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RESERVOIR SOLUTIONS

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To solve well-spacing problems, Lee proposes pre-run simulations

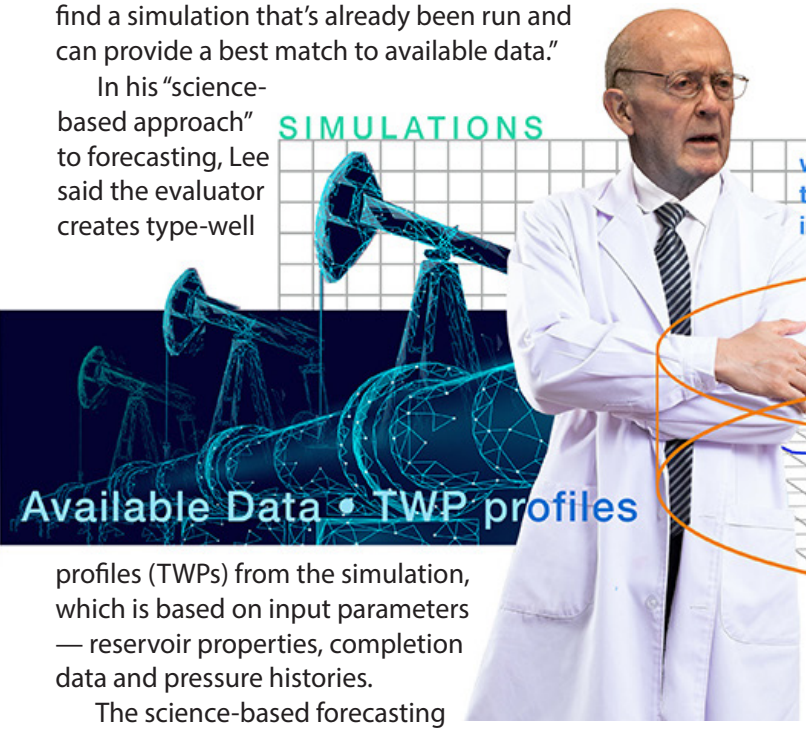
Results more "accurate" than decline-curve analysis (DCA) and just as fast, he says

Evaluators may not have to endure the painstaking steps of history matching (HM) individual well histories to head off well-spacing problems — that is, if the right data is available, according to **John Lee**, professor at Texas A&M University.

Overly dense spacing per acre causes excessive interference between wells which eventually leads to steeper declines and deteriorating economics. In those cases, overlap of stimulated reservoir volumes (SRVs) is the root of the problem. A frac hit.

"Simulations are already available within the ranges of parameters considered important," he said. "We can fairly quickly find a simulation that's already been run and can provide a best match to available data."

In his "science-based approach" to forecasting, Lee said the evaluator creates type-well profiles (TWPs) from the simulation, which is based on input parameters — reservoir properties, completion data and pressure histories.



The science-based forecasting (SBF) process leverages stored simulation results in a system that retrieves reservoir and completion data that correspond to the best matching profiles. "It finds a best match to historical data using the parameters for the best fit," Lee said.

In other words, the evaluator history matches actual data from the primary (in some cases, parent) well to develop best-fit spacing and timing scenarios for the offsets. The goal is to settle on a pre-drill field development plan built around well-placement patterns, timing and interference.

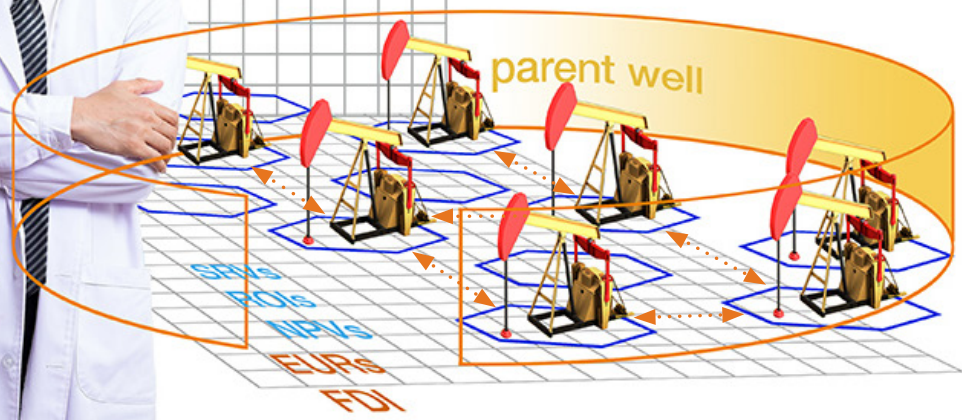
"We can compare pre- and post-drill TWP profiles. Based on practical simulation, we can analyze well spacing and interference caused by overlapping SRVs," he said. "We can examine the effect of timing of infill-well drilling, and the results, and infill quickly after drilling the primary well or wait 6, 12 or 18 months."

The plan can vary depending on whether the producer wants to boost return on investment (ROI), net present values (NPVs) or estimated ultimate recoveries (EURs).

Data acquisition can be costly. "If some of the data is not available (for the model), then we have to make certain assumptions about what's most appropriate," Lee said.

He stressed that robust simulations can be time consuming while the practical, physics-based simulations he proposes "can be applied to more wells, more quickly."

John Lee



Accelerated production at what cost?

Too much cross-well communication caused by tight spacing and pad drilling is hurting production and returns on invested capital. The press has criticized some oil and gas companies in the U.S. market for overly optimistic production forecasts for child (infill) and parent wells in pressure communication.

Researchers are gathering historical data and using multivariate data analysis and other techniques to put together a clearer picture.

In the slide deck, Lee showed a Bakken modeling study that

Please see To Solve Well-Spacing Problems on page 2

TABLE OF CONTENTS:

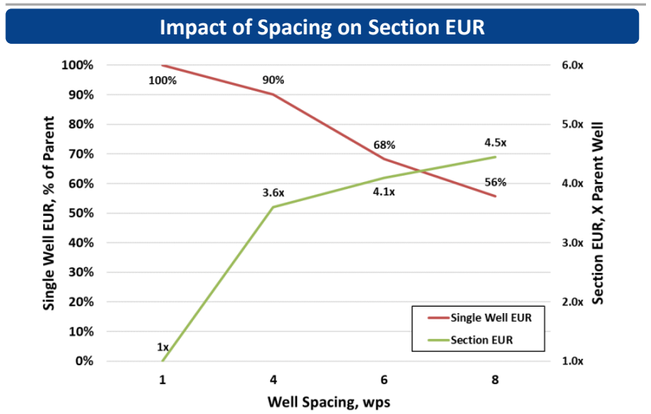
To Solve Well-Spacing Problems – Cont. from page 1

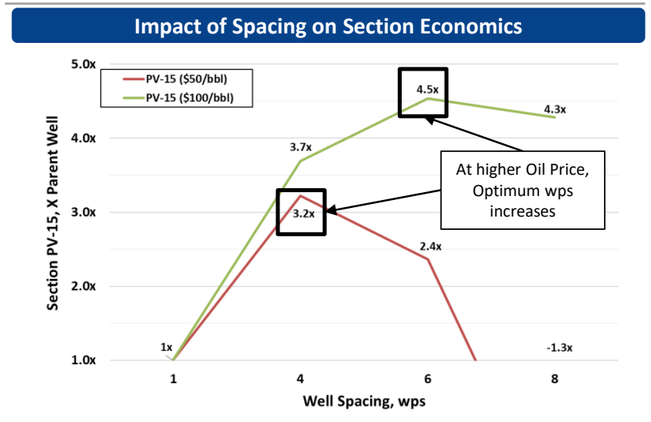
was presented at the Houston Geological Society luncheon on March 27, 2019. The study analyzed well spacing and related factors, including economics.

Lee said, "Based on actual field performance, the study shows interference occurs in the section studied."

Optimal well spacing is based on the economic goals of the producer in maximizing ROI, discounted NPV or EUR. The following two charts plot well spacing and economics, respectively, in the Bakken section.

Illustrative Well Spacing and Economics
What is the Right Inter-Well Spacing?





The top plot on the left shows a single well EUR (red line) as a percent of the EUR from the parent well vs. the EUR from four, six or eight wells per section. With one well per section (WPS), the producer is at 100 percent of EUR. With four wells, each has, on average, about 90 percent of the EUR from the original well. For six wells, it drops to 68 percent and eight wells to 56 percent. The green line shows multiples of the single-well EUR as more wells are added. More wells increase interference and degrade well performance.

The chart on the bottom attempts to answer how spacing affects section economics. A multiple of the NPV discounted at 15 percent for the parent well is plotted against different well-spacing densities per section. The red line shows the multiples of the NPVs for the parent well, as calculated if oil is at $50 per barrel. The green line is the multiple of NPVs for $100-per-barrell oil.

"What we see is that, we can improve recovery from the section by drilling more wells, but the cost of drilling and completion is not justified by the accelerated production," said Lee. "It turned out in this study, at $50 a barrel, four WPS were optimum in this area of the Bakken, and anything more led to poor economics."

The study concluded that "drilling more wells in a higher-price environment is a rational decision while widening spacing in low-price environments also makes sense."

DCA vs. SBF

Lee compared the strengths and limitations of DCA and SBF, examining well spacing, interference and timing sensitivity results.

DCA, which is easily learned and applied, is the No. 1 choice for evaluators. On unconventional assets, they use a modified Arps equation with changing b factor and terminal decline. DCA does not model the physics of fluid flow, but with reasonable assumptions, it adequately accounts for the behavior of flow regimes.

"If we use a two-segment Arps decline model, for example, we have to select a decline rate at which we switch from a segment dominated by transient flow to one with boundary-dominated flow (BDF)," said Lee. "We also have to assume what the Arps b parameter is during BDF."

The assumptions are where a calculation can go awry. "Many assume that b will be zero, but that's not necessarily the best choice," said Lee. "In fact, my analysis indicates that a b between 0.3 and 0.5 for that final segment of boundary-dominated flow is actually a much more realistic modeling technique."

Arps defined parameters for the hyperbolic b factor to be 0<b<1. Lee summarized the advantages of using SBF vs. DCA in the chart as follows on the next page.

Comparison of SBF and DCA-Based TWPs

SBF
- Fast, easily learned and applied
- Models well interference
- Includes multiphase flow when pressure drops below bubble point or dew point
- Allows studies of different well spacing alternatives
- Allows investigation of variable timing of infill drilling
- EUR based on rigorous modeling

DCA
- Fast, easily learned and applied
- Interference modeled only if present in well data used to construct TWP
- Includes multiphase flow only if present in data used to construct TWP
- Restricted to well spacing affecting data used to construct TWP
- Restricted to actual timing of infill wells in available data
- EUR depends on D_{min} and final b assumed

Lee said that he has been asked for a long time whether interference shows up in decline curves, and although he cannot generally confirm it, he cited situation-specific information that documents the phenomena. His source is "Well Spacing Optimization in Eagle Ford Shale: An Operator's Experience," SPE Paper No. 2695433-MS, **Mehdi Rafiee** et al, Equinor ASA, 2017. It is available at www.onepetro.org.

Lee said, "It's interesting that in terms of what appears to be rather conventional Arps decline curve analysis that well spacing clearly showed up in decline curves. The authors found that there's really quite a correlation between the parent Arps b factor, which fits the average of the data, and the well spacing."

The study incorporates fracture modeling, production HM and pressure communication from offset wells in the Eagle Ford shale play. Rafiee et. al conducted data analytics on almost 400 wells. The authors modeled stimulation of wells with sensitivities to fluid and proppant job sizes.

"When there is a single well, far from any others, a b factor of 1.1 was good for forecasting for longer durations up to 160 months post-completion," said Lee.

At 800 ft spacing, the b factor fit dropped to .9. then at 500 ft, dropped to 0.7, and settled at 0.5 at 250 ft. "I don't have the backup info to tell you more," said Lee.

RTA and full-scale simulation

Besides comparing SBF with DCA, Lee also cited other methods to ascertain optimum well spacing, including rate-transient analysis (RTA) and full-scale, HM reservoir simulation.

Evaluators use analytical flow models in RTA software packages to HM available transient data to solve for major unknowns, such as effective matrix permeability and fracture half-length. In the forecast, they vary the well spacing to analyze the effects of interference.

"The limitation is that analytical solutions, despite efforts to improve, ultimately depend on simplifying assumptions, such as single-phase solutions to flow equations," said Lee. "If pressure drops to bubble point or dew-point pressure in an oil or gas condensate reservoir, then multiphase solutions are needed."

He also remarked that reservoir simulation, although time consuming, solves well-spacing problems. Lee said that coupling geomechanical and flow models is an effective approach discussed in "Time Dependent Depletion of Parent Well and Impact on Well Spacing in the Wolfcamp Delaware Basin," SPE Paper No. 191799-MS, **Cyrille Defeu** et al, Schlumberger Ltd., 2018. It is available at www.onepetro.org.

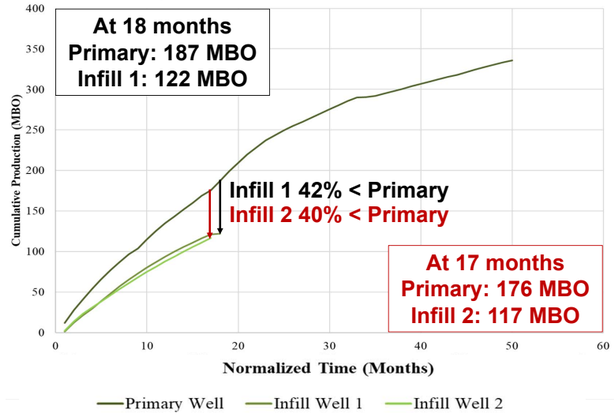
A high-resolution simulator feeds an updated pressure profile into the geomechanical simulator at selected timesteps during the production phase, the authors stated. The coupled simulators then compute the corresponding 3D change in stress, deformation and rock displacement in the reservoir and beyond in the adjacent rock formation.

"In this way, the spatial and temporal changes in the in-situ stress field from parent well production are computed," they stated. The paper presents an advanced modeling workflow to determine the impact of parent depletion on infill-well spacing at various periods of the parent well production.

Tit for tat: DCA and SBF

Lee said he was involved in a side-by-side study of SBF- and DCA-derived TWPs for the Delaware Basin Wolfcamp A formation. The study was based on public information. From the 44 wells, he chose a primary well that outperformed its two child wells. Both methods matched the 18-month history for Infill Well 1. They also matched the 17-month history for Infill Well 2. See the following chart.

The Fundamental Problem Illustrated:
Primary Well Outperforms Two Infill Wells



"So far, no real advantage has shown up," said Lee. "However, I'm going to claim, based on other studies, that with data to estimate bottom-hole pressure, we can match much more of the production profile. At least we can match by the time the bottom-hole pressure has settled down, and get rather close."

The chart of P50 cumulative oil results on the next page shows that with SBF, the best match for Infill 1 was 2 percent higher than the actual cum and 6 percent higher than Infill 2. With DCA, estimates were 11 and 12 percent higher for infills 1 and 2, respectively.

He remarked that DCA cannot quantify the effect, if any, of

Please see To Solve Well-Spacing Problems on page 4

Summary P50 Cumulative Oil Results

Infill Well 1

Cum at 18 months	Actual C1 (MBO)	SBF P50 Cum (MBO)	DCA P50 Cum (MBO)	DCA 2018+P50 Cum (MBO)
Case 1	122	125	136	127
% Difference (wrt C1)		2%	11%	4%

Infill Well 2

Cum at 17 months	Actual C2 (MBO)	SBF P50 Cum (MBO)	DCA P50 Cum (MBO)	DCA 2018+P50 Cum (MBO)
Case 1	117	124	132	122
% Difference (wrt C1)		6%	12%	4%

- **SBF accurately approximates infill production.**
  - **I1: 2% difference in actual vs. SBF**
  - **I2: 6% difference in actual vs. SBF**
- **DCA also approximates infill production accurately.**
- **Cannot quantify effect of interference with DCA alone.**

To Solve Well-Spacing Problems – Cont. from page 3

interference while SBF enables an evaluator to look at optional development strategies for well spacing and completion techniques.

"It's difficult to model interference with the DCA approach, unless interference effects are present in the histories and the well spacing in those histories are roughly the same for future wells," said Lee. "It's difficult to model the effects of timing infill wells and their spacing."

Conclusion

The rest of Lee's presentation covered sensitivity analyses of well spacing in the Delaware Basin, sensitivity of EURs to infill-well spacing, infills to optimize EURs and quantifying fracture interference with a fracture-driven interaction (FDI) calculation. He also discussed the effect of FDI on production forecasts and effect of fracture interference on EURs.

Lee concluded that relying solely on DCA-based TWP construction underestimates interference caused by close well spacing and long fractures in resource plays. His slide deck, which has charts and graphs, is posted at https://ryderscott.com/presentations/.

Editor's Note: Dr. John Lee is a recognized expert in petroleum reserves evaluations. Ryder Scott is grateful for his annual participation in our events as a speaker. The content of conference presentations is based on our speakers' fact finding and opinions, and are not necessarily those of Ryder Scott. Our firm's speakers also present content that does not necessarily reflect the views of Ryder Scott.

SBF promising but not the answer for every situation

— **Miles Palke**, *managing senior vice president*

Ryder Scott offers a full range of reservoir simulation services, from single-well conceptual models to full-field models with hundreds of wells. Our simulation modeling experience ranges from the simplest gas reservoirs to fully compositional models of gas recycling projects.

While science-based forecasting is a promising new technique, there are many situations in which a detailed, bespoke model for a particular well, reservoir or entire field is the preferred approach. Ryder Scott is in a unique position because the firm possesses high-end technical simulation expertise, combined with unmatched geoscience capability and a wealth of traditional reservoir engineering experience with every sort of reservoir imaginable. The blending of those skills enables Ryder Scott to assist clients with a wide variety of simulation-based needs. For more information, please send an email to miles_palke@ryderscott.com

Miles Palke

Average annual oil price for SEC reserves reporting lowest since modernization of rules

The annual average prices for reporting year-end 2020 petroleum reserves to the U.S. Securities and Exchange Commission are the lowest since regulators modernized its rules 11 years ago. Please see chart below.

The WTI Cushing crude oil benchmark did not break $40, tumbling from $55.69 a barrel to $39.57 — a 29-percent decline over last year.

Public issuers apply differentials to benchmark prices, adjusting them for quality — including gravity and sulfur content — and for energy content, transportation fees, and regional and local differences. The adjusted prices are used to prepare annual reserves filings with the SEC.

Current rules require public issuers to use an unweighted, arithmetic average of the first-day-of-the-month price for each month in the calendar year. Before 2010, average annual prices were based on the last day of each month, including Dec. 31.

The additional 30 days have given companies more time to prepare and publicly file petroleum reserves by the March 15 deadline, which has remained the same.

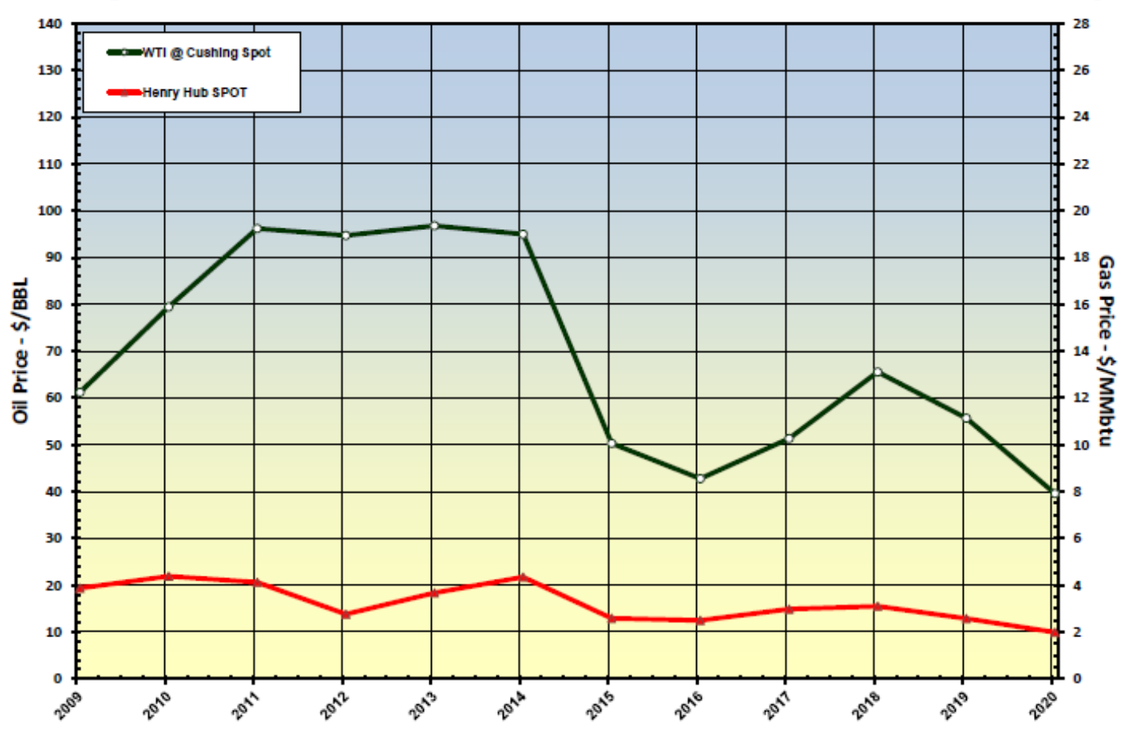
The Brent crude oil benchmark settled in at $41.77 per barrel for the year — a significant 34-percent decrease from $63.15. The price of Brent is used to set prices for about two-thirds of the world's oil.

The Henry Hub gas benchmark had a more modest decrease of 23 percent from $2.577 per MMBTU to $1.985.

Other benchmarks and information on using differentials are posted at www.ryderscott.com/wp-content/uploads/FDOM_Benchmark_Prices.pdf.

More than 160 oil benchmarks have been established worldwide. For clarifications on 2020 year-end prices, please send requests via email to **Fred Ziehe**, advising senior vice president, at fred_ziehe@ryderscott.com.

Average YE Prices for Oil and Gas Benchmarks Used in U.S. SEC Filings



WTI Cushing average annual oil prices and Henry Hub gas prices dropped to lows not seen during the "modernized" era of reserves reporting to the U.S. SEC.

SPEE Monograph 5: A work in progress

Monograph 5 is still a work in progress despite anticipation by the Society of Petroleum Evaluation Engineers working committee two years ago for "final publication" in 2020. The monograph will focus on recommended practice guidelines for constructing type well profiles (TWPs).

Lately, the news media, investors and others have criticized E&P companies in the Permian Basin and other unconventional plays for overly optimistic production forecasts derived from TWPs.

In October, an SPEE Denver meeting video presentation at https://vimeo.com/473489413 provided updates, including discovery of "significant error" using a simple, common approach to TWPs. The committee found that averaging individual monthly rates and dividing by the producing well count results in unsubstantiated, inflated EURs.

A simple adjustment to the common approach, namely implementing a constant well count, leads to more reliable TWPs. The evaluator starts by including production rates over the full-life cycle — historical plus projected out to a technical limit — of all underlying producing wells. Then, if necessary, the evaluator includes additional "zero" months to extend the life of individual wells after reaching the end of their forecasts, including any shut-in or abandoned wells that are part of the sample set.

That results in a group of wells with the same lifespan, and when normalized to a common point in time, a TWP is generated based on a constant well count. This process improves the match between the EUR of the TWP and the average of the well samples, as well as the overall rate-time profile.

The presentation has numerous charts that illustrate the approaches.

Denver manager elected to SPEE board

Steve Gardner, managing senior vice president, was elected to the board of directors of the Society of Petroleum Evaluation Engineers in November. He took his seat in January 2021 for a three-year term, concluding in December 2023.

Gardner manages the Ryder Scott Denver office, where he conducts and supervises petroleum evaluations, audits and process reviews of both upstream and midstream assets. He has approximately 20 years of on- and offshore experience in petroleum engineering and has been a member of SPEE since 2012.

"Steve has earned the recognition and reputation among SPEE members such that his bid to join the board has been successful," said **Guale Ramirez**, president at Ryder Scott.

Steve Gardner

Wilson sees gas potential in wake of 2020


Scott Wilson

"When two black swans—weak industry fundamentals and a global pandemic—collided midair, a downward spiral became a freefall," wrote **Scott Wilson**. "Accompanied by the human tragedy of illness and financial hardship, industry employment shrunk at a pace not seen since 1986 and caused a contraction to the lowest international rig count since Baker Hughes started keeping records 43 years ago."

That dramatic "lead" kicked off a Nov. 1 article in *JPT* magazine, the flagship publication of the Society of Petroleum Engineers. The article is at https://pubs.spe.org/en/jpt/jpt-article-detail/?art=7787

Wilson is a senior vice president for Ryder Scott in Denver.

In his article, he answers the question: How has this upheaval affected the demand for natural gas and our industry supplies? Not very much, opined Wilson.

He cited natural gas and its reliability in maintaining essential goods and services. Wilson maintained that gas-fired electricity usage has increased, as stay-at-home orders nullify the economies of scale provided by shared workspaces.

Please see Wilson Sees Gas Potential on page 11

Market volatility and uncertainty create potential for oil price swings


K. Lehi Woodrome

Oil prices last year fluctuated wildly as crude from shale plays overwhelmed available storage and a worldwide pandemic stifled demand.

"As long as supply exceeds demand, there is a limited margin of error in oil prices," said **K. Lehi Woodrome**, vice president. "Anything can swing it, both up and down, at this time, probably more downward."

He made his remarks at the Ryder Scott webinar in September. Woodrome researched the oil market and created custom-built graphs for his presentation, "The Supply and Demand Imbalance Leading into Oil Price Volatility."

Woodrome used petroleum data, rig counts and oil pricing from the U.S. Energy Information Administration, Baker Hughes Co. and CME Group Inc. His presentation is available at https://ryderscott.com/presentations/.

He said the worldwide market "could be affected by drastic swings in oil prices caused by events such as limited storage, shutdowns due to further outbreaks (of the pandemic) and price wars."

Woodrome also looked at the prices of West Texas Intermediate (WTI) light sweet crude, a widely traded benchmark, and various news articles to explain the April 20 oil price meltdown. The July 2020 *Reservoir Solutions* newsletter reported on the collapse at https://ryderscott.com/wp-content/uploads/Rs3rdQTR-July16th.pdf.

The article stated that on April 20, traders hurried to sell off positions in the near-term May crude oil futures contract because it was expiring the next day and set to mature April 21.

"Futures traders could see that the crude held in Cushing was rapidly increasing and there was nowhere else to put it," Woodrome remarked. "Cushing is an important gathering hub for shale oil production."

Cushing, OK, is the settlement point for WTI on the New York Mercantile Exchange. Woodrome said that Cushing has 90- to 93-million barrels of shell storage capacity with about 76- to 77-million barrels of working storage capacity, which is the volume between the maximum safe fill and quantity above effective pump suction. That working capacity was rapidly declining at the time of the April 20 selloff, as oil closed at negative $37.

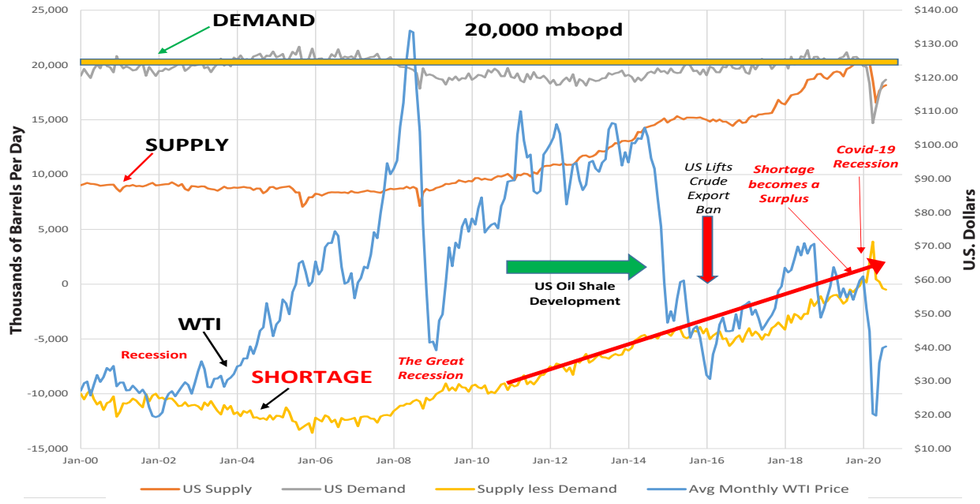
Woodrome analyzed WTI price vs. Cushing storage utilization in a chart not shown. Storage utilization is based on working capacity and does not include oil in pipelines, in transit by rail or water or in the Strategic Petroleum Reserves.

WTI prices, supply and demand

Woodrome plotted EIA data for U.S. supply and demand curves as well as WTI prices and historical shortages and surpluses caused by past events. Please see the following chart.

Please see Market Volatility and Uncertainty on page 8

WTI Price vs US Supply/Demand



Market Volatility and Uncertainty – Cont. from page 7

The supply-and-demand curve includes total petroleum products, not just crude oil. The EIA counts crude oil, lease condensate, NGLs and other liquids in the totals.

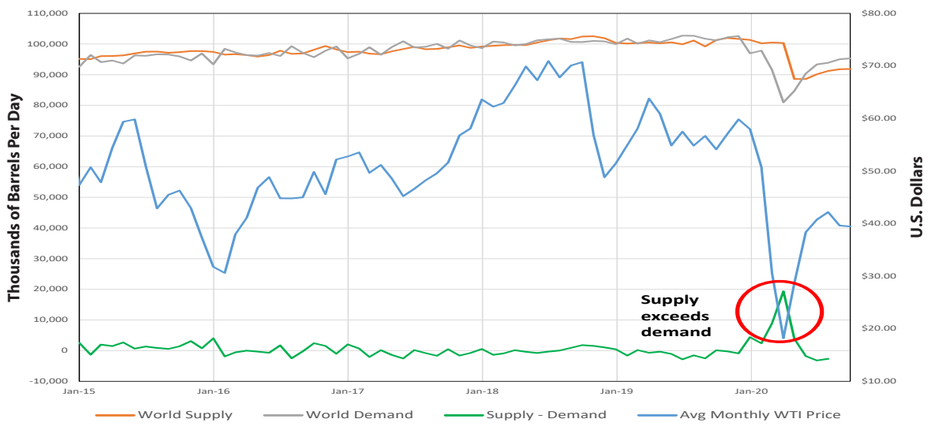
Woodrome pointed out that during the 2008 great recession, oil prices dropped drastically from almost $135 per barrel to $40. The chart also indicates other important time frames and events in the U.S. causing surpluses, shortages and price swings, including the 2001 recession, shale oil development starting in 2011, lifting of the crude oil export ban in 2015 and the Covid-19 recession in 2020.

Over the past 20 years, U.S. demand for total petroleum products has been fairly steady, hovering around an average of about 20-million barrels per day.

"Really, 2011 is where you can see a strong inflection point where the beginning of U.S. shale development began," said Woodrome. "This is where supply really started to take off. Subsequently, because demand remained steady over the last 20 years, the supply/demand curve slowly but surely, grew from a shortage to a surplus."

He showed a chart of WTI price trends and worldwide supply and demand as follows.

WTI Price vs Worldwide Supply/Demand



World supply and demand movements are at the top of the chart. The difference between supply and demand has been at a balanced equilibrium and remained fairly constant until December 2019 when supply started to exceed demand in the global market. This was a precursor to April 20.

Woodrome also plotted the reaction of the industry to the April price plunge which resulted in immediate, significant cuts in capital spending. See the chart on the top of the next page.

"I was very shocked when I put this chart together, because you can see there was an immediate reaction," he said. "Rig counts are a good reflection of capital spending."

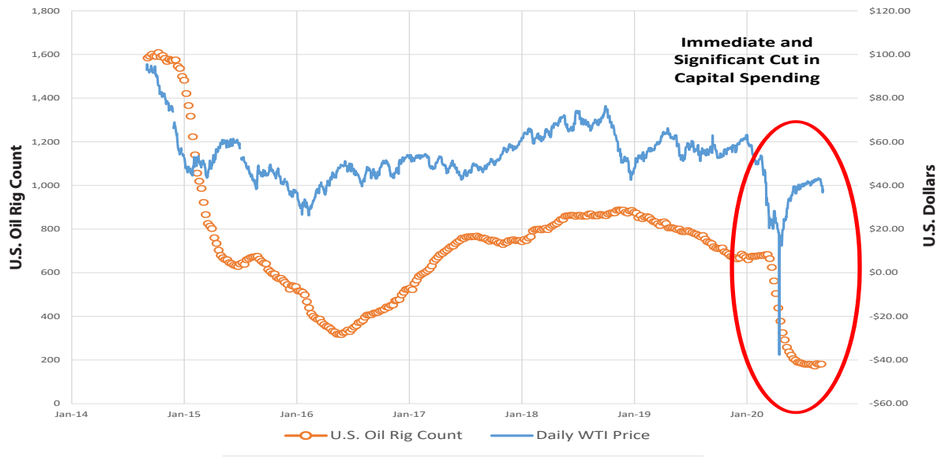
At the beginning of 2020, those counts dropped from roughly 650 to 700 rigs to about 180.

"That's a very rapid drop," said Woodrome. "You can see in the previous five years, including the previous recession, we didn't see a sudden rig count drop like that."

He also concluded that the market is efficient. "U.S. operators responded appropriately by drastically cutting capital expenditures as evident in both the Cushing storage utilization and the oil rig count in the aftermath of the dramatic price drop," said Woodrome.

WTI for February delivery settled at $48 a barrel on the NYMEX — an increase of $2.57 or almost 6 percent on optimism that Covid-19 vaccines will lead to a swift recovery in global energy demand as soon as this year.

WTI Price vs US oil Rig Count



ESG should be daily business practice, says attorney

Katherine Wauters, staff writer

Jamie Jost

As stakeholder demands rise, "ESG is becoming a leading factor in where financial institutions and private equity will place their money," said **Jamie Jost**, founder and managing shareholder of Jost Energy Law PC. She made her remarks at the virtual 16th Annual Ryder Scott Reserves Conference in September. In her ethics presentation on Zoom, she focused on ESG (environmental, social and governance) issues and their influence on legislation in Colorado at federal, state and local levels.

SB 19-181: What Colorado needs to know

Signed into law in April 2019, SB 19-181 was "adopted to prioritize the protection of public safety, health, welfare and environment, and wildlife in the regulation of the oil and gas industry by modifying the oil and gas statute and by clarifying, reinforcing, and establishing local governments' regulatory authority over the surface impacts of oil and gas development."

Some key provisions of the law include changing the language from "foster" to "regulate," the creation of a professional commission, broadened authority at city/town/county levels, and a change in the definition of "waste."

The full text of the law is at https://leg.colorado.gov/sites/default/files/2019a_181_signed.pdf.

Prior to SB 19-181, much of the authority was concentrated at the state level in organizations such as the Colorado Oil and Gas Conservation Commission (COGCC) and the Colorado Department of Public Health and Environment (CDPHE). Today, local governments are "charged with regulating the surface impacts of oil and gas operations in a reasonable manner… and to protect and minimize adverse impacts to public health, safety, welfare and the environment."

This redistribution of authority to local governments has led to moratoria on oil and gas in several cities and counties. The city of Boulder has had a moratorium in place for more than seven years.

Jost discussed oil and gas regulations at both the county and city levels, as well as lobbying from environmental groups to reinstate fracing bans.

The demand by investors for ESG and socially responsible investment (SRI) has led to an overhaul of Colorado's oil and gas regulations at every level of government. The COGCC is currently working on modifying its 100-to-1200 Series rules.

"The work ranges from new definitions for every series rule, procedural modifications, and limitations on transfer of operatorship, to name a few," said Jost.

Please see ESG Should Be Daily Business Practice on page 10

ESG Should Be Daily Business Practice – Cont. from page 9

She presented the following takeaways:

- Consult an ESG expert and educate yourself on impacts ESG can have on your business.
- Remain proactive with regard to ESG, realizing that environmental and social factors can sometimes be most crucial.
- Understand that ESG factors and criteria remain fluid, so be open to change.
- Incorporate ESG into daily business practices. After all, it's just good business sense.

ESG in general

Jost clarified ESG activities as follows:

- **Environmental criteria** — How a company performs as a steward of nature
- **Social criteria** — How a company manages relationships with employees, suppliers, customers and communities
- **Governance** — Relates to company leadership, executive pay, audits, internal controls and shareholder rights

The origins of ESG date to 2004. Today, more than 70 percent of institutional investors use ESG principles as part of their investment approaches and decision-making processes, according to a survey of more than a year ago by RBC Global Asset Management Inc.

Jost said it is critical for the oil and gas industry to incorporate ESG into daily business practices. "ESG leadership comes from the top and runs down through the company in every aspect. It is expected the company's governing body will work to create an ESG-centric culture and mandate a culture that exudes from all levels of the business," she said.

Topics for corporate consideration include, but are not limited to, the following:

- Environmental justice
- Sustainability
- Pollution reduction
- Racial equity and diversity
- Good stewardship of stakeholders' interests
- Corporate reputation and treatment of companies by the media

Jost's complete presentation is posted at https://803.9a5.myftpupload.com/wp-content/uploads/09_JOST_Presentation.pdf

Wilson Sees Gas Potential – Cont. from page 6

On the demand side, natural-gas-powered delivery trucks bring goods to homes as people stay away from crowded stores. While office buildings are kept cool or warm for a small number of onsite workers, work-from-home employees now demand a comfortable home 24 hours a day rather than just evenings and weekends.

Worldwide demand has dropped but Wilson writes that decline has been matched by the decrease in associated gas from shut-in oil wells.

"Natural-gas suppliers continue to provide uninterrupted service despite fewer people and smaller budgets. Like other essential workers, they are heroes and deserve our sincerest thanks," wrote Wilson.

He introduced three related SPE technical papers for November and recommended additional papers.

Ryder Scott is a top workplace

Ryder Scott won a Top Workplaces 2020 honor from the *Houston Chronicle* newspaper. The award is based on a third-party survey measuring employee feedback on 15 drivers of engaged cultures — including alignment, execution and connection.

In the small company category (50 to 149 employees), Ryder Scott was in the top 19th percentile.

Employees have consistently rated issues of connection and alignment most important in the surveys, with pay and benefits taking on less importance. Employees rate "connection" high when they feel appreciated and their work is meaningful. If an employer and employee agree on the direction and values of the company, then alignment is high.

"Workplace engagement during 2020 was especially challenging considering the repercussions of a pandemic and a greatly expanded work-from-home environment," said **Dean Rietz**, CEO. "This honor confirms that the environment we have cultivated for decades, including an esprit de corps throughout Ryder Scott, has held up."

Obituaries

Douglas L. McBride

Douglas L. McBride, 68, a petroleum engineer at Ryder Scott for 25 years, died Nov. 8. He worked at Ryder Scott from 1981 to 2006, and was a senior vice president.

"I traveled overseas with Doug on business. He was always a gentleman. Please keep Doug and his family in your thoughts and prayers," said **Dean Rietz**, CEO at Ryder Scott.

Before working at Ryder Scott, McBride was a reservoir engineer at Amoco Production Co. during 1974 to 1979. He graduated with a BS degree in architectural engineering from the University of Texas-Austin in 1975. McBride was a registered professional engineer in Texas.

He founded his own company, Morning Star Consultants LLC in Austin, TX, in 2006.

Ronald Arthur Lenser

Ronald Arthur Lenser, 88, of Dallas died Oct. 9. In 1967, he joined Ryder Scott in Wichita Falls, TX, and later, moved to Houston to help establish the firm's new office.

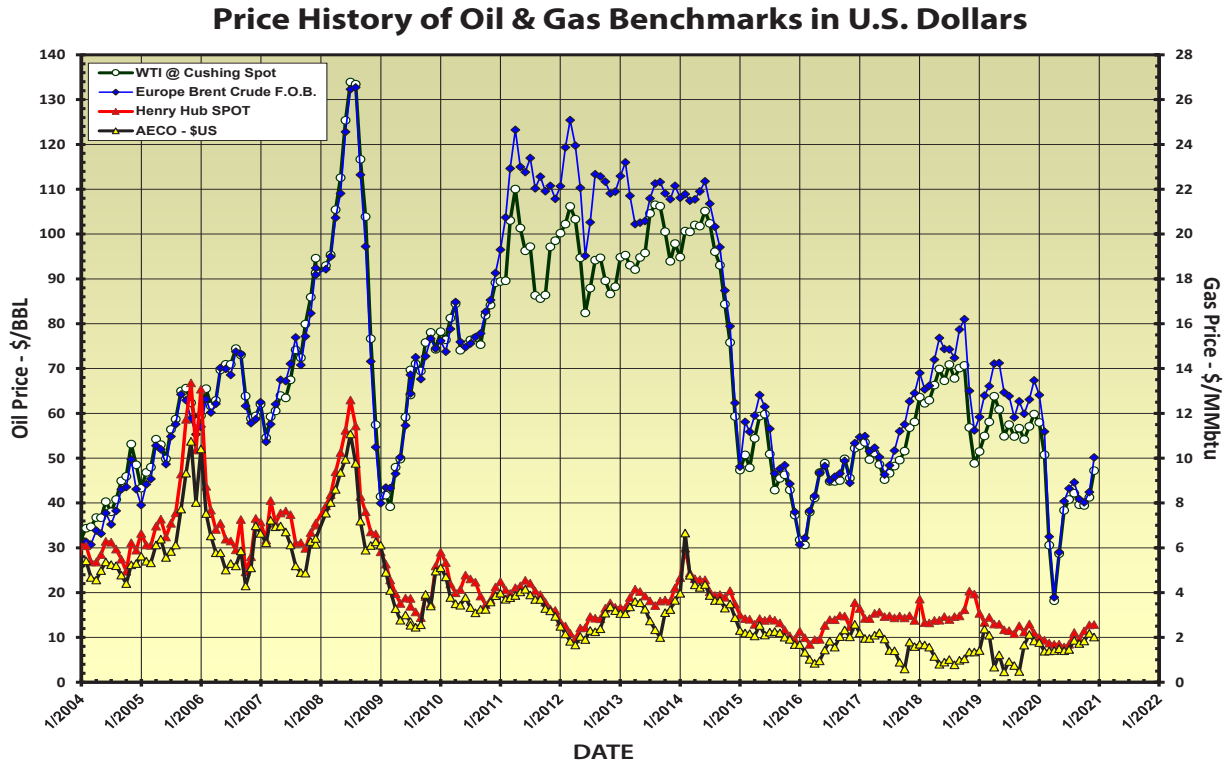
"Ron was one of the early leaders of our consulting firm, and helped transition it from waterflood engineering to petroleum reserves evaluations," said Rietz.

In 1980, Lenser started R. A. Lenser & Associates Inc. He graduated from Kansas University in 1956 with a BS degree in petroleum engineering.

EIA redesigns U.S. Energy Atlas

On Jan. 4, the U.S. Energy Information Administration (EIA) released the U.S. Energy Atlas which is posted at **https://atlas.eia.gov/**. The improvements include a new interface for web map applications and a comprehensive open data catalog. The U.S. Energy Atlas shows detailed energy infrastructure in redesigned maps with enhanced navigation and data accessibility features. With the U.S. Energy Atlas, users can now combine EIA's data with information from other sources to customize their own geospatial analysis.

The U.S. Energy Atlas features 84 map layers, 60 of which are based on EIA surveys. EIA data published in the U.S. Energy Atlas includes locations of power plants, coal mines, oil and natural gas wells, pipelines, storage facilities, natural gas processing plants, refineries, and other types of energy facilities.



Publisher's Statement

Reservoir Solutions newsletter is published quarterly by Ryder Scott Co. LP. Established in 1937, the reservoir evaluation consulting firm performs hundreds of oil and gas reserves studies a year. Ryder Scott multi-disciplinary studies incorporate geophysics, petrophysics, geology, petroleum engineering, reservoir simulation and economics. With 119 employees, including 80 engineers and geoscientists, Ryder Scott has the capability to complete the largest, most complex reservoir evaluation projects in a timely manner.

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RESERVOIR SOLUTIONS

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Survey provides deepest insight into what industry wants in a new petroleum engineer

Updates planned, says Ryder Scott

To know what companies want in a new petroleum engineer (PE), use the direct approach. Ask.

Over the past three years, at least a half-dozen SPE papers have explored a so-called new age of petroleum engineering, required skills and commensurate education. Only one asks companies what they want to see in new PE graduates.

Those survey results are published in "An Industry Look at the Petroleum Engineering Curricula," SPE Paper No. 195965-MS, by **Dean Rietz** and **Adam Cagle** at Ryder Scott and **Mohamed Soliman** at the University of Houston, 2019. By extension, it is a look at what training and skills are most important to oil and gas managers, who hire and work with new PEs, defined as those with five or fewer years' experience.

"Our purpose was to try to understand the balance between expectations of a changing industry and the academic training … in place for years," stated the authors.

Please see Survey Provides Deepest Insights on page 2

TABLE OF CONTENTS:

Survey Provides Deepest Insights – Cont. from page 1

2010s: Highs and lows

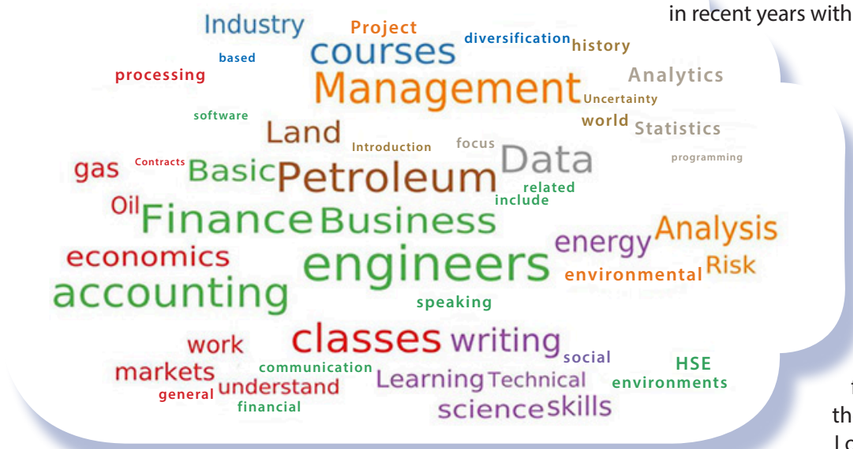
Rietz et al. discussed the great crew change, which was supposed to accelerate the retirement of older boomers during the 2010s. However, the lure of lucrative shale plays incentivized some to delay retirement.

Then came the 2014–2017 industry layoffs. Demand for new grads cooled while their numbers peaked. They found themselves in an oversupply. Starting salaries dropped.

"In 2015, oil and gas producing organizations experienced significant pressure to reduce costs, resulting in layoffs and other methods to lean out the organizations," the authors stated. "Rightsizing" included cuts to geological and engineering staffs.

The change was sudden. In the earlier part of the decade, prices fluctuated around $100 a barrel of oil. The call to action in shale plays was "drill, baby, drill." Companies enticed new petroleum engineering graduates with signing bonuses.

A PE degree was a hot ticket to a six-figure starting salary, more than any other engineering discipline at that time.



The importance of new courses outside of petroleum engineering that should be added to the curriculum, say respondents. In a word cloud, the larger the word, the greater the importance.

One-two punch

In the intervening two years since the SPE paper, industry has soured even more. Weak returns and the Covid-19 pandemic unleashed a one-two punch. Massive layoffs and retirements accelerated "employee churn." More than 100,000 oil and gas workers lost their jobs because of sluggish demand.

"U.S. O&G companies laid off about 14 percent of permanent employees in 2020, and …research shows that 70 percent of jobs lost during the pandemic may not come back by the end of 2021," states the Deloitte 2021 oil and gas industry outlook.

Like a controlled burn, the pandemic has thinned the ranks of petroleum engineering undergraduates and working PEs, many of whom started small consultancies. The promise of new growth hangs in the air.

It's Not the End of Petroleum Engineering as We Know It

March hope

In March, oil settled in at a volatile $65 a barrel that was down to $58 in early April. Less volatility in commodity prices, whenever that comes, will spur upstream companies to invest in human capital — especially technical expertise, to increase production and monetize upstream assets.

One scenario is with prolonged $60+ per BOE or higher, producers, hobbled by staff cuts, will begin recruiting graduates again.

As of today, economic drivers have yet to loosen a still tight job market for PE grads.

"The industry has attracted thousands of young people in recent years with the promise of secure careers as shale drilling took off and made the United States the world's largest producer of oil," stated the *New York Times* this year. "But many students and recent graduates say they are no longer sure that there is a place for them in the industry. Even after the pandemic ends, some of them fear that growing concerns about climate change will lead to the inevitable decline of oil and gas."

The article, "A Slap in the Face: The Pandemic Disrupts Young Oil Careers," focuses on young PEs and students and their stories during the pandemic.

Long term, the pandemic will not have a lasting effect on the industry. Nearly 80 percent of oil and gas professionals feel less secure in their jobs than before the pandemic, the Global Energy Talent Index (GETI) reported this year. However, two-thirds expect advances in engineering will open up opportunities in the next three years.

The percentage of energy the world needs from oil and natural gas is expected to decline from about 53 percent to 48 percent over the next 30 years. However, the amount of production is actually expected to increase by 20 percent for oil and 50 percent for natural gas, stated **Medhat M. Kamal** in his paper, "Future Need of Petroleum Engineering," SPE-200771-MS.[1]

The U.S. Bureau of Labor Statistics (BLS) projects that by 2029, the number of working PEs will be 34,400, a net increase of 1,000 jobs over 10 years, or 3 percent.

Relatively speaking, the uptick is not as anemic as it might seem. Electrical engineers are at 3-percent growth over a decade. BLS forecasts mechanical engineers will increase 4 percent.

Just ask

Survey designers made sure the 200 respondents were highly qualified. Survey-takers were those who hired, trained and worked with young petroleum engineers, and were able to draw on direct experience to share what new grads offer and what they lack.

More than half of the respondents had BS degrees in petroleum engineering and about 25 percent had masters or PhD degrees.

More than 75 percent had 20 years or more experience. Engineers, supervisors, executives and owners comprised almost 96 percent of the respondents.

More than half of the survey-takers worked at independent oil and gas companies. One quarter worked at service companies, consultants or major integrated companies. Slightly more than 5 percent worked at national oil companies. Two-thirds worked at employers of 1,000 or more employees.

A higher representation of reservoir engineers in respondent demographics may have biased the results in that direction. Future surveys conducted by the authors will include questions regarding respondent background with respect to petroleum engineering subdisciplines.

The high percentage of independent companies in the survey also may have weighted skills to those needed to evaluate unconventional plays.

Big data

All six papers, including the one by Rietz et al., argue that graduates must have "big data" analytics training to automate and streamline oil and gas E&P operations. "Seasoned and experienced petroleum engineers are not properly trained with the latest technologies that are driving our transforming industry," said Rietz et al.

They added that data analytics and risk analysis are especially important in evaluating shale areas, sometimes described as "statistical plays."

"The new technologies and buzzwords of today, such as big data, machine learning, artificial intelligence, digital transformation and automation, are all assisting to better understand unconventional assets," stated Rietz et al.

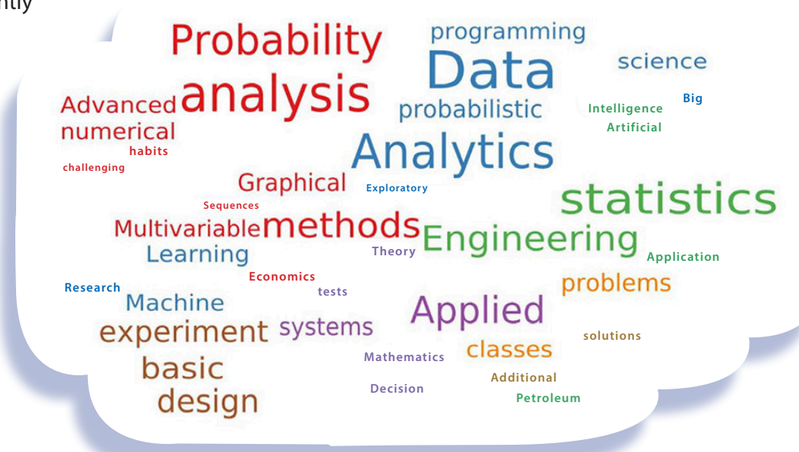
JPT magazine reported three years ago that unconventional operators were "finally beginning to use to their advantage the nearly endless stream of data they've collected over the years." Expanding data analytics capabilities in the Eagle Ford has helped ConocoPhillips Co. "drill 80 percent more wells per rig, recover 20 percent more hydrocarbons per well, and achieve an 8 percent increase in direct operating efficiency," according to a company presentation cited by the magazine.

One of the respondents in the industry survey said, "Engineering statistics is not sufficient for modern engineers in the age of big data and artificial intelligence."

JPT stated that the most downloaded SPE paper in 2019 … was "The End of Petroleum Engineering as We Know It," which predicted a significant change in what engineers do and the number needed to do it over the long term (SPE Paper No. 194746)."[2]

The paper's authors stated, "Given the highly dynamic environment of the technical operations in our sector, only 20 to 25 percent of activities can be automated. However, 70 to 75 percent of those same operations can be augmented."

No doubt, automation will displace engineers. However, the authors conclude that the change may not drastically reduce the number of engineers. Each engineer will do more than anyone could have previously accomplished — a case of extension vs. elimination.



In a word cloud, the larger the word, the greater the importance.

"Future petroleum engineering duties will require a different way of thinking and different skills," the industry survey states.

Big data not so big

Royal Dutch Shell is turning to data analytics to cut costs, improve business processes and generate revenue. Shell is launching online training in AI skills to employees, including petroleum engineers, chemists and geophysicists, the *Wall Street Journal* reported this year. Shell has about 82,000 employees.

Big data is a big deal. However, it is not singularly the future of petroleum engineering.

The industry survey put the importance of data analytics into perspective with other core engineering curricula. Respondents answered the question, "What skills/subjects are most important for new petroleum engineering graduates?"

Please see Survey Provides Deepest Insights on page 4

Survey Provides Deepest Insights – Cont. from page 3

See table at page bottom, "Importance of Skill/Subject." Surprisingly, data analytics was in the middle of the pack.

Sustainability

Mathieson et al. state, "The next generation of petroleum engineers will have to address demands for sustainability, lower carbon intensity and needs for radical productivity improvements, which only AI and digital can drive."

Another SPE paper, No. 201755-MS, "Rise of Machines: Time to Change the Petroleum Engineering Curriculum," agrees, stating, "Lots of efforts are being taken to transition from oil and gas to renewable and sustainable sources of energy."[3]

The paper recommends that educators integrate courses on sustainability of well-life cycles. "It is time to examine the core curricula being taught at petroleum schools…," stated the author.

Kamal recommended courses on carbon capture and underground storage for the future. Other recent papers have also proposed similar academic focus.

The survey by Rietz et al. finds no industry preference for petroleum engineering graduates with introductory non-core courses in energy and sustainability. The survey did not measure whether respondents placed less importance on those courses because they were introductory rather than advanced.

Among answers to those open-ended questions, economics scored highest. This is not surprising since, as noted before, there may be a bias in the survey toward reserves and the economic evaluation of oil and gas assets.

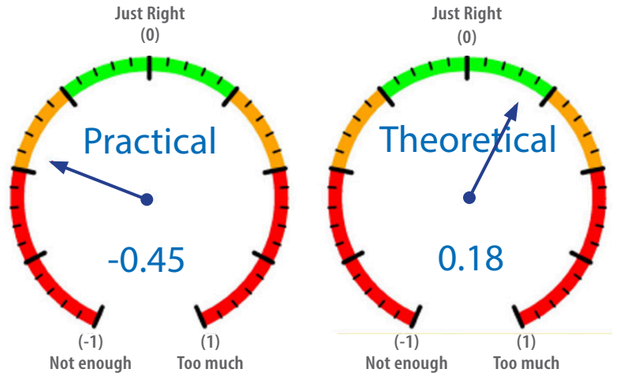
Importance of Skill/Subject

Skill/Subject	Total Score	Normalized Score
Logic/Critical Thinking	414	1.0
Ethics	404	.98
Communications	393	.95
Economics	371	.90
Soft Skills/Professionalism	351	.85
Data Mining/Analytics	319	.77
Project Management	306	.74
Programming	169	.41
Environmental Stewardship	159	.38
Entrepreneurship	139	.34
Legal	124	.30
Geopolitics	80	.19
Forensics	77	.19

Logic and critical thinking are at the top. Ethics, communications, economics, soft skills/professionalism all scored higher than data mining/analytics.

Practice makes perfect

The survey found that industry wants more practical approaches in course curricula. For instance, in the computer and computer programming category, training in commercial software, a practical skill, made graduates slightly more valuable to industry than programming for engineers — a more theoretical/fundamentals skill.



Industry wants grads with a greater understanding of practical applications of modern tools to solve petroleum-engineering problems. At the same time, companies want academia to maintain curricula on theory and principles-based approaches.

Industry cannot have it both ways.

JPT pointed out that universities cannot increase undergraduate course hours considering the packed, time-intensive schedules over four years. The requirements of the Accreditation Board of Engineering and Technology leave little room for additional coursework, labs or fieldwork, the publication stated. Most schools require 130-plus credit hours.

"Today's graduates are expected to be fluent in data analytics, machine learning and data sciences, and to understand concepts, such as cybersecurity and physical security. In addition, many are expected to use their subsurface engineering skills to plan and design carbon sequestration solutions," stated *JPT*.

Mathieson et al. argued, "Advanced material sciences, supply chain, big data analytics, etc. can hardly be touched in the undergraduate curriculum. … Most firms hiring engineers today accept entry-level engineers with a BS degree, but this may change as the discipline requires increased sophistication."

Partnering: Academia and industry

New curricula demand instructors who have mastered the material and can impart that to their students. Author **Robello Samuel**[3] asked if universities are ready to adapt to change.

"Faculty development programs and the recruitment of a new generation of faculty to teach cross-disciplinary courses may be needed to meet the demands of a changing industry," he stated.

Samuel adds that universities need to develop a pipeline of qualified faculty who can be in alignment with the cutting-edge technology so that faculty and industry partners are in alignment in better preparing students.

Surprise ending

Universities may not be facing any drastic changes in faculty or curricula, according to the survey by Rietz et al.

They remarked, "We were a bit surprised that there was not an appreciable number of individuals calling for significant changes to the petroleum engineering curricula."

The respondents, as a group, were fairly unified in their sentiments: "Keep the curriculum generally the same in terms of courses, but modernize the materials to include the practical application of new technologies — software, statistics, and data science tools in general — that are being utilized in the industry to address new challenges presented by unconventional/shale plays, big data and the digital revolutions."

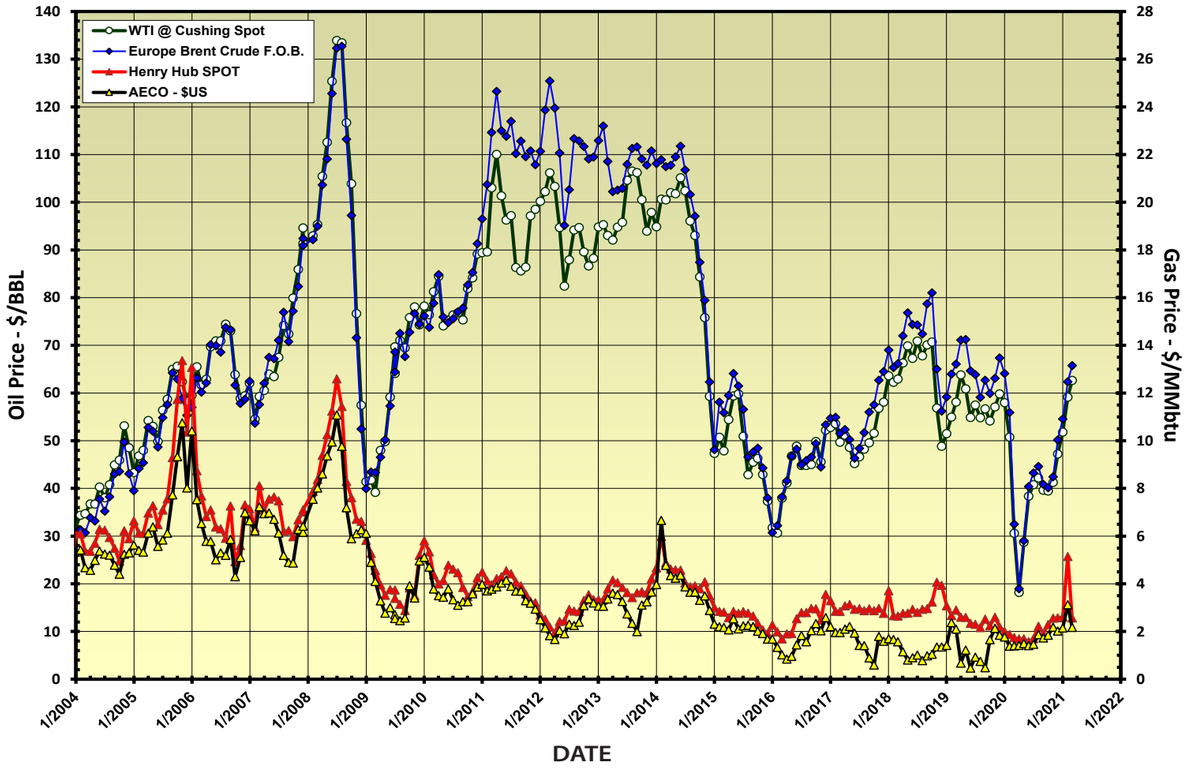
It is not the end of petroleum engineering, as we know it. Rather, it's a continuation with some tweaks along the way.

Editor's note: *Please see the full citation on the Rietz et al. survey: "An Industry Look at the Petroleum Engineering Curricula, "Dean Rietz, Mohamed Soliman and Adam Cagle; SPE-195965-MS, 2019. Please see this paper and the ones below by ordering at onepetro.org.*

Other References

1. "The End of Petroleum Engineering as We Know It," Derek Mathieson, D. Nathan Meehan, Jeff Potts; SPE-194746-MS; 2019
2. "Future Need of Petroleum Engineering," Medhat M. Kamal, SPE-200771-MS, 2021
3. "Rise of Machines: Time to Change the Petroleum Engineering Curriculum," Robello Samuel, SPE-201755-MS, 2020

Price History of Oil & Gas Benchmarks in U.S. Dollars



Published, monthly-average, cash market prices for WTI crude at Cushing (NYMEX), Brent crude and Henry Hub and AECO gas.

Assessing reservoir uncertainties, project risks is key to successful deepwater development

A head advisor at Ryder Scott, **Sandeep Khurana**, recently said this economic environment is familiar ground for those in deepwater projects over the last decade.

"I know I would be wrong if I said these are unprecedented times in our industry for deep water, because we have been here before," he said.

Khurana referred to the 2010 Maconda incident and resulting deepwater drilling ban, sudden oil price crash from $120 a barrel to $60 in 2014, price drop to $30 a barrel in 2016, negative oil prices last year in the spot market, and skyrocketing price in electricity market in February 2021 during the big chill in Texas.

"So, what has it done for us? It has helped us to make this industry more sustainable," said Khurana, with an existential twist, "What doesn't kill you makes you stronger."

His comments were an update to a presentation he made at last year's Ryder Scott annual reserves conference on how to assess, plan and generate value in deepwater projects. The focus was on integrating reservoir evaluation and facilities engineering, before and after project sanctioning, to reduce technical and economic risks.

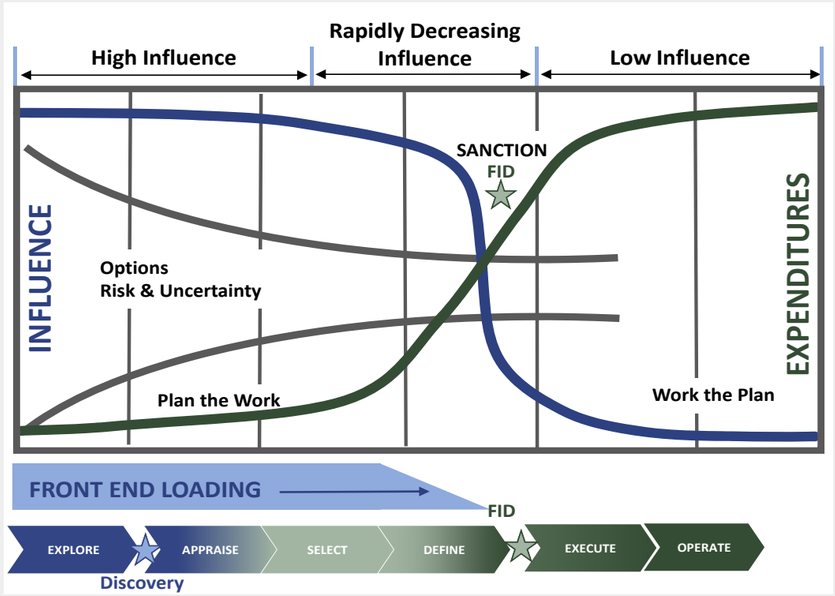
Front-end loading

At the project management level, the challenge is to align specialties in subsurface, surface well activities, surface facilities and commercial activities early in the project. That is when companies are making strategic decisions when project-development risks and uncertainty in reserves estimates are high.

Front-end loading is when companies have the highest influence to handle value-driven processes from discovery to financial investment decision (FID). Exposure to expenditures is the lowest. See the following chart.

Front End Loading (FEL)

- Discovery to Final Investment Decision (FID) is commonly referred to as Front End Planning or Loading, a stage for an oil company where they have the highest influence and lowest expenditure exposures
- The company works to characterize and narrow Uncertainty (in reservoir) and Risks (Project Development) to arrive at FID



During execution of the development plan and operation stages, the influence of evaluators is the lowest.

"Once the project is sanctioned, then the train has pretty much left the station. That's where you put large investments on the table to execute the development plan," said Khurana. "At Ryder Scott, we have experts in the necessary disciplines at the front end, and have aligned work streams from first look at the assets to FID."

During early concept screening, engineers for surface facilities are looking at concepts/Pre-FEED (front-end engineering design) and FEED after that. Subsurface (reservoir) evaluators are progressing similarly by delineating the discovery, and then performing reservoir characterization.

"All these disciplines have to work in sync to drive the value of a development," said Khurana. "The same concept actually takes you into the world of the SPE-PRMS."

Mapping FEED to SPE project maturity

Project maturity is nothing more than a depiction of the development process. The SPE-PRMS subclasses of project maturity very clearly pinpoint two main elements to consider — discovery and commerciality. After discovery, of course, hydrocarbons can still be unrecoverable or booked as contingent resources. For commerciality, an evaluator will need to have an understanding of commitment to develop the field, but issuance of an FID is not necessary.

The operator has to show proof that it intends to develop the field. Discovery, sanctioning the project, and producing first oil are the three milestones that have a direct impact on a company's valuation.

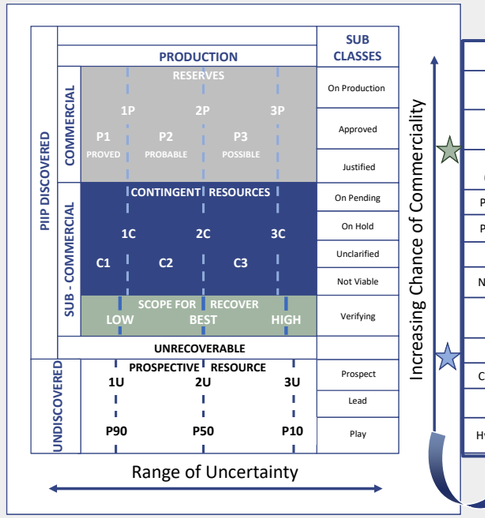
Big gap

Ryder Scott conducted a recent study for a client struggling with the big gap between discovery and FID — a duration in which the discovery can result in commercially unrecoverable hydrocarbons.

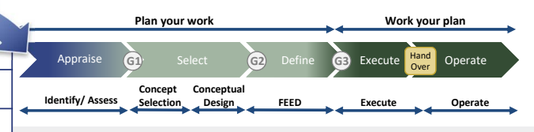
Khurana said, "We came up with a scope for recovery in the client's methodology. We took the client's way of looking at reserves, mapped it back to SPE-PRMS and then looked at the development process, and created a gate system."

"Scope of recovery" is not an industry-recognized term but is sometimes used to account for volumes while transitioning from Discovery to Development. Please see the following chart.

Mapping – A Case Study



Project	STATUS
Operate	Developed
Post G3	Undeveloped Project Awarded
Post G3 (Commitment)	Undeveloped EPC Progress
Post G2 / Pre G3	FEED Progress
Post G2 / Pre G3	FEED on Hold
Pre G2	Undeveloped
No activities @ G	Undeveloped
Pre-Project	Undeveloped
Commercial Dev.	Undiscovered
Feasible Dev.	Undiscovered
Hypothetical Dev.	Undiscovered



- We did mapping to SPE-PRMS for Client's project maturity to maximize cash flow and protect investors by incorporating "Scope for Recovery"
- Decision Gates (G) were directly linked to Project sub-classes and maturity Status
  - Committed Projects (Reserves) Post DG3 w/ FEED (CAPEX defined)
  - Project under investigation (Contingent Resources)- DG2 to DG3
  - Conceptual Project (Scope for Recovery)

"We demonstrated a one-to one relationship in the progression and how to make sure the reservoir volumes are characterized from prospective to contingent resources and then to reserves," said Khurana. "We showed the stipulations to follow in the gate system up to where the quantities are reserves and commitment is firm."

Please see Assessing Reservoir Uncertainties on page 8

Assessing Reservoir Uncertainties – Cont. from page 7

Devil in the details

Just like reserves, estimated costs have accuracy ranges. AACE International, through its Recommended Practice No. 87R-14, provides characteristics of five price-estimate classifications for E&P. The classifications follow project maturity levels defined in the SPE-PRMS. Maturity is the primary characteristic in the classifications, and other characteristics are secondary.

This chart from AACE International shows five classes of costs — with 1 as most accurate estimate and 5 least accurate. Please see the following chart.

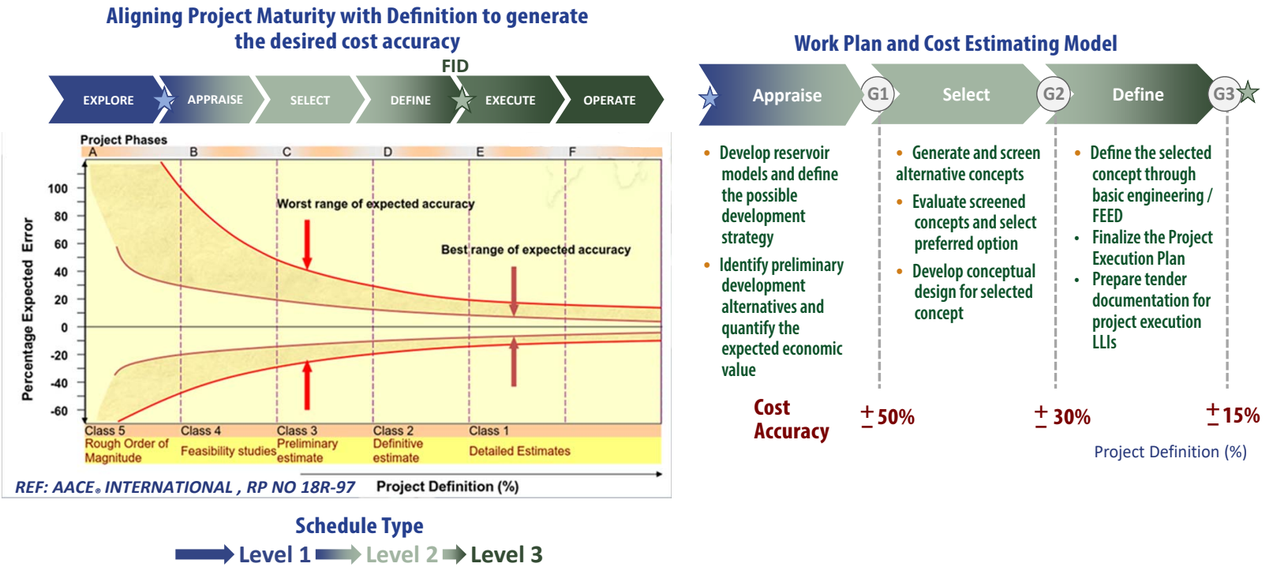
"In the early days, you are in Class 5, if you do not define the project or perform minimal engineering on it," said Khurana. "If you define the project further, you can get a more reliable cost estimate. If you define the project in detail, you can get a definite cost estimate of Class 1 or 2."

He has noticed that often, offshore operators do not align project definitions with the project maturity.

"Often, companies with new discoveries strive to get to a Class 1 estimate," Khurana said. "That has no value because of so much uncertainty in the resource."

A producer cannot establish firm costs and schedules under those circumstances. The right approach is to incorporate resource uncertainty as part of the project design to be prepared for eventualities.

Cost and Schedule Assessment



The horizontal axis of the cost curve is project definition, not project maturity. The operator has to cite the details of engineering work to define the project. The more definition in a project, the more reliable cost estimates will be.

Lowering BEP

Khurana cited work done for a client by Ryder Scott in the Gulf of Mexico, including a resource assessment for every block. The client wanted a lower break-even point (BEP). "The evaluation team looked at histories, prices and capex, current information and where to make a step change to reduce BEPs," said Khurana.

"We characterized deep water with Floating Production Systems (FPS) rather than the water depth, because deepwater definitions have changed over time," said Khurana.

He mapped 52 GOM deepwater fields, from 1993 to today, equipped with FPSs as well as semi-sub, spar, TLP and Shipshape platform types.

Khurana looked at FPS sanctions and BEPs in the deepwater GOM from 1993.

"It was low capex and capex inflation those days," he said. BEP oil price was $15 to $20.

From there, the supply chain became overextended and rising capex inflation came into play. During 2010 to 2014, inflation was so high it took $60 to $85 per BOE to develop a field.

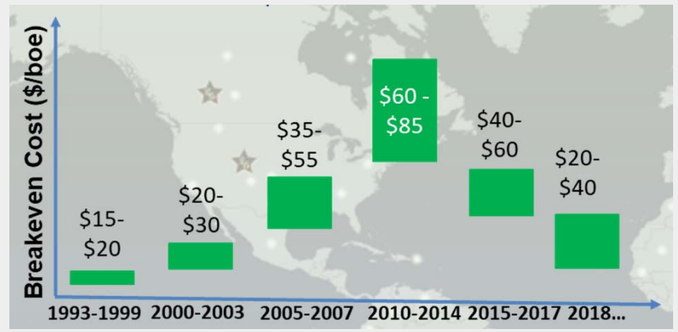
A correction in the market occurred from 2015 to 2017, as oil prices dropped. Capex in the deep water became relatively inexpensive. BEP dropped into the $40-to-$60 range per BOE.

"There was a step change going on. I recall our client asking us to design for, 'fit at 40,' that is, trying to reduce BEP to $40 a barrel," said Khurana.

Innovation and technology were the drivers of this change.

GOM Case Study • Floating Production Systems (FPS)

FPS sanction activities can be broadly divided into six phases based on number of projects sanctioned and recent efforts to reduce breakeven oil price of sub-$30



- Evolution 1993-1999: Low Capex inflation
- Exuberance 2000-2003: Supply chain extended
- Inflation 2005-2007: Capex inflation matches WTI
- Hyper-Inflation 2010-2014: Capex inflation above WTI
- Correction 2015-2017: Capex Reduction
- Innovation 2018…: A Step Change

Deepwater costs and technology

Ways to reduce costs included the following:

- Reducing project complexity by understanding how the development process works. A good understanding of risk and uncertainty is required in the front-end planning.
- Standardization, including the advent of long tieback fields or reservoirs.
- Digitalization or remote monitoring, which has decreased the BEP for development costs.
- New technologies are also emerging. In 2019, Chevron Corp. sanctioned the Anchor project, the first-ever 20,000 psi-rated field to be developed in the Gulf of Mexico. Seismic technology continues to advance. BHP Group Ltd. and BP Plc recently installed ocean-bottom nodes in the GOM to improve seismic data and to conduct advanced processing.

Step-down approach, standardization

A simple rule of thumb in the offshore industry is an increase in water and drill depths results in cost increases. As a work-around, Shell nixed its plan for the costly Vito EOR project and a large platform host. In its place, the company switched to a depletion scheme with gas lift and a smaller platform, which made the investment profile smaller.

"Then came the next realization for Shell," said Khurana. "Why do we have to have company-specific standards?' We could go to the public domain and join a consortium to promote standardization of various product lines in the industry."

Shell decided to rely on standardizations common to the industry. The company carried out competitive benchmarking and collaborated with various vendors. Ultimately, Shell was able to reduce project complexity and costs.

The definition of standardization has evolved. In 2005, Exxon applied a "design one, build two" approach to FPSOs (floating production storage and offloading unit) in Angola.

"They did it very successfully," said Khurana. "Exxon was able to reduce costs because it installed the same FPSO design in two locations."

The company is expanding this model to "design one, build many" in Guyana, with SBM Offshore NV as FPSO supplier.

"The main evolution in standardization has been an adoption of vendor standard packages and solutions promising fast delivery and lower capex. SBM made these standardization efforts by looking at the development specifications and supply chain, and other industry vendors are doing the same," said Khurana.

Five years ago, the EIA asked a key question for the deep water, and that was how quickly and to what degree could industry develop efficiencies similar to onshore development, given what the EIA called "the lack of critical mass and diversity of projects."

Soon after, industry emphatically answered back.

Please see Assessing Reservoir Uncertainties on page 10

Assessing Reservoir Uncertainties – Cont. from page 9

In 2019, at a HESS Corp. earnings announcement, a financial analyst compared the company's Guyana development to a Delaware Basin project.

"A side-by-side chart showed how competitive the deep water had become by reducing complexity and implementing standardization," said Khurana. For the deep water, the BEP oil price was $30 per barrel compared to $40 a barrel for the Delaware Basin onshore project.

"The breakeven price will continue to decrease in the subsequent phases of the development," said Khurana.

One of the innovative areas in subsea infrastructure is extending tieback distances, which has increased from 20 miles to 40 miles. That advancement is a cost saver by eliminating a need for another hub 20 to 40 miles to the tieback.

"Similarly, other technology advancements, including digitalization, have caught our attention and accelerated lately, because of the pandemic," said Khurana.

An ongoing effort is to move toward unmanned platforms, remote monitoring and lower headcounts in operations. Khurana cited Equinor ASA and its use of remote technology for automated intervention, as a good example.

Commercial arrangements

Khurana also presented advances in commercial arrangements for deepwater infrastructure that he recounted from his 2020 Offshore Technology Conference paper. He, along with **Justin Rostant** and **Julie Wilson** at Wood Mackenzie, wrote the paper, OTC-30806-MS, "Private Equity Financing and Third-party Infrastructure: Future Enabler." It is available at onepetro.org.

"I made the presentation last year, but the concept and commercial elements are still applicable in today's market," he said.

They involve third parties — such as midstream companies, private equity, service providers, etc. — taking stakes in production and processing facilities and related infrastructure. In that way, operators mitigate project risks.

Such commercial arrangements range from traditional leasing and take-or-pay contracts to innovative production handling agreements.

"To capture upside, those consortia create a win-win for all involved," said Khurana.

Khurana's slide deck is at https://ryderscott.com/wp-content/uploads/03_KHURANA_Presentation.pdf. It has detailed charts covering all aspects summarized in this article and more. The presentation also includes in-depth explanations.

For further information, contact Khurana at sandeep_khurana@ryderscott.com. *Reservoir Solutions* published a recap of the OTC presentation in July at https://www.ryderscott.com/wp-content/uploads/Rs3rdQTR-July9th-Article6.pdf.

E&P companies work to get ahead of GHG standards

Oil and gas companies in North America and abroad are taking major steps to reduce greenhouse gas (GHG) emissions. GHG initiatives in the United States, Canada and Europe have introduced standards and milestones for companies to reach to stay in compliance. Public agencies have a strong focus on emission standards for upstream and midstream oil and gas operations.

Major IOCs (international operating companies) in North America and Europe recently announced plans to achieve net-zero emissions by the middle of the century. The Covid-19-driven downturn in the industry has hastened emission-reduction plans and abatement programs.

Amid this backdrop, **Herman Acuna**, executive vice president at Ryder Scott, manages a team that assists in environmental, social and corporate governance (ESG) activities.

He said, "This is an emerging area for Ryder Scott, and one that we are adding to our traditional services."

Ryder Scott is moving to independently audit any one of several ESG programs and processes, and will recommend ways to improve workflow to reach corporate goals. For instance, to reduce carbon footprints, reports will recommend cost-effective ways to reduce GHG emissions from oil and gas facilities by using better programs and processes.

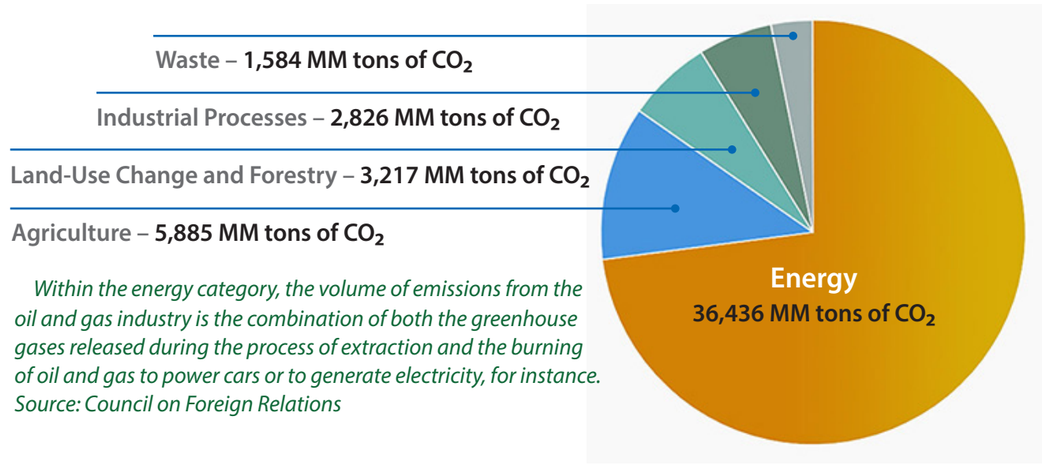
Deliverables include independently certified sustainability reports. A textbook definition of sustainability is the process of managing available resources, investments and technologies to maintain and optimize operations for greater safety, reliability, efficiency and environmental and social awareness.

Ryder Scott also analyzes renewable energy options and scenarios to determine optimum solutions.

For more information, please contact Acuna at his email address, herman_acuna@ryderscott.com.

Acuna plans to present "GHG Management Facilitating Frameworks" July 15 via a Zoom webinar. For more information, please see announcement on Page 13.

World Greenhouse Gas Emissions by Economic Sector – 2017



Within the energy category, the volume of emissions from the oil and gas industry is the combination of both the greenhouse gases released during the process of extraction and the burning of oil and gas to power cars or to generate electricity, for instance. Source: Council on Foreign Relations

More to helping foster kids than posting on social media, says geoscientist

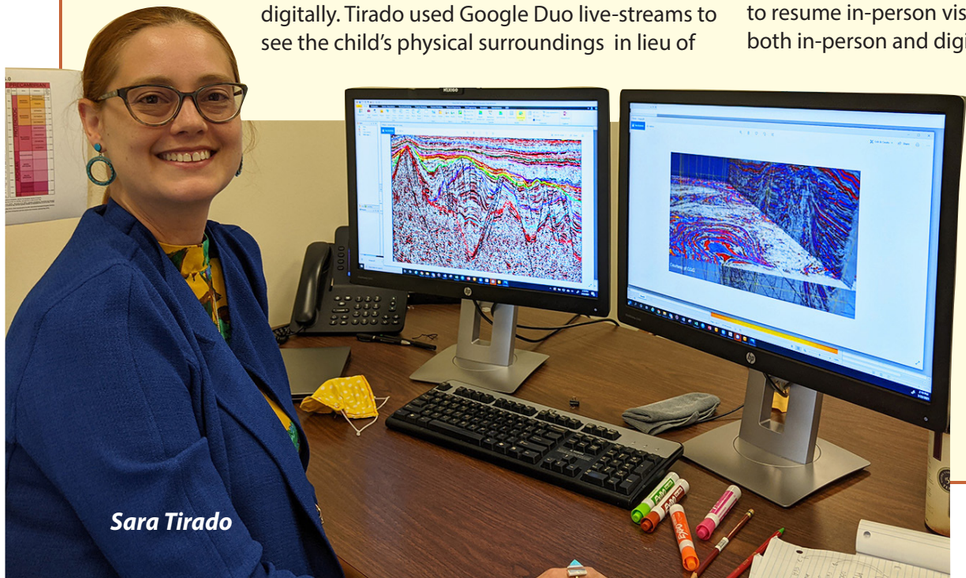
-- Katherine Wauters, staff writer

Court-appointed child advocate **Sara Tirado** helps those who cannot help themselves. She works up to 10 hours a month with foster children, who have suffered abuse or neglect, and were removed from their environment by court order. She is also a senior geophysicist at Ryder Scott.

Covid-19 made in-person visits with the kids impossible for a year, so Tirado kept up communications by connecting digitally. Tirado used Google Duo live-streams to see the child's physical surroundings in lieu of monthly visits.

"Normally, I visited the children wherever they were placed," Tirado said. "During the pandemic, it was a matter of calling. I tried to call more frequently, because calls were not as valuable as in-person visits."

She was delighted in March to receive the OK to resume in-person visits. Tirado plans to use both in-person and digital methods of contact.


Sara Tirado

She has worked as a child advocate for five years. For Tirado, the worst part of volunteering was waiting at the courtroom.

"You just waited and never knew when you were going to be called," she said. "The family court system is very

Please see More to Helping Foster Kids on page 13

Azerbaijan celebrates anniversaries of first oil well, petroleum institute

The first country to drill a successful oil well was Azerbaijan 175 years ago. The United States, with the iconic Drake well, was second by more than a decade.

Ryder Scott published a five-page article in *Reservoir Solutions* newsletter on the Bibi-Heybat well and the Azerbaijan oil industry in 2012 at https://ryderscott.com/wp-content/uploads/news-2012-sep.pdf.

"While the U.S. well was an industry maker, the earlier well in Azerbaijan had little effect," the article stated. "The Russian oil business fizzled until reforms were made."

Mir-Yusif Mir-Babayev, a professor at Azerbaijan Technical University, translated the history of the Azerbaijan oil industry and Bibi-Heybat well into English in 2002 and gained international recognition for the accomplishments of the Baku pioneers.

Mir-Yusif Mir-Babayev *(right), received an Honorary Oilman of Azerbaijan award from* ***Rovnag Abdullayev****, president at State Oil Company of Azerbaijan Republic (SOCAR) on Dec. 29, 2019.*

Wisdom applied

Last year was the 100th anniversary of higher petroleum education in the country. Azerbaijan launched the Baku Polytechnical Institute in 1920. After eight name changes, the institute is now the Azerbaijan State University of Oil and Industry.

"The decree establishing the institute was the most important event in the lives of the Azerbaijani people," said Mir-Babayev, who has a doctorate in chemical sciences. "They gained access to advanced technical education for the first time at the state level."

In 1993, the school changed its curricula into a more Western model, with its first bachelor and master degree graduates in 1999.

SPE student chapter information is at https://www.spe.org/en/chapter/5965.

The Bibi-Heybat oil field, rendered here around 1900, was the site of the first drilled oil well in 1846. Courtesy of Azerbaijan National Archives and Petroleum History Institute.

Virtual Webinars May to July

Ryder Scott plans to present three two-hour virtual webinars via Zoom starting next month. The firm will stream each prerecorded video feed on a schedule followed by a live Q&A between the speaker and audience.

For more information, please send an email to RSCConfHouston@ryderscott.com and put "Invite" on the subject line. Updates will be posted on the website at ryderscott.com.

Please see the following dates and agenda.

Tuesday, May 11 — Corporate Transformation

- Chevron Corp. Transformation and Vision — 45 min.
- Validation & Verification Process — 45 min.
- Case Example — 30 min.
- Q&A

Thursday, June 10 — Carbon Capture, Utilization and Storage

- Corporate Experience
- Assessing a CCUS project
- Case Example
- Q&A

Thursday, July 15 — GHG Management Facilitating Frameworks

- Code of Federal Regulation 40CFR98
- Global Reporting Initiative (GRI)

More to Helping Foster Kids – Cont. from page 11

frustrating. Some days you show up and they say, 'we've canceled.'"

Ironically, with the pandemic, good emerged from bad.

"The system became more efficient using Zoom to hold court proceedings," she said. "The online alternative allowed for more organized timing and less interruption to the day."

Tirado is a guardian ad-litem, which is a special advocate for a child or sibling group for the duration of a court case. Those cases are intended to end with permanent, healthy homes for the children.

"One happy endpoint is reunification with parent(s), or, in some cases, a joint conservatorship in which the parents or another caretaker share custody and decision-making," she said.

Family members, fictive kin, foster families, or non-relatives may also end up adopting the child or children.

"Being a guardian ad-litem is not for everyone. It is incredibly heartbreaking most of the time, and yet, you have real tangible things to help know you're making a difference," Tirado said. "Just be prepared. You're going to see and hear things that will blow your mind."

In Harris County (Houston), nearly 7,000 children were confirmed victims of abuse or neglect in 2020. As many as nine in 10 cases are unreported.

Tirado volunteers for Houston-based Child Advocates Inc., a 501(c)(3) charitable organization, which relies on volunteers and contributions to succeed.

"It's more important than ever to volunteer," she said.

Child Advocates has opportunities to volunteer for special events and outings for the children, to work in the office or to conduct fundraising activities.

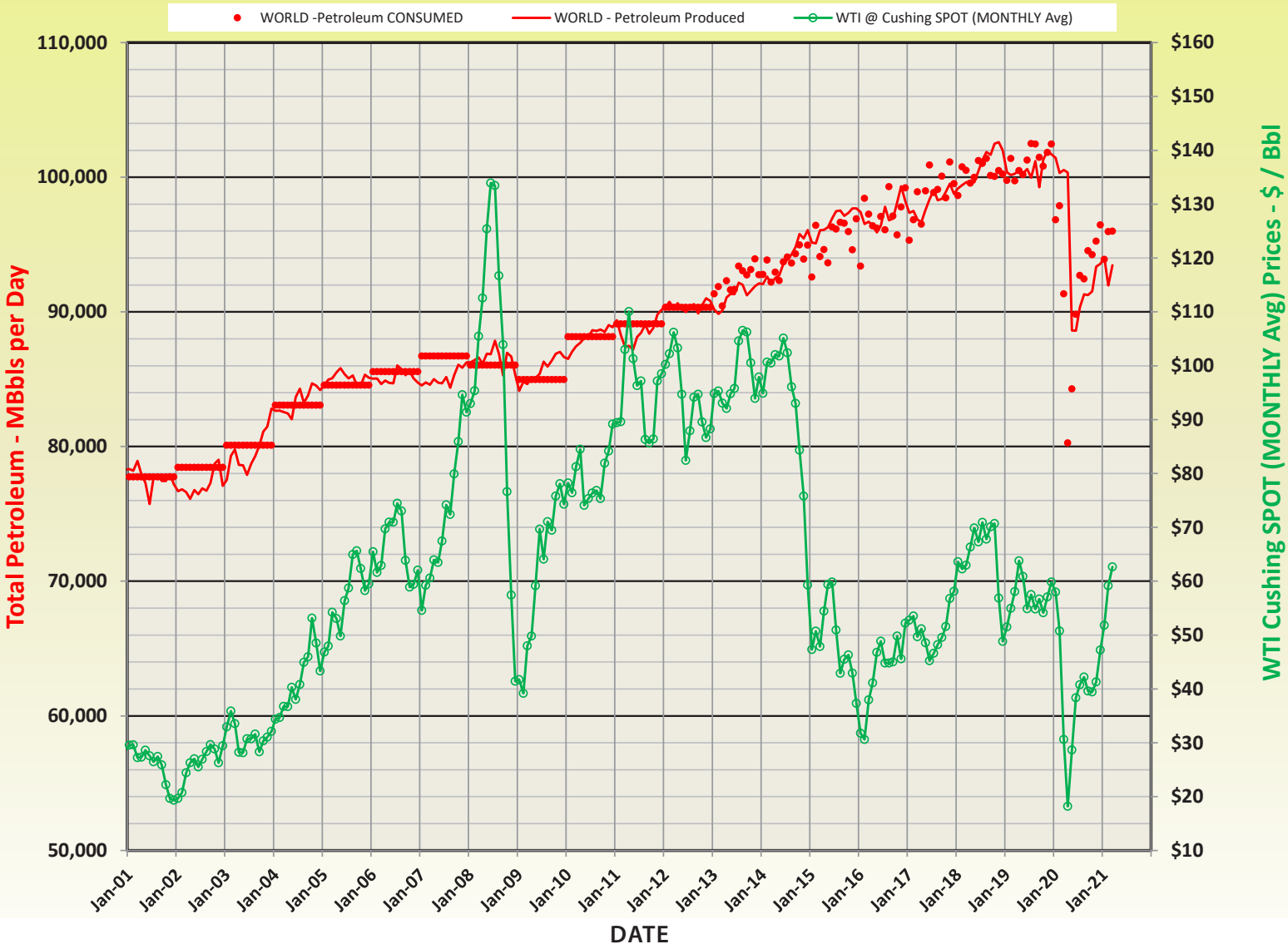
"It allows you to actively do something. It seems now justice and activism is just posting on your own social media. For me, it's important to actually get out and do something," said Tirado.

To donate or volunteer, contact Child Advocates or call (713) 529-1396.

WORLD Petroleum Produced & Consumed

(Includes crude oil, lease cond, NGLs, & Other Liquids [biodiesel, ethanol, liquids from coal, gas, & oil shales etc])

EIA Table 3a http://www.eia.gov/forecasts/steo/report/us_oil.cfm



Publisher's Statement

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Ryder Scott geothermal audit in oil and gas reserves software is newest wrinkle

Ryder Scott broke ground late last year, setting a company-first on a geothermal energy audit of reserves for a potential acquisition by client Cyrq Energy Inc.

The audit focused on production performance and was relatively similar to an oil and gas reserves audit of PDP (proved developed producing) reserves, said **Steve Gardner**, who performed the work. He is a managing senior vice president at the Denver office of Ryder Scott.

Early in a project, the most common approach to estimate geothermal reserves is the volumetric method. Later, when the evaluator has more historical data and wells, numerical modeling is frequently used.

Ryder Scott conducts thermal modeling with the CMG STARS simulator. Cyrq had built a reservoir simulation model, but wanted Ryder Scott to attempt using decline-curve analysis (DCA) for the audit, which is a very trusted technique for oil and gas producing wells.

In DCA or simulation, evaluators use historical performance trends to forecast future production. Evaluators start with an inventory of available data to decide on a forecasting method. Cyrq provided data on steam and water mass, total mass production, enthalpy, and wellhead pressures and temperatures.

Outside the box

To facilitate the DCA and economic calculations, Gardner and the Cyrq team decided to modify PHDWin, a full-featured commercial software program designed for the oil and gas industry.

Gardner said, "This was probably the first time anyone had attempted to forecast declining steam production with a standard reserves software," he said. "The workaround turned out to be similar to our normal approach for forecasting oil and gas. There were just different production streams and slightly different decline characteristics."

While not part of the project scope, it appeared that economic calculations would also be similar to what an evaluator sees in an oil and gas reserves project. Gardner indicated the potential to incorporate prices derived from electricity sales, operating costs, maintenance capital, and so on.

Some considerations during the audit also included depth, temperature, intensity of the heat source and rate of recharge and/or re-heating of the water.

"It is common for geothermal projects to outrun their heat supply either by withdrawing water faster than it is recharging

Please see Ryder Scott Geothermal Audit on page 11

Cyrq Energy Inc. produces from geothermal deposits in the Hudson Ranch field more than 100 miles east of San Diego in the Salton Sea area of California. Pictured are cooling towers emitting water vapor at the plant. Flashing of high-temperature, hyper-saline brine from the Hudson Ranch field results in a major buildup of iron-rich silica scale. Many fields use downhole scale-inhibitor injection to reduce wellbore scaling and associated clean out costs.

TABLE OF CONTENTS:

Dynamic duo: Oil/gas and geothermal

Greater capital discipline and mitigated project risk have leaned up the current E&P sector. As economics begin to line up post pandemic, industry has set its sights on getting back to the business of pumping $70-a-barrel oil and building up returns to investors.

Business as usual, though, may have a few obstacles this time around. A push from investors is driving industry to realize that oilfield capital is contingent on demonstrable ESG (environmental, social and governance) programs and records.

Case in point is Exxon Mobil Corp. Activist hedge fund Engine No. 1 flexed its muscles this year after bulking up on institutional investment, including pension-fund backing. The "little engine that could" bought big chunks of Exxon equity and last May, voted in board members aligned with ESG.

Oil and gas companies now face the real prospect of change from the inside out. With little choice but to comply, industry has to take a serious look at renewable resources, including offshore wind energy and increasing stakes in solar energy.

The sun beneath our feet

Perhaps the most natural fit for energy diversification is the extraction of heat from hydrothermal reservoirs where water in the host rock is heated by a high geothermal gradient in the earth's crust. Tapping into the earth's natural heat to power residences and businesses is the essence of geothermal power.

Geothermal, considered a niche industry, is often overlooked. It only accounts for 0.4 percent of net electricity generation in the United States, which produces the most geothermal electricity in the world: more than 3.5 GW or enough to power about 3.5 million homes.

"How Geothermal Energy Works," published by Save on Energy LLC, outlines three main types of geothermal energy plants – dry steam, flash steam and binary cycle.

Expansion Pipework at the Nga Awa Purua geothermal power station in Taupo, New Zealand. Courtesy Creative Commons by Geothermal Resources Council; Licensed under CC BY-NC-ND 2.0

Binary ORC plants

Binary cycle plants circulate hot subsurface waters or steam in closed-loop systems (similar to a radiator). Water/steam is pumped to a heat exchanger where it heats a second liquid — an organic fluid, such as isobutene, which boils at a lower temperature than water. The Save on Energy primer summarizes open- and closed-loop systems.

Closed-loop systems with power generation based on Organic Rankine Cycle (ORC) are making it possible to produce electricity from low-temperature geothermal resources less than 100º C.

This opens up vast opportunities worldwide for geothermal energy. ORC has generated more than 2.7 GW of installed capacity for more than 700 power plants worldwide.

Focusing on ORC, **Mariia Shmeleva** wrote "Geothermal Energy Production from Oil and Gas Wells," an MS-degree thesis at the Gubkin Russian State University of Oil and Gas in 2018.

The thesis summarizes in more detail the ORC technology used to maximize thermal energy from oil and gas wells.

"ORC power generation using low-temperature geothermal resources is one of the most common geothermal power generation technologies," she writes. "The extracted water from a well is pumped to the evaporator where it transfers its heat to the organic working fluid. Shell and tube heat exchangers are widely used.

The Raft River geothermal plant, constructed in 1979, was the first binary-cycle commercial power plant in the U.S. Courtesy Creative Commons by Idaho National Laboratory; Licensed under CC BY 2.0

The heated organic fluid boils and high-pressure vapor drives the axial flow or radial inflow turbine, which is coupled to a generator. So, mechanical work is converted into electrical power. Then organic fluid is cooled and condensed. From the condenser, it is pumped back … (as) the cycle repeats again."

Crossover potential

For oil and gas drillers, geothermal developments have good crossover potential.

"No one is better at digging holes than the oil and gas sector. Over the last century, the industry has perfected the art of extracting fossil fuels many miles below the surface. Its future, however, may be in digging for heat," stated climate reporter **Michael J. Coren** in an article published by *Quartz Media Inc.* this year.

For oil and gas personnel in transition, geothermal makes use of many of the same skills.

"The transition from oil and gas to deep geothermal is a big opportunity for a highly skilled workforce that operates the drilling platforms," **Igor Kočiš**, CEO of Slovakia-based GA Drilling, told *Rigzone* recently. "On the side of upstream, the jobs are the same or similar – drilling, casing, cementing, drilling muds, logging, reservoir, production, etc."

Bottom line in kWh

In the renewables world, geothermal is a fledgling unable to compete with solar and wind, as measured by lobbying budgets and political pull. Solar and wind energy have historically raked in higher subsidies and incentives than geothermal companies.

Solar and wind also are reigning in costs more rapidly than geothermal.

The latest report from the International Renewable Energy Agency recently reported that solar and onshore wind remain as the cheapest new energy sources. Solar photovoltaics (PV) shows the sharpest cost decline over 2010-2019 at 82 percent, followed by concentrated solar power (CSP) at 47 percent, onshore wind at 40 percent and offshore wind at 29 percent.

Electricity costs from utility-scale solar photovoltaic cells fell 13 percent year-on-year, reaching nearly 7 cents per kWh in 2019. Onshore and offshore wind both fell about 9 percent

Please see Dynamic Duo: Oil/gas and Geothermal on page 4

Dynamic Duo: Oil/gas and Geothermal – Cont. from page 3

year-on-year, reaching 53 cents per kWh and more than 11 cents per kWh, respectively, for newly commissioned projects. Costs for CSP, still the least developed among solar and wind technologies, fell 1 percent to 18 cents per kWh.

Costs for utility-scale geothermal energy are as high as 17 cents per kWh for greenfield developments in remote areas. Where the costs begin to become more interesting to the oil and gas sector is second-stage development of existing fields for a rock-bottom 4 cents per kWh.

Wind and solar are developing and using battery back-ups, enabling those industries to provide more reliable power generation whether the wind blows or sun shines.

Nevertheless, geothermal is the most reliable source of renewable energy during various base- and peak-load cycles for electricity. Geothermal has a vital role in the energy mix that powers electrical generating plants during critical periods.

"Over the last few years, a number of start-ups in the geothermal space have gained traction, such as Eavor Technologies, Fervo Energy, Sage Geoystems, and GreenFire Energy," stated **Katie Brigham**, a *CNBC* producer, in May. A video accompanied the summary.

The new ventures are not big companies, but have the financial backing of several IOCs (international oil companies).

Petroleum-geothermal mix

The cost of drilling geothermal wells is 30 to 70 percent of the total investment to establish an industrial plant. That has given rise to a renewed interest in repurposing abandoned oil and gas wells for geothermal purposes.

"Practically, however, it's not that straightforward," according to an article by **Irina Slave** this year in *OilPrice.com* that answers the question, "Can Abandoned Oil Wells Be Used To Generate Geothermal Power?"

"For starters, flow rates from such wells are much lower than from newly drilled geothermal wells," **Jamie Beard** told *Oilprice*. She is executive director of the Geothermal Entrepreneurship Organization at the University of Texas at Austin.

"Then there is the issue of heat: most oil wells are simply not hot enough to make sense if we are talking about electricity generation, said Beard. "Existing wells often suffer from well integrity issues that will make them ill-suited for a 20- to 40-year lifespan as a producing geothermal asset."

Another article this year considered the repurposing of abandoned oil and gas wells. **Matthew Veazy** at *Rigzone* interviewed **Karl Farrow**, CEO of the geothermal project development firm CeraPhi Energy Ltd.

"So, we shouldn't expect that a repurposed oil well will replicate the results you would expect from a purposely drilled geothermal well in a geyser zone in California," said Farrow. "However, consider the repurposing of oil and gas wells effectively as having pilot test wells or the wildcat already-drilled well – following from which you then have the ability to prove up a new commercial case to help decarbonize a business model on that site and, if commercial, you have scalability and can drill new wells specifically for the production and configuration you require."

Derrick at St. Gallen geothermal project. Courtesy Creative Commons by Kecko; Licensed under CC BY 2.0. Geothermal drilling rigs are indistinguishable from oil and gas rigs. St. Gallen in Switzerland was temporarily sealed in 2013 after a gas kick and earthquake, and is now used for research.

The politics of oil well abandonment will also influence the future of retrofitting for geothermal, as lawmakers and regulators erect hurdles.

In an *OilPrice* article last May, "How Canada Could Repurpose Oil Wells for Its Renewable Revolution," **Felicity Bradstock**, a freelance writer, examines the tradeoffs.

In the article, **Regan Boychuk** at the Alberta Liabilities Disclosure Project said, "It's a transparent attempt to pass this liability to someone else."

Bradstock points out that repurposing the wells in Canada "would effectively shift the clean-up burden from the government to private companies, taking away the cost to the taxpayer," which is estimated at $166 billion.

Watered out, not down for the count

In some cases, operators of mature oil and gas fields with high water cut can use produced water as a carrier of heat.

Industry has established hydrothermal projects with low-temperature energy recovery in several regions of the world. Potential candidates for this conversion are mature oil and gas wells with adequate exit pressures, surface temperatures greater than 135º C, 10,000 B/D total fluid-flow rates and water cuts of more than 50 percent. Conversion of heat to electricity is used to power the field or nearby host communities.

"A high bottom-hole temperature, reliable wellbore integrity, and large production capacity make a well a viable candidate for geothermal energy extraction. Because geothermal energy has caught the attention of the oil and gas industry, there is interest in modifying existing wells. …Abandoned oil and gas wells can play a vital role in geothermal resource utilization," stated the authors of "Potential for heat production by retrofitting abandoned gas wells into geothermal wells," a paper published by Public Library of Science, 2019.

Outside ring of fire

California is the epicenter in the U.S. for shallow, hot reservoirs suitable for economic generation of thermal energy. Sliding through the state is the "ring of fire" created by the interaction of the Eurasian, Pacific and Indian-Australian tectonic plates.

The ring enables California to be the No. 1 source in the world for electricity from geothermal energy. The Geysers in northern California comprise the largest dry steam field in the world.

Not every geothermal energy producer can be located in the ring of fire. Oil and gas companies looking at opportunities have no further to go than their own backyards, in some cases.

For instance, the deepest, hottest reservoirs in the Permian Basin are in the Delaware sub-basin, and are the focus of a well repurposing study by TGS, an energy data and intelligence company headquartered in Oslo, Norway.

The company published a technical article this year on oil and gas well data for use in geothermal prospecting.

"There is a vast resource of data and analyses utilized by the oil and gas industry that may be effectively repurposed for other industries, such as developing geothermal resources," the report stated.

Useful information includes oil and gas well performance and production data, well completion data and basin temperature data and models.

"Combining end of life economic data with well depth, producing formations, completion intervals, and maximum production rates within a stratigraphic framework offers value to companies interested in assessing alternatives to abandoning their assets," the TGS article stated.

TGS plotted decline curves of Delaware Basin production wells for comparative analysis of potential fluid flow rates to evaluate repurposing. The firm also built a temperature model.

Artificial hydrothermal reservoirs

Industry and government have collaborated in developing engineered enhanced geothermal systems (EGSs) that, in some cases, make use of oil and gas wells and technology.

The EGS concept is to extract heat by creating a subsurface fracture system and adding water through injection wells. Creating an enhanced, or engineered, geothermal system requires improving the natural permeability of rock, which is dependent on fractures and pore spaces between mineral grains.

In a dual-well system, an injection well pumps water into a thermal reservoir of hot, dry rocks. That opens natural fractures and creates new fracture networks and flow paths that intersect the wellbore. The increased permeability maximizes heat exchange and output.

A two-way circulatory flow system includes bringing steam to the surface through a production well. After the heat energy feeds into a turbine for electrical power, the leftover condensed water is collected and reinjected downhole.

"The implementation of enhanced (or engineered) geothermal systems, following the original hot dry rocks (HDR) two-well or doublet model, has been met with technical and economic challenges, lower-than-expected performance and limited public acceptance, as they typically require the 'engineering' of the reservoir by artificial stimulation to create the necessary heat exchange in the subsurface," stated a U.S. Department of Energy paper, "Assessment of Deep Geothermal Energy Exploitation Methods: the Need for Novel Single-Well Solutions," Volume 160, October 2018.

However, the energy landscape and politics have changed dramatically in the three years since the DOE publication. Energy providers are seriously assessing the scalability and profit potential of EGS.

For one, it makes it possible to tap into deep high-temperature reservoirs that are much more abundant than shallow hydro-geothermal energy sources, such as hot springs, volcanoes, geysers and other tectonically active areas.

Secondly, drilling-and-completion technology developed for shale plays is successfully used in geothermal projects. Most production wells have been vertical, but horizontal wells hold more promise. Geothermal projects can make use of

Please see Dynamic Duo: Oil/gas and Geothermal on page 6

A section of the Hellisheidi geothermal power plant complex. Courtesy Creative Commons by Martin V. Morris; Licensed under CC BY-SA 2.0. Hellisheidi, the newest and largest geothermal project in Iceland, is a flash steam plant that can generate 300 MW of power and 400 MW thermal.

Dynamic Duo: Oil/gas and Geothermal – Cont. from page 5

hydraulic fracturing developed and refined over the past 15 years to tap into tight oil and gas plays.

Shale plays have become proving grounds for staging repeatable "manufacturing" processes. Geothermal is poised to be scaled that way.

Some indirect evidence in models predicts multi-stage horizontal wells will experience early thermal breakdown along higher-conductivity fractures, and as such, will need intervention.

EGS can produce from a greater "inventory" of dry thermal reservoirs with wider ranges of porosity, permeability, fracture distribution and connectivity than conventional hydrothermal accumulations. Lower reservoir-risk profiles also reduce exploration-and-development uncertainties.

High heat

Three "classes" of fluid temperatures at the wellhead are high (>180º C), intermediate (100 to 180º C) and low (30 to 100º C). High-temperature geothermal resources generate energy for industrial power plants, while low and medium temperatures typically are used for small-scale local power and heat pumps.

The offshore oil and gas industry has developed high-temperature, high-pressure (HTHP) drilling, completions and downhole tools, which are essential in geothermal energy extraction.

This year, an article published in the *Journal of Petroleum Technology*, introduced the growing concept of applied HTHP technology for geothermal projects.

Judy Feder wrote the January article, "Geothermal Well Construction: A Step Change in Oil and Gas Technologies."

She stated, "The cutting-edge technological developments in geothermal are devoted to drilling into deeper, hotter and harder rock. Oil and gas expertise and know-how holds the key to cost reduction."

The service companies are taking the lead on this technical front.

"Numerous oil and gas service companies are contributing to game-changing capability and cost improvements in deep (especially horizontal) well construction, logging, and materials that enable completions in ultrahigh-temperature regions; high-temperature cement and well casing that increases long-term well integrity; research ... on different working fluids, such as water and supercritical CO^2 (sCO^2)—that is, above the temperature at which it is neither gas nor liquid, but has properties of both," wrote Feder.

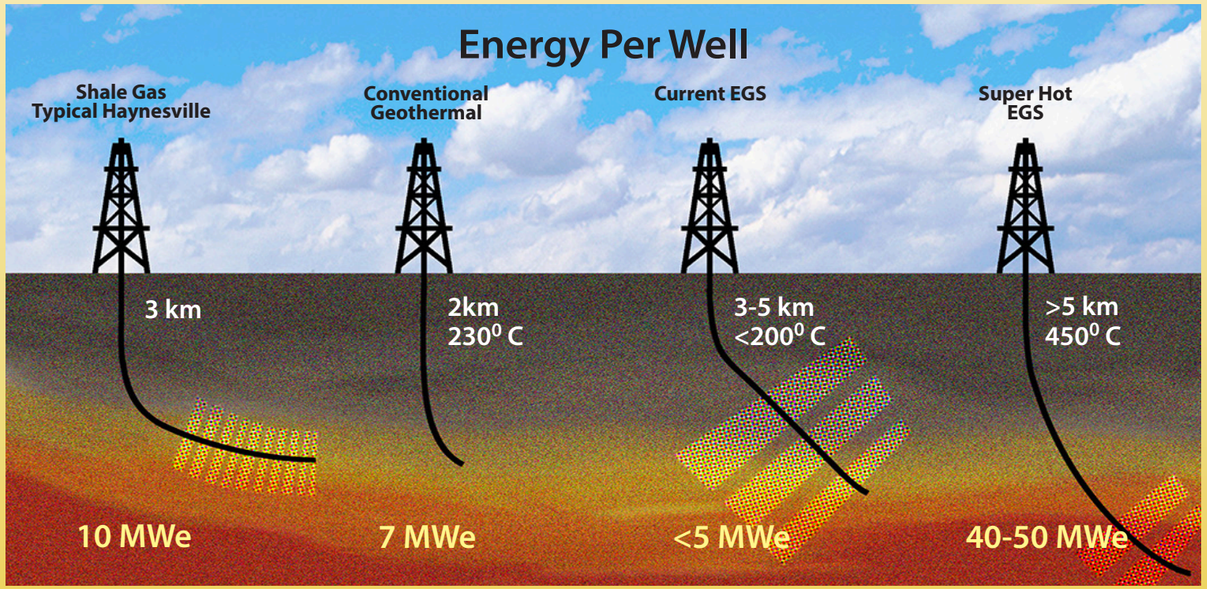
Hotter rock may be the future of EGS. Japan, Iceland, Mexico, Italy and New Zealand are investigating the development of very high temperature geothermal resources greater than 400º C using EGS methods.

A technical paper by **Susan Petty**, et al., "Technology Needs for Superhot EGS Development," explores the potential of harnessing the thermal energy of superheated rocks in brittle-ductile transition zones some of which are 5- to 6-km deep.

The paper, presented at the 45th Workshop on Geothermal Reservoir Engineering last year at Stanford University, delves into three areas of short- and long-term development needs: Wellfield development, reservoir characterization and creation, and long-term resource management.

The following chart from the paper shows relative megawatts (MW) of energy per well.

Please see Dynamic Duo: Oil/gas and Geothermal on page 9



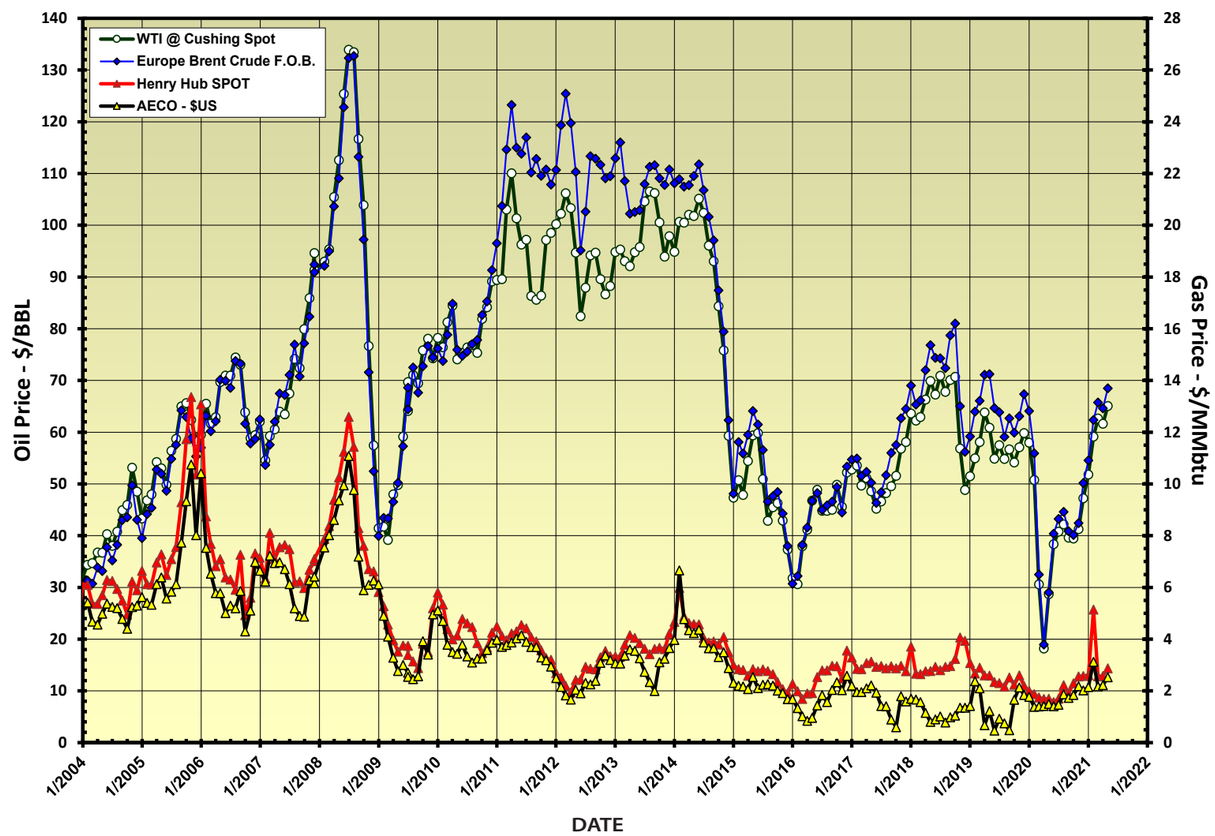
Why is earth hot inside?

The heat of earth's interior comes from a variety of sources. These include the heat contained in the objects that accreted to form earth, and the heat produced when they collided. As earth grew larger, the increased pressure on earth's interior caused it to compress and heat up. Heat also came from friction when melted material was redistributed within earth, forming the core and mantle.

A major source of earth's heat is radioactivity, the energy released when the unstable atoms decay. The radioactive isotopes uranium-235 (235U), uranium-238 (238U), potassium-40 (40K), and thorium-232 (232Th) in earth's mantle are the primary source. Radioactive decay produced more heat early in earth's history than it does today, because fewer atoms of those isotopes are left today (Figure 3.14). Heat contributed by radioactivity is now roughly a quarter what it was when earth formed.

– Article courtesy of Karla Panchuk permitted under Creative Commons license (CC BY-NC-SA 4.0).

Price History of Oil & Gas Benchmarks in U.S. Dollars



Published, monthly-average, cash market prices for WTI crude at Cushing (NYMEX), Brent crude and Henry Hub and AECO gas.

E&P companies work to get ahead of GHG standards

The "greening" of the petroleum industry is accelerating now as oil and gas companies showcase their plans to reduce greenhouse gases (GHGs).

In that vein, Ryder Scott presented a two-hour webinar May 11. The participants presented industry efforts to cut upstream emissions, manage data on sustainability and independently validate renewable energy processes.

Julie Mulkerin

Julie Mulkerin, general manager - energy transitions strategy at Chevron Corp., kicked off the webinar with the company's "market-based approach" for decreasing emissions and increasing returns.

Chevron aims to reduce upstream CO_2 emissions intensity by 40 percent for oil and 26 percent for gas under a 2016-to-2028 schedule. The company also plans to reduce the much more harmful GHG, methane, by 53 percent under that schedule. Chevron plans to lower emissions from flaring by 66 percent, said Mulkerin.

The company said it has invested $1 billion in carbon capture, utilization and storage (CCUS).

Carbon pricing is the primary policy tool for Chevron to achieve GHG emission reduction goals while increasing returns. There are two main types of carbon pricing: emissions trading systems (ETS) and carbon taxes. An ETS – sometimes referred to as a cap-and-trade system – caps the total level of greenhouse gas emissions and allows those industries with low emissions to sell their extra allowances to larger emitters.

"Establishing a High Quality Sustainability Data Management Program," was presented by **Adrian Wain**, carbon advisory & solutions lead at Underwriters Laboratories (UL).

Consumers universally are familiar with the UL logo and fine print inconspicuously etched on the back of electrical products, stating that the device meets safety standards.

"Underwriters Laboratory has 120 years of experience testing and inspecting products for safety," said Wain. "We don't have the same recognition for ensuring safety through a stable climate, removal of toxic substances and other activities."

UL-inspected products are used at oil and gas drilling sites, refineries and on- and offshore facilities. The company tests and certifies sustainability of products and services. UL also furnishes software platforms that help companies track and measure environmental, health and safety (EHS) management and sustainability data.

"The cost of capital is based on sustainability measures," said Wain. "Companies that do not conform to sustainability-related metrics and standards may not be able to do business with potential partners."

He also pointed out that companies that report poor results in sustainability performance management run the risk of being sold off.

UL has restructured, so the advisory services unit, which handles decarbonization and renewables, is separate from certification services. Ryder Scott and UL plan to assist oil and gas companies and collaborate to validate and verify emissions targets and the diversification of energy resources, said **Dean Rietz**, CEO at Ryder Scott.

Herman G. Acuña, executive vice president at Ryder Scott, presented "Third-Party Validation and Verification Process," which summarized the firm's GHG management services and renewable energy consulting services.

Herman G. Acuña

"GHG is not a fad. A GHG statement is a factual, objective declaration made by the responsible party," he said. "The company should be capable of consistent measurements against suitable criteria by a validator or verifier."

Acuña drew a distinction between validation and verification. Validation involves the evaluation of the reasonableness of assumptions, limitations and methods that support the statement on future outcomes. Verification is evaluating a statement of historical information to determine if it is materially correct and conforms to criteria.

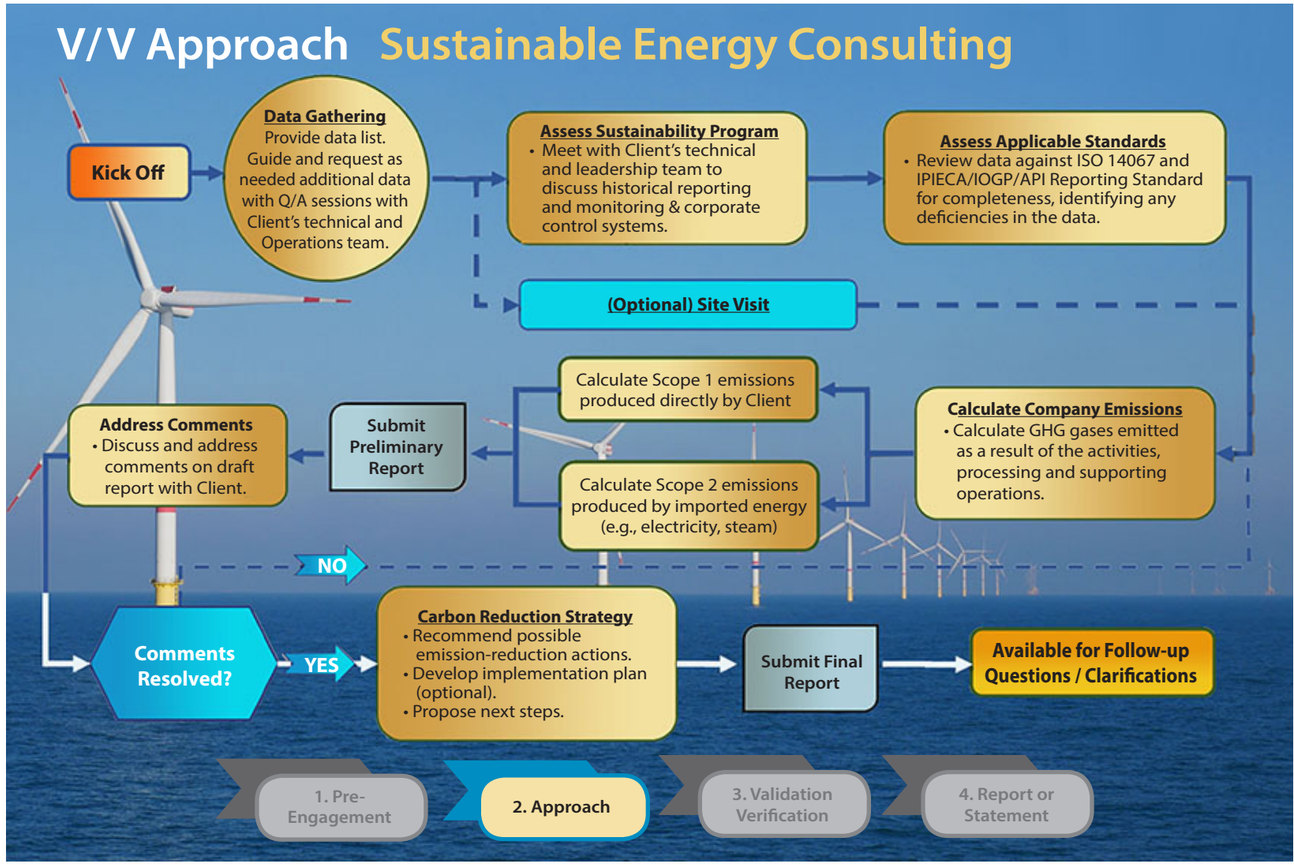
Acuña showed a flow chart (next page) of the validation and verification (V&V) approach, starting with data gathering and ending with submission of the final report and follow-up questions and clarifications.

"Ryder Scott provides added assurance that GHG forward-looking statements are consistent with activities associated with reserves and resources disclosed to the public and financial markets," said Acuña.

Ryder Scott estimates GHG emissions through direct measurement, stoichiometric calculations and emission factors and follows guidelines of the International Petroleum Industry Environmental Conservation Association, International Association of Oil & Gas Producers and American Petroleum Institute.

V&V engagements vary in scale and scope. Establishment of the evaluation boundaries and inventories is key to the success of the evaluation.

For more information, contact Acuña at herman_acuna@ryderscott.com or **Sandeep Khurana**, head advisor–integrated services, at sandeep_khurana@ryderscott.com.



Dynamic Duo: Oil/gas and Geothermal – Cont. from page 6

Petty, et al., state that water at 450º C has four times the energy density of water at 200º C while the energy conversion efficiency is 2.5 times that of ORC. Energy density is the amount of energy stored in a given system or region of space per unit volume. Energy conversion efficiency is the ratio between the useful output of an energy conversion machine and the input, in energy terms.

"While the U.S. DOE is focused on EGS at lower temperatures, the international geothermal community understands the economic value of producing supercritical fluid," stated Petty, et al.

No looking back

SPE is co-sponsoring the second part of a high-temperature well cementing workshop Oct. 7 to 9 in San Diego.

The event will be an opportunity for the petroleum and geothermal industries to share knowledge on the latest technical innovations, advancements, and best practices.

In addition to well completions events, SPE has presented the drilling side at the SPE/GRC (Geothermal Resources Council) Workshop, "High-Temperature and Corrosion in Drilling and Production - Exploring Geothermal and Oil and Gas Synergies," in March 2017.

The new name of the GRC professional association is Geothermal Rising.

If the pundits are right, the upstream industry will have to embrace change to survive long term. Undoubtedly, geothermal fills in all the blanks for the petroleum industry and its future. Crossover potential includes leveraging oil and gas technology developed over more than 75 years to scale up geothermal development.

SPE-AAPG merger talks reflect industry downturn, pandemic

The Society of Petroleum Engineers and American Association of Petroleum Geologists announced May 25 that they are exploring a potential merger.

SPE said, "A new, combined organization is in response to an evolving energy sector and challenging Covid-impacted market environment."

Revenue has been down dramatically for virtually all associations.

"Many associations depend on net revenue from in-person events to make up much of their annual budgets," said the American Society of Association Executives (ASAE).

Neither SPE nor AAPG cited financials in their press releases, but public disclosures point to declining sources of income. Tough times for the petroleum industry and its affiliated organizations began well before the pandemic.

Over the past five years in the industry, profit margins narrowed, stock prices tumbled, EBITDA and revenues plummeted, write-offs proliferated and investors suffered heavy losses. As industry goes, so does its organizations.

The latest blows were social distancing and quarantines that effectively canceled face-to-face events -- traditional cash cows for SPE and AAPG.

SPE

SPE hemorrhaged $3 million in total net losses from operations during April 2019 to March 2020, right before the global shutdown.

At press time, the society had not published its consolidated statement of financial position ending March 31, 2021.

During the pandemic, SPE had to resort to virtually hosting its two most attended events -- annual meeting and offshore technology conference.

The latest published IRS Form 990 for 2018 shows that SPE took in more than $20 million in revenues from meetings, which accounted for 44 percent of almost $46 million in total revenues. Meetings were the No. 1 income item for SPE and AAPG.

The SPE 2019-2020 annual report shows proceeds of $13.4 million for "meetings and training courses," a big drop from the earlier Form 990 amount.

AAPG

The latest financial statement published by AAPG accounted for a period from July 1, 2018 to June 30, 2019. Conferences and meetings accounted for $7.4 million of operating income from $16.3 million in total income. The result is AAPG took in 45 percent of its revenue from conferences.

A year before that, sponsored events were relatively an even bigger moneymaker for AAPG. In its 2018 Form 990, revenue from meetings was $9.6 million or 56 percent of total revenues of $17 million.

The latest published information shows that AAPG cut its losses to $18,600 during 2018-2019. For the previous fiscal year, the association posted a shortfall of almost $600,000.

Beyond the numbers

In a joint statement, the organizations said, "The industry relies on subsurface geoscience and engineering teams rather than siloed disciplines. The new organization would reflect this interdisciplinary approach."

Synergies would reduce operational overlap and redundancy, thereby increasing efficiency and return on investment for members.

"Many of our stakeholders have made it clear that they do not have the resources to support as many professional organizations going forward," said **Tom Blasingame**, 2021 SPE president.

Income taken in by SPE has been about three times that of AAPG, so the merger would not be between equals, which raises some questions on how the organizations would structure the union. On paper so far, losses by SPE are heavier proportionately and in absolute terms than those of AAPG.

Soon-to-be-released annual reports will reveal more about the fiscal management and financial accounting of the two organizations.

An SPE-AAPG steering committee will seek input from each organization's membership and expects to present recommendations to its respective governing bodies late this year or early next year.

The ASAE stated that some mergers necessarily require that the stronger association not overplay its dominance, while the weaker association must be realistic and not seek more from the deal than is fair or achievable. Neither SPE nor AAPG are as strong as they once were, but if the current rebound in the industry has staying power, both stand to get back on their feet separately or together.

With hopes for a fading pandemic, both associations are poised to welcome back the crowds that disappeared. SPE has scheduled its annual technical conference and exhibition Sept. 21 to 23 at the Dubai World Trade Centre. For more information, go to https://www.atce.org/.

AAPG has already started a merger of annual meetings with the Society of Exploration Geophysicists. They have planned the first of two joint annual meetings to be held at the Colorado Convention Center in Denver from Sept. 26 to Oct. 1.

The event will mark the first time the two organizations have jointly hosted their annual conventions since 1955.

Rick Fritz, AAPG president, said, "It represents a strategic response to shifting industry conditions. I think our members and clients will enthusiastically embrace the benefits of one annual meeting to connect with fellow geoscientists."

For more information, go to https://ace.aapg.org/2021.

Ryder Scott promotions announced

The board of directors promoted the following personnel:

- **Dave Haugen** to managing senior vice president
- **Jean LiuHalfe** to senior vice president
- **David Garcia, Sandeep Khurana, Mark Nieberding** and **Hugo Ovalle** to vice president
- **Yao Tian** and **Jeremy Xia** to senior engineer
- **Hanna Ottoson** to engineering analyst

Ryder Scott Geothermal Audit – Cont. from page 1

or by causing the heat source to cool in some manner," said Gardner. He added that injected water, in some cases, is not given enough time heat up before being produced again.

"Voidage in the reservoir can lead to problems, too," said Gardner. "Considering the depletion of enthalpy, an operator could theoretically shut in a field for a decade or more, and potentially recover the heat supply."

No SPE-PRMS equivalent

Gardner said the standards for estimating, categorizing and reporting geothermal reserves are not as well developed as those in oil and gas.

"That has been identified as a gap that needs to be addressed to cultivate common understanding within the sector and to compare opportunities and companies," he said.

In the audit, Gardner classified resource volumes as conservative, mid-range and aggressive.

In the oil and gas sector, SPE has been the organization responsible for issuing industry guidelines for classifying and categorizing petroleum reserves. No geothermal organization has developed an industrywide, robust system to estimate resources and reserves.

That is not to say that the geothermal industry hasn't used certain reserves definitions that may gain acceptance.

"Geothermal reserves are defined as quantities of thermal energy which are expected to be recovered from known reservoirs of a given date forward. The reserve is part of the resources which is currently known and characterized by drilling, geochemical, geophysical and geological evidence and could be legally extracted," stated a 1978 USGS geothermal resource **assessment** by L. J. Patrick Muffler.

SPE, through its members, has presented and discussed the concept of geothermal reserves, but the society has not proposed a reserves system. The U.S. SEC has "punted" on this.

In 2019 mining guidelines, the SEC states, "In a change from the proposed rules, the adopted definition of mineral resources does not include geothermal energy. We have been persuaded to exclude geothermal energy from the definition of mineral resource due to the lack of consensus regarding how to regulate the disclosure of geothermal energy resources."

Four established geothermal resource classifications are summarized in what is now a five-year-old paper from Ametis Institute, **"Geothermal Resource Classifications: Can We Talk the Same Language?"**

This paper provides an overview of "thin" standards from the Australian Geothermal Energy Association and Australian Geothermal Energy Group, Geothermal Energy Association, United Nations Framework Classification and Indonesian National Standard.

As established as they are, the systems do not approach the breadth and depth of SPE-PRMS guidelines or SEC regulations on oil and gas.

Engineer joins RS upstream/midstream integrated services group

Alexander MacKay joined the Ryder Scott Houston office in June as a project engineer. He will work in the upstream/midstream integrated services group.

Alexander MacKay

MacKay previously worked at Granherne, a consulting subsidiary of KBR Inc., for six years. He conducted energy planning and due diligence studies.

MacKay also executed feasibility and front-end engineering studies for onshore and offshore developments as a pipeline engineer, subsea engineer and field development planner for an LNG terminal.

He worked on various front-end and desktop studies of on- and offshore properties in Ghana and Senegal-Mauritania in West Africa. That included supporting the BP Tortue project from concept definition through FEED with project engineer roles, including subsea, umbilicals, risers and flow-lines engineering.

After that, he worked with Lixia Capsia Gestionis LLC to analyze the planned development of infrastructure for an LNG facility in Morocco. The project included an energy-planning component for supporting infrastructure development. MacKay also evaluated the development of the Alumar aluminum smelter in Brazil.

In addition, he conducted a feasibility and front-end study for the Vaalco Etame offshore project in Gabon. For that assignment, MacKay developed reconfiguration concepts for replacing the current FPSO with an FSO and platform extension.

He has a BS degree in mechanical engineering from the University of Texas at Austin and is a member of the American Society of Mechanical Engineers. MacKay was recognized this year as a member of the founding class of the OTC Emerging Leaders program.

Publisher's Statement

Reservoir Solutions newsletter is published quarterly by Ryder Scott Co. LP. Established in 1937, the reservoir evaluation consulting firm performs hundreds of oil and gas reserves studies a year. Ryder Scott multi-disciplinary studies incorporate geophysics, petrophysics, geology, petroleum engineering, reservoir simulation and economics. With 119 employees, including 80 engineers and geoscientists, Ryder Scott has the capability to complete the largest, most complex reservoir evaluation projects in a timely manner.

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RESERVOIR SOLUTIONS

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Ryder Scott launches price differential freeware

Ryder Scott has designed and released its *Reservoir Solutions* price differential program for Excel. The download link for the HC Price Xplot program and the other 13 freeware applications is posted on the website.

Public issuers apply differentials to benchmark prices, adjusting them for quality — including gravity and sulfur content — and for energy content, transportation fees, and regional and local differences. The adjusted prices are used to prepare annual reserves filings with the U.S. SEC.

HC Price Xplot is designed to assist the professional engineer easily and quickly to determine price differentials, which are the differences between "hub" or reference prices and the prices actually received at the wellhead. The template assists in determining the expected wellhead price based on any given benchmark hub price.

"It is important to remember that for determining differentials, you should only use monthly average hub prices and monthly average wellhead prices in the analysis," said **Fred Ziehe**, advising senior vice president. "Do not mix daily prices and monthly averages for received prices while determining the differential."

Users apply differentials to reference prices, such as the SEC 12-month average price, NYMEX price, average differential to the indices derived from monthly index prices and lease operating statements, etc.

Price differentials are sometimes referred to and based on the following:

1. The "delta difference" between wellhead price and hub price
2. Ratio of wellhead price to hub price
3. More rigorous method in which the actual received prices are cross-plotted against the hub price, with a "best-fit" line drawn to represent the equation for the differential. This is sometimes called the dynamic differential method.

Today, thousands in the industry the world over use the 13 Excel add-ins.

The differential analysis will appear as an equation for the "best-fit" line (below) through the data on the cross-plot of Field Prices vs. Benchmark Prices. This equation represents the relationship of the differential between field price and hub price, and can be entered into ARIES.

Please see Ryder Scott launches price differential freeware on page 2

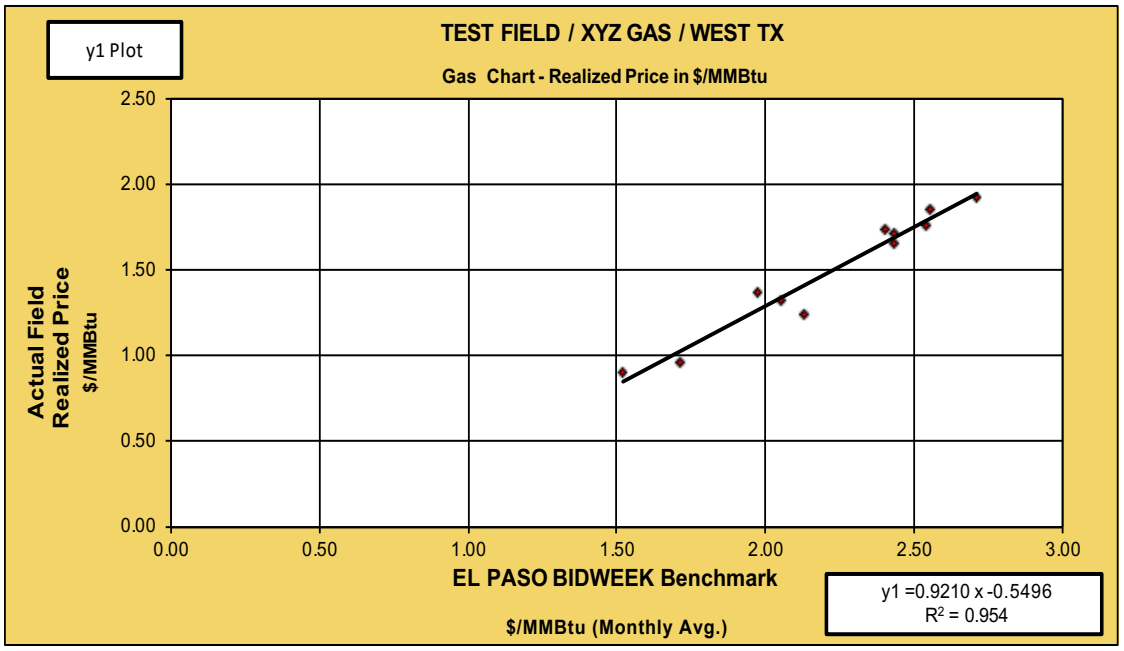


TABLE OF CONTENTS:

Ryder Scott launches price differential freeware – Cont. from page 1

HC Price Xplot easily determines the differential for all three of those methods with minimal effort and data.

"Keep in mind that if you are using an escalated pricing forecast, you may find that the differential will vary at low prices vs. higher prices. In that case, the best-fit line from the cross-plot may prove the most useful method," said Ziehe.

For support, contact **David Garcia**, vice president, at David_Garcia@RyderScott.com or by phone at +1-713-651-9191, ext. 5509. Additional support is provided by Ziehe at Fred_Ziehe@RyderScott.com or by phone at +1-713-751-5576.

More than 20 years ago, Ryder Scott released its first *Reservoir Solutions* freeware program and by 2006, the number of petroleum engineering and geoscience applications had grown to 10. Today, thousands in the industry the world over use the 13 Excel add-ins.

Reservoir Solutions user manuals are included in all Excel add-ins. All posted freeware programs produce presentation-quality, on-screen views and printer-friendly, hard-copy output.

Ryder Scott also distributes USB drives with the freeware from its booth at the SPE-ATCE and NAPE events.

Editor's Note: *Ryder Scott does not guarantee or warrant the accuracy or reliability of the Reservoir Solutions software and disclaims its fitness for any particular purpose.*

Acknowledgements: *Many thanks to Ziehe and Bob Paradiso, vice president, for their invaluable contributions in making this program an excellent, user friendly product.*

Office 365 "fix" necessary to display RS freeware template in Excel

Reservoir Solutions freeware downloaders on Office 365 have reported problems with loading and displaying the engineering menus. After installation, the menus normally appear on the add-ins tab of the Excel ribbon, but not for Office 365 users.

The following procedure may solve the loading problem: By default, the start screen is the first screen of Excel to display when the program is opened. For users who see the start screen displayed on startup, turn it off. The start screen blocks the auto-run procedure that creates the engineering menu.

Steps to fix problem: In Excel, go to File, then Options to display the Options Dialog Box. It defaults to the General category. Scroll down to the last item under Start Up Options, and uncheck the box for "show the start screen when this application starts." Click OK and restart Excel.

The procedure may not work in every case. For assistance, please contact **David Garcia**, vice president, at David_Garcia@RyderScott.com.

Note: Templates or workbooks created in previous versions of Reservoir Solutions software are not compatible with current versions.

Third-party assurance of ESG set to grow, says E&Y

©ricochet64/123RF.COM

Ernst & Young released a YE 2020 U.S. oil and gas benchmarking study on Aug 30, and part of its focus was on ESG disclosures. The report analyzed the industry's 50 largest publicly traded E&P companies.

"ESG and sustainability have become essential to attracting capital and creating long-term value for all stakeholders. Interestingly, very few companies in our study — only 16 percent — are providing third-party assurance over ESG metrics. Due to a lack of standardization and companies following various frameworks, the importance of third-party assurance to investors is going to grow," the report stated.

The U.S. SEC is starting to consider disclosure requirements and standards in ESG reporting by public companies.

"ESG independent certification is becoming more important now that the SEC has also questioned the reliability of the ESG reports," said **Herman Acuña**, executive vice president at Ryder Scott, who heads up the firm's third-party ESG validation and verification services.

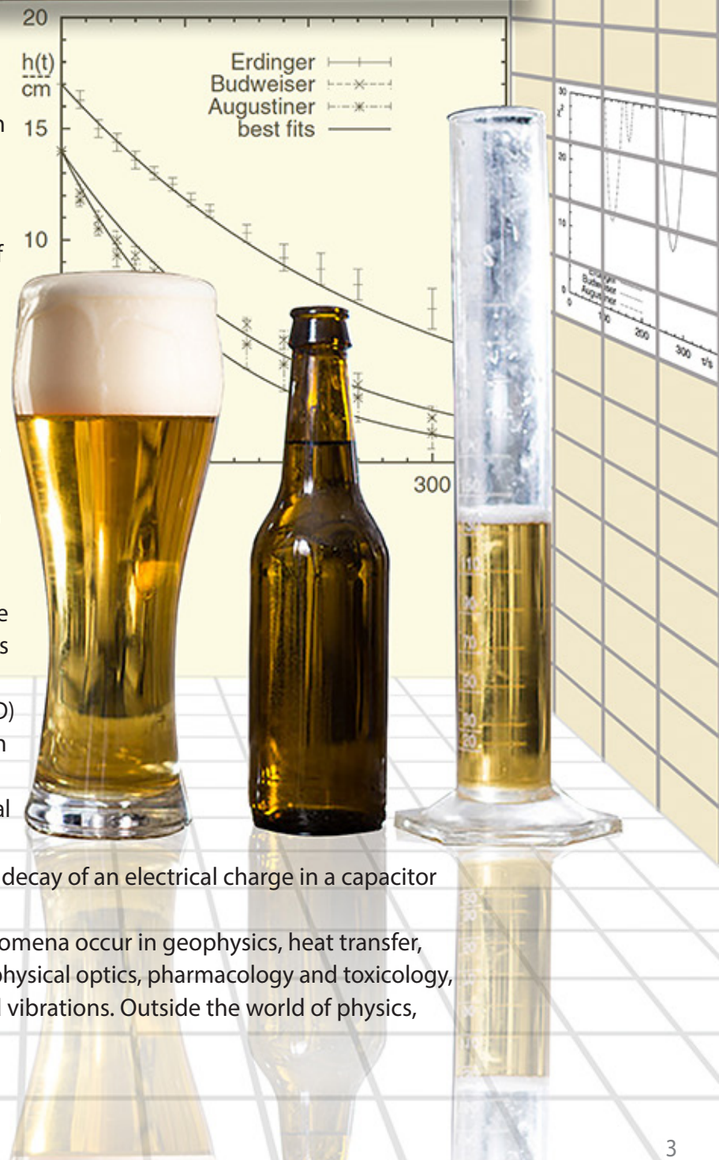
At YE 2020, more than three-quarters of the companies published an ESG or sustainability report. Of the studied companies, ESG goals were most often identified for environmental topics (53 percent), rather than goals for social (33 percent) or governance (10 percent).

"Some have advocated that the (SEC) commission rely on the work of one or more external third parties to devise and maintain updated ESG disclosure standards and then incorpo-

Please see Third-party assurance of ESG on page 13

Oneness in nature: Beer foam, oil production and the universe

$$h^{th}(t) = h(0)\left(1 - \frac{t}{T}\right)\theta(T - t)$$



What do end-stage oil production and beer foam have in common? They both exponentially decline.

Twenty years ago, students at the Ludwig Maximilian University of Munich demonstrated exponential decay of volumes of beer froth. They measured the height of the "head" for several brands of beer.

Arnd Leike, at the university, designed the experiment and wrote a paper.

In the oil industry, another term for exponential decline is terminal decline. For tight wells, it bolts on to the Arps hyperbolic model as the exponential tail. Petroleum reserves engineers also use a "stretched" exponential production decline (SEPD) model to estimate future production from tight, fractured formations.

Surprisingly, decay in an electrical charge is an analog for SEPD. The model is based on the exponential decay of an electrical charge in a capacitor under a constant external load.

Other exponential-decay phenomena occur in geophysics, heat transfer, chemical reactions, luminescence, physical optics, pharmacology and toxicology, radioactivity, thermoelectricity and vibrations. Outside the world of physics,

Oneness in nature on page 13

Ryder Scott, government and E&P companies work together to attain success in T&T

1936
First employee of Ryder Scott, Donald T. May, analyzed cores brought back from T&T by founder Harry M. Ryder.

1972 to 1987
Evaluated 22 oil and gas fields using an intensive geologic approach in estimating the volumetrics.

1973 to 1981
Performed gas-deliverability and reserves studies of a license area offshore the east coast.

1978
Performed extensive study of all offshore gas reservoirs on the east and west coasts.

1980 to 1981
Evaluated gas fields offshore the east, southeast, west and north coasts for the Ministry and National Energy Corp.

1982 to 1994
Performed several independent studies for the government as it pursued a strategy of monetizing T&T gas reserves.

1995
Conducted an independent determination of gas reserves and resources for the National Gas Co.

1998
Conducted integrated field development studies of several fields in the Gulf of Paria.

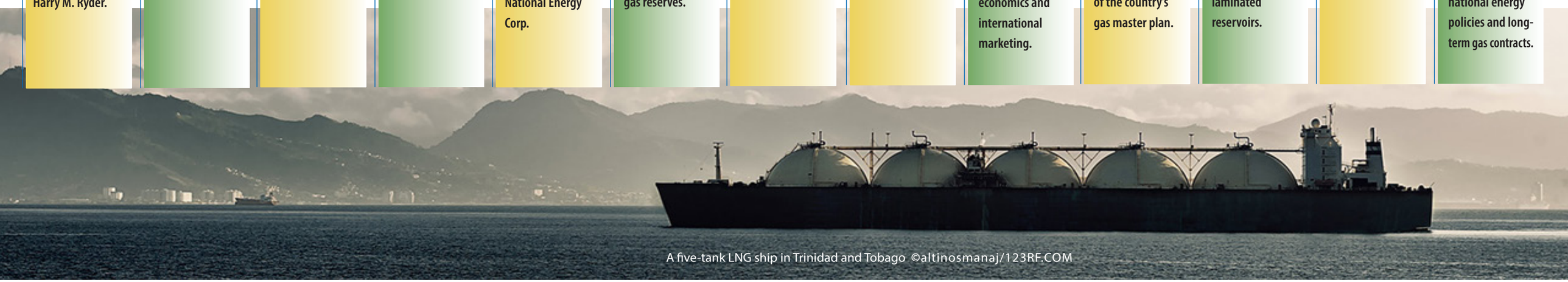
2000
Evaluated gas volumes, commercial structures of Atlantic LNG Co. projects, including economics and international marketing.

2001 to 2003
Conducted countrywide deterministic and probabilistic evaluations of 100 fields as part of the country's gas master plan.

2005 to 2007
Audited gas resources and reserves. Evaluated complicated petrophysical data of the thinly laminated reservoirs.

2008
Began a country-wide evaluation of the petroleum reserves and resources of the oil fields.

2008 to present
Conducted countrywide evaluations of offshore gas reserves. T&T uses reports to develop national energy policies and long-term gas contracts.



A five-tank LNG ship in Trinidad and Tobago ©altinosmanaj/123RF.COM

Trinidad and Tobago has many positives to celebrate over the last several reserves audits, replacing 100 percent or more proved reserves and C1 contingent resources. Those volumes are represented in the country's technically recoverable resources (TRR) from 2016 to 2019.

TRRs are those quantities of petroleum producible using current available technology and industry practices, regardless of commercial or accessibility considerations. C1 volumes have the same level of technical certainty as proved reserves but have one or more commercial or accessibility constraints.

At a press conference, **Herman Acuña**, executive vice president at Ryder Scott, said, "Most of the gains came from successful exploration of deepwater blocks."

EOG had success with the Mento and Osprey East exploration wells and BHP had deepwater success with the Bele, Boom and Tuk exploration wells.

In 2019, operators drilled the largest number of exploration wells in the past 20 years at 16, a record that was last equaled in 2001, stated **Christian Welsh**, Ministry of Energy and Energy Industries, in an SPE technical paper this year.

Steeped in history and geology

Ryder Scott history with T&T began 85 years ago, a year before the firm was incorporated in Pennsylvania. In 1936, Ryder Scott's first employee, **Donald T. May**, developed chip-coring analysis using core samples taken from unconsolidated sands in Trinidad. Using that innovative technique, May was able to analyze porosity, permeability, saturations and other properties from a single plug of sand.

Decades later, Ryder Scott evaluated 22 oil and gas fields for Amoco Corp., National Energy Corp. and the government from 1972 to 1987. The firm used an intensive geologic approach in estimating the volumetrics, including generating structure and isopach maps for every pay sand in every field.

Today, the reservoirs of interest still exhibit a high degree of geological complexity, and are highly faulted with multi-layered pay zones.

Deji Adeyeye, vice president, recently made a presentation on the T&T work, and said, "The complexity of the subsurface leads to a large number of reservoir data records and a significant amount of geology work underpinning the gas reserves estimates, which are based on volumetrics, material balance (P/Z) and performance."

As data began accumulating, Ryder Scott geologists saw the opportunity to integrate a geographic information system (GIS) with its mapping, so in 2017, the project began. GIS technology has advanced capabilities in spatial analysis and visualization of subsurface data. Ryder Scott set up ArcGIS as its GIS.

Brett Gray, senior vice president and geologist, said, "Initially, it was partial fact finding and digging through Ryder Scott archives to find missing pieces of data that the ministry had not collected from the operators themselves."

"With GIS, we can create, manage, analyze and generate maps. GIS links spatial with non-spatial data," said Gray.

He uses Microsoft applications Power BI and the Power Query base function in Excel with ArcGIS.

"The power in these apps is they allow you to quickly extract, transform and load data into common data tables that can be pushed into the GIS project," he said. "It allows me to create match tables, normalize operator names and remove typos in a quick, efficient manner vs. going through every spreadsheet in every year and table to ensure all those pieces are normalized."

Ryder Scott is working on using more open source database types.

"This will help with future implementation and allow us to implement cross-platform support," said Gray. "We can load information from ArcGIS into Spotfire. I've got a Spotfire dashboard set up and you can click a field and it will provide map information, locations, etc."

Welsh stated in his paper that, "the Ministry of Energy and Energy Industries has and will continue to manage the hydrocarbon resources with the aid of independent petroleum consultants to assist in keeping the public aware of important developments in the oil and gas sector and to guide government policy in the development of the country's hydrocarbon resources."

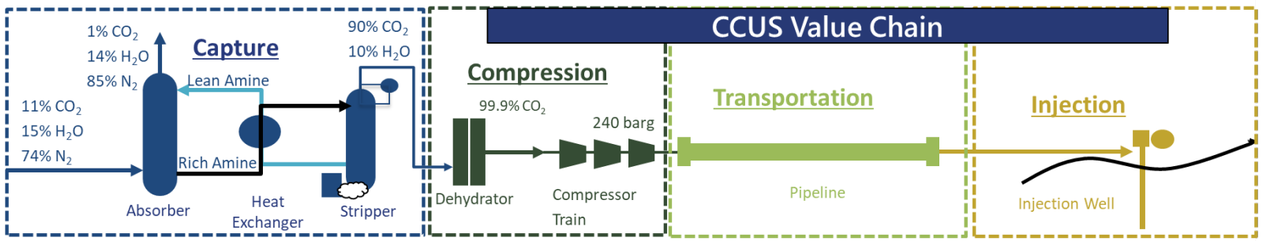
The SPE paper, "20 Years of Independent Oil and Gas Audits: The Trinidad and Tobago Story," SPE-200985-MS, is available at onepetro.org.

Carbon Capture, Utilization and Sequestration (CCUS) Value Chain

Limiting global temperature increases to 1.5 °C by 2050 will require an additional 5,635 MTPA (million metric tonnes per annum) of carbon capture capacity to meet the climate target set by the Intergovernmental Panel on Climate Change (IPCC). As of 2021, 39 MTPA of deployed carbon capture capacity exists worldwide, with 43 MTPA of full-scale projects currently in various stages of development. The striking difference in available vs. required carbon capture capacity shows the market is ripe for new CCUS projects.

These projects in development are concentrated mostly in the U.S., Northern Europe, and China, and are driven by carbon price incentives. The facilities are strategically located in industrial belts based on carbon sources and proximity to suitable reservoirs or formations. Nevertheless, CCUS economics can be challenging, making it necessary to understand the different segments of the CCUS value chain to bring projects to fruition.

Figure 1.0 depicts a case study for post-combustion carbon capture from a coal power plant. The process involves capture of 1.4 MTPA of CO_2 from flue gas from a 240-MW turbine. The supercritical-state fluid is transported via an 82-mile pipeline and injected into a well at an Enhanced Oil Recovery (EOR) project.



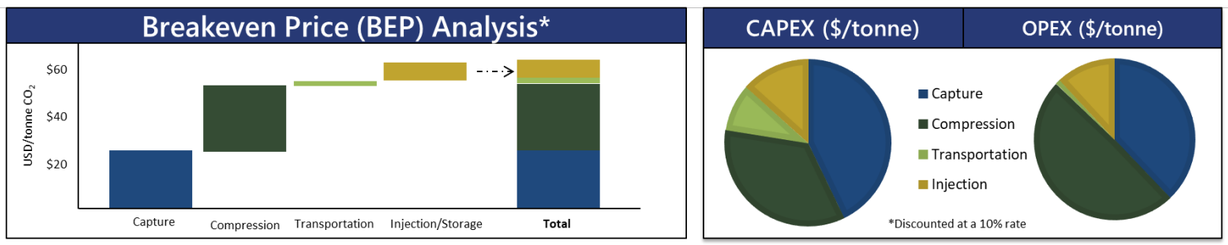


Figure 1.0: CCUS Value Chain and Project Economics

The economics also are shown on Figure 1.0. A vertically integrated project connects the value chain segments — capture, compression, transportation and injection — and results in a breakeven price of $65 per tonne of CO_2. That is a 10% rate of return on the investment. The equivalent price of CO_2 reflects the benefits in incremental oil recovery in EOR projects and related carbon capture tax credits. The capital expenditures (CAPEX) and operating expenditures (OPEX) in the value chain indicate that capture and compression, respectively, are the main contributors to the costs.

Academic and industrial jargon have inconsistent terms to describe the capture configuration, and show the location of CO_2 capture and the technology used to separate and generate the pure CO_2 stream. Although configuration and technology are interrelated, Figure 2.0 depicts the processes and equipment organized by capture and separation configurations and their typically associated technologies.

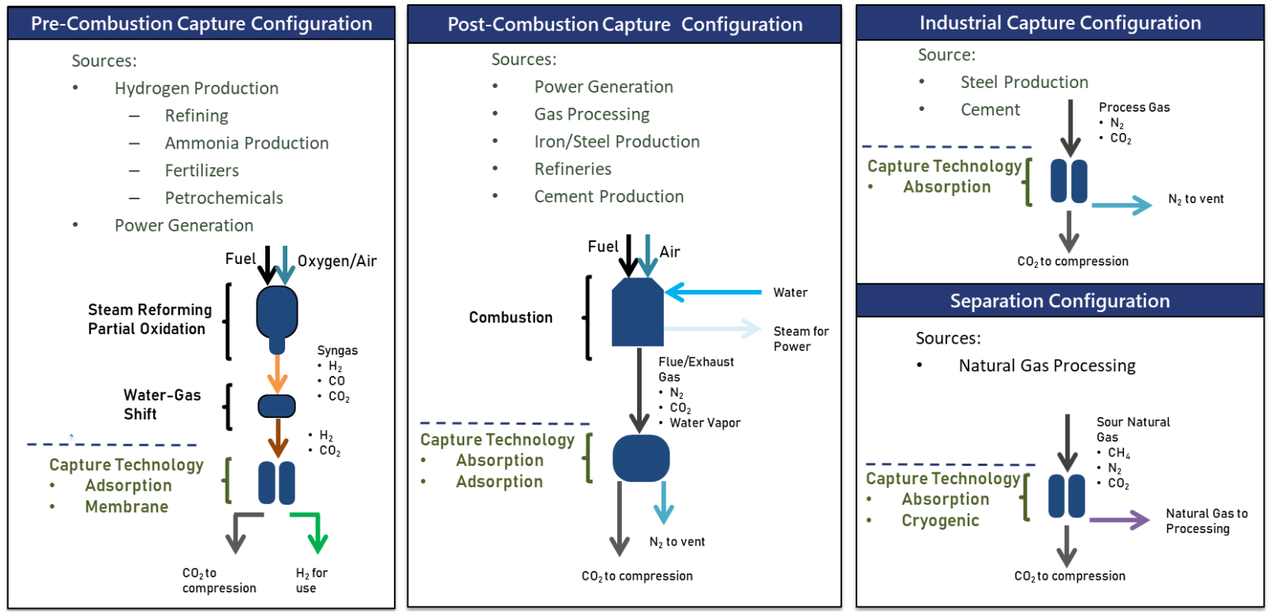


Figure 2.0: CO2 Capture: Configurations and Typical Associated Technology

The capture configurations are as follows:

- **Pre-combustion** is normally utilized during hydrogen-generation processes that include steam reforming or partial oxidation. Because of the high volumes of hydrogen generated, pre-combustion capture can be tied to refining, ammonia and fertilizer production and petrochemical manufacturing.
- **Post-combustion** makes use of a capture unit located after the combustion process. It separates CO_2 from a flue gas stream, as in the earlier example.
- **Industrial processes** generate CO_2 through the manufacturing chemistry. Steel and cement production emit significant amounts of CO_2 as a direct result of process chemical reactions.
- **Separation capture** removes CO_2 from reservoir gas streams.

The most common configurations in use today are pre-combustion and separation, mostly because of hydrogen manufacturing in ammonia and fertilizer production and gas processing when reservoir CO_2 concentrations are high.

The major capture technologies are as follows:

- **Absorption** is the most commercially mature carbon capture technology and consists of a liquid solvent, usually amine-based, which selectively absorbs CO_2 out of a gas stream in an absorber column. Recent advancements in absorption have focused on optimizing the solvent or process configuration.
- **Adsorption** is commonly used in conjunction with the pre-combustion configuration and uses a solid sorbent instead of a liquid solvent. CO_2 is adsorbed onto the sorbent packing in a column until saturation, where the sorbent is regenerated by manipulating the column temperature (Temperature Swing Adsorption (TSA) or pressure (Pressure Swing Adsorption (PSA). The latest advancements in adsorption have focused on improving the sorbent material and shape of the packing.
- In **membrane separation**, a thin membrane selectively lets certain gas species (the permeate) across, while the remainder of the gas cannot cross the membrane (retentate). Membrane separation is promising based on startups and pilot plants with small-scale success, but has not yet been proven to scale-up.
- Finally, **cryogenic separation** is a physical process that manipulates stream temperature to remove CO_2. Cryogenic separation has only been attempted at a pilot scale. With no upscaling or technical advancements, the technology remains non-commercial.

Depending on the distance of capture-to-market location and volumetric requirements, CO_2 can be transported in

Please see Carbon Capture, Utilization and Sequestration on page 8

Carbon Capture, Utilization and Sequestration – Cont. from page 7

different physical states. In the gas phase, CO_2 has lower density, and higher capacities that require larger pipeline diameters. For instance, Kinder Morgan transports CO_2 in gas phase from basins in Colorado to the Permian requiring relatively large-diameter pipelines. Supercritical and dense phase CO_2 exhibit higher densities closer to those of liquids so more CO_2 can be transported with a smaller diameter pipeline. However, high pressures are required to achieve supercritical or dense phase CO_2, thereby requiring additional compression and greater pipe-wall thickness. Further compression to injection pressures can require significant energy: the back end of a high-pressure compressor can reach 3,500 psi. Design considerations influence initial CAPEX requirements, and include a number of compressor stages and a dehydration package. The energy requirements to operate the compressors dictate OPEX, which is typically higher for low CAPEX. As always, tradeoffs must be studied to arrive at an optimal cost for the compression segment of the value chain.

As of 2018, only 5,000 miles of CO_2 pipelines existed worldwide and we anticipate the CO_2 midstream market will increase rapidly in the near future to accommodate the requirements of large-scale CCUS. Repurposing of existing oil and gas pipelines rather than constructing new CO_2 pipelines is a possibility to reduce cost. When comparing CO_2 pipelines to oil and gas pipelines, key differences stand out. CO_2 forms carbonic acid in the presence of water, which is highly corrosive to steel. Therefore, it is necessary to dehydrate the CO_2 stream to high purity using a TEG (tri-ethylene glycol) system before it enters the pipeline. Internal corrosion protection is used depending on the pipeline design life and CO_2 purity. It is also important to maintain operating conditions within a certain pressure and temperature to prevent phase transition.

Injection of CO_2 began commercially in 1972 and is considered technically mature. CO_2 requires corrosion-resistant materials in various well components. For example, piping, valves and wellheads may require Stainless Steel 316 for corrosion resistance. Tubing requires Glass Reinforced Epoxy (GRE)-lined carbon steel, Internally Plastic Coated (IPC) carbon steel or another Corrosion Resistant Alloy (CRA). Additionally, a supercritical pump may be required to pressurize the CO_2 to injection pressure, or miscibility pressure if EOR is considered.

In addition to being utilized for EOR, CO_2 can be stored for long-term sequestration in depleted oil and gas reservoirs or deep saline formations. Most long-term storage projects today inject CO_2 into saline formations, but many planned projects in the near future will store CO_2 in depleted oil and gas fields. The depleted fields must be evaluated for CO_2 storage capacity considering pressure requirements, potential leakage pathways, reservoir integrity and the optimal configuration of injection wells. Finally, storage requires a robust monitoring, reporting and verification (MRV) plan per 40 CFR 98.440 from the U.S. EPA.

For storage capacity certification, the SPE approved the CO_2 Storage Resources Management System (SRMS) in 2017.

Besides optimizing each value chain segment, we reviewed potential capture concepts for multiple natural gas processing plants located in a region shown in Figure 3.0 on opposite page.

The development includes seven (7) plants that process more than 10 Bscfd of natural gas, with one processing acid gas with a significantly higher H_2S and CO_2 content. The compressed CO_2 is then distributed back to the fields for EOR. In the development, one extreme is an individual capture case for each gas processing facility with its own carbon capture plant getting CO_2 from the flue gas generated from onsite power as well as an individual compressor station. At the other extreme is a single hub wherein all CO_2 from the flue gas is captured at one central location, with the exception of the acid gas plant, which transports a pure stream of gas-phase CO_2 to the central compressor station. A single hub is significantly cheaper at \$36/tonne CO_2 compared to \$44/tonne CO_2 for the individual capture. Within that range, the company considered numerous cases of mixed hubs for a phased approach to reduce the initial capital expenditure.

This case study proves that taking advantage of economy of scale and phasing development are effective ways to make a CCUS project economical. It also shows the importance of applying the hub concept to capture, compress and transport CO_2 to various locations for EOR. This conclusion applies equally to regional collaborative CO_2 storage hubs.

Figure 4.0 summarizes breakeven price reduction avenues we have discussed in both case studies.

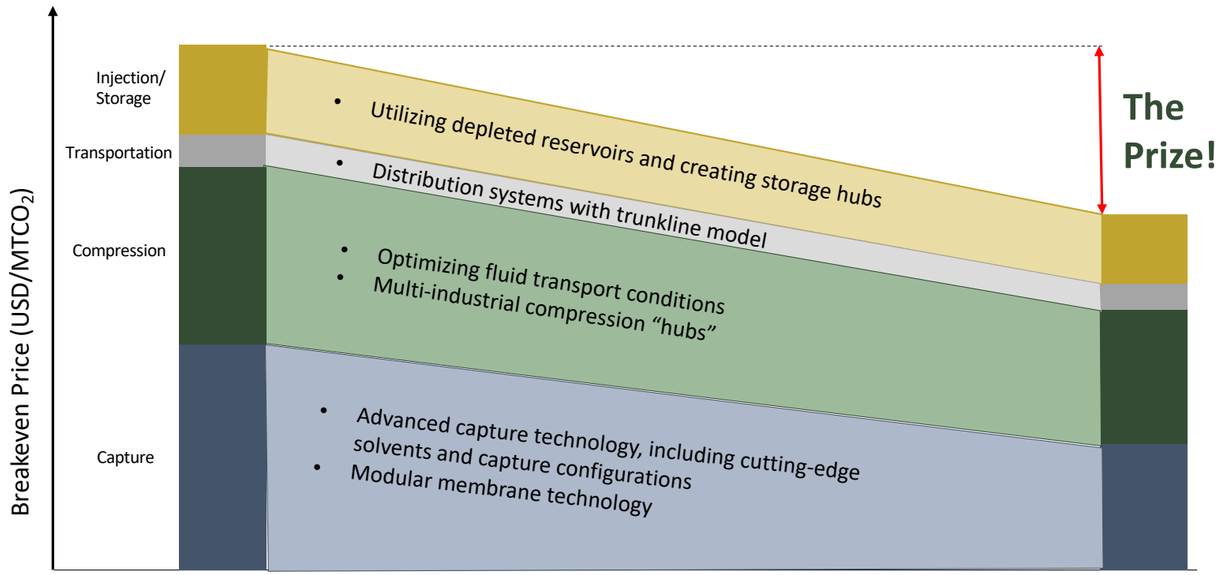


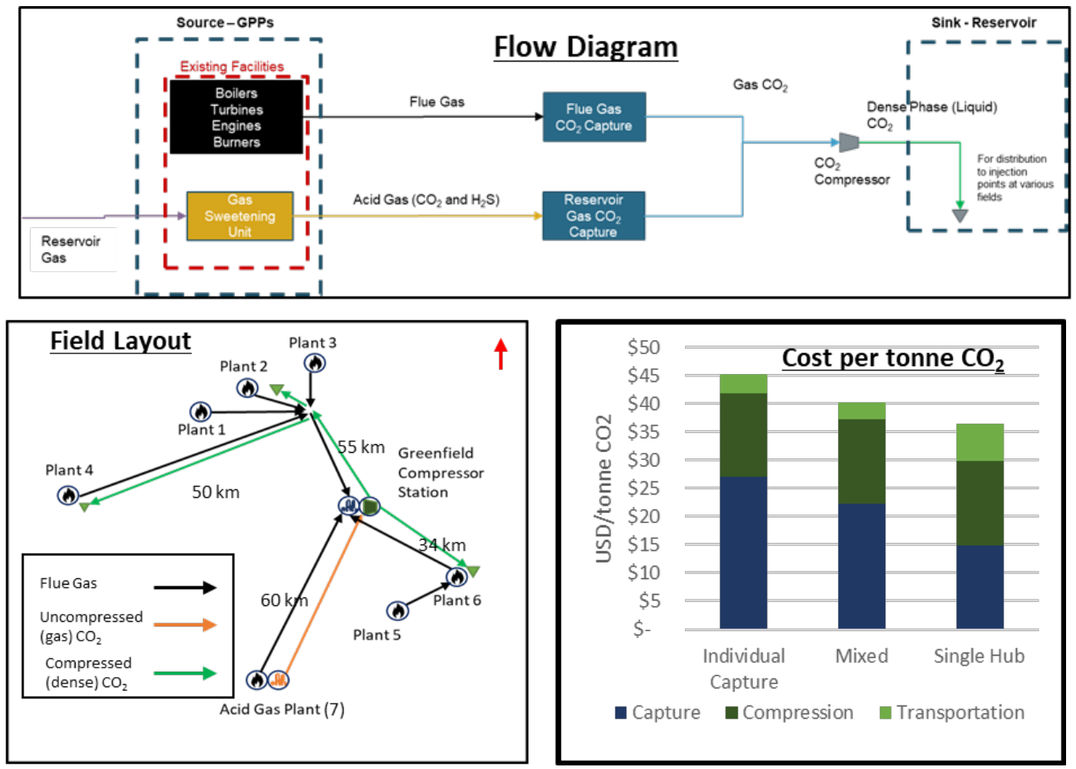
Figure 4.0: Breakeven Price Reduction

Restating the opportunities to reduce the breakeven price are as follows:

- For injection and storage, identify and select formations to create strategic storage hubs with optimal injection plans to reduce costs.
- For transportation, the biggest way to reduce costs is to optimize pipeline lengths or operating conditions, or to use a trunkline model. Alberta Carbon Pipeline has done the latter with an operating facility that gathers carbon from a couple of different facilities and transports it in one pipeline (trunkline) downstream for injection.
- For compression, opportunities to reduce costs are evident in hubs, commercial and public/private partnerships and optimization of fluid transport conditions.

Please see Carbon Capture, Utilization and Sequestration on page 13

Figure 3.0: Regional Development



Reservoir engineering expertise important in CCUS projects

Miles Palke

Miles Palke, managing senior vice president at Ryder Scott, presented "Greenhouse Gas — The Role of the Petroleum Engineering Consultant," at a July 15 company-sponsored webinar over Zoom.

He discussed the subsurface aspects of carbon capture, use and storage (CCUS); what a traditional reservoir engineering firm can provide; and how CCUS fits in with the Ryder Scott sustainable energy consulting practice.

Palke said that the Ryder Scott CCUS subsurface services include the expertise of drilling engineering for well design and cost estimates, engineering for completion design and stimulation and production engineering for vertical and inflow performance. Ryder Scott offers a nodal analysis package to clients that can be helpful for vertical flow.

Palke cited the firm's strength in evaluating and designing field development plans to enhance oil recovery through miscible CO_2 floods.

This includes estimating reserves, evaluating reservoir performance and infill drilling results, reviewing surface facility design for CO_2 re-injection compression projects, optimizing CO_2 flood management and calculating cash-flow economics.

Ryder Scott has evaluated most of the Permian Basin CO_2 floods.

"A lot of fields don't have prior histories of CO_2 flooding, so we have to bring in analogs," he said. "We have a big database of existing CO_2 floods we've studied and have dimensionless curves built for this. This can be done pattern-by-pattern or on a larger basis."

"We also have a strong background in natural gas storage. This is the process of using older reservoirs to hold natural gas produced in other places, and to withdraw the gas at required rates for peak shaving or seasonal needs," said Palke.

Ryder Scott underground gas storage services share technical features of potential GHG sequestration projects. Underground storage can include salt-mined caverns or porous media, such as retired oil and gas fields and aquifers. Ryder Scott assists clients in developing gas storage reservoirs through the use of reservoir simulation.

On subsurface gas storage projects, he stressed analysis of injection well construction, including metallurgical issues, and vertical well performance curves.

"We have to look at what it's going to take to make wells that can withstand the pressures required to inject gas at the required rates into the storage reservoirs," said Palke.

Understanding the inflow performance of injectors for a given bottomhole pressure and how much gas can be injected at what rate are key issues to tackle.

"There may be potential issues with containment of injected GHGs in subsurface media, which can be porous sandstone or carbonate, salt caverns or depleted oil reservoirs," said Palke.

Other subsurface factors include aquifer displacement and integrity and size of the trap. An effective trapping mechanism is necessary to prevent upward migration of oil and gas or GHGs through the reservoir rock.

Palke cited PVT properties of GHGs and miscibility pressure. "Gas injection has to reach a certain pressure to achieve a full EOR benefit. Mixing other gases with CO_2, such as separator gases from the field, will change miscibility and effectiveness. Not only will it change how the injectant reacts with in-situ fluids, it will change how much CO_2 is ultimately stored in the reservoir," he said.

Palke pointed out that tax credits and any EOR benefit can make or break project economics.

Ryder Scott has several geoscience tools and combines those with PVT analysis and material balance to estimate the size of the "tank," and more importantly, to assess the soundness and integrity of the reservoir.

The reservoir engineering approaches ensure that CO_2 stays in the ground and does not migrate out of the known accumulation.

Palke said the reservoir simulation group has full capabilities for each reservoir engineering tool cited in the chart below, including compositional reservoir simulation.

Ryder Scott CCUS Subsurface Services

Keeping CO_2 in the Subsurface

- Total Reservoir Engineering Approach inclusive of:
  - PVT Analysis
  - SCAL Analysis
  - PTA/RTA for Estimation of Reservoir Properties
  - Volumetric Analysis
  - Material Balance Analysis
  - Analytical Performance Modeling for Enhanced Oil Performance Estimation
  - Compositional Reservoir Simulation

A compositional reservoir simulator calculates the PVT properties of oil and gas phases once they are fitted to an equation of state (EOS). The simulator uses the fitted EOS equation to predict movement of the phases, and their compositions, in the reservoir.

"How many wells? What is the development planning process? You'll have to build it around a certain volume to be handled on an annual or other time basis," said Palke. "You're going to need to know how many wells it will take to get those volumes in the ground within the required time frame as well as some sort of contingency on top of that."

Ryder Scott uses pressure-transient analysis (PTA) and rate-time analysis (RTA) to estimate permeability and mobility, which in turn, provide answers on what injection rates to expect.

"Typically, when we're looking at the enhanced recovery benefit from a CO_2 flood, we're looking at dimensionless recovery curves that plot a tertiary recovery factor of oil vs. CO_2 or other gas injectants," said Palke. "We like to look at the prior performance of the reservoir, analyze how it's performing under CO_2 flooding to get a sense of performance and then build a dimensionless curve that will project it going forward."

Ryder Scott generated the model below that shows a reservoir used for gas storage. It was originally a gas discovery produced down until it was depleted and then the reservoir was converted to gas storage by injecting a working storage volume of gas into it.

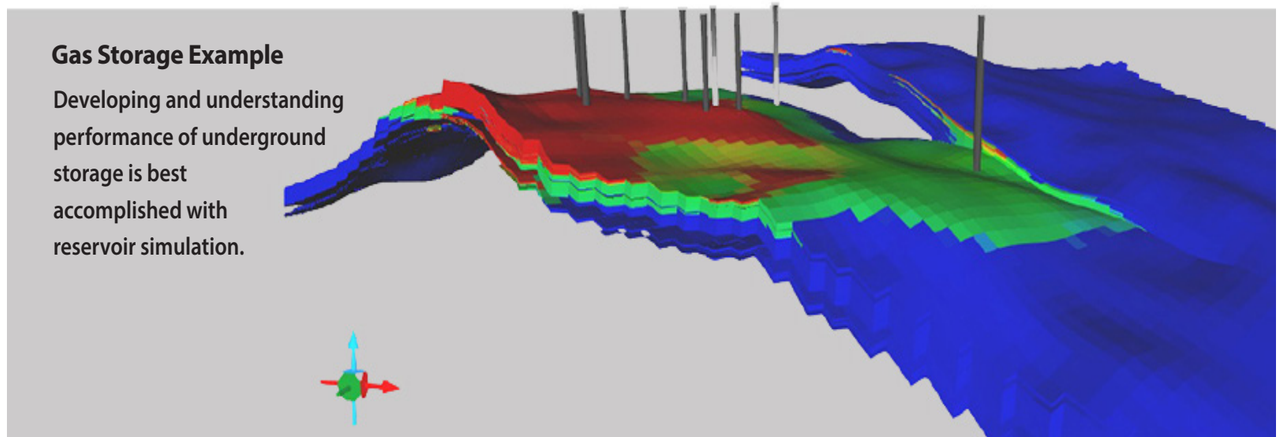
"This is an interesting problem because the reservoir simulation showed the original gas accumulation in this high area in red. However, the reservoir actually has a fault separating it from an upthrown fault block in blue and that fault dies out to the south," he said.

Over injection cycles, gas had been pushed down to a spill point (where the green meets the blue.)

"Everywhere you see color is gas that has migrated out of the original location of the gas accumulation. The simulation model was helpful to demonstrate what migration had happened in the past. The example shows a typical kind of problem when storing gas in the subsurface in a gas-saturated phase," said Palke.

If the trap has any faults/flaws, the simulation can calculate how much gas has been lost and how much would probably be lost in future storage cycles for optional development scenarios.

For more information, please contact Palke at miles_palke@ryderscott.com.



Two reservoir engineers join Ryder Scott

Freddy Alvarado

Freddy Alvarado and **Carlos Alvarez** joined the Ryder Scott Houston office recently, bringing with them more than a half century of combined reservoir engineering experience at IOCs, NOCs and service companies.

Alvarado is a senior petroleum engineer with more than 20 years of diverse experience in reservoir engineering and economic analysis. His competencies include nodal analysis, integrated production modeling, material balance and production analysis and forecasting.

Most recently, Alvarado was a senior reservoir consultant with Miller and Lents Ltd. He evaluated reserves and analyzed the economics of U.S. and international projects. Alvarado also audited the reserves of deepwater projects in the Gulf of Mexico and provided technical advice to the operator. He implemented tools to evaluate production-sharing agreements.

Before that, Alvarado worked at Chevron Corp. starting in 2015, as a reserves advisor and intellectual property manager. He provided petroleum reserves quality assurance, oversaw reserves bookings in the Trinidad, Colombia, Brazil Venezuela, and Argentina units, and ensured reserves alignment with the corporate reserves group.

Alvarado was also a reserves coordinator at Chevron Saudi Arabia. He supervised reserves evaluations for carbonate and sandstone fields in Saudi Arabia and Kuwait, and ensured reserves compliance. He streamlined the reserves booking process to better coordinate efforts between the business unit and corporate reserves group. Alvarado also formed steamflood-booking strategies.

Before that, he was a chemical EOR project manager at Chevron Corp. starting in 2011. He designed chemical-enhanced oil recovery processes and was the subsurface lead for IOR/EOR evaluations of Latin American assets. His work involved calculating recovery factors, forecasting production and conducting numerical analysis for properties in South America.

Alvarado also worked at BP Plc. in Houston as a reservoir engineer for seven years beginning in 2004. He designed and delivered new technologies, including Bright Water in polymer flooding and Losal in EOR miscible gas and CO2 flooding.

Alvarado also conducted thermal/compositional simulations to design pilot options for several Venezuelan heavy oil fields in the Cerro Negro area of the Orinoco Belt.

He started his career at Pennsylvania State University, as a teaching assistant, and at Universidad Central de Venezuela, Caracas, as an instructor.

Alvarado has a BS degree in petroleum engineering from the Universidad Central de Venezuela, and MS and PhD degrees from Penn State.

Carlos Alvarez

Alvarez is a senior reservoir engineer with more than 30 years of diverse experience in that discipline. He specializes in EOR and IOR processes, and has taught numerous courses in this field.

Alvarez has evaluated and optimized oilfield development plans in Venezuela, Mexico, Norway and the U.S.

Before joining Ryder Scott, he worked at Gaffney, Cline & Assoc. for nine years as a principal advisor and project manager. Alvarez was a team lead for projects in the Gulf of Mexico, Mexico, Colombia, Trinidad, Suriname, offshore Brazil, Bolivia and Argentina.

He also evaluated the technical feasibility of production technologies for field development projects, including those in IOR/EOR/polymer, steam and CO_2 injection.

Before that, Alvarez was a senior reservoir engineer in Mexico at Baker Hughes Reservoir Development Services. He provided reservoir engineering analysis to support corporate exploration-and-development activities.

Alvarez was an IOR /EOR advisor for reservoir development at PDVSA Intevep in Venezuela during 2005 to 2010. He helped establish standard methodologies for pilot test design of thermal and chemical IOR methods in Venezuela oil fields. The project also included evaluation of the technical and economic feasibility of new technologies for improving oil production.

Alvarez coordinated multidisciplinary teams to evaluate oil fields in the Orinoco Oil Belt, Lake Maracaibo and north of Monagas in Venezuela. He collaborated in integrated reservoir studies for various oil fields. The components of those studies included analysis of potential implementation of IOR projects inside current development plans.

Alvarez also conducted analytical modeling and performance evaluations, including decline-curve analysis, material balance and other methods. He was also a technical project manager for the first pilot test of the WAG process in Lake Maracaibo.

Before that, Alvarez was the IOR advisor for reservoir development in PDVSA east and west divisions for heavy and extra heavy oil at Lake Maracaibo and the Orinoco Belt, starting in 1990. He was also an invited consultant for the Rogaland Research Group in Norway for a technology transfer program in IOR technologies between Venezuela and Norway.

Alvarez has a BS degree in mechanical engineering from the Universidad del Zulia in Venezuela and an MBA degree from the Universidad Catolica Andres Bello in Venezuela. He is a member of the European Association of Geoscientists and Engineers, SPEE and SPE.

Please see Third-party assurance of ESG – Cont. from page 2

rate those standards into our regulatory regime," said Commissioner **Elad L. Roisman** at the SEC last June. "While this approach seems expedient and responsive to concerns about expertise, we have to acknowledge that this is not a 'plug and play' solution."

He compared a standard-setter in ESG to FASB which sets accounting guidelines for the SEC, and cited "a fear about the (FASB) standard-setter's independence and credibility being compromised by its funding sources and proximity to the industry it regulates."

Roisman acknowledged that the Sarbanes-Oxley Act mostly resolved those funding issues when it required companies to pay accounting support fees.

"Questions persist about FASB's independence from market participants," he said.

Oneness in nature – Cont. from page 3

financial funds, with monthly payouts, experience an organic exponential decrease. The Internet makes use of an exponential-decay model to decrease routing failures (flapping) on the World Wide Web.

Using radioactive decay as an example, the basic formula is as follows: N is the size of a population of radioactive atoms at a given time t, and dN is the population decrease in time dt. Rate of change is generated by the equation, $dN/dt = -\lambda N$, where λ is the decay constant.

The simple, yet powerful equation models decays and associated declines that change the world in big and small ways.

Carbon Capture, Utilization and Sequestration – Cont. from page 9

- In capture, the biggest opportunity to reduce costs per tonne of carbon is in the technology, which includes optimizing the solvent or configuration or using a technology that hasn't necessarily been proven at a commercial scale, but has been relatively successful on a pilot scale.

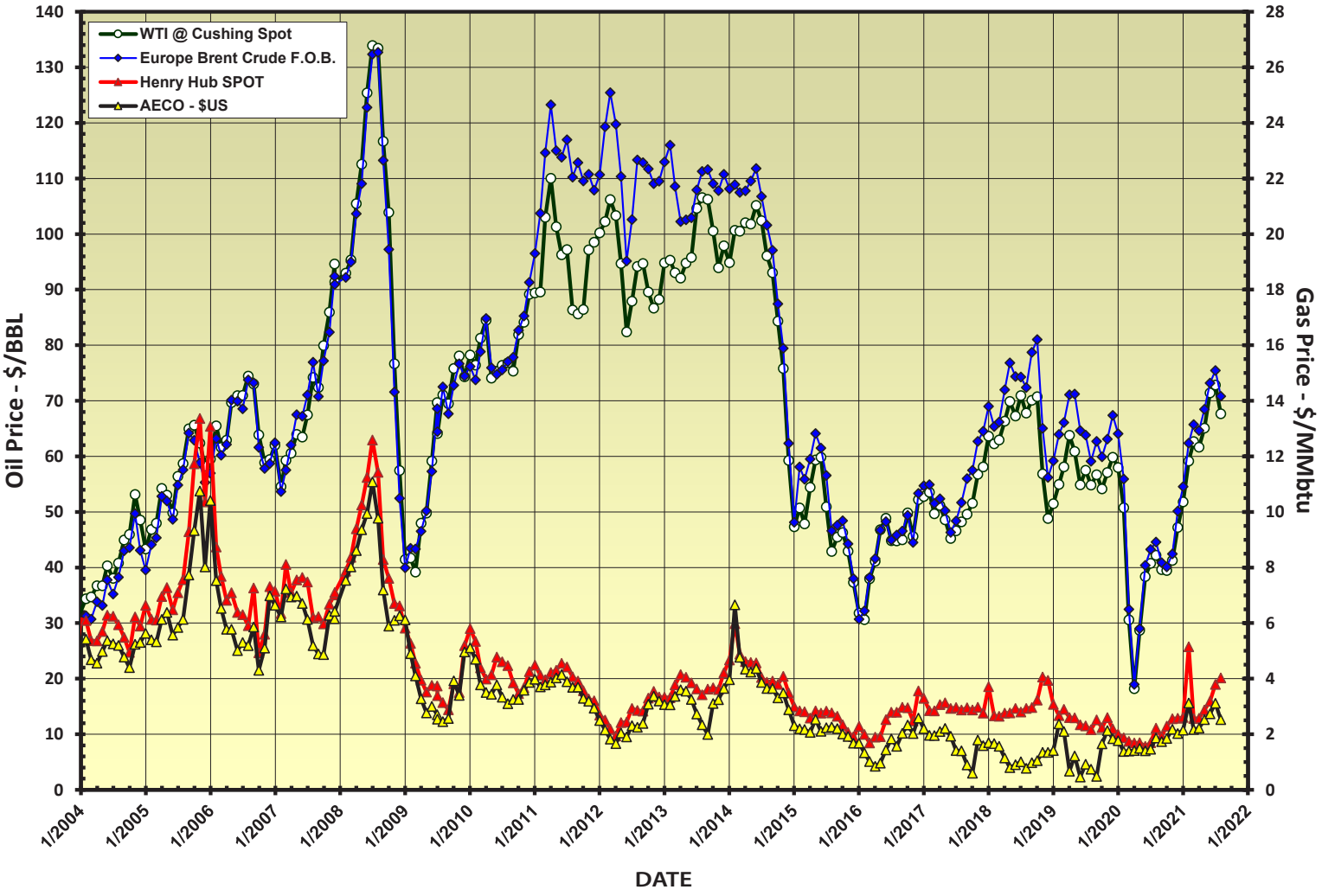
In addition to cost reduction opportunities, policy continues to increase the price of carbon to improve revenue. Policy instruments like carbon taxes and tax credits, e.g. 45Q, allow tax offset opportunities to maximize profits from a primary revenue stream, such as the sale of oil or power. Emission trading systems (ETS) allow companies to trade emission allowances, typically in units of tonnes of CO_2, which provide a revenue source directly generated from storing carbon. The number and magnitude of these policy instruments have steadily increased and are expected to increase more rapidly in the future.

In conclusion, the two main components to increase commerciality are reducing costs and increasing revenue. Innovative solutions are formed using appropriate contracting and commercial models generated via a deep comprehension of CCUS value chain components, technology, designs, project configurations and risks and coupling them with carbon-credit incentives.

Ryder Scott is focused on technologies for capture, compression and transportation. This is useful to clients that want to understand a new technology marketed by a startup and how to contextualize that in a larger CCUS market. The firm's geologists, geophysicists and reservoir engineers are highly competent when assessing formations and utilizing carbon for EOR or long-term storage. Ryder Scott monetization strategies focus on incremental oil recovery from EOR, tax credits and emission-allowance benefits from long-term storage. Ryder Scott also offers verification and validation of emissions to help navigate the complex regulatory standards in reporting.

For more information, contact the authors of this article: **Sandeep Khurana** at Sandeep_Khurana@ryderscott.com or **Steven Beck** at Steven_Beck@ryderscott.com.

Price History of Oil & Gas Benchmarks in U.S. Dollars



Published, monthly-average, cash market prices for WTI crude at Cushing (NYMEX), Brent crude and Henry Hub and AECO gas.

Publisher's Statement

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