# State of the Oil and Gas Sector

# I. Oil - Worldwide Market

2010-2019

- 2019 Worldwide demand > 100 MMBOPD (crude/other liquid hydrocarbons)
- Oil demand increased 12 MMBOPD (1.3 MMBOPD per year)
- U.S. tight oil and NGL production increased by 9 MMBOPD
- Saudi Arabia increased production by 2.5 MMBOPD
- Russia increased production by 1 MMBOPD.
- US increased production accounted for 3/4ths of the world's increased demand.
- Oi prices ranged 50-70 $/BBBL (WTI) over last 3 years during US expansion

Pre-Corona Crisis Oil Market Expectations

- World demand was predicted to increase ~1.2 MMBOPD per year
- US to max out at < 15 MMBOPD by 2022 - actual was 12.9 MMBOPD 11/2019
- Saudi - 2.5 MMBOPD spare "sustainable" capacity, others producing max rates
- OPEC/Saudi/Russia would pick up additional demand 2022-2025
- Prices expected to be 55-70 $/BBL range until 2025.
- Oil markets would then tighten with prices increasing till peak demand~2030

Post-Crisis World Oil Outlook

- Oil is now viewed as a transportation fuel, with lower future expected demand with the possible peak demand already reached
- As demand returns, Saudi/Russian to gain market share at US producer's expense
- Many US oil producers are paralyzed with large debts, some will go bankrupt
- New oil drilling expenditures are being drastically curtailed (>$40 B)
- Currently WTI oil < 40 $/BBL with futures priced $40 - $50 / BBL for the decade.
- EIA forecasts 2020 average WTI = 38.5 $/BBL, 2021 WTI= 45.073 $/BBL.

Demand/Supply

- EIA 2020 2nd Q 2020 demand 85 MMBOPD down 15.8 MMBOPD 3rd Q 2020 94.9 down 6.7 MMBOPD YOY, average 2020 demand 93.1 MMBOPD down 8.1 MMBOPD
- EIA 2021 average demand to increase 7.0 MMBOPD YOY to 100.1 MMBOPD
- EIA 2020 supply 2nd Q 2020 91.8 MMBOPD down 8.6 MMBOPD YOY
- Aug 2020 demand was 94.3 MMBOPD, forecast 2021 average is 99.4 MMBPD
- US crude inventory = 494 MMBO (13% or 58 MMBO above 5 yr. average)

Positives for rebalancing:

- OPEC/Russia cut oil production 9.4 MMBOPD, USA / Canada down 3.5 MMBOPD
- US oil prod fell from 12.86 to 10.0 MMBOPD, 2021 forecast avg. 11.1 MMBOPD
- USA oil rig count - 180 rigs down 553 (-75%) from 733 rigs YOY and moving lower
- Low prices reduce activity as unconventional shale plays, W. TX., most offshore and international are non-economic (marginal for even the best producers).

# II. US Natural Gas

- Natural gas is a very different situation, now viewed as the clean energy source of choice on a world-wide basis for the foreseeable future.
- All recent press has been on oil, the much more important story is US Domestic Gas.
- EIA YOY Report – Industrial Demand, Electric Power, Exports, LNG at all-time records

**Demand/Supply**

- 2019 Gas was 37% of US power generation, 2020 ~40% - **record 41 BCFPD (8/2020).**
- Gas will displace all coal fired and nuclear plants being retired. 40 GW plant retirements announced thru 2025. 23 BCFPD remains to be displaced (25% US power grid).
- **Gas exports to Mexico reached a record 5.6 BCFPD** in 6/2020 and increasing.
- LNG exports 9 BCFPD (12/2019), to 3.1 BCFPD 7/2019), **back to 9 BCFPD (11/2020)** Forecasts average 7.3 BCFPD (2021), 13 BCFPD (2022) and to 18 BCFPD (2024).
- An addition 30 BCFPD of second wave LNG projects already proposed.
- HS Markit states associated gas could fall by 8-10 BCFPD by12/2021.
- Total demand growth of 17 BCFPD 2020 to 2025 (LNG, Coal, Electric, Industrial).
- Rystad's 6/2020 report shows US gas production to decline 10 BCF YOY by late 2020.
- Gas prod peaked at 96.4 BCGPD, 2019= 92.2, 6/2020 = 88.2, 4/2021=**82.7 BCFPD.**

**Current Activity**

- Existing domestic gas prod is >**70%** unconventional (high decline rates). **(EIA=81.8%)**
- US Gas base decline rate is assumed to be 26% per year (R. Davis Assoc. says >28%).
- **>20 BCF Per Day of New Gas needed Per Year** to maintain current production levels.
- New gas drilling will decrease drastically if not stop altogether in most shale plays Haynesville, Marcellus, Fayetteville, and Barnett shales all need > 3.50 $/MCF.
- Gas Rig Count = **72 (all-time low 68 two weeks ago)** down 90 from 162 last year.
- Gas Rig Count down **96% from 2008 high of 1,606.**

**Future Pricing**

- 2020 gas expected < 2.5 $/MCF, Industrial down 8.7%, Storage = 3.4TCF up 13.4%.
- BP using average 2.90 $/MCF for 2021 forward.
- **Goldman Sachs Report predicts 3.25-3.50 $/MCF in 2021.**
- **EIA predicts a 2021 average of 3.19 $/MMCF (**9/9/2020 forecast).
- NYMEX Gas **2021 12 mon. strip at 3.01 $/MCF** (9/8/2020).

**With the existing domestic gas base declining at the highest rate ever, new drilling at an all-time low, and increased demand from power generation, LNG exports, coal and nuclear plant displacement, with gas shales uneconomic, and producers in dire financial shape, where will new large gas reserves needed for the Gulf Coast's LNG/petrochemical going to come from?**

## III. State of the US Oil and Gas Industry

- The only viable solution is large reserve conventional oil and gas fields (low decline rates, high flow rates, low LOE) located within existing infrastructure on the Gulf Coast.

- Large reserve conventional oil and gas fields on the Gulf Coast have always been and are now far and away the most profitable asset in the industry. Large conventional gas fields within the Gulf Coast infrastructure/markets will become the most desired asset in the sector and will remain so for the coming decade.

- During the last 15 years with the advent of horizontal drilling, multistage fracking , high prices and available monies from Wall Street and private equity, the onshore domestic oil and gas industry moved almost exclusively into the shale plays, and W. Texas. All made $100 MM-$B+ investments in acreage, wells, people, and infrastructure in these unconventional resource plays.

- Most oil and gas companies are in bad financial shape and severely pregnant with their huge investments in the shale plays. The large US gas producers as a group are in the worst financial shape with most having unmanageable debt levels.

- The onshore <u>conventional</u> sector has been completely abandoned for over a decade. The majors/large independents do not even have conventional onshore E&P groups.

- Major advances have been made in seismic acquisition, geophysical interpretation and seismic processing which allows the geoscientist to better image the subsurface. These advances increase the probability of success (P(s)) on conventional prospects. In the 1980's with 2D seismic the P(s) was 1/8, with advanced seismic processing the P(s) can be >50%. New techniques (AVO's, full wave form inversion) can now show direct hydrocarbon signatures.

- Large reserve conventional discoveries are needed to feed the US's increasing appetite for natural gas. To make large reserve conventional gas discoveries, one must drill a <u>large portfolio of large reserve, high deliverability modest risk conventional gas prospects.</u>

- Prior to the majors exiting the onshore US in the late 1980's, they and the large independents alike drilled a portfolio of prospects every year. For 75 years they used this profitably and repeatable strategy. The large conventional discoveries profits overwhelmed the costs of the dry holes. Portfolio theory is still successfully utilized today worldwide by every major.

- Portfolio theory was successful with old technology and can be even more successful with using new seismic advances. The current opportunity is for a well-capitalized entity to return to the onshore USA and use a portfolio approach utilizing advanced geophysical techniques to drill up large reserve gas prospects along the Gulf Coast

# IV. Natural Gas Supply and Demand Fundamentals

### i) EIA Natural Gas Short Term Report (7/2020)

- U.S. dry natural gas production set a record in 2019, averaging 92.2 BCFPD expected to decline to average 89.7 BCFPD in 2020 and forecast to average 85.4 BCFPD in 2021.
- Dry gas/month expected to decline from a 11/19 record 96.2 to 83.6 BCFP/D (3/21)
- The falling production mostly occurs in the Appalachian and Permian regions. In the Appalachian, low natural gas prices are discouraging producers from engaging in natural gas-directed drilling and in Permian low crude prices reduce associated gas.
- Storage at 3.07 TCF (+.4 - 5 yr. avg.) @10/31 expected = 4.0 TCF (+17 % -5 yr. avg).
- EIA forecasts that 2020 natural gas prices will average $2.04 / MMBTU with LNG declining from 8.9 to 3.1 BCFPD (7/2020), industrial demand -2 BCFPD, commercial demand -.49 BCFPD, and residential -.74 BCFPD.
- EIA 2021 residential +.36 BCFPD, commercial +.16 BCFPD, industrial +.67 BCFPD
- **EIA forecast 2021 natural gas to average of $3.14/MMBTU.**

Although the EIA natural gas report is very bullish, they may be underestimating the future gas production decline from the domestic gas base due to the following:

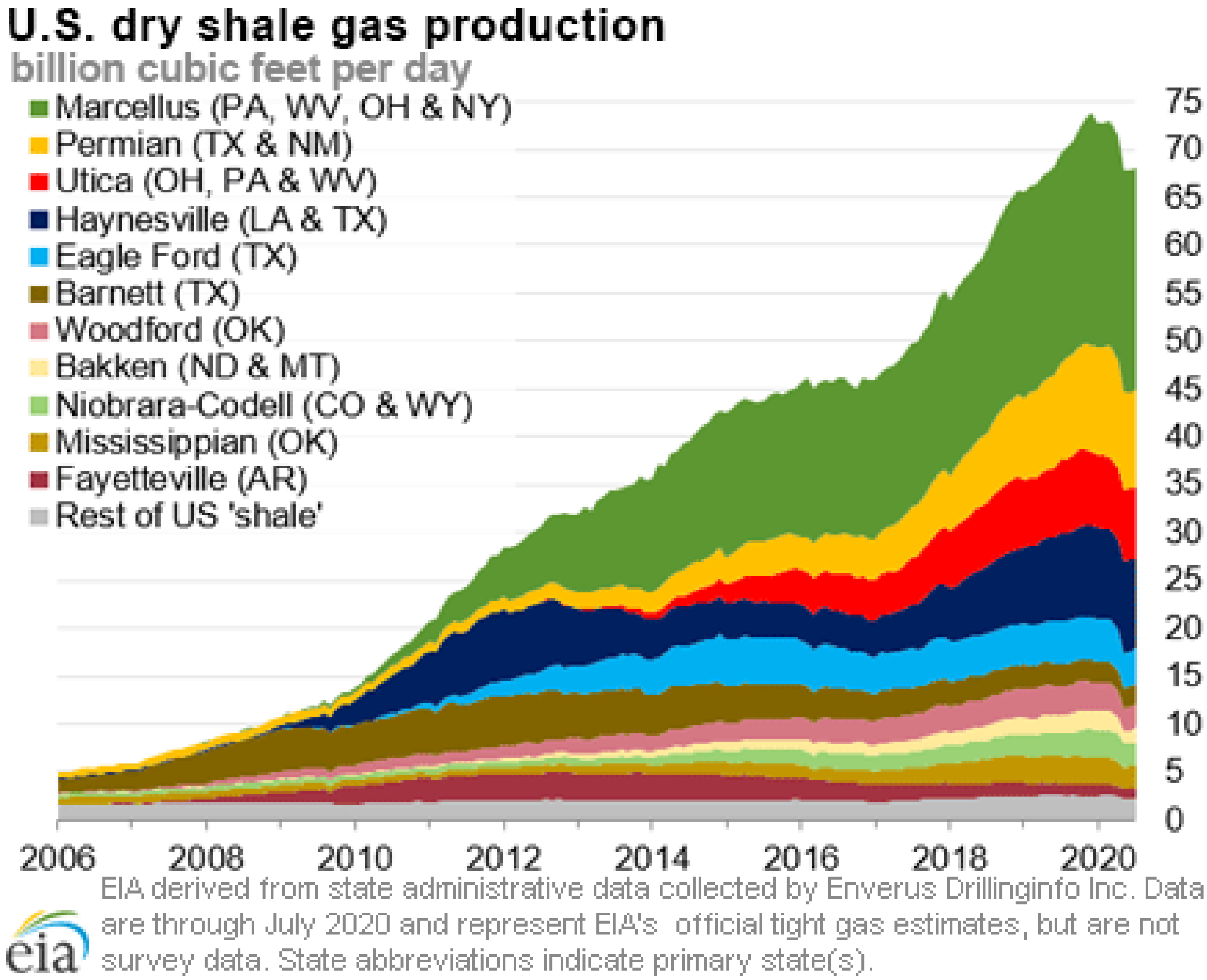
- The USA's largest gas producers are EQT (4.2 BCFPD), Exxon (2.574), Chesapeake (2,278), Southwestern (2,221 BCFPD), Cabot (2,000 BCFPD), Antero (1,945), BP (1,900), Range (1,502), CNX (1,282), and Ascent Resources Utica Holdings (1,254). Besides Exxon and BP, none of these companies have access to capital due to extreme debt levels. They will have to severely curtail or eliminate most new gas drilling.

- The USA's 10 largest gas producing co. flowed 22 BCFPD, the top 20 produced 32 BCFPD, top 30 flowed 37.5 BCFPD and the top 40 produced 39.7 BCFPD. No other USA company produced >175 MMCFPD (NGSA). The remaining 58% of US gas production is from smaller co. in worse financial shape than the larger oil/gas companies.

- **>70 % of the natural gas base is unconventional with high decline rates.** Actual decline rates have been masked by continuous drilling, hyperbolic type curves, etc. As drilling is curtailed, the actual declines will be revealed. We expect substantially higher declines than advertised by the oil & gas co. Both public and private co. who required capital to prosecute these marginal resource plays have consistently overestimated gas reserves and underestimated individual well declines during the entire shale boom.

- Even the large companies are curtailing their capital expenditures. Exxon in the Permian, Marathon stopped all Permian drilling, BP shut down all Haynesville (14 rigs).The 10 majors have already announced >$30 B of cutbacks .

- Oil prices below 45 $/BO will cease most new onshore and offshore US oil drilling and the associated gas from existing wells will decline proportionately.




**EIA 2020 Gas Supply**

| | | | |
|---|---|---|---|
| **Tight/Shale Gas** | **27.4 TCF** | **81.79%** | **75.3 BCFPD** |
| **Lower 48 offshore** | **1.2 TCF** | **3.58%** | **3.30 BCFPD** |
| **Lower 48 onshore** | **3.7 TCF** | **11.04%** | **10.16 BCFPD** |
| **Other** | **1.2 TCF** | **3.58%** | **3.30 BCFPD** |

## Natural Gas Production - Supply Demand Elasticity

- Historically, a gas price increase would spur activity and increase gas production. It is now inelastic below ~3.50 $/MCF Henry Hub.
- Most all the above gas shale plays are uneconomic when you include the basis differential (ex: Marcellus/= .80 $/MCF).
- Permian gas production is dependent on oil prices as most is associated gas from oil production.
- Only the Haynesville becomes marginally economic at 3.50 $/MCF at Henry Hub
- Gas producers are in dire financial shape and have no access to capital
- Most core areas have been drilled, remaining is peripheral thinner shales

# ii) Goldman Sachs Commodity Research Report (3/24/2020)

**Goldman raised their 2021 natural gas forecast to 3.25 $/MCF (summer), 3.50 $/MCF ( winter).** They predict a 2.4 BCFPD production decline against a 5 BCFPD demand increase (+1.3 BCFPD Industrial, .5 BCFPD, Power, +2.2 BCFPD LNG export, .8 BCFPD residential and +.6 BCFPD Mexican exports). The production decline is a result of existing base gas decline rate, new activity decrease, and associated gas decrease from a 1.3 MMBOPD/yr. oil decline. Continued strong demand will rebalance gas and set the stage for a "whiplash" in US natural gas markets. Concluding that "the deficit we expect to see in US gas balances next year is so significant that it would likely take a near $1 MMBTU gas price move to incentivize supply and demand responses that are large enough to address the problem". They recommend going long NYMEX gas. This report assumes:

**Demand and Supply:**

| | Supply (BCFPD) | | | | Demand (BCFPD) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Prod** | **Imports** | **Total** | | **Mex** | **LNG** | **Res** | **Ind** | **Power** | **Other** | |
| **Total YOY** | | | | | | | | | | | |
| **Winter 2021** | **90.8** | **6.3** | **98.6** | **5.7** | **10.6** | **39.6** | **25.6** | **25.6** | **5.1** | **114.7** | **2.3** |
| **Summer 2021** | **91.5** | **5.7** | **98.0** | **6.3** | **10.9** | **11.4** | **31.3** | **31.3** | **5.2** | **89.5** | **2.1** |
| **2020 year** | **92.5** | **5.0** | **98.5** | **5.6** | **8.9** | **22.3** | **22.3** | **31.1** | **5.2** | **97.9** | **2.1** |
| **2021 year** | **91.6** | **5.9** | **98.7** | **6.1** | **10.9** | **23.5** | **23.5** | **29.1** | **5.1** | **100.5** | **2.6** |

**Storage**

The report's base case forecasts Oct 2020 storage to reach 4.324 TCF (range 3.9 - 4.7 TCF). This gas supply keeps 2020 prices low, with a forecasted average 1.75 $/MCF in 3rd Q2020. Goldman's base case March 2021 storage goes down to a low of 1.4 TCF (2020 =1.95 TCF) The low range could approach the all-time storage low of 837 BCF in the 2013-4 polar vortex.

**Goldman's premise is that a small (3/2021) 1.4 TCF storage fundamental number and a visible deficit of demand versus supply of 7 BCFPD will move 2021 gas prices to 3.25 - 3.50 $/MCF**. The low 2020 gas prices will lull the market resulting in their predicted "Whiplash".

Goldman's report may be too optimistic for US natural gas production due to the following:

1. HS Markit states associated gas is 33% of US gas production. Using a linear extrapolation of ~10% oil production decrease (~1.3 MBOPD/YR) results in a decrease > 3.3 BCFPD alone.
2. Most gas producer's dire financial position will reduce new gas drilling further than expected.
3. The report assumes no increase gas demand for power generation.
4. Most analysis expects a 1-2% minimum increase from gas' current 38% power grid (+.6 BCFPD).The report does not consider coal to gas switching and coal/nuclear retirements
5. 78 gas rigs are now drilling in the USA.
6. 2/3rd of the gas production is unconventional, the actual decline rate > assumed 26% per year.

- KCI Research - 4/11/2020 "2021 Natural gas going above $3.00 is mathematically inevitable "
- Enverus - 4/2020 "expects dry gas production to decline > 6 BCFPD 12/2020 from 2019.The data analytics co. forecasts that natural gas prices will exceed $4/MMBtu and could reach $4.50/MMBtu as early as the coming winter. Longer term, natural gas prices are expected to average $2.80/MMBtu"
- Tudor, Pickering, Holt & Co - 4/2020 "the U.S. oil supply declines from shut-in wells, analysts expect natural gas prices will see some relief, with the likelihood they could increase above $3.00/Mcf."

## iii) EIA Natural Gas Year over Year Overview

Aggregate demand (national consumption + exports) for American natural gas increased by 7.84% y-o-y in Dec. 2019 to 116.76 BCFPD. Despite the fact that there were 2.3% fewer total degree days than last year, natural gas consumption increased by 4.86% y-o-y to 101.24 BCFPD. Exports surged by as much as 32.34% y-o-y to 15.52 BCFPD. Overall, y-o-y consumption of dry natural gas in Dec 2019 decreased in two of the four consuming sectors, increased in the other two. Deliveries of natural gas by consuming sector in Dec 2019 were:

- **Residential deliveries**: 751 BCF/Mo., or 24.2 BCFPD. Down 1.8% compared with 24.7 BCFPD in Dec 2018. Residential deliveries were the lowest for the month since 2015.

- **Commercial deliveries:** 456 BCF/Mo., or 14.7 BCFPD. Down 0.7% compared with 14.8 BCFPD in Dec 2018. Commercial deliveries were the lowest for the month since 2015.

- **Industrial deliveries:** 776 BCF/Mo., or 25.0 BCFPD. Up 1.6% compared with 24.6 BCFPD in December 2018. **Industrial deliveries were the highest for the month since EIA began using the current definitions for consuming sectors in 2001.**

- **Electric power deliveries:** 897 BCF for the month, or 28.9 BCFPD. **Up 17.7% compared with 24.6 BCFPD in December 2018. Electric power deliveries were the highest for the month since EIA began using the current definitions for consuming sectors in 2001.**

- **Exports:** External demand remained elevated, mostly due to stronger pipeline exports into Canada and robust sales of LNG, which increased by 9.06% and 79.57% y-o-y, respectively. **Total natural gas exports were the highest per month since EIA began tracking in 1973.**

- **In Dec 2019, the USA exported 7.1 BCFPD of LNG to 24 countries. LNG exports were the highest for any month since EIA began tracking them in 1997.** Strong growth in exports and an increase in national consumption ensured that the growth in total demand stayed positive.

- On an annualized basis, aggregate demand has not posted a single negative growth since 2010

# EQT Gas Hedging

- EQT is the USA's largest producer of gas, currently 4.2 BCFPD.
- EQT has long term debt of $4.6 B .
- As the largest gas marketer of gas, they have knowledge of the physical gas markets.
- In 2020, they hedged 87% of their gas production (considered a near full hedge).
- Moody states: "EQT needs a sustained average Henry Hub price of about $2.50/MMBtu to generate a sustainable retained cash flow/debt ratio above 30%, the minimum for an E&P investment-grade rating, EQT's termination of its hedges for 2021 and beyond enhances its near-term cash generation and reinforces its debt-reduction plan, but also leaves EQT vulnerable"
- EQT's current hedges show extreme confidence in 2021 forward gas prices as prices < 2.50 $/MCF triggers the debt metric to cause their securities to fall below Investment Grade, a true death blow.
  - 2020 Swaps 575 MMDTH
  - 2021 Swaps 467 MMDTH
  - 2022 Swaps 0 and have sold puts of 135 MMDTH (net long))
  - 2023 Swaps 2 MMDTH
  - 2024 Swaps 2 MMDTH
- July 27, 2020 EQT Corporate Presentation, they state:

  "**Current commodity price environment does not incentivize adequate supply response to meet future demand. We believe gas supply will be short heading into 2021 and the natural gas strip is undervalued."** Operating Costs =1.32 -1.44 $/MCF not including interest Net Loss 2$^{nd}$ Q 2020= $263 MM.

- Rystad Energy Aug 11$^{th}$ – "We argue that for sustainable medium-term dry gas production growth, the industry needs WTI at $50, or higher, and Henry Hub at $3 or above"

# V. Baker Hughes Rig Count (9/11/2020)

- North American Rig Count is 332 down 655 rigs from 987 last year (-66%).
- US rig count declined 24 consecutive weeks, now at 261 down 599 rigs from 860 (-70%).
- US rig count had reached an all-time low 15 weeks in a row (1940 all-time low of 404).
- Raymond James predicts the US rig count will be 200 by year end 2020 with 225 in 2021.

**Oil Rig Counts:**

- US oil rig count is 183 down 530 rigs from last year's 713 (-74%).

**Gas Rig Counts:**

- **Gas rig count is 75, (all-time record low=68) down 71 rigs from last year's 146.**
- **Gas rig count is down 95% from the high of 1,606 in 2008.**
- **Gas rigs % reached an all-time low of 13.5% in March 2020.**
- **Vertical drilling rigs reached all-time low of 7, an all-time low of 2.3 % of the total rigs (97.7 % horizontals), currently 13, almost no exploratory drilling in conventional plays.**
- US offshore rigs are 14, record low 11 two weeks ago, **none drilling for gas.**

**International Rig Count:**

- Canadian rig count is 71, reached all-time low of 18, down 56 (-44%) from 127 last year.
- International rig count is 747 down 298 from last year's 1,045 (-28%).

# VI. <u>Oil Supply and Demand Fundamentals</u>

<u>2010-2019 Oil Demand</u>

- Worldwide demand last year was > 100 MMBOPD (crude and other liquid hydrocarbons)
- Worldwide demand increased 12 MMBOPD (1.3 MMBOPD per year)
- U.S. tight oil and NGL production increased by 9 MMBOPD
- Saudi Arabia increased production by 2.5 MMBOPD
- Russia increased production by 1 MMBOPD.
- US accounted for meeting three-quarters of the world's increased demand.

Saudi has reported spare "sustainable" capacity of another 2.5 MMBOPD, although there is a debate on what production level is sustainable and how many $B it would take to get there. Barclays recently estimated that Saudi could sustainably increase production only 1 MMBOPD. Russia can produce flat out *maybe* supply another 400 – 800 MBOPD before entering secular decline.

RSEG estimates that the big five U.S. liquid shale plays have about the same three-quarter cycle breakeven costs as other major *new* supply sources: offshore fields in the North Sea, Latin America, and the Gulf of Mexico. All required a minimum of $45-60 $/BBL to move forward.

Few operators, and almost none outside the Permian Basin, can generate free cash flow <50 $/BBL. Most operators in major shale basins generate healthy free cash flow at >$65 $/BBL. Oil prices at 35-45 $/BBL will substantially decreases or eliminates most new drilling in USA shale plays and W. TX. Many offshore and deep water oil projects will be deferred or cancelled. These prices, poor financials, commitments to unconventional oil plays and the extreme debt levels of most USA energy companies only exacerbate this situation.

Current demand destruction is > 8 MMBOPD, so until the current recession is over prices will remain low until markets return to pre-crisis demand levels. US oil production peaked at 12.9 MMBOPD (11/19) with May 2020 production already down to 10.01 MMBOPD. This exceeds EIA's 2021 forecast to average 11.1 MMBPD.

IHS Markit expects production could decline by 2.9 MMB/D by year end. Once the recession is over and if demand increases, Saudi and Russia will increase production likely maintain prices below the US breakeven, to maintain or increase their worldwide market share at the expense of the US producers. Worldwide demand then becomes a function of the increase in renewables, electric transportation conversion, and industrial growth. Economic analysis should use ~40 $/BBL (2021) escalated at 2 % per year and capped at 55 $/BBL. This makes most new US unconventional, shale, Permian Basin, offshore and deep water ventures uneconomic and will break the net debt/ebitda and other bank covenants of many US Oil Co. All including the majors will bear extreme financial pressure to cut E&P expenditures. ***Even with this future oil***

***pricing scenario, large reserve prolific onshore US conventional oil fields within existing Gulf Coast infrastructure will remain economically attractive.***

## VIIA. Future US Gas Supply

Where is the future gas demand needed on the Gulf Coast going to come from?

New gas production must come from large new gas fields within the existing Gulf Coast infrastructure. With gas shales uneconomic, the only economically attractive gas development is from prolific high deliverability large reserve low decline conventional gas fields.

To discover conventional gas fields requires the drilling of a large portfolio of large reserve modest risk conventional gas prospects.

Outside of SKH, there is not a single entity that currently owns such a portfolio nor is there to our knowledge a single entity that is even actively trying to assemble such a portfolio of conventional onshore Gulf Coast gas prospects.

The barrier of entry is high if not closed. An investment thesis to form a start-up to pursue this strategy is extremely risky. It requires a staff with conventional expertise (very few people remain), 3-5 years of work, $MM of seismic data and overhead with no guarantee that such a multi-year effort could generate a significant prospect portfolio. Having performed this exact methodology, we do not believe that it can be replicated. Having worked all the onshore Gulf Coast's prolific gas trends and most of the seismic data with state of the art processing, we have identified the large undrilled features. A start up working these plays would likely find these same attractive prospects several years from now. We expect to have them all either drilled or leased up. To attract capital to pursue this strategy would be difficult.

If only several prospects are assembled, the portfolio cannot be drilled because the number of outings must mitigate/mathematically eliminate the individual prospect risk to attract capital.

If gas prices increase >3.50 $/MCF, some unconventional gas plays will return, but this could take considerable time. Most existing gas producers will have either gone bankrupt or are such bad financial shape that they cannot raise additional capital. The majors like BP could restart drilling the Haynesville, but much more will be required to balance gas demand and supply. Many gas producers will not survive the current downturn, they are financial "zombies".

The US will have a strong domestic gas market during the next 5-10 years. The company that owns a large portfolio of onshore large reserve conventional gas prospects on the Gulf Coast should be well positioned to attract large capital sources to drill and develop these gas assets.

Large onshore conventional gas prospects along the Gulf Coast will be highly valued by mid-2021and can be used as a currency to secure carried interests in large capital expenditures.

The companies that discover and develop conventional large reserve gas fields on the Gulf Coast will be the USA's next great energy companies.

## VIIb. Future Oil Supply

The expensive horizontal (7,500'-10,000' laterals) which require million dollar multi-stage fracking (20-50 stages or more) are not economic at oil prices < 50 $/BBL .

This will curtail expenditures in most US Basins including the Permian. Due to their $B sunken costs, the majors and very large independents will continue to drill the Permian Basin albeit at a slower pace. Most other unconventional resource oil plays will be totally abandoned.

If WTI prices remain < 50 $/BBL, drilling in the inland basins (Bakken, Canada's WSB) with high basis differentials will certainly be curtailed or stopped in all but the very best core areas.

A few onshore Gulf Coast oil plays that are shallow (<12,000'), inexpensive to drill (< $2 MM) and require simple completions (< $1 MM) with prolific conventional reservoirs will remain attractive.

Specifically, the Gulf Coast's Jurassic aged Smackover and Norphlet Sands, TX. and S. LA. shallow Miocene/Eocene sand and East Texas' Cretaceous carbonates are attractive even at low oil prices. These plays offer relatively shallow conventional reservoirs with high porosities and permeabilities. Completed well costs are < $3 M per well with expected reserves > 1 MMBO per prospect. Due to their high flow rates, large reserves and low operation costs, these shallow conventional oil plays are still profitable < 25 $/BBL.

The above mentioned plays are mature with most of the large structural targets already drilled. The prospects remaining in these plays are stratigraphic or combination traps which require advanced 3D seismic inversion processing which the industry has not performed.

Companies with extensive data and expertise in high quality shallow conventional reservoirs along the Gulf Coast will continue to prosecute these conventional plays. Conventional oil prospects which offer large reserves and prolific flow rates remain economically attractive.

The net result will be a decrease of US oil drilling activity. US oil production has already declined 2 MMBOPD in 6 months with the EIA forecasting an additional decline of 1.0 MMBOPD by 3/2021. The US oil rig count has already fallen > 75%. Most oil producers with significant debt will go bankrupt or survive in severe financial condition.

The future for energy companies with large positions in unconventional oil plays, expensive offshore, deep water, and production away from the coastal markets looks extremely bleak.

# VIII. Purchase of Natural Gas Producing Assets

The USA's largest gas producers are EQT (4.2 BCFPD), Exxon (2.574), Chesapeake (2,278), Southwestern (2.22 BCFPD), Cabot (2.0 BCFPD), Antero (1.95), BP(1.90), Range (1.50), CNX (1.28), and Ascent Resources Utica (1.25). Besides Exxon and BP, most of the other companies have limited access to capital due to extreme debt levels.

The US's top 40 gas co. produce 39.7 BCFPD ~44% of total US production (NGSA).

The remaining 56% of US gas production is from smaller companies in worse financial shape than the larger oil/gas companies. All remaining companies produce < 175 MMCFPD. Associated gas from oil wells accounts for ~ 35% of daily gas production (HS Markit).

**Purchase an existing Natural Gas Producing Company**

Aside from the integrated oil and gas majors, we do not see a single public or private gas producing company of interest to purchase for the following reasons:

- Most have almost 100% unconventional gas production (large unprofitable)
- Most have extreme debt levels and have no access to additional capital.
- Most require continuous uneconomic or marginally economic development expensive drilling to develop their gas reserves (at today's prices they should not be gas reserves).
- These shale developments and companies are illiquid due to potential buyer's unwillingness to commit to the required continuous drilling programs.
- Not a single company has substantial (if any) onshore US conventional gas production within the Gulf Coast infrastructure.
- Many have marginally or unprofitable oil operations as a large component of their production base, so they are not a pure play for natural gas.
- Many have production located in areas with high price differentials such as in Appalachia (Marcellus and Utica) or in the Rocky Mountains.

**Purchase Gas Producing Properties**

Conventional gas production purchase

- Due to the focus on unconventional shale gas for the last 15 years, there have been very few conventional gas discoveries during this time frame.
- There is little new conventional gas production available for purchase. Currently few large Gulf Coast conventional gas wells exist for sale.

- Old conventional wells producing at low rates, with limited reserves, high relative LOE, and P&A liability are of no interest.
- Most profitable conventional gas wells are in the major oil company's hands and are likely the last assets to be sold.
- Some associated gas of producing oil wells can be purchased. Buying oil wells for the associated gas is not economic, too diluted to be of interest.
- Offshore gas production burdened by high operating costs, platform costs and BOEM regulations are of no interest.

Unconventional gas production purchase

- High decline unconventional gas wells are undesirable to the gas buyer.
- A significant amount is geographically undesirable with high price differentials (Appalachia, Permian Basin, Rockies), recently made worse by pipeline cancellations.
- All require expensive development drilling to offset the high decline rates.
- Development drilling of these unconventional plays are uneconomic below $2.50 with marginal economics until gas prices reach 3.50-4.50 $/MCF.

**Gas production purchases have the additional problem of being sold at auction.**

- Most oil and gas production are sold through the auction process using Energy Net (44,000 registered buyers), PLS (27,000 buyers) and a few other sites. The process works well for the seller, properties typically receive 10-15 bids, several low offers, many bids at a fair value of PV20 - PV10, a few at full value (PV0) and a few offers above the properties future value. The seller contacts the highest bidder and usually negotiates a slightly higher number to close. In an auction process with multiple buyers, the high bidder almost always overpays (normal distribution curve of bids is attached).

**Timing is to late**

- The 2021 NYMEX gas strip is >2.75 $/MCF, with many reports forecasting 2021 gas >3.00 $/MCF. It is now too late to buy gas production at a discounted price. Gas producing companies are aware of the future gas market and even with debt problems will not sell gas production cheap. The time to purchase low decline profitable gas assets if they could be found was probably 2018-9.

For the above reasons, we do not believe one can make an attractive large gas purchase today either through purchasing an existing gas producer or by purchasing gas producing assets and it will become increasingly more difficult as gas markets strengthen into 2021.

The best strategy to secure gas reserves is to assemble large conventional gas prospects, raise capital to drill these prospects in a portfolio approach and retain direct interests in large reserve low decline conventional profitable gas fields.

## VIIIb. Purchase of Oil Producing Properties

There will a substantial inventory of oil production for sale due to uncertain prices, company's financial positions and bankruptcies. 2020 may be a reasonable time to purchase low decline oil production from companies in dire financial shape if oil prices hold up.

However similar problems cited above for gas exist to achieve an attractive oil purchase.

- There is limited good quality new conventional low decline oil production for sale.
- Most production will be sold by auction with many bidders with varying price decks.
- Most oil production will be unconventional high decline wells.
- Most oil production for sale will be in the Permian, Williston, Oklahoma and inland basins which will have differing WTI basis.
- Unknown future oil pricing is an additional risk.

Making a large purchase of oil production even in these difficult times will not be easy as it is still a problem to find large reserve low decline US oil assets located in favorable markets.

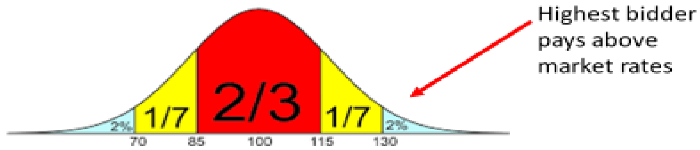
If the oil production has a high annual decline rate (unconventional) then most of the well's production will be at these low near term prices. Even if prices recover by 2022, the oil asset's PV10 valuation will be largely unaffected.

The oil price environment will determine how desperate companies become to sell assets as their financial position deteriorates. The price of oil may remain low for longer which will make most oil purchases even more problematic.

Although there will be undoubtedly be a lot of oil production for sale, most will be either unconventional with high declines, old low rate wells or offshore production with high LOE and future P&A costs.

## Oil and Gas Production Purchases

- Each oil and gas producing property is sold at auction
- Each producing property receives multiple purchase offers or "Bids"
- The bids received are normally distributed to the fair value, some low offers some higher.




- The highest bidder becomes the winning bid.
- The purchaser must pay significantly too much based on current prices

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# IX. Current Onshore USA Conventional Activity

There is not a single major or large independent that has a generated onshore *conventional* gas prospects on the US Gulf Coast in almost a decade and few for the last 20 years.

Currently no major or large independent even has a conventional US onshore conventional division or staff in place. They perform conventional E&P offshore and internationally, but the onshore US has been an arena for unconventional shale plays only.

To resurrect an onshore conventional effort would require massive data acquisition, addition of unavailable staff and expertise, complete internal restructuring, and years of retooling. To return to generate prospects in the onshore US conventional is not even a remote possibility.

Over the last decade, onshore conventional lower 48 exploration was left to a few privately owned E&P Co. with specific geographical focus and expertise. Most have now retired, recently deceased, financially distressed or are now inactive creating a complete vacuum in the domestic onshore conventional E&P sector. The following lists the active conventional E&P co. in the onshore 48 outside of a few very small independents:

| **Principle** | **Company** | **Area of Activity** | **Current Status** |
|---|---|---|---|
| Robert Tucker | West Bay Exploration | Michigan Basin | Semi-retired (78) |
| Les Ballard | Ballard Exploration | Texas Gulf Coast | Recently Inactive (83) |
| Jimmy Harris | Midroc | AL, Smackover | Recently deceased |
| Dudley Hughes | Hughes | MAFLA region | Recently deceased |
| Gary Loveless | Square Mile | East Texas . | Semi-retired |
| Howard Sklar | Sklar Exploration | AL Smackover | Filed bankruptcy 4/2020 |
| Schusterman | Samson Oil & Gas | Texas Gulf Coast | Sold Co. active offshore GOM |

| **Paul Sigmund** | **SKH** | **Gulf Coast** | **Active** |
|---|---|---|---|
| Lee Barberito | Manti | S. Louisiana | Now in Permian |
| John Stoika | Castex | S. Louisiana | Bankruptcy, Inactive |
| Charles Goodwin | PetroQuest | S. Louisiana | In TX CV/LA. Chalk plays |
| Clayton Williams | CWEI | E. Texas, S. La. | Deceased 2020 |
| | Cimarex | Jeff. Co., TX. | Exited Gulf Coast - Ok. Scoop |

In 2010, Chevron briefly made a deep subsalt S. La. Paleocene onshore play. The last significant US onshore E&P effort was made by McMoRan (2005-2011). They along with Plains E&P was sold to Freeport McMoRan ($20 B) in 2012. Freeport exited the oil & gas business to return to their core copper/gold business. The last onshore Gulf Coast conventional gas play was the expanded Yegua play of Jefferson Co., TX by Samson/Ballad/Cimarex/SKH from 2006-2012. The last onshore conventional oil play was the Alabama up-dip Smackover play made by Midroc/Sklar/Hughes in 2006-2011 with development ongoing till 2018.

## X. Recent History - Onshore US E&P

After the 1986 oil price collapse the major oil companies left the onshore USA in pursuit of larger prospects offshore, international and in the deep water arenas. The large independents followed and the USA onshore was left to a group of small independent E&P companies.

After George Mitchell pioneered the Barnett Shale and with the advent of horizontal drilling and multistage frack technologies, several large independents (Chesapeake, Devon, etc.) pursued the unconventional resource plays of onshore North America. High oil and gas prices and the simplicity of these “shale plays’ attracted Wall Street and private equity funds. The large independents used disproportionate promotions of multi-national corporations (Chinese, Japanese, Korean, and European) and even the majors returned to finance the development of these unconventional resource plays.

The shale play’s results have been an “unmitigated disaster”(CEO- EQT). We have calculated actual losses of > $800 B from 2015-2019. Haynes and Boone list over 220 E&P oil and gas company bankruptcies involving >$171 B in aggregate debt from 2015-6/2020, with $49B this year. At current prices and the shale plays true economics exposed, the losses will be even more staggering. Oil field services has seen 221 bankruptcies with $95 B in aggregate debt.

After the shale plays, almost every large independent and major oil company moved aggressively to the Permian Basin. Most recently due to >$180 B of consolidation, the Permian Basins are largely controlled by several majors and large independents.

Currently almost every small-large independent and majors now have their entire onshore USA portfolio of assets tied to unconventional resource plays and/or the Permian Basins of W. TX.

Most has made multi-hundred MM$ and in many cases multi-B$ expenditures in expensive lease positions, initial wells, infrastructure, gathering systems, and employees in unconventional resource plays. These companies are pregnant with these shale plays with large sunken costs and in many cases huge forward commitments to mineral owners, drilling rigs, fracking companies, sand suppliers and other service companies.

They must continue to drill their leases to avoid lease expirations and/or lessor demands for developments from their leases. In addition, the high decline rates in these unconventional wells requires continuous drilling to maintain production levels. All these companies, small private equity backed entities, large independents and majors alike are firmly committed to (many for a decade) to their respective unconventional resource and W. Texas plays.

Today's commodity prices challenge the economics for all but the most prolific of the resource plays and make the multi-B$ investments in deep water plays and overseas investment tenuous at best. The high lease costs (>50 K/acre) paid in the Permian Basin makes this play less attractive than it was for the legacy owners and earlier lease acquirers.

With the fall in oil prices all these unconventional resource plays, shale plays, Permian Basin plays are uneconomic and will be severely curtailed, and in many cases completely shut down.

Recent example: Equinor (Statoil) shut down 100% of all US Marcellus, Utica, Eagle Ford, and Bakken activity. Marathon curtailed 100% of all Permian drilling. Exxon cut $10 B expenditures (largely Permian). Many others will eliminate most or all expenditures to survive.

Continuous drilling of these shale plays increased domestic production from 2014-2019. The massive expenditure cuts and severe curtailment of activity in the unconventional plays will expose the high decline rates of the existing gas base.

Private equity, debt or other financings are now unavailable to develop these uneconomic resource plays. Large companies will curtail spending to concentrate all available monies on debt service, dividends, and projects with contractual commitments. (overseas and deep water).

**Recent US Onshore <u>Conventional</u> E&P**

The onshore conventional sector has been almost totally abandoned and largely ignored for over two decades. Due to the industries already sunken investments in the unconventional and West Texas plays, the conventional sector will be continued to be ignored for the foreseeable future.

A large reserve conventional onshore oil and gas discovery is far and away the most profitable asset in the energy sector. By definition, a conventional reservoir has superior flow and recovery characteristics than an unconventional tighter reservoir and is far less expensive to develop and much more profitable.

Due to the lower costs, existing infrastructure, and the world's most attractive deal terms (relatively small royalties to private mineral holders), the US onshore conventional sector offers superior profit margins to the offshore or international conventional plays. Currently it is the most attractive sector of the entire worldwide oil and gas industry.

For example: a single conventional US onshore 10 MMBOE discovery is in most cases more profitable than a 100+ MMBO discovery made offshore or overseas or a multi-100 well unconventional resource play. Large onshore Gulf Coast conventional gas discoveries (>100 BCFE) will be the most attractive energy asset for the foreseeable future

**Liquidity**

The unconventional plays have no liquidity, there are few buyers who desire high decline wells with low current prices which require additional capital for continuous drilling with poor returns. In contrast, there are many buyers of low decline, large conventional wells which are viewed as an annuity with an inflation hedge. Producing conventional assets can be easily monetized at PV10+ in a single EnergyNet or PLS auction.

**Portfolio Theory**

To discover conventional onshore USA fields, a company must own and methodically drill a portfolio of high reserve prospects. The present value of large onshore conventional discoveries overwhelms the costs of the unsuccessful tests resulting in repeatable profitable E&P projects.

The onshore conventional sector must be prosecuted as it was pre 1980's, with a drilling program of large reserve modestly risked geological and geophysical diverse prospects - a portfolio approach. The challenge is to own a large enough portfolio of diverse high quality prospects to delimit the risk associated with each, all owned by one entity, all at the same time.

Drilling a diverse portfolio of large reserve modest risk conventional prospects has been the proven strategy for profitability for the multi-national oil companies for over 100 years. E&P conducted in the US offshore, deep water and overseas are still practiced this way today.

Recent improvements in geological concepts (seis-strat etc.), seismic acquisitions, seismic interpretations and especially the paradigm shift in seismic processing has increased the probability of success in conventional E&P from (1980's) 1 in 8 to almost 50%.

Currently there is a lack of existing onshore conventional prospects.

- Prospects - very few high quality large reserve moderate risk onshore conventional prospects are available due to the last decade's lack of generation.
- Continued lack of new seismic work - The lack of focus on the conventional US will only exacerbate this situation. The onshore industry is and will continue to be starved for conventional seismically delimited high reserve modest risk (high quality) prospects.

Currently there is a lack of geoscientists with onshore conventional generational expertise

- Post 1986 - new geoscientists were employed to work offshore, deep water, or overseas.
- Post 2000 - all new geoscientists were trained exclusively in unconventional plays.
- Technically proficient geoscientists with onshore expertise who worked pre 1986 oil collapse with large companies or majors (now > 60 years old) have either retired or were transferred to the unconventional, deep water or overseas plays long ago.
- Most independent geoscientists were also forced to work unconventional plays during the last 20 years to gain employment, consulting work or to promote prospects or projects.
- There are now just a handful of geoscientists who have continually worked these onshore Gulf Coast Basins from prior to 1986 till today. There are just a few experts remaining in each conventional onshore basin along the gulf Coast.

Due to the absolute lack of competition, in place infrastructure, inexpensive lease costs, inexpensive existing seismic data, and inexpensive drilling, development and overall finding costs there exists an exceptional opportunity for a few well capitalized conventional focused E&P companies to take advantage of the advances in seismic technology to make extraordinary returns within the Onshore Gulf Coast.

## XI. “Portfolio Player” First Mover becomes the Aggregator
## What is the current Differentiator and Opportunity?

Conventional prospects now have a Probability of Success (P(s)) ranging from 20% - 75%. Therefore, Conventional E&P must be done utilizing a Portfolio Approach. Major and large independent oil companies have done this repeatedly and profitably for over 75 years and continue to use this strategy offshore and overseas.

Examples: In 2019, Shell Oil drilled 12 prospects in the GOM resulting in 5 discoveries and 7 dry holes. The discovery’s (two major fields) future profits dwarf the costs of the dry holes. In 1981, using poor quality 2D seismic data, Shell drilled 67 wells with 12 discoveries. The 12 discovery’s profits easily paid out the costs of the 55 dry holes.

Prior to the large oil companies exiting the onshore US back in the late 1980’s, they were the “Portfolio Players” who each drilled 50-100 prospects per year. Geoscientists and small oil and gas companies sold their individual prospects to the major and large independents. These “Portfolio Players” purchased these individual prospect(s) and by absorbing the prospect(s) into their portfolios diversified the individual prospect’s risk.

**Currently there are no “Portfolio Players” remaining in the US Conventional E&P Gulf Coast Sector.**

What is today’s” Differentiator”? To use portfolio theory, an onshore conventional E&P company must have an initial platform of 20-30 independent large reserve conventional gas prospects located on the Gulf Coast. **One entity must have a large prospect**

**portfolio of large reserve conventional prospects, all leased at the same time, and assembled in a short term drilling program.**

Only then can they purchase additional individual conventional prospects to add to their drilling program, no matter how good the individual prospect's risk reward ratio is. Currently there is no market for an individual conventional prospect due to the potential and unacceptable complete loss of capital due to the possibility of a dry hole.

**First Mover** – Whichever firm is the first to secure a large portfolio of prospects in the US Conventional Onshore will become the First Mover Portfolio Player. They will have a virtual monopoly to purchase individual prospects from geoscientists or small E&P Co. The Portfolio Player will become the aggregator of individual prospects. With a portfolio of prospects, they can attract capital to drill conventional prospects. Investors will not drill a singular conventional prospect as they desire to have their risk delimited and/or mathematically eliminated using portfolio theory to participate in drilling a large group of prospects.

As an example: 15 test wells with each prospect having a P(s)= 50% has a 99.63% chance of having at least 3 discoveries, a 94% chance of having 5 or more discoveries. If the individual prospects are large, just one or a few discoveries can pay out the 15 well project thereby mitigating project risk. Using modern geophysics, the most likely outcome is 6-10 discoveries resulting in multiple returns.

This Portfolio Player can assemble a second prospect portfolio by internal generation and/or purchasing outside submitted 3rd party generated prospects. They can secure funding for this new prospect portfolio and receive carried interests. This process can be repeated making the Portfolio Player the "Onshore Conventional E&P Co".

Competition – Currently there is none. No company including the majors or large independents have a large portfolio of conventional gas prospects on the Gulf Coast.

Once successful, can others try to emulate this strategy? Having performed this exact methodology, we do not believe that it can be easily replicated.

To pursue this strategy , a large company or major oil would have to form a new division, hire new people with expertise (after being out of the USA onshore conventional for >30 years), retool their entire company and scrap existing budgets. The majors and large independents each have in most cases already expended > $B in leases infrastructure, people and data in the unconventional resource plays and are committed to these projects for the next decade. They cannot and will not enter the conventional onshore E&P sector.

For a small company or start-up to compete, they would have to hire a significant staff with conventional expertise (very few people remain), spend 3-5 years of full time effort working these onshore plays and spend > $20+ MM for seismic data and overhead. To attract a large capital source to pursue this strategy would be very difficult.

The first company to secure a large portfolio of conventional gas prospects and assemble a portfolio will become the onshore E&P “Portfolio Player”. They will have a first mover competitive advantage over all others in securing funding and purchasing additional prospects from third party generating geologist or small oil companies.

This Portfolio Player will have a First Mover position in the conventional E&P onshore sector that will be difficult to complete against and will become the aggregator of conventional prospects and future capital in the sector.

**Portfolio Player Carried Interest** - The First Mover Portfolio Player can attract capital and receive carried interests in the drilling/ development of their prospect portfolio, they have no initial drilling risk. If each independent prospect has moderate risk and high gas reserves, the drilling and development of this portfolio of prospects will make their investors an excellent ROI. The Portfolio Player retains the carried interest and will have an even higher ROI as they have no drilling and development costs.

# XII. Investment Opportunities - Today’s O&G Industry

1. **Exploration in the Deepwater Gulf of Mexico** – This requires a multi-billion dollar investment, long lead terms and extreme expertise. Deal terms with the major oil companies typically require large carried working interests (50%). Cobalt went bankrupt trying this strategy, Venari and Deep Gulf suffered $B+ losses. Due to the immense costs, competing with the major oil co. in the expensive deep GOM is not a viable investment option.
2. **Exploration and Development Overseas** – The Production Sharing Arrangements (PSA) of most countries now allocate almost all profits to the sovereignty with little room for the oil and gas companies to profit. For example: the latest Abu Dhabi PSA contract gives .50 cents per barrel profit sharing. In addition, long lead times and $B investments are the norm. Although decades ago, PSA terms were acceptable, the foreign governments have now made the terms, taxes, and fees to great for profitability. The risk reward proposition is no longer attractive.
3. **Onshore USA Unconventional Resource Plays (Shale Plays)** – Due to the large lease holds required upfront, expensive lease prices, horizontal drilling costs, and expensive fracking costs these plays require multi-hundred $MM investments. All the non- Permian Basin resources plays have been leased and the core areas have been developed. Most of the peripheral lands of these plays are uneconomic without the previous multi-national corporation’s disproportionate promotions. At today’s oil and gas prices these plays are not a viable investment option.
4. **Permian Basins of West Texas** – Most, if not all the large contiguous land positions have been leased. Recently the industry is consolidating, with multi-billion dollar mergers (Exxon -Bass $6.6 B, Concho -RSP Permian $9.5 B, Diamondback - Energen $9.2 B, Denbury -Penn Virginia $1.7 B, Encana-Newfield $7.7 B). The leasehold costs (up to 75,000 $/acre) combined with low oil prices makes development uneconomic. 8 large companies now control most of the basin.

5. **Drilling Individual Oil and Gas Prospects** – There is a possibility of complete loss of funds. No matter how probable the outcome, even with a single well's P(s) = 75%, there is a chance of 100% loss of investment making one prospect exploration/investment an unacceptable strategy.
6. **Funding a new 3D Seismic Survey** – Shooting a new onshore 3D survey costs $50K-100 K/sq. mi (100 sq. mi. shoot = $5-$10 MM) and take over a year including the design/permitting/ shooting/processing and interpretation. The seismic survey may yield no drillable prospects, or prospects that cannot be leased, or prospects already owned by another E&P company resulting in complete loss of capital. Shooting a singular 3D Survey has too high a risk to be viable.
7. **Production Purchase**
   This is the most common initial investment for novice oil and gas investors, and the by far the worst of all strategies. Producing oil and gas properties are sold on an auction basis through online brokerage sites such as Petroleum Listing Services or EnergyNet (each have over 25,000 registered buyers). In all cases the seller knows more about the property than the buyer. The seller puts a minimum bid price on the property (typically more than it is worth) and then offers the property at auction. Each property typically receives multiple bids, some low ball offers, several bids near the PV10 value, and a few higher outlier bids made by bidders who have over-estimated the reserves or have a higher price deck. The highest outlier bid is accepted, almost guaranteeing that the high bidder (auction winner) is paying too much for the producing property. Unless oil and gas prices increase the returns are negative. If one desires to bet on the commodity price deck, then direct energy futures and swaps are available on the exchanges.
8. **Production Purchase with Development Drilling**
   This is also a common investment strategy for oil and gas investors. As discussed above, the purchase of the producing assets through an auction process results in an overpayment of the producing asset, so one starts at a deficit. The initial operator produces most of the reserves with the crestal most prolific wells drilled early and then delineates the field with 3D seismic data. Advanced processing can sometimes result in discovering additional reserves in and around the producing fields. However, in most cases, the reserve additions are marginal and late development wells are drilled near the flanks of the field's existing production, at the oil water contact, or at the gas water contact. The development wells are geologically risky or find marginal additions. Usually the original operator exploits the profitable reserves and the later monies spent on developing the field results in losses or churning dollars. Purchasing production at a premium cost and paying for undeveloped reserves (which are the technically most difficult and expensive to develop) usually results in negative or marginal returns.
9. **Prospects away from Infrastructure or Markets (USA, Canada, or Overseas)**
   Oil and gas discoveries without in-place infrastructure or away from markets can be almost worthless or extremely discounted in valuation. In many cases, the pipelines or companies with infrastructure hold the discovery hostage and extract any profits. Examples include Canadian crude trading at a large discount to WTI. Gas in the Rockies, W. Texas and Pennsylvania

receive considerable discounts to the Henry Hub prices. Oil and gas discoveries must be made near infrastructure and ready markets especially during low price cycles.

With all the above strategies economically unattractive, the only viable investment strategy for exposure to the oil and gas sector is Gulf Coast Conventional Onshore E&P.

10. **Conventional Onshore Oil and Gas Discoveries**

The large reserve conventional onshore oil and gas discovery within the Gulf Coast infrastructure is the most profitable asset in the oil and gas sector. It is the origin of most of the significant profits made thought out the history of the oil and gas business. The relatively inexpensive costs of drilling and developing large reserve prolific onshore discoveries creates profits unavailable from high cost overseas, offshore, or unconventional (shale) plays.

**Large reserve conventional onshore US gas fields near Gulf Coast markets are now the asset of choice**. **The "smart money" invests in the undeveloped assets, makes the oil and gas discoveries, and sells the proven production to the Production Buyer ("dumb money")**

# Is Purchasing Working Interests in 3rd Party Generated Prospects a Viable Strategy?

**Promoted Prospects** - Typically the buyer pays upfront cost reimbursement of land, seismic and G&G and a generation fee. The generator typically retains a royalty and a back-in or carried working interest. The purchaser pays >100% of the costs for 75% of the working interest revenues APO, > 60% of actual oil and gas production revenues minus operating fees.

**Great Prospects are not marketed** - Well capitalized companies only promote out their higher risk or smaller reserves prospects. Example: Marathon showed prospects at Nape every year but never showed their CV Reef Play. Even with under-capitalized entities, the very best prospects are usually funded by insiders, family, friends, or partners who previously funded the generator. The very best prospects are rarely shown to outside 3rd. parties or the industry.

**Time Problem** - Purchasing interests in prospects one at a time and drilling prospects one at a time requires long time frames to reduce risk through portfolio theory. Major Oil Co.'s achieved portfolio theory risk reduction by drilling 100 prospects per year. Today this cannot be achieved due to the limited availability of prospects and time (most are not "drill ready", permitted, etc.).

**Singular Trend** - Most generators work one play thereby limiting buyer scope and diversity. For ex: if you are investing with a S. TX Wilcox generator, you may see other 3rd. party Wilcox submittals but may not see a Rob L prospect in S. LA. generated by a Lafayette based geologist.

**Lack of Conventional Prospects** - With the abandonment of the onshore in favor of the unconventional plays most prospect generators moved to the shale plays. Very little effort or monies were spent on generating new conventional prospects. Currently there are few conventional prospects generators and a dearth of high quality outside generated prospects

**Diversification** – Today it is impossible to construct a well-diversified portfolio of drilling prospects by purchasing 3rd party prospects. Most high-quality ideas were drilled years ago.

**Due to the limited available, low quality and small reserve size of 3rd party prospects, purchasing interest on promoted terms from the industry likely results in trending water.**

**Previous Onshore Success** -After the 1986 oil price crash, several independents (North Central, Rudman, Odyssey, Cabot, and a few others) generated prospects and shared risk with each other. They were the only remaining buyers of prospects. After the layoffs, many geoscientists left their previous large/major oil companies with prospects. Over 5 years, this group were able to achieve diversification by their own generation, their shared participation with each other and collective participation in 3rd. party generated prospects. Although there have been individual successes, this anomalous period was the last time where the strategy of purchasing WI in prospects was successful. These companies were sold, North Central to Pogo for $680 MM, etc.
**Previous Offshore Success** – During the 1980-90s, several independents (Superior, Zilka, Samedan, Walters etc.) had success farming in shallow GOM prospects from majors that were not pursued due to size and/or perceived risk.

## XIII. Advantages of Onshore US Conventional Oil and Gas

- **Location on Gulf Coast** - ready markets with WTI+ oil and Henry Hub gas prices
- **Inexpensive lease costs** – limited aerial extent with 1/10th -1/100th cost of shale plays.
- **Inexpensive drilling costs** – vertical wells
- **Inexpensive completion costs** –simple completions, no multistage fracking required.
- **Existing infrastructure** – main pipelines and gathering in-place, cryogenic plants etc.
- **Excellent market options** – end users, LNG facilities, petrochemical plants, or pipelines
- **Large oil and gas reserves** – select to drill and develop prospects with significant reserves
- **Prolific flow rates** – conventional reservoirs are typically high porosity & high perm.
- **Excellent lease terms** – private mineral ownership without competition, typically 3-5 year term with 75% a net revenue interest or better.
- **Available seismic** – Purchase existing seismic data from Seismic Data Inc (SEI), Seitel or other seismic libraries at ~ 1/10th of the original acquisition costs.

- **Seismic processing** – Full Wave form Inversions and other new processing techniques are recently available to better image the features and increase the success rate P(s).

- **Permit/Environmental** – Gulf Coast locations pose no environmental/ permitting issues.

- **Sovereign Risk** - Foreign assets have nationalization risk and more importantly deal term risk where taxation, royalties, repatriation, and other terms can be changed by the host government especially during regime change. US assets offer no such political risks.

- **Valuation/Salability** - conventional oil and gas discoveries are easily valued by conventional engineering and sold at valuations typically PV10 or better. Post discovery they are much more easily monetized than unconventional resource projects

- **No competition** – few conventional E&P groups remain, little expertise

- **Time to First Sales** – typically wells can be brought online < 90 days after completion

## XIV. Liquidity of Oil and Gas Assets

## Conventional O&G Fields – Excellent Liquidity

**Exit Strategy – known reserves, low decline, stable cash flows yield a known PV10 value. Easily monetized through auction process (EnergyNet 45 K+ buyers), public, private O&G and financial co.'s. Production buyers desire low decline cash flow assets.**

Known Oil & Gas Reserves – accurately calculated and confirmed 3 ways

- Material Balance — clear P/Z analysis for gas, cum vs. FTP for oil reservoirs
- Volumetric — 3D aerial extents, pay height, log porosity and water saturations
- Decline Curve — simple straight line exponential declines.

Future Cash Flows – Predictable and Profitable

- Few wells — High quality reservoirs (high Por, Perm), large recoveries per well
- Flow rates — High flow rates with low annual exponential declines
- Low LOE — Low operating costs - (no re-fracks)
- Future costs — Little to no costs required to sustain long term cash flow
- Lease costs — Very low cost/acre with small aerial extents minimize upfront costs
- Location — Gulf Coast receives premium prices, Henry Hub gas, WTI/LLS oil

# Unconventional O&G Production – No Liquidity

**<u>Old Exit Strategy</u>**

- Purchase large leasehold and complete several proof of concept wells.
- Over-estimate reserves using hyperbolic decline or type curves, underestimate actual development and operating costs, then multiply by the number of potential development wells. Sell to public companies using land price and production metrics of previous transactions to justify price. Previously, they disguised return of capital as return on capital.

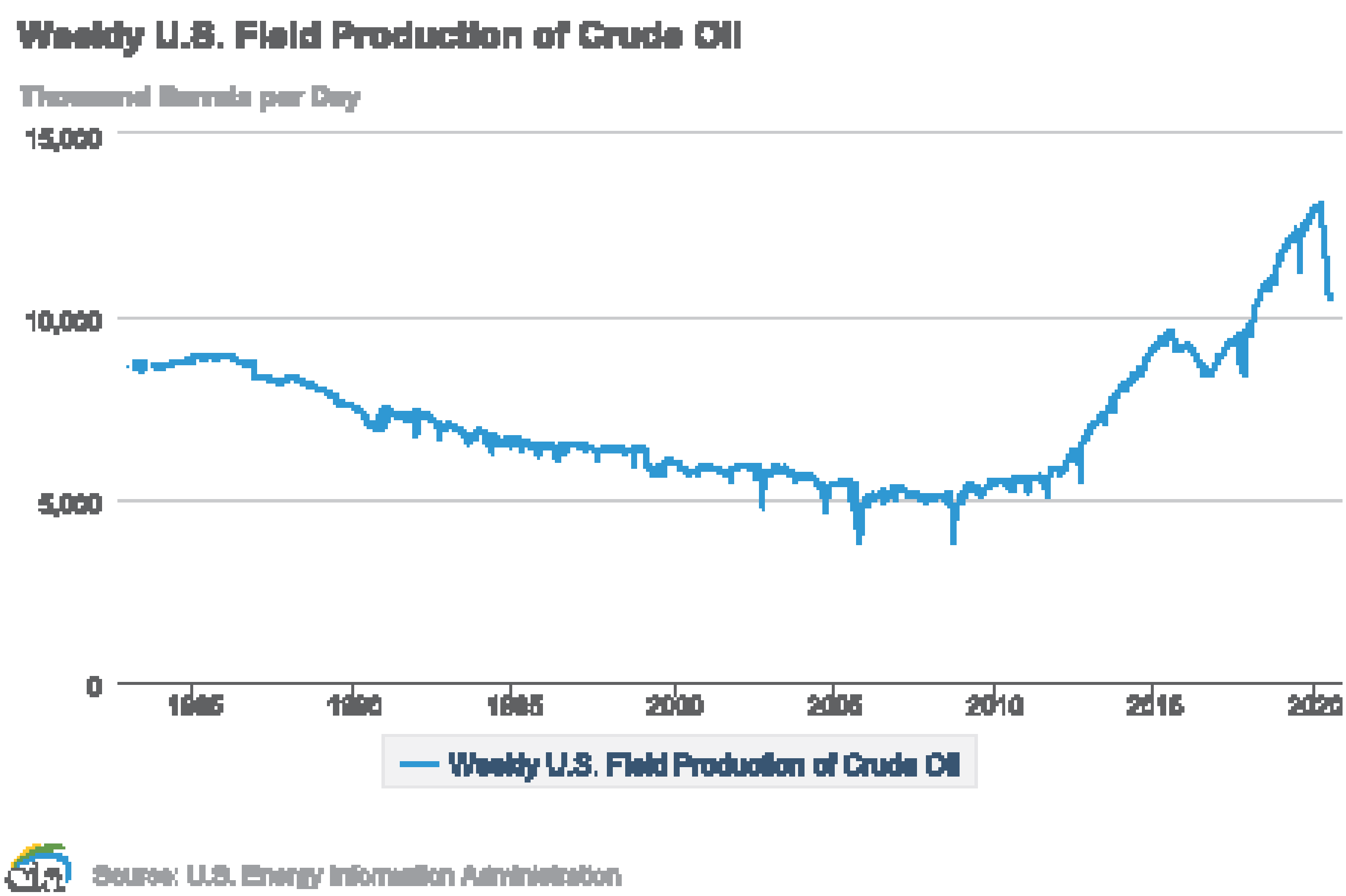
**<u>2020 Exit -</u> Few buyers exist for marginal return cost intensive assets. They have few near-term monetization options and have almost no ability to raise capital. Production Buyers do not want high decline producing assets.**

<u>Un Known Oil & Gas Reserves</u>

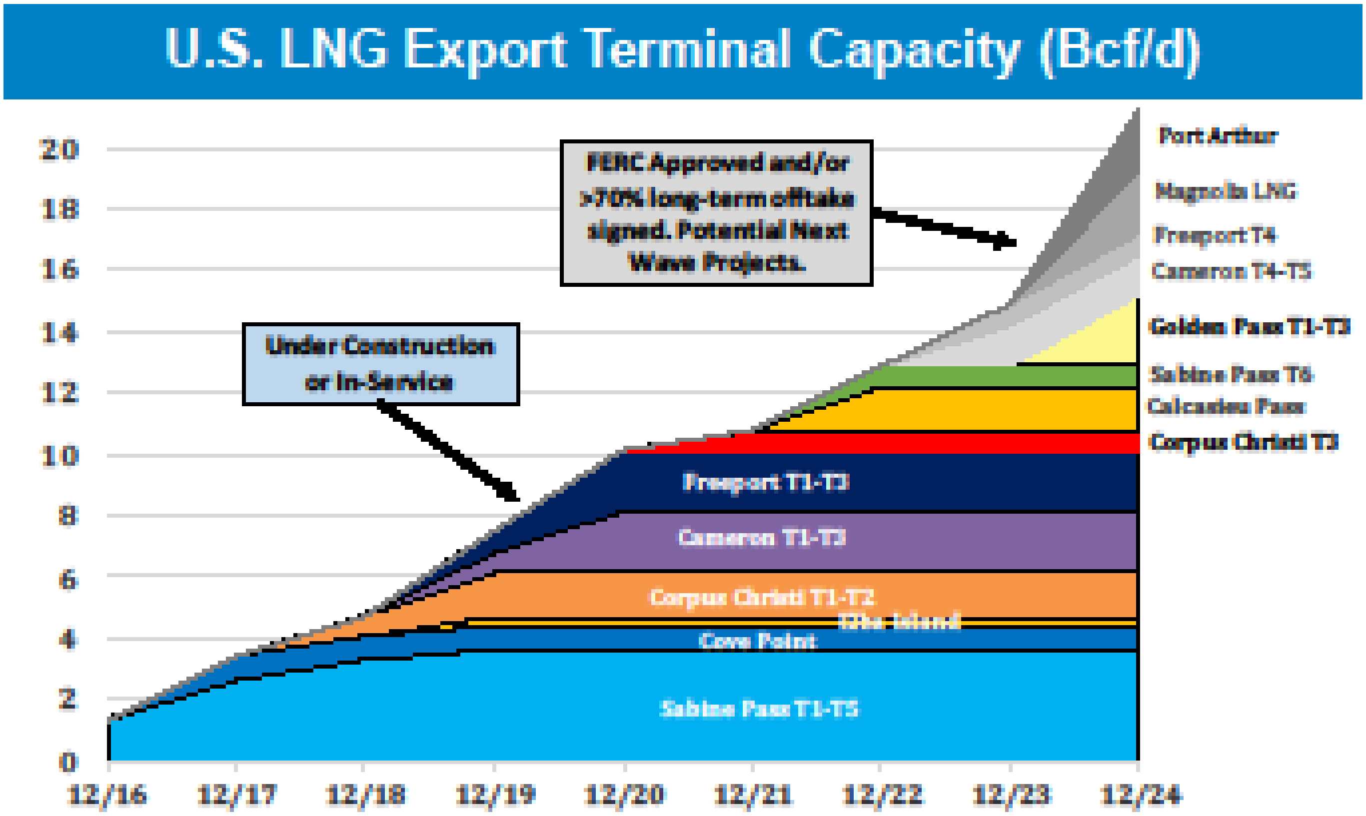
- Volumetric — Cannot be calculated for fractured low porosity wells.
- Decline curve — Un-reliable hyperbolic declines or type curve estimates.

<u>Future Cash Flows - Unknown</u>

- Decline rates — Very high initial decline rates with unknown future declines
- High LOE — Many have high water disposal costs, re-fracks necessary
- Future costs — Continuous drilling required to maintain production and cash flow
- Lease costs — Large upfront land costs severely reduce PV10 Profit valuation
- Location — Many have high price differentials. (Permian, Appalachia, Rockies)



# LNG USA Export Facilities




Range Resources 6/2020 Company presentation

# EIA Short Term Energy Outlook - LNG

LNG exports capacity is at 8.9 BCFPD with peak 10.1 BCFPD. The US is now the 3rd largest LNG exporter behind only Qatar and Australia.

In January 2020, a record 74 cargoes were loaded in the USA totaling 8.1 BCFPD.

Daily natural gas deliveries to LNG export facilities peaked at 9.8 BCFPD in March 2020 but have fallen to >3.2 BCFPD in June 2020. More than 70 cargoes have been cancelled in June and July due to high natural gas storage inventories in Europe and Asia due to COVID 19 related decreased demand.

LNG exports peaked at 8 BCFPD (12/2019) fell to 7 BCFPD in April, 5.8 in May, 3.2 in June and 3.1 BCFPD in July 2020. The EIA expects LNG exports be at 9 BCFPD by Nov 2020 and to average 7.3 BCFPD in 2021.

# LNG - US Export Facilities

**Current USA LNG Exporty Facilities**

| Operator | Project | | BCFPD | MTPA | EIA 2020 BCFPD |
|---|---|---|---|---|---|
| Cheniere | Sabine Pass T1-5 | | 3.50 | 26.60 | 3.00 |
| Dominion Energy | Cove Point | | 0.76 | 5.78 | 0.70 |
| Kinder Morgan | Elba Island | | 0.33 | 2.50 | 0.30 |
| Cheniere | Corpus Christi T1-2 | | 1.80 | 13.68 | 1.20 |
| Cameron LNG | Cameroon T1-3 | | 1.97 | 14.95 | 1.80 |
| Freeport LNG | Freeport T1-3 | | 1.97 | 15.00 | 2.00 |
| | | Total | **10.33** | | **8.90** |

**Future USA LNG Exporty Facilities**

| Operator | Project | | BCFPD | MTPA | On Line |
|---|---|---|---|---|---|
| Cheniere | Corpus Christi T-3 | | 1.20 | 9.12 | 1H 2021 |
| Venture Global | Calcasieu Pass | | 1.32 | 10.03 | 2021 |
| Cheniere | Sabine Pass T-6 | | 0.40 | 3.04 | 2021 |
| | Golden Pass T1-3 | | 2.00 | 15.20 | 2023 |
| Cameron LNG | Cameron T4-5 | | 1.31 | 9.97 | 2022 |
| | Freeport T4 | | 0.30 | 2.28 | 2022 |
| | Magnolia LNG | | 1.60 | 12.16 | 2023 |
| | Port Arthur | | 1.00 | 7.60 | 2023 |
| | | Total | **9.13** | | |

**In Financing Stages**

| Operator | Project | | BCFPD | MTPA |
|---|---|---|---|---|
| Tellurian | Driftwood | | 3.63 | 27.6 |
| | (20 trains @1.38 MTPA each) | | | |
| Sempra | Port Arthur | | 1.78 | 13.5 |
| | (potential for add to 45 MTPA) | | | |
| Sempra | ECA (West Coast) | | 1.00 | 7.6 |
| | | Total | **6.41** | |

# EIA Weekly Storage Report

**Natural Gas (9/16/2020)**

Working gas in storage is 3,614 BCF. Stocks are + 535 BCF over last year and + 421 over the 5 year average of 3,116 BCF (+13.2%).

**Crude Oil (9/23/2020)**

US commercial crude oil in inventories (excluding those in the Strategic Petroleum reserve) decreased 1.6 MMBBLS to 494 MMBBLS which is 13% above the 5 year average after reaching an all-time high 5 weeks ago of 540 MMBBLS.

| | | |
|---|---|---|
| Gasoline Inventory | -4.0 MMBBL | 1% above 5 year average |
| Distillate | -3.4 MMBBL | 21% above 5 year average |
| Propane/Propylene | +1.7 MMBBL | 12% above 5 year average |
| Total Petroleum Inventories | +4.3 MMBBLS from last week | |

| | | |
|---|---|---|
| Total Products Supplied | 17.8 MMBBLS | -15.9% from last year |
| Gasoline supply (4 week avg.) | 8.5 MMBBLS | -9.0% from last year |
| Distillate Fuel (4 week avg.) | 3.6 MMBBLS | -8.2% from last year |
| Jet Fuel Supply(4 week avg.) | | -45.8% from last year |

**EIA Short Term Energy Report Gas (9/9/2020)**

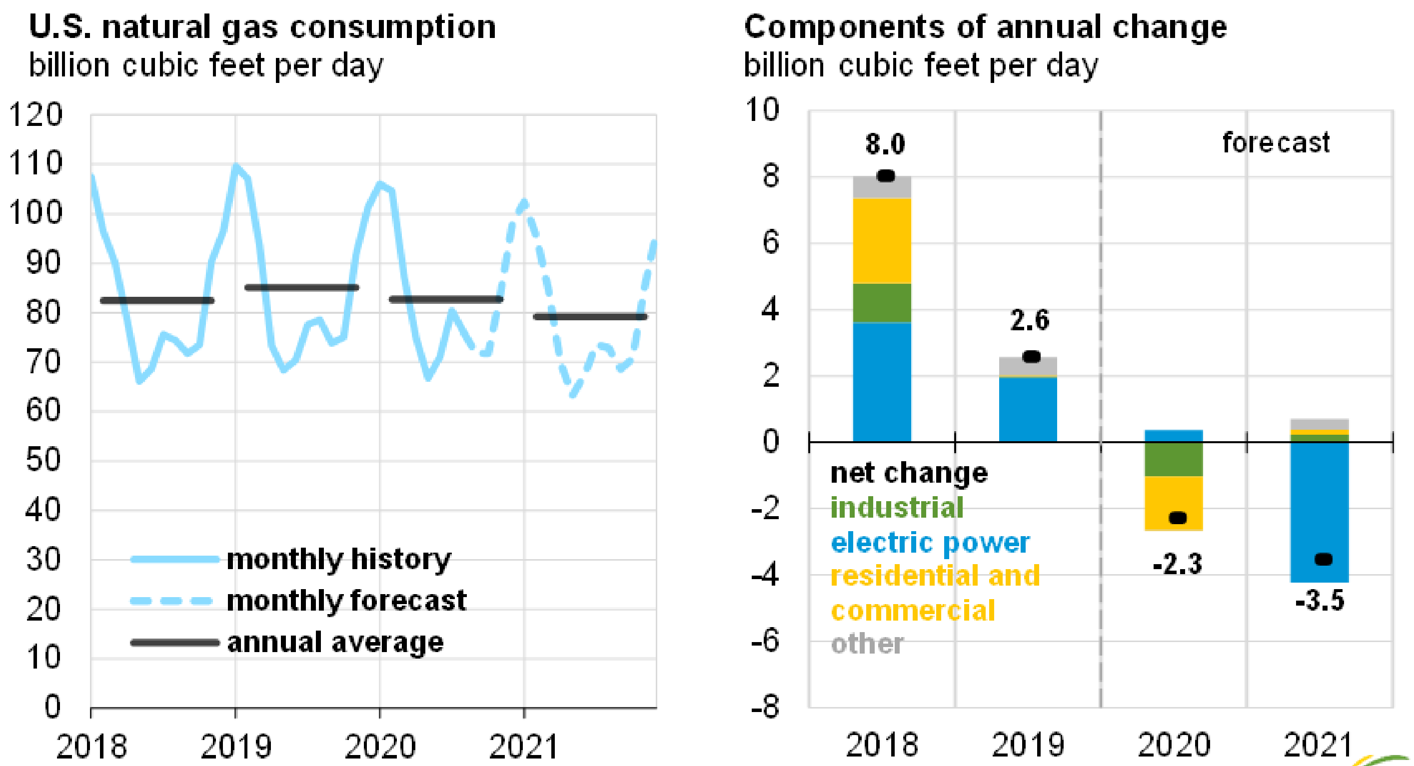
EIA forecasts the end of storage (EOS -October 30th) inventory to be 3.946 TCF, 277 BCF or 6% above 5 year average of 3,723 BCF (2016 EOS=4.013 TCF).

| 2020 US Consumption | | | |
|---|---|---|---|
| Electric Power | 31.35 BCFPD | +.4 BCFPD | |
| Industrial Consumption | 21.9 BCFPD | -1 BCFPD | |
| Residential | 12.9 BCFPD | -.8 BCFPD | |
| Commercial | 8.8 BCFPD | -.8 BCFPD | |
| US Total | 82.7 BCFPD | -2.3 BCFPD | (-2.7%) |

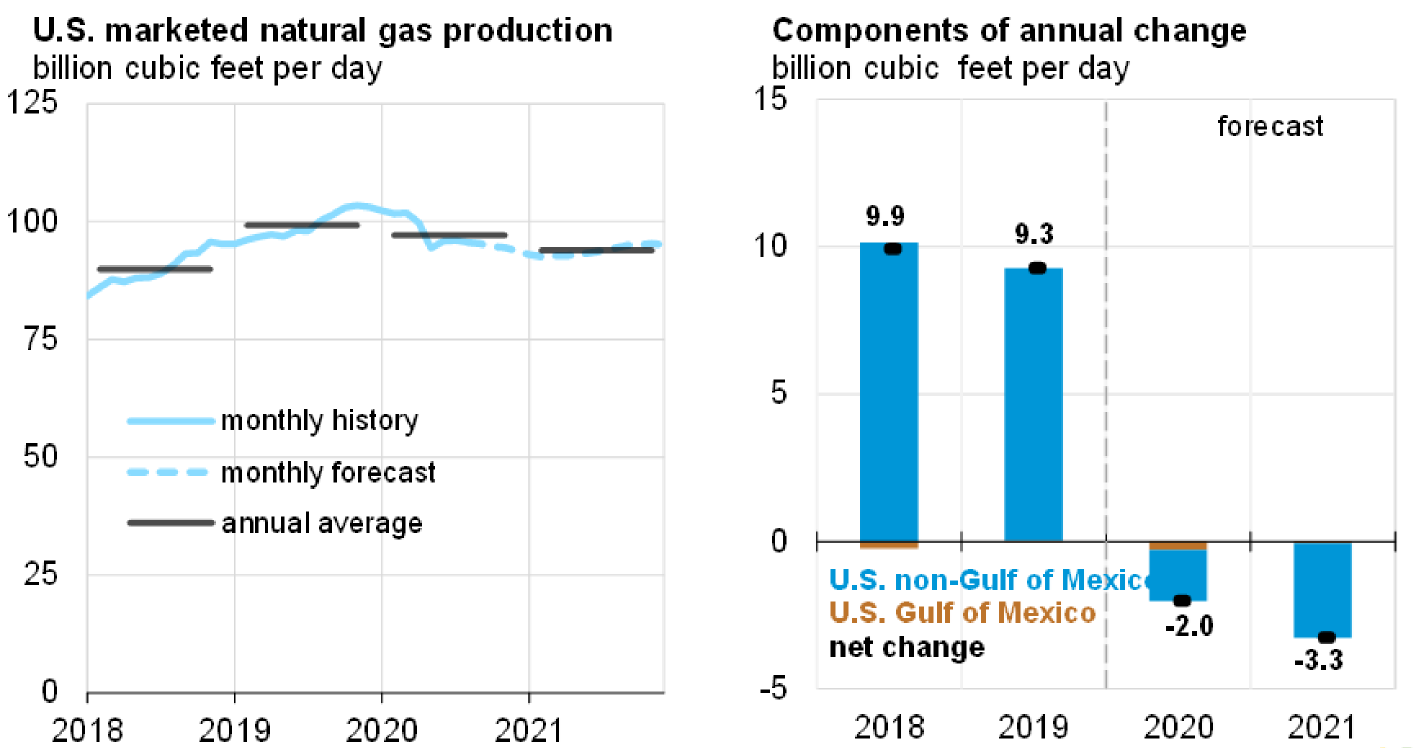
| 2020 Production | |
|---|---|
| US Dry Gas | 89.9 MMCFPD (peak of 96.2 down to 85.5 Feb 2021) |
| Imports | 6.84 BCFPD |

2021 Forecast Production    86.6 BCFPD yearly average -9.6 BCF (-10%) from peak

EIA Monthly Production Report (9/14/2020)
Sept to October 2020    Shale Oil = -68 MBOPD  Shale Gas = -428 MCFPD

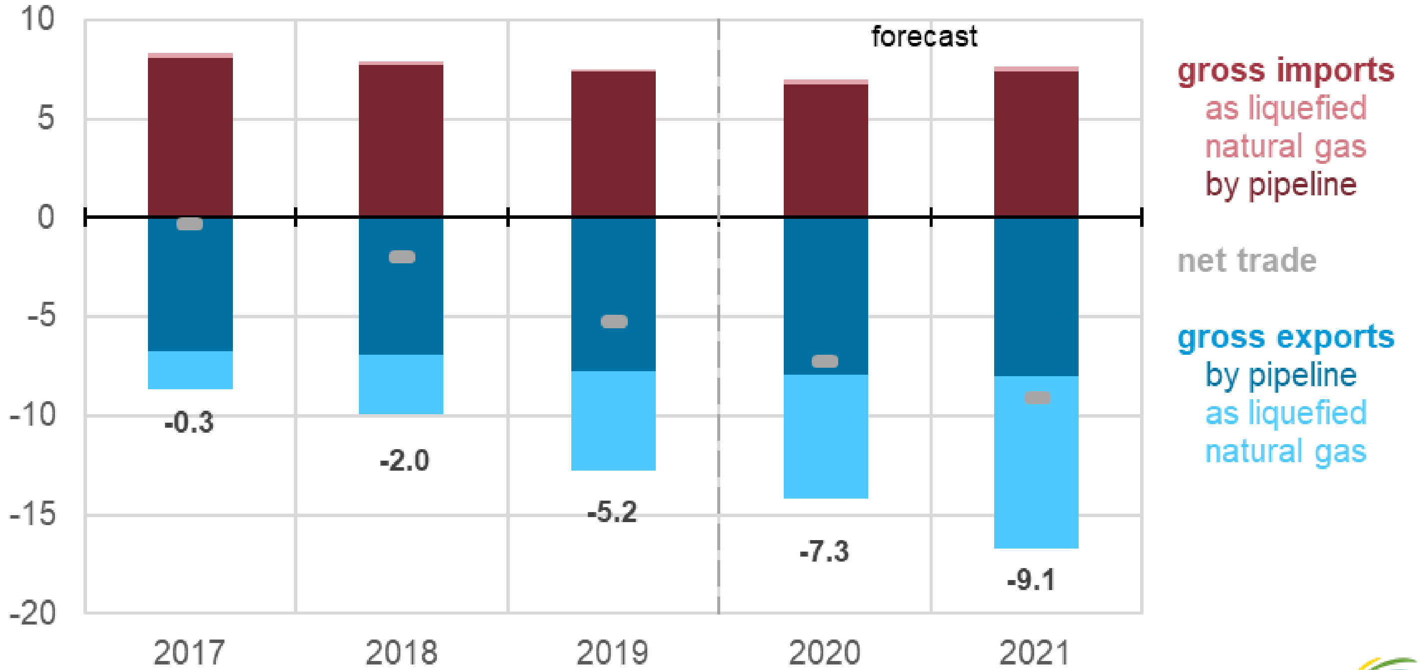



Source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2020



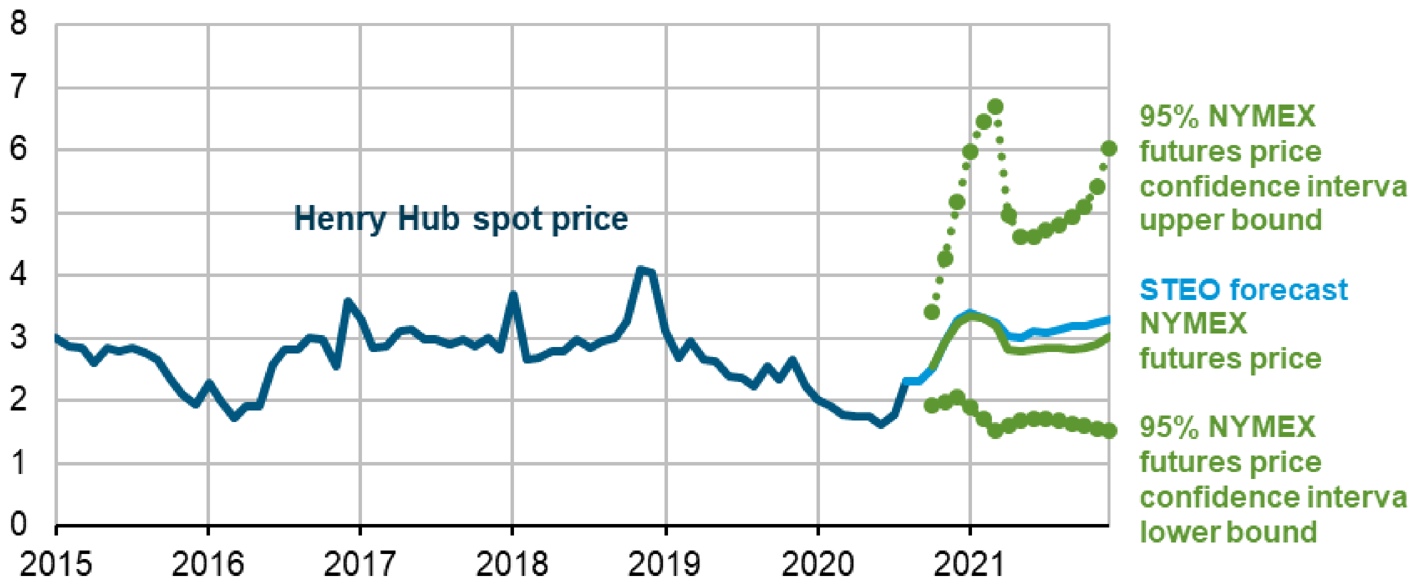

Source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2020

**U.S. annual natural gas trade**
billion cubic feet per day




Source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2020

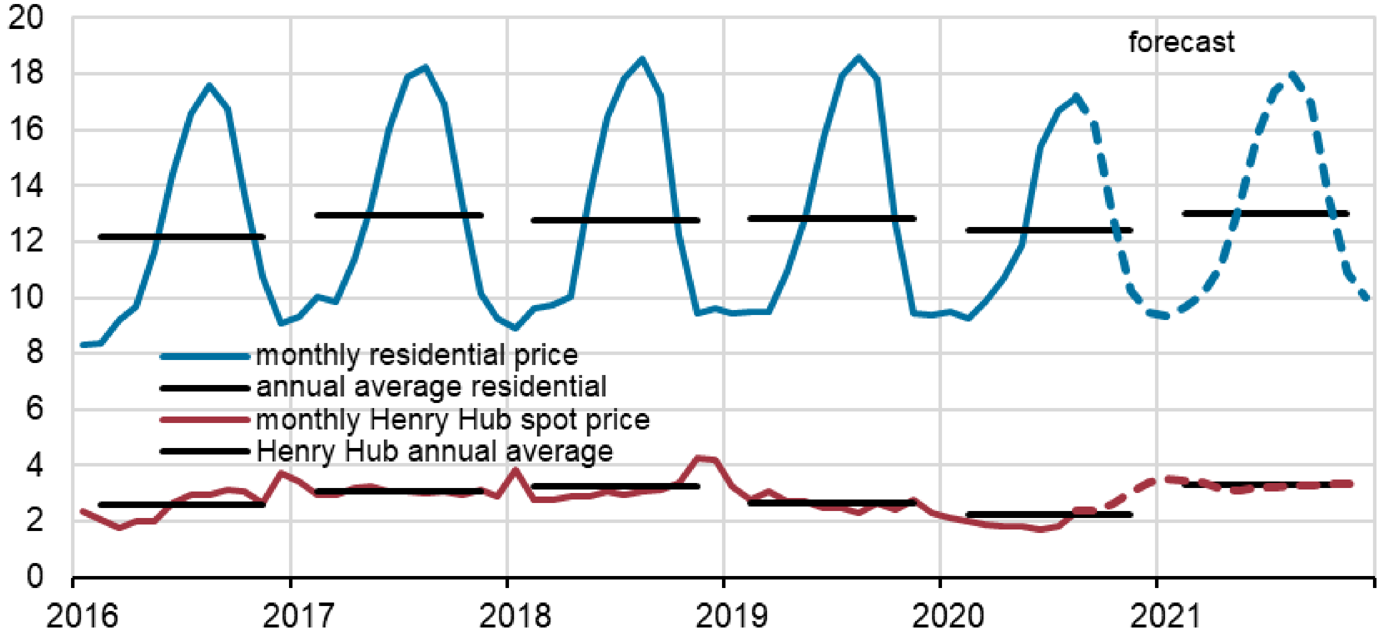
**Henry Hub natural gas price and NYMEX confidence intervals**
dollars per million Btu




Note: Confidence interval derived from options market information for the five trading days ending Sep 3, 2020. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Sources: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2020, and CME Group

**U.S. natural gas prices**
dollars per thousand cubic feet




Sources: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2020, and Refinitiv

| US Liquids Production | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| TYPE | 2019 | | 2020 | | 2021 | |
| | MMBOPD | % | MMBOPD | % | MMBOPD | % |
| | | | | | | |
| Tight Crude | 7.80 | 42.16% | 6.78 | 39.67% | 7.08 | 40.83% |
| GOM | 1.88 | 10.16% | 1.89 | 11.06% | 1.94 | 11.19% |
| Conventional | 2.65 | 14.32% | 2.40 | 14.04% | 2.18 | 12.57% |
| | | | | | | |
| Unconventional NGLs | 4.01 | 21.68% | 4.14 | 24.22% | 4.21 | 24.28% |
| Conventional NGLs | 0.80 | 4.32% | 0.78 | 4.56% | 0.76 | 4.38% |
| Biofuel and other | 1.36 | 7.35% | 1.10 | 6.44% | 1.17 | 6.75% |
| | | | | | | |
| **Totals** | **18.50** | | **17.09** | | **17.34** | |
| OPEC (8/2020 report) | | | | | | |

# Recent Consolidation - Mergers and Acquisitions

| Buyer | Seller | Basin (Play) | Price ($B) |
|---|---|---|---|
| **Permian Basin** | | | |
| Chevron | Noble | Permian/DJ/Overseas | 13.00 |
| Oxy | Anadarko | Permian/other | 57.00 |
| Cimarex | Resolute | Permian | 1.70 |
| Callon | Undisclosed PE Co. | S. Midland Basin | 0.26 |
| Concho | RSP Permian | Permian | 9.50 |
| Noble | CWEI | Permian | 3.20 |
| BP | BHP | Pemian/Eagleford | 10.50 |
| Diamondback | Energen | Permian | 9.20 |
| Diamondback | Ajax | Permian | 1.25 |
| RSP Permian | Silver Energy | Permian | 2.40 |
| Carizo | Devon | Delaware Basin | 0.22 |
| Oasis | Forge | Delaware Basin | 0.95 |
| Centennial | GMT | Delaware Basin | 0.35 |
| Concho | Endurance | N. Delaware Basin | 0.43 |
| Earthstone | Sabalo | Permian | 0.95 |
| Exxon | BOP | Permian | 5.60 |
| Noble | CWEI | Permian | 3.39 |
| Parsley Energy | Double Eagle | Permian | 2.80 |
| Ring Energy | WishboneEnergy | Central Platform | 0.30 |
| Percussion (Carnelian PE) | Spur Energy ( KKR) | New Mexico | |
| Callon Petroleum | Carrizo | Permian/Eagleford | 0.75 |
| Elliott Management | QEP | Permian | 2.07 |
| Kimmeridge Energy Mgmt. | Desert Royalty | Delaware Basin | |
| Parsley Energy Inc. | Jagged Peak Energy | Delaware Basin | 2.30 |
| Pure Acquisition | Highpeak,Grenadier II | Permian | 1.58 |
| WPX Energy | Felix Energy II | Delaware Basin | 2.50 |
| | | **Sub-Total** | **132.19** |
| **Eagle Ford - S. TX** | | | |
| Magnolia (TPG Spac) | Enervest | Eagle Ford | 2.60 |
| Denbury | Penn Virginia | Eagle Ford | 1.70 |
| Chesapeake | WildHorse | Eagle Ford | 4.00 |
| Repsol | Equinor | Eagle Ford | 0.33 |
| | | **Sub-Total** | **8.63** |
| **Scoop/Stack - Ok.** | | | |
| Encana | Newfield | Stack/Scoop | 5.50 |
| AMR (Riverstone Spac) | Alta Mesa/KingFischer | Scoop | 3.80 |
| Apache | Presidio, Red Wolf | Stack/Scoop | 0.60 |
| Chisholm Oil and Gas LLC | Gastar Exploration LLC | Stack | ? |
| Contango | White Star Petroleum | Stack | 0.13 |
| Citizen | Roan Resources | Scoop/Stack | 1.01 |
| | | **Sub-Total** | **11.05** |

| Buyer | Seller | Basin (Play) | Price ($B) |
|---|---|---|---|
| **Gulf Of Mexico** | | | |
| Murphy | LLOG | GOM Deep Water | 1.38 |
| Kosmos | Deep Gulf | GOM Deep Water | 1.23 |
| Cox | EXXI | GOM Shelf | 0.32 |
| Fieldwood | Noble GOM | GOM Shelf | 0.48 |
| Shell | Delek | GOM - Caesar Tonga | 0.97 |
| Talos | Stone | GOM Shelf | 1.60 |
| | | **Sub-Total** | **5.97** |
| **USA - Other** | | | |
| Comstock | Covey Park LLC | Haynesville | 2.20 |
| Amplify | Midstates Petroleum | Merger | 0.43 |
| Sandridge | Bonanza Creek | DJ Basin | 0.75 |
| EQT | Rice Energy | Marcellus | 8.20 |
| Aetheon Energy | QEP | Haynesville | 0.74 |
| DJR | Encana | San Jaun | 0.48 |
| Northern O&G | Flywheel Energy | Williston Basin | 0.31 |
| QEP | Elliot Management | Permian, Williston | 2.00 |
| Vantage (Spac) | QEP | Williston Basin | 1.65 |
| PDC Energy Inc | SRC Holdings | DJ Basin | 1.70 |
| Osaka Gas | Sabine | East Texas | 0.61 |
| | | **Sub-Total** | **19.06** |
| **Asset Purchases** | | | |
| Encino | Chesapeake | | 1.90 |
| Ascent Resources | CNX Resources, Hess Oil | | 1.50 |
| TPG Pace Energy | Enervest | | 2.66 |
| Bruin E&P Partners | Halcon Resources | | 1.40 |
| HG Energy | Noble Energy | | 1.13 |
| Hilcorp Energy | ConocoPhillips | | 2.70 |
| Ensign | Pioneer | Eagleford | 0.48 |
| Sanchez Energy | Anadarko | | 2.30 |
| Spur Energy Parners | Concho | New Mexico | 0.93 |
| Mach Resources LLC | 3 Purchases | Miss Lime | |
| Hilcorp Energy | BP Alaska | | 5.60 |
| SRC Energy Corp. | Noble | DJ Basin | 0.61 |
| Kalnin Ventures | Devon | Barnett | 0.77 |
| | | **Sub-Total** | **21.96** |
| * - Did Not Close | | | |
| | | **Total- USA** | **198.85** |