gas Reporting "revised the definition so that it does not include the application of a range of values with respect to economic conditions because those conditions, such as prices and costs, are based on historical data, and therefore are an established value, rather than a range of estimated values." The SEC should adopt such a PRMS approach.

- The prevailing guidelines leave the door open for misunderstandings for those unfamiliar with the background mathematics, geology and/or reservoir engineering. Oil and gas reserves are generally approximated thanks to a random variable with a lognormal distribution. Combining the latter with a practice which seems to consider probabilistic P90, P50, and P10 with the respectively Low, Best, and High Estimates in a deterministic context equally good sets the stage for "methodology dependent" 1P, 2P, and 3P disclosures. It might well be the interest of resource evaluators and auditors, analysts, regulators, and investors to find an unequivocal resource volume figure; and quite another one which describes the measure of uncertainty of the estimations, ideally both properly quantified in terms of dollars as well. Additional significant mathematical and semantic oddities may need to be addressed as well.
- With "proven reserves" subject, among other parameters, to "existing operating conditions" that include "operational break-even price," any given proven reserve within a reservoir should vary (sometimes widely) based upon economic factors alone, i.e. even when estimated quantities would remain unchanged in between. Additional granularity regarding different types of economically recoverable reserves should be considered for more accurate disclosures and valuations.

The reported oil and gas reserves are experts' estimates and any estimate carries uncertainty. Both "a priori" (i.e. prior to field development) and "a posteriori" (i.e. after the completion of field development) resources remain estimates. Although uncertainty decreases with maturity, the volumes pertaining to the different probability categories, including P50, may – sometimes relevantly – differ. The natural consequence is that proved and probable reserves (2P) of the very same accumulation will be different in the undeveloped and in the developed status, even if conditions regarding commerciality remain unchanged. Regulators, in their attempt to protect investors from disappointments caused by reserves write-off, pursue oil companies to apply certain "conservativism" in their resource assessment and reserve disclosure. The attempt seems to fail to reach the desired goal and can result in estimation biases.

The implications of the elements aforementioned are not only theoretical or academic. The SEC and PRMS seem to limit the disclosures and methods, with a notably skewed bias towards "insiders" and some highly sophisticated investors with advanced knowledge of reporting intricacies. Moreover, since reserves and resources are the lifeblood of this sector, in addition to the reserve-based finance (RBL, VPP, etc.) methodologies relying on…reserves estimates, all oil and gas financial matters are at least in some way indirectly connected to them.

It might be worth recalling that typical American and foreign stockholders do exist and that institutional investors have been investing for quite some time now into significant stockholdings of oil and gas companies, big and small. "Big Oil" could as well find it in their interest to work towards some more modern forecasting and reporting methods with a goal of reaping some additional returns opposite to their increased "commercial risks."

Risky investments

Technically speaking, the first modern commercial well in Titusville, PA eventually succeeded. Now, it had certainly more to do with implausibility and Knightian uncertainties than probabilities and Drake ended his life a pauper.

The use of probabilities has made improvements possible and helped sustain this industry. The fact that they are still used some 150 years later is a testament to the difficulties associated with the characterization of reservoirs, the uncertainties still pertaining to reserves, and to the risky investments and hard decisions that oil and gas companies have had to make. Two examples illustrate this quite well:

- On the exploration front, the US shale reserves are not yet deemed "reasonably certain" by leading experts, and
- the lag between upfront investments in big projects and their actual dollar outputs is but one illustration of the risky nature and the "optimism bias" plaguing the production end of the business.

Regarding the technical side of the business, much time, effort, and money have been devoted to geophysics, geology, engineering, and varied technologies to mitigate the risks of dry wells, boost production, etc. In short, as pointed out in a recent Wall Street Journal article, if you combine what Chevron, ExxonMobil, and Shell spent in 2013, the costs equal roughly the same "in today's dollars as putting a man on the moon." Moreover, the article suggests that "the three oil giants have little to show for all their big spending." Without further explanation, the article adds that "one of the biggest problems" is that "costs are soaring."

Even at historically high oil prices, new developments (CAPEX for 2014 projected north of a whopping $700 billion) could be cancelled or delayed due to actual project executions. Expenditures are nonetheless expected to more than double compared to the preceding five-year period. Notwithstanding, this and other news suggest that costs/investments are viewed favorably within the industry. Meanwhile, other reports tend to focus more on latest lackluster results as well as on the current project portfolio mix.

There is indeed more to the exploration and production business than what some petroleum engineers would prefer to believe. Less or inadequate attention and resources have been given in their management systems to cover the economics and the underlying financial mathematics. The so-called "commercial risks" deserve a closer look. They go beyond the discrete P10/P50/P90, NPVs, hurdle rates, and Swanson formula.

Two well-written chapters inside the 2011 PRMS Guidelines are certainly a step in the right direction. Now, since the authors are not privy to how advanced the use of commercial and financial mathematics actually is within each and every oil and gas company, the authors manage to remain confident (and certainly hope) that none of these companies stops their commercial and financial analysis there.

Investment risks

Investment risk can take many forms and affect companies of many different sizes. Apart from direct or disguised expropriation (certainly a part of the investment risk relative to petroleum resources), tax optimization has been an integral part of the management system of petroleum resources at least since the interesting negotiations with King Ibn Saud in the 1930s. The increased sophistication of fiscal terms has helped facilitate a better understanding between countries with their hard currency providing guests, a.k.a. IOCs.

Another form of investment risk can be illustrated by way of a recent development as described in the WSJ article previously mentioned: "The spending surge has drawn attention from US securities regulators, who have demanded more disclosure from Chevron as to whether the jump will get even bigger and affect the company's liquidity." Chevron told regulators it "will provide more details." One has to hope that Chevron's shareholders and stakeholders will now get some of the answers they rightfully deserve.

Portfolio asset allocation comes to mind when mentioning investment risks in addition to the obvious investment risks stemming from the sheer size of some of the biggest projects. In other words, the higher costs associated with finding and developing oil fields is not the only culprit. The solution need not necessarily exclusively come through lowering CAPEX budgets, morphing CAPEX into OPEX or from further (costly) advances in energy technology. Strategies already followed by a few suggest that quantitative tactical asset allocation can provide risk mitigation and/or better risk-adjusted returns.

Unfortunately, when all sorts of mathematics are used on the technical side, some reluctance towards quantitative techniques seems to remain on the commercial end, not to mention a virtually non-existent PRMS financial risk side.

Considering that the set of reserves and resources oil and gas companies possess is increasingly varied, that the PRMS mentions aggregation (with some computations), and the SEC and the PRMS guidelines refer to each other, ignoring the "portfolio effect," this just makes less and less sense. The authors' understanding is that the testing of some senior managers holding such knowledge would have prevented them from sharing any of the formulas intended for audiences who usually are not able to understand them.

Some recent statistical/ stochastic methods and uncertainty concepts such as why no "exact" number can "just" be given, active portfolio management and/or nonlinear option pricing could certainly be worth a (renewed) look. All in all, more elaborate mathematical finance techniques and solutions should now take more room inside the Big Oil tool box and be applied when big-bet strategies drain cash piles and mandate buying back fewer shares.

Investor relations

As part of their duty of pleasing their owners, oil and gas companies might consider justifying more thoroughly at least some of their investments, risks, and decisions pertaining to their business via different forums, investor relations departments surely included. More widely sharing information, even reluctantly, could prove helpful to those companies for several reasons:

1. Remembering that Graham and Dodd's Security analysis, "a roadmap for investing that I have now been following for 57 years" (Warren Buffett), states, "It is a notorious fact, however, that the typical American stockholder is the most docile and apathetic animal in captivity" won't provide help under the present circumstances.
2. Employees are stakeholders and sometimes shareholders as well via their 401k plans.
3. Institutional investors have already shown they have choices in terms of the stocks and the sectors they want to overweight and underweight.
4. The financial sector at large could look at the industry with kinder eyes (and consequentially lower fees) if they perceive it as less risky, i.e. more predictable. Now, the data provided might need to be more directly actionable, readily accessible and at times forthcoming to make better-informed decisions.

It has been well documented that private investors and financial market participants (bankers included) hate outliers, a.k.a. "surprises," and it is not unheard of that "risk premiums" are attached to the latter. Moving forward, this could be not only the right thing to do, but the smart thing to do, potential/actual big project roadblocks included.

The latest profit warnings have been an additional unwelcome surprise to investors and may be a symptom of a wider trend. Some room for improvement could exist at Big Oil (investor relations included) at a time when WTI and Brent have more than doubled within the last five years and the SPDR S&P Oil & Gas Exploration & Production ETF has "jumped" less than 20%. Even taking into account other underlying factors in terms of individual stock performance, it is notable that relative newcomer Google's market capitalization has been neck and neck with ExxonMobil's, and no oil and gas company is likely to approach that of Apple anytime soon.

Some additional non-technical risks, e.g. environmental risks and/or actual incidents may be less directly quantifiable, legal fees included. They nonetheless rarely fail to "transpire" in the arena of public opinion and on the stock market, including in terms of the overall E&P risk reward ratio as perceived by investors, particularly when compared with other industries. A broader view suggests that another kind of activist other than environmental may speak louder in the future, namely activist investors.

Summary and conclusions

As far as reserves and resources are concerned, significant progress has been made on the technical side. Less has occurred regarding the commercial, financial, and financial markets sides of the business even if the past PRMS has been a timid first step in this right direction.

Reserves and resources production are the cornerstone of the entire oil and gas industry. Now, only two ways exist for companies encompassing actual E&P departments to add/renew reserves and be viable in the long run: 1) an appropriate, i.e. competitive, portfolio management of their existing and potential future assets, e.g. quantitative asset allocation, and 2) significant purchase of competitors' reserves through Wall Street. Some volatility as well as changes/transitions in strategy may be expected, and as before, only the fittest survive.

Let's face it. It is not the nature of the business that gives oil and gas companies an image problem and an investor issue. In addition to relying on their technical expertise, oil and gas companies will gain and/or sustain a competitive advantage within their industry by providing additional actionable information to stakeholders and shareholders (e.g., accuracy, granularity, and economics regarding reserves, resources and projects); and by better managing and mitigating the commercial and investment risks pertaining to their exploration and production, thanks to advanced quantitative portfolio and finance techniques.

Evaluating the Impact of Venezuela's Oil Production

Dr. Luis Quintero is Halliburton's Chief Advisor in Production Management. He received his B.S. in Electronic Engineering from Universidad Simon Bolivar in Venezuela and his master's and Ph.D., both in petroleum engineering, from Louisiana State University. Dr. Quintero has served the Society of Petrophysicists and Well Log Analysts (SPWLA) as 2016-17 President and 2014-15 Vice President – Technology and is also a recipient of SPWLA's Medal of Honor for Career Services. He is currently a member of the Texas Railroad Commission's Oil & Gas Regulation and Cleanup (OGRC) Fund and the Society of Petroleum Engineers' Legion of Volunteers and previously served as Technical Editor of SPE's Reservoir Evaluation & Engineering journal. Since 1984, Dr. Quintero has worked for operators and service companies in over 40 countries and has dealt with petrophysics, reservoir engineering, business development, financial analysis, project management and production management. Dr. Quintero is SPRE's first three-time Distinguished Speaker and is currently a Distinguished Speaker for SPWLA as well.

Building a Dynamic Simulation Model for the Purpose of 1P, 2P, & 3P Reserves Estimation

Miles Palke is a Managing Senior Vice President at Ryder Scott with more than 23 years of reservoir engineering experiences with a heavy emphasis on reservoir simulation studies. Palke's expertise includes sector- and full-field modeling; reservoir simulation studies; fluid characterization studies; well test analysis; reserves and economics studies; probabilistic studies and more. Prior to joining Ryder Scott, he worked for BHP Billiton as a Subsurface Engineering Manager and Senior Staff Reservoir Engineer. Palke is a registered Professional Engineer in the State of Texas and earned his bachelor's degree in petroleum engineering from Texas A&M University and his master's in petroleum engineering from Stanford University.

Strategies for a New Energy Future / Forward Thinking. Future Success

Rita Creasy-Reed is a Sustainability Project Coordinator at NRG Energy and a Sustainability Consultant with Round Rock Business Consulting. Through her work, Creasy-Reed seeks to lead companies to twenty-first century solutions to twentieth century problems in the areas of sustainable, cleaner, & lower-carbon energy, corporate social responsibility, and environmental stewardship. Creasy-Reed has previously served as the Finance Committee Chair for the Geophysical Society of Houston and as a Business Development Manager and Global Environmental, Health, Safety, & Quality (EHS&Q) Manager for Petroleum Geo-Services. Creasy-Reed received her bachelor's degree in geological/geophysical engineering from Louisiana State University and her Master's degree in executive sustainability leadership from Arizona State University.

Historical Analysis of the Real Global Price of Oil

Bill DeMis is President of Rochelle Court, a geoscience consultancy and has over thirty years of experience in the petroleum industry. DeMis has held the position of Exploration Manager for Marathon Oil Company, Exploration Vice President for Roxanna Oil Company, Geology Technical Expert for Southwestern Energy, and Chief Geologist for Goldman Sachs. DeMis is an American Association of Petroleum Geologists (AAPG) Charles Taylor Fellow, former AAPG Books Editor, and former Associate Editor of the AAPG Bulletin. He is a Trustee Associate of the AAPG Foundation and a member of AAPG, the Houston Geological Society, the Society of Independent Professional Earth Scientists, and the Rocky Mountain Association of Geologists. DeMis is also a member of the University of Texas Littlefield Society and has authored over a dozen publications.

HISTORICAL ANALYSIS OF THE REAL GLOBAL PRICE OF OIL

William D. DeMis
President, Rochelle Court, LLC, Houston, USA

Abstract

The Real Global Price (RGP) of oil is the price of oil corrected for inflation and for changes in the value of the US dollar on global currency markets. The RGP of oil is a superior measure of oil's value because it measures oil's purchasing power with respect to OPEC.

The US dollar's value has fluctuated as much as 45% on global currency markets after the U.S. abandoned the Bretton Woods system in 1971. Key OPEC countries obtain 60-90% of their revenue from oil sales that are almost exclusively traded in US dollars. Changes in the RGP of oil can have a profound effect on OPEC's purchasing power.

An historical analysis of the RGP of oil over the OPEC era shows that in 1973, 1979, and 1995, OPEC reacted to a low US dollar with nominal price increases, supply cuts, and/or openly suggesting abandoning the dollar. When the RGP was low enough, non-OPEC countries collaborate with OPEC to push up the nominal price (e.g., Mexico and Norway in 1998; Russia and others in 2016).

OPEC has over-corrected with nominal price spikes when oil supplies were tight. From 1974-1985, and 2005-2014, oil was over-valued in an RGP analysis. These two RGP spikes ultimately led to reduced demand, new competing oil supplies and nominal price declines in 1986 and 2014.

A commodity analysis corroborates this exchange rate analysis. Gold and oil prices have historically tracked closely over the OPEC era. But from 1986 to 2000, and after 2014, this relationship became decoupled. During these decoupled periods, oil was undervalued relative to gold.

In the absence of significant changes in the US dollar's value, or profound changes in oil supply, the price of oil will most likely trade in a RGP range of $30-46/bbl, or $45 to $70 in nominal prices. The probability that the nominal price of oil will drop below $40/bbl or rise above $80/bbl is low. If the US dollar's value were to drop by 25%, the nominal price of $80/bbl would be at the low end of the current RGP trading range. If oil prices cross the low side of the RGP trading range, history has shown that OPEC (and sometimes non-OPEC) countries collaborate to force up nominal prices to regain purchasing power.

Part 1 - Oil's Value, Exchange Rates, and the Collapse of the Almighty Dollar

Introduction

Commodities, with rare exceptions, are contracted for and traded around the world in US dollars. The dollar-denomination of crude has long been transparent to Americans because they live in a "dollar bubble." Exchange rate variations of the greenback are not felt by Americans until the price of gasoline goes up; and then the price change is blamed on OPEC, or "greedy" oil companies. However, changes in the US dollar's value have had a profound effect on OPEC (e.g., DeMis, 1996, 2000; Salman, 2004). OPEC has reacted to changes in the value of the US dollar since 1971 with nominal price increases, production cuts, and calls to abandon the US dollar as a basis for pricing oil (Platt's Oilgram News, 1995; DeMis, 1996, 2000). After supply-and-demand balance, the single biggest driver of OPEC's actions has been the changing value of the US dollar.

Many geoscientists today are familiar with the inverse relationship between the US dollar's value and oil prices. This inverse relationship (and most geoscientists' awareness of it) has only come about in the last dozen years. Nevertheless, before 2005, OPEC's reactions to losses in purchasing power a drop in the value of the US dollar have been anything but subtle (e.g., DeMis, 2000).

Economists typically show two data series when discussing value: nominal prices and "real" prices (Figure 1). The nominal price is the price in dollars of the day (DOD) - it is not corrected for anything. The "real" price is the price corrected for inflation, usually using the US consumer price index. Even today, key industry publications like BP's *Statistical Review of World Energy* (BP, 2017) still show a spurious data series for the historical oil price graph (ibid; their unnumbered figure on page 20). The graph shows oil prices in "real terms", meaning the price of oil corrected for inflation, but in this case, *using the American consumer price index. This* in a British publication! This important publication does not account for profound changes in the value of the US dollar after the Bretton Woods system ended in 1971.

The fallacious assumptions of using the uncorrected "real" price of oil for analyzing price behavior include: 1) the US dollar's value has been constant on global currency markets; 2) the US consumer sets the price of oil, and; 3) the oil market is entirely internal to the US. Upon inspection, any reader knows that points 2 and 3 are wrong. The point of this paper is fallacy number 1. The US dollar's value has fluctuated wildly since the end of the Bretton Woods system (Figure 2).

The Real Global Price (RGP) of oil corrects for inflation *and* for variations in the value of the US dollar on global currency markets. The RGP of oil is a superior measure of oil's value because it measures oil's purchasing power with respect to OPEC. This paper traces the history of the Real Global Price over the OPEC era. An RGP analysis allows for a better understanding of OPEC past actions and allows for better prediction of long-term oil value trends. Although supply-demand factors cannot be excluded.

Literature Review

A computer search of "exchange rates and oil prices" produces a torrent of papers that fall into two types: classical economic papers and non-economic papers.[13] A review of classic economic literature would fill an encyclopedia. A limited review of classic economic papers is provided.

Trehan's (1986) early but obscure work uses vector analysis to show that drops in the US dollar's value might lead to oil price increases. However, he concludes with the bizarre statement that his analysis "…is not meant to deny a role to OPEC" and that "it is difficult to believe *that OPEC does not take the value of the dollar into account when setting the dollar price of oil*" (emphasis added). Even a casual reader has to question why the author <u>*would need to speculate*</u> about OPEC's regard for the greenback's value ("What? You can't just ask them?").

At the very time interval used for Trehan's (1986) analysis, there was a plethora of published comments by frustrated OPEC oil ministers on the eroding value of the dollar. For example, Iraq's oil minister is quoted in the New York Times (a then-widely read and respected newspaper) in 1977: "Although we sell a barrel of crude oil for $13, its effective purchasing power is no more than $5." OPEC's focus on the dollar's value was broadcasted in New York Times articles[14], non-economic papers (e.g., Eaker, 1979), and fee-based information services[15]. Economists' selective avoidance of reading actual OPEC statements and understand OPEC's motivations is common in "classic" economic papers. This myopia will be addressed later in this paper.

Amano and van Norden's (1995, 1998) influential papers on the US dollar exchange rates and oil prices concludes that the "…two variables appear to be "cointegrated" (sic.) and that *causality runs from oil prices to the exchange rate and not vice versa"* (emphasis added). The authors do not cite Trehan (1986). The authors do not include any OPEC press releases with "gripes" from OPEC oil ministers that the low US dollar is under-cutting their purchasing power. This myopia is particularly noteworthy because in the mid-1990s, at the very time of Amano and van Norden's work, OPEC was vociferous about the declining value of the US dollar and its effect on their budgets (e.g., Tachibana, 1995; Hammadi, 1995; Platt's Oilgram News, 1995; DeMis, 1996). OPEC enacted production quotas to force up the nominal price in response to a declining US dollar (DeMis, 1996, 2000).

Nevertheless, Amano and van Norden's work dominated economists' reasoning for years. For example, Marten (2008) states in *Current Economics*, "The causality between the USD and oil is usually assumed to work *from the oil price to the USD*" (emphasis added). Even today, popular news outlets stridently echo economists' consensus about causality with news articles titled, "Why Oil Prices Affect Exchange Rate, not Vice-Versa" (Norman, 2015).

More recently, Beckmann et al (2017) provide a comprehensive review of classic economic

---

[13] Caution to readers. Many papers address oil price effects on currencies besides the US dollar. These non-US dollar papers are irrelevant to this discussion because OPEC transacts in US dollars almost exclusively.

[14] For example: *New York Times*, August 4, 1977 headline: "OPEC might switch to SRDs if Dollar Plummets, Officials Says". For example, *New York Times*, March 17, 1978 headline: "For Oil Pricing, a Basket of Currencies in Offing?" - to list a very few of the widely read articles being printed at the time.

[15] *Petroleum Intelligence Weekly*, May 12, 1980, cited in Samii and Clemenz (1988)

literature on exchange rates and oil prices. Their conclusion on causality derives from an arcane distillation of 47 classic economic papers. They conclude, "…causality from US dollar depreciations to increases in the price of oil often materializes at a *daily frequency or over a few months*" (emphasis added). Their analysis is entirely weighted by the previous 12 years when oil prices quickly responded to dollar changes because oil supplies were tight. But any non-economist, even geologists like me, can look at a graph of dollar's value vs oil price and see this relationship from across the room.

This paper is about more than the obvious inverse relation of the last dozen years. US dollar depreciations in 1990s caused OPEC to increase nominal prices (e.g., DeMis, 2000; Salman, 2004), but these price changes did not happen "daily" or even "over a few months", but over years (ibid.). More importantly, with the excess supply of oil of today, the tight inverse relationship of the last dozen years will become decoupled (meaning the dollar can fall while the nominal price of oil falls, too), and price perditions will become more opaque if people do not actually read OPEC press releases.

Classic economic papers have two systemic problems. They are mathematically dense treatises that render voluminous data into complex mathematical formulae that all gets jammed into computer models. The resulting numbers are then groomed for statistically significant relations (e.g., see Uddin et al, 2013 for arcane and esoteric complexity). Classic economic papers have no mechanism for capturing quotes from OPEC about drops in the value of the US dollar because "statements" cannot be digitized and jammed into a computer.

Indeed, the word "OPEC" is only included once, and only in a citation, in Beckmann et al's (2017) comprehensive review of 47 classic papers! Economists' myopia regarding OPEC oil ministers' disgust for a falling US dollar in their "classic economic papers", a disgust that was commonly quoted in contemporary newspapers, is not unusual.[16]

The second problem is that economists rarely write retrospectives. An economist who reviewed DeMis (2000) said, "What you have done is an historical retrospective. Historical retrospectives in economics are very out-of-favor today. Nobody gets tenure for publishing them." (Dr. J. Farley, 2000, personal communication). Books like, <u>This Time is Different,</u> are brilliant exceptions to this generalization.

Papers that are not classical economic analyses, and OPEC press releases, show OPEC has long offset the declining US dollar by enacting production quotas to increase nominal prices (e.g., DeMis, 1996, 2000, 2016). Non-classic economic papers written by members of OPEC - *<u>and remember these are the guys who set the price</u>* - contain no ambiguity that causation runs from drops in the US dollar to losses in OPEC's purchasing power to OPEC-orchestrated nominal price increases by cutting production (e.g., Hammadi, 1995; Salman, 2004).

---

[16] Please see Danielle D. Booth's book, <u>Fed Up</u>, for insights into academic and detached concerns of economists at the Federal Reserve. Per Ms. Booth, what was eye-opening at the Federal Reserve of Dallas was not that dozens of PhD economists missed the mortgage and banking melt-down of 2008, but that they were still running computer models that showed everything was all right during the crisis. "You could have looked out the window and seen things were not okay!" Ms. Booth correctly predicted the '08 crash, as did the men celebrated in the book and popular movie "The Big Short." None of them, including Ms. Booth, have PhDs in economics.

The analysis provided in this paper uses a simple exchange rate model to calculate oil's value to OPEC. When oil prices are viewed in an RGP analysis, in concert with OPEC statements, OPEC's motives and long-term price moves can be easily understood.

Value of the US Dollar

The value of the US dollar must first be calculated to define the RGP of oil. The value of the US dollar is calculated using a reference basket of currencies: The G-7 countries plus the Swiss franc. The basket is weighted with respect to each country's gross domestic product (GDP). Figure 3 shows the value of the greenback over the OPEC era. Parity (100%) is set to the US dollar's value in 1970. After 2000, the value of the US dollar shown is the trade-weighted average provided by the Federal Reserve of St. Louis (FRED data). The FRED data series post 2000 is corrected 20% to fit the 1970 base and so the two data series overlap.

The US dollar's value is also calculated by the International Monetary Fund (IMF) and is expressed in Special Drawing Rights (SDRs). SDRs are the pseudo currency the IMF uses to determine member countries reserves. SDRs are expressed as a percent of their 1970 base and used as calibration points on Figure 3 (much like vitrinite reflectance is used to calibrate a maturation model). The currencies data series fit the SDR calibration points. It's a good enough match.

This RGP analysis also includes a correction for inflation. The GDP deflator for the reference basket of currencies is used. Interestingly, the US GDP deflator produces virtually the same results (DeMis, 1996).

Real Global Price

Figure 4 shows the Real Global Price of oil. OPEC had strong purchasing power in two periods, 1974 to 1986, and 2005 to 2014. Oil was manifestly *over-valued* during these times, when it was over about \$40/bbl (RGP). OPEC's painful threshold is defined by times when OPEC called for abandoning the US dollar as the basis for pricing oil (e.g., 1995), or when non-OPEC countries collaborated with OPEC to cut production (e.g., 1998, 2016). OPEC and non-OPEC countries collaboration in 2016 to push up nominal prices suggests that their imbedded social cost, and military costs, have risen significantly since 1998. Thus, OPEC's lower threshold in 1973 to 1995 was \$18/bbl (RGP). In contrast, by 2016, OPEC and non-OPEC's lower threshold appears to be \$28/bbl (RGP), although this new "painful threshold" is too new to be clearly defined. History is always the best guide. Oil has long had a *value* floor that someone defended. Before OPEC, the Texas Railroad Commission defended oil prices in times of excess supply (Yergin, 1991).

Oil can be over-valued because its value is manipulated by a cartel and thus oil's value does not find a natural equilibrium. The two episodes of high RGP of oil were un-natural and brought on large non-OPEC production from provinces like the North Sea, the North Slope, and the North American "shale revolution" (Figure 5).

Recent History the Dollar

Bretton Woods System

The Bretton Woods system fixed the US dollar's value on global currency markets from World War II until 1971. The collapse of this system, and floating the US dollar, allowed the greenback to swing wildly on global currency markets; gaining and losing as much as 45% in value. This monetary event has been the single biggest driver of the vicissitudes of US oil industry since 1973 (DeMis, 2000; see AAPG Search and Discovery article #70037). Changes in the US dollar's value are sparingly mentioned in The Prize (Yergin, 1991). Indeed, Yergin (1991) makes no mention of "Bretton Woods" or the date, "August 15, 1971" in his book. But the accord's collapse profoundly affected OPECs purchasing power and resulted in the 1970s "oil price shocks".

So, what was Bretton Woods? In 1944, major Allied Powers held a meeting at Bretton Woods, New Hampshire to establish a post-war basis for currency exchanges. The Bretton Woods agreement created a modified gold exchange among signature countries. The US treasury agreed to make gold and the US dollar convertible for foreign banks at $35/oz at the "gold window." Each nation agreed to fix its currency to a 1% trading range with respect to the dollar. The US dollar became as "good as gold," and the world's reserve currency. The US became the world's banker.

Bretton Woods worked very well immediately after WW II when Europe had no gold and needed to re-build using US dollars (from the Marshall Plan). But things never stay the same.

Europe re-built and their economies grew. By the 1960s, European countries had recapitalized their central banks (backed by gold and US dollars) and gained stable currencies in their own right. In the middle 1960s, it was generally agreed by central banks that there were too many dollars in circulation; the greenback was overvalued. Attempts to "defend the dollar" by the London Gold Pool in the 1960s failed (Ghizoni, 2013). Then things got worse. By the late 1960s, inflation from the war in Vietnam and deficit spending on President Johnson's Great Society program (Spencer, 1974; IMF Bulletin, 2008) caused profound downward pressure on the US dollar.

Many countries, notably France and Switzerland, converted their US dollars to gold at $35/oz at the "gold window" while the free market price rose to $40/oz on the streets of Zurich where they sold gold for US dollars, then run back to the gold window to convert those greenbacks into more gold bullion at $35/oz. There was a run on gold at Fort Knox. By July 1971, the US had only 10 billion of gold bullion left (Spencer, 1974). On August 15, 1971, President Nixon announced that the "gold window" is closed; Bretton Woods ended. The US dollar was "floated" on global currency markets. It floated like a rock. The effects on OPEC will be detailed in the second part of this three-part series.

Part 2 and 3 will be continued in subsequent issues.

Part II - Oil prices and a fluctuating US Dollar

This is the second part of a three-part series on the Real Global Price of oil. The first part provided an explanation of the different ways oil can be valued and showed that a common "real price" analysis is flawed because it does not account for changes in the US dollar's value on global currency markets. It also demonstrated how classic economists missed this important distinction. The first section also recounts the demise of the Bretton Woods Agreement which fixed the value of the US dollar to gold. Part II shows the interplay between the declining US dollar and OPEC's response.

Part III - Real Global Price Predictions

This is the third part of a three-part series on the Real Global Price of oil. The first two parts showed the superiority of a Real Global Price Analysis, and why the US dollar's value became un-pegged on global currency markets. The two previous parts also traced OPEC's reactions to the vicissitudes of the changing value of the US dollar. This third part provides some past and current predictions about oil prices using a RGP analysis

Figures

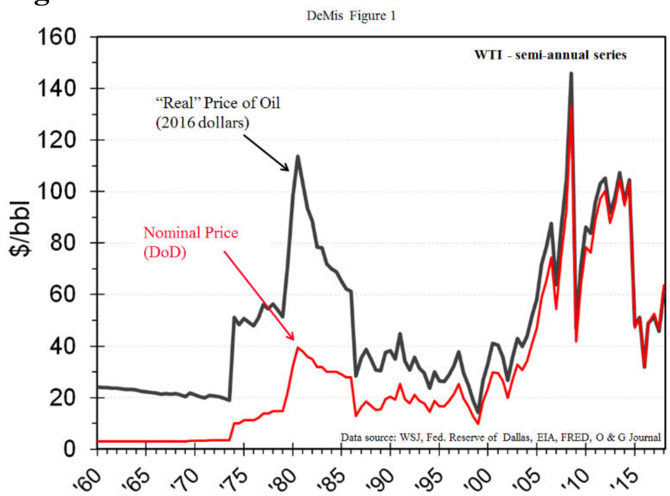


Figure 1. Oil prices throughout OPEC era. Horizontal axis is time; 1960 to February 2018 for this and other figures. Nominal price is in dollars of the day (DOD); it is not corrected for anything. The "real" price is the price of oil corrected for inflation to a 2016 base, using the US CPI. The "real" price is extensively used in oil industry literature for this global commodity (e.g., BP, 2017)

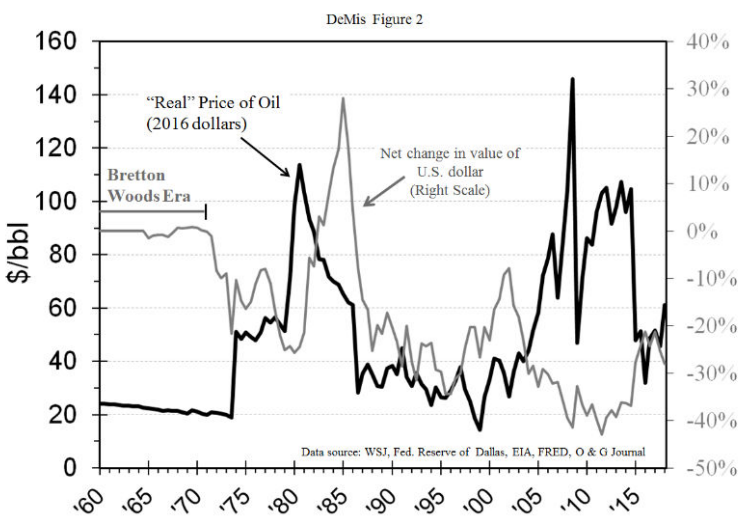


Figure 2. "Real" price of oil and value of the US dollar. Percent changes in the value of the US dollar are relative to the 1970 base. After the Bretton Woods system ended, the value of the US dollar has floated. The dollar's vicissitudes have vexed OPEC. Drops in the value of the US dollar have eroded OPEC buying power; a fact not shown on a common "real" price analysis.

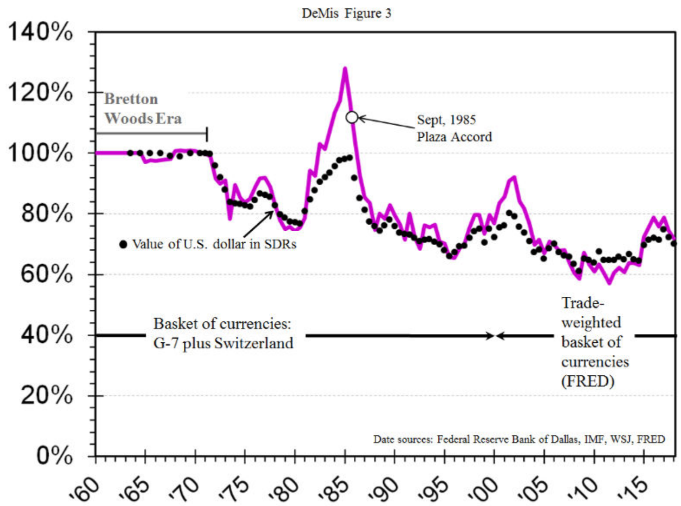


Figure 3. Value of the US dollar on global currency markets. Reference basket of currencies is weighted with respect to each country's GDP. Parity (100%) is the value of the basket in 1970. After 2000, the Federal Reserve of St. Louis' trade-weighted value of the dollar is used (from FRED website). The FRED data series is corrected to a 1970 base. Calibration points (black dots) are the IMF's calculation of the US dollar's value as expressed in SDRs, also normalized to a 1970 base. Semi-annual data series.

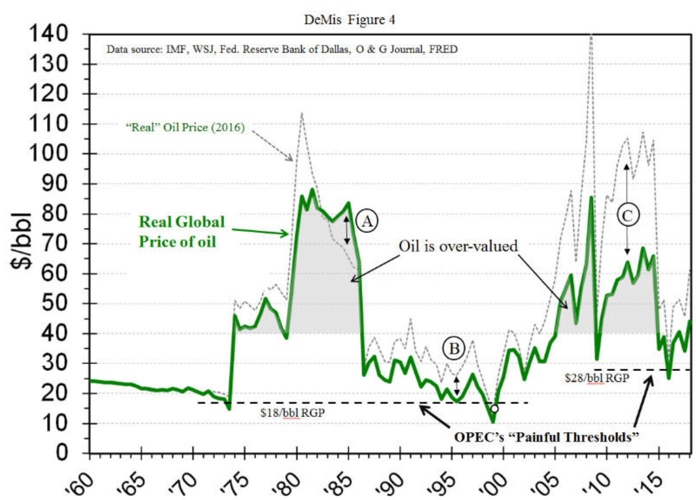


Figure 4. Real Global Price (RGP) of oil throughout the OPEC era. "Real" price of oil shown by dashed line. OPEC had more purchasing power in 1973-'85, than in 2005-'14. Above about $40/bbl (RGP) oil is over-valued. Point A shows when rising greenback gave OPEC strong purchasing power, even as "real" prices fell. Point B shows when OPEC's purchasing power in RGP terms was the same as 1973. Point C shows that the recent "real" price high had less value in a RGP analysis. OPEC's lower limit to purchasing power, it "painful threshold" was $18/bbl (RGP). In 2016, this threshold seems to have risen to about $28/bbl(RGP).

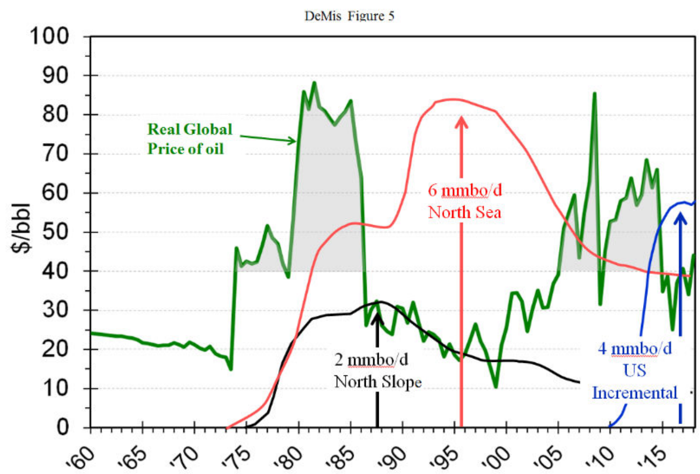


Figure 5. Real Global Price and new oil supplies. Production profiles depicted schematically, not to scale. Above about $40-45/bbl (RGP), the high value of oil brings on major new oil supplies.

References

Amano, R. A., and Simon Van Norden, 1998, Oil prices and the rise and fall of the US real exchange rate: Journal of International Money and Finance, vol. 17, no. 2, pg. 299 - 316.

Amano, R. A., and Simon Van Norden, 1995, Exchange rates and oil prices: Bank of Canada, Working Paper #95-8, 28p.

Bahree, B., and J. Tanner, 1995, OPEC plan to life oil prices goes awry: The Wall Street Journal, March 10, p. 2.

Berman, Art, 2016, OPEC Production Cut Unlikely until US Oil Output Falls another Million Barrels per Day: Forbes, Feb 10; Accessed March 3, 2018

Beckmann, Joscha, Robert Czudaj, Vipin Arora, 2017, Prices and Exchange Rates: Theory and Evidence: US Department of Energy, Working Paper Series Accessed February 18 2018 https://www.eia.gov/workingpapers/pdf/oil_exchangerates_61317.pdf

Blas, Javier, 2018, Frenemies: OPEC finds US Shale Oil an Intractable Problem: Bloomberg, March 3, 2018; Accessed March 3, 2018.

BP, 2017, Summary of Statistical Review of World Energy 2018: British Petroleum, London, 52 pages.

Clayton, Blake, 2015, As oil prices tank, where did OPEC go wrong?: Fortune Magazine, March issue; accessed March 5, 2018

Chellaney, Brahma, 2017, Sri Lanka the latest victim of China's debt-trap diplomacy, Asia Times, December 24, 2017, accessed January 14, 2019.

DeMis, W. D., 1996, Historical Changes in US Dollar Exchange Rate and Real Value of Oil, abstract, AAPG Bull., v. 80, issue 13 (annual meeting), pg. A35-A36. Search and Discovery #91019

DeMis, W. D., 2000, Historical Analysis of Real Global Price of oil: Implications for Future Prices (abstract), AAPG Bull., v. 84, No 13 (supplemental). Search and Discovery #70037

DeMis, W. D., 2016, Real Global Price of oil in the Unconventional Era (abstract): AAPG Pacific Section and Rocky Mountain Section Joint Meeting, October 5, Las Vegas, Nevada.

Eaker, Mark, 1979, Special Drawing Rights and the Pricing of Oil: Journal of World Trade, v 12, no. 22, p 22-30

Fattouh, Bassam, June 2006, Spare Capacity, Oil Prices and the Macroeconomy: Oxford Institute for Energy Studies, presented to Oxford Economic Forecasting's conference 'Global Macro and Industrial Outlook' held in London on 6-7 June 2006 http://www.oxfordenergy.org/presentations/spare_capacity.pdf, Accessed March 21, 2018.

Gately, Dermot, Nourah Al-Yousef, and Hamad M. H. Al-Sheikh, 2013, The Rapid Growth of OPEC's Domestic Oil Consumption: Energy Policy, July issue; http://dx.doi.org/10.1016/j.enpol.2013.07.044

Ghizoni, S. K., 2013, Nixon Ends Convertibility of US Dollars to Gold and Announces Wage/Price Controls. The Federal Reserve history February 5, 2018: http://www.federalreservehistory.org/Events/DetailView/33; Accessed March 1, 2018

Goldstein, L. J., 2017, A Russia-China Alliance?, The National Interest, April 25, 2017, accessed January 12, 2019.

Hammadi, S., 1995, Arab oil exporters lost $966 million in 1987-1992 from price erosion: Middle East Economic Survey, v. 38, no. 24, b1-b2.

Henning, C., and I. Destler, 1988, From Neglect to Activism: American Politics and the 1985 Plaza Accord: Journal of Public Policy, *8*(3-4), 317-333. doi:10.1017/S0143814X00008643

Ibrahim, Youssef M., 1999, OPEC is prepared to Reduce Oil Production to Raise Prices: *The New York Times*, March 22, New York.

Ibrahim, Youssef M., 1978, For Oil Pricing, a Basket of Currencies in Offing? *The New York Times*, March 17, New York.

Irwin, Neil, 2014, Europe gets Negative Interest Rates. What does that even mean? *The New York Times*, June 4, 2014.

IMF, 2008, The End of the Bretton Woods System (1972-1981): International Monetary Fund web page; accessed 2/17/2018, https://www.imf.org/external/about/histend.htm

Lansberg-Rodríguez, Daniel, 2017, Exit the Dragon: Why China Should Stop Supporting Venezuela: New York Times, Feb. 15, 2017

Marten, Sonja, 2008, The Dollar-Oil Puzzle: Current Economics, July issue, p.

Martel, Frances, 2018, Russia Announce Military Base in Venezuela: Breitbart News, December 19, 2018; accessed 1/15/2018

Martin, George, 2018, Russia announces plans to set up its first ever military base in the Caribbean - the country's largest presence in the region since the Cuban Missile Crisis in 1962, The Daily Mail, December 17, 2018.

MEES, 1985, Yamanii Says OPEC market share must be well above 16MN B/D: Middle East Economic Survey, October, v. 29, issue 10.

MEES, 1973, OPEC Countries Demand Full Compensation for Dollar Devaluation: Middle East Economic Survey, March 23, 6 pgs.

Norman, Mike, 2015, Why Oil Prices Affect Exchange Rate, not Vice-Versa: The Street; https://realmoney.thestreet.com/articles/05/27/2015/why-oil-prices-affect-exchange-rates-not-vice-versa; accessed 2/26/2018

Oil & Gas360, 2018, Alberta Orders Oil Production Cuts for 2019; December 3, 2018, https://www.oilandgas360.com/alberta-orders-oil-production-cuts-for-2019; accessed 1/22/2019

Paul, James, A., and Marianna Quenemoen, 2003, Fall of the Dollar: Global Policy Forum, August, https://www.globalpolicy.org/component/content/article/214-general/43906-fall-of-the-dollar.html; accessed 2/2018.

Platt's Oilgram News, 1995, An Old Question Arises Anew: Will Dollar Stay as currency of Oil? *Platt's Oilgram News*, Standard & Poor's, vol. 73, no. 83, May 1, p. 1-4.

Querubin, Emily, 2019, Latin American producers aim to stem the tide: Petroleum Economists, January 4, 2019. Accessed January 14, 2019.

Rogers, J., 1996. The Specter of Inflation: Worth Magazine, February Issue, p. 35-37.

Salpukas, Agis, 1999, It's Official: BP is Planning to Buy ARCO: *The New York Times*, April 2, 1999.

Samii, Massood V., and Claude Clemenz, 1988, Exchange rate fluctuations and stability in the oil market: Energy Policy, vol. 16 no. 4, pg. 415-423.

Salman, Ramzi, 2004, The US dollar and Oil Pricing Revisited: Middle East Economic Survey, vol. XLVII, no. 1.

Smith, Anne K., 2015, Why the Strong US dollar Scares Investors: Kiplinger, June.https://www.kiplinger.com/article/investing/T038-C008-S002-why-the-strong-u-s-dollar-scares-investors.html; Accessed March 5, 2018

Spencer, M. H., 1974, Contemporary Economics: Worth Publishing, Inc., New York, 670 p.

Tucker, Michael, 1992, The Impact of Non-Dollar-Denominated Oil Pricing: Eastern Economic Journal, vol. 16, no. 2, pg. 229 – 235.

Trehan, Bharat, 1986, Oil Prices, Exchange Rates and the US Economy: An Empirical Investigation: Economic Review, Federal Reserve Bank of San Francisco, No. 4, pg. 25-41

Tachibana, Toru, 1995, OPEC pricing reviewed: SDRs or a declining US Dollar?: Middle East Economic Survey, v. 33, no. 44, p d1-d4.

Uddin, Gazi s., A. K. Tiwari, M. Arouri, F. Teulon, 2013, On the Relationship between Oil Prices and Exchange Rates: A wavelet analysis: Economic Modeling, v. 35, p. 502-507.

Wright, T., and B. Hope, China offered to Bail out troubled Malaysian Fund in Return for Deals; Wall Street Journal, January 7, 2019.

Yergin, D., 1991, The Prize: The Epic Quest for Oil, Money and Power, Simon & Schuster, New York, 885 p.

The Shifting Politics of Oil Investment in Latin America

Dr. Francisco Monaldi is the fellow in Latin American Energy Policy at the Center for Energy Studies, the Mexico Center, and the Latin America Initiative at the Rice University Baker Institute and is also a lecturer in energy economics at Rice University. He is a nonresident fellow at the Center on Global Energy Policy at Columbia University, a member of the executive session on the politics of extractive industries at the Columbia Center on Sustainable Investment, the founding director and a professor at the Center for Energy and the Environment at IESA in Venezuela. Monaldi holds a Ph.D. in political science from Stanford University and an M.A. in international and development economics from Yale University.

Toolkit for Making Better Decisions when Faced with Ethical Dilemmas

Susan Howes is the Vice President of Engineering at Subsurface Consultants & Associates, LLC (SCA). She began her career with Anadarko where she held a variety of engineering positions before joining Chevron, where Howes was tasked with providing reservoir management functional leadership that resulted in improved production and reserve trends. Howes has coauthored several papers and articles on the topics of uncertainty, risk, ethics, and talent management and has previously served as Regional Director for the SPE Gulf Coast Section. She is an SPE Honorary Member and a recipient of the SPE DeGolyer Distinguished Service Medal. Howes holds a BS degree in petroleum engineering from the University of Texas.

Risk Reduction for Reservoir Delineation Utilizing Amplitude Attribute Analysis in Visualization and Processing Software (or How to Find the Exact Reservoir to Drill in an Anastomosing Channel Sand System)

Coerte Voorhies is a geophysical and geological interpreter with 30+ years of global experience. Voorhies is an expert user of the CGG InsightEarth 3D Visualization, Processing and Interpretation Software Technology and is currently providing InsightEarth consulting services for Gustavson Associates. He has developed and managed G&G projects in the Permian, Gulf Coast, Colombia Llanos, South China Sea, and West Africa Offshore Gabon basins. Voorhies has served in various capacities as manager, technical expert, and consultant to ExxonMobil, Chevron, BHP, and others. He holds bachelor's and Master's degrees in geology from the University of Louisiana – Lafayette and is a professional geoscientist in Texas.

Toolkit for Making Better Decisions when Faced with Ethical Dilemmas

Dr. Susan Nash is Director of Innovation and Emerging Science and Technology for the AAPG. Her responsibilities involve locating cutting edge technologies and scientific breakthroughs in the area of energy and environmental resources. Including new analytics, Big Data management, machine learning, as well as tools, chemicals, and infrastructure, Nash focuses on interdisciplinary approaches and tools. In addition, Nash launched U-Pitch, designed to help young companies commercialize their products and processes, as well as find partners and investors. Nash earned her Bachelor of Science in geology, Master of Arts, and Ph.D. at the University of Oklahoma.

How to Reduce the Risk of Squandering Billions on Your Next Unconventional Project

Creties Jenkins is a registered professional geoscientist and engineer in Texas. Jenkins earned his Bachelors in Geological Engineering and his Masters in geology, both from the South Dakota School of Mines. Jenkins joined Rose & Associates, LLP in February 2013 after 26 years with Tenneco Oil, ARCO, and DeGolyer & MacNaughton. He specializes in the characterization of unconventional reservoirs, including tight sandstones and carbonates, shales, and coals. He has conducted integrated studies, peer reviews, and resources assessment work for dozens of companies around the world. Jenkins has served as an SPE distinguished lecturer and is a recipient of the AAPG Distinguished Service Award.

SPRE AND JPRE RECRUITMENT

1. SPRE Assistant to Worldwide Chapters Coordinator
2. JPRE Assistant Editor

If interested, contact saad.siddique@spreconomists.org

CALL FOR ARTICLES FOR JPRE ISSUE 4: 2019 QUARTER 3

Submission Details:

Word limits:	300 / 1000 / 2500
Deadline for submission:	July 15, 2019
Journal issue date:	August 2019
Submit articles to:	jpre@spreconomists.org
Format:	Times New Roman font, size 12, single spaced, single column, .doc
Note:	All references to be included at end of article.
More Information, contact:	saad.siddique@spreconomists.org, jc.rovillain@spreconomists.org

Criteria for Judgement:

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

SPRE 2019 MEMBERSHIP BENEFITS AND PRIVILEGES

- Free access to all Society of Petroleum Resources Economists (SPRE) regularly held meetings all over the world
- Discounted access to special SPRE events and conferences
- Free or discounted invitations to SPRE member-only events
- Free access to all presentation materials made available by speakers at SPRE events
- Free eligibility to free/discounted access to industry events (from global conferences to local events)
- Free eligibility to benefits from organizations with whom SPRE has established a partnership
- New in 2019! Free access to our Journal of Petroleum Resources Economics (JPRE)
- Eligibility to hold office within the SPRE and authorization to publish affiliation with the SPRE
- Cost: For Professionals: $120, For Students: $30 Purchase membership at https://www.eventbrite.sg/e/2019-spre-membership-tickets-54278610786
- Contact membership coordinator Mr. Jim Garland, at jgarland@spreconomists.org if you have any questions.

JPRE COST

For SPRE members: Free

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