OIL MARKET FORECAST – NOVEMBER 2020

Summary

This forecast sees a continuing reduction in oil inventories through the remainder of the year, but with higher inventories in 2020 and a larger build in 2021, due mainly to revisions in earlier estimates of supply and an earlier and stronger than expected recovery in the US onshore.

While the EIA published its International Energy Outlook for 2020 last month, this revision does not include an update of their long term demand forecast. As all the major long term forecasts have now been updated, this section looks at the implications of peak oil demand in the next decade or two for the industry.

A few key points:

- Oil inventories will fall to 2019 levels around 2023.
- Under current assumptions, the oil market returns to oversupply in 2021 and then a small supply deficit in 2022, which accelerates into 2023.
- Estimates of global crude stocks in 2021 support and extension of OPEC+ production curbs.
- A comparison of breakeven prices suggests that low operating costs will be more important than low lifecycle breakeven costs once oil demand begins to decline.
- US shale will be the best positioned asset type once oil demand begins to decline.
- In the expectation case, a structural supply deficit emerges in 2023 and continues beyond as demand recovers while supply stagnates. The structural supply deficit is exacerbated by higher demand in the OPEC case.

Oil Supply and Demand

Demand estimates from the latest IEA report[i] show a decline in demand for the second half of 2020 and the first quarter of 2021, with demand estimated at 91.0 MMbbl/day and 96.8 MMbbl/day for 2020 and 2021 respectively. The latest EIA report[ii] is mixed with slightly higher demand in 2020, at 92.9 MMbbl/day, and slightly lower demand in 2021, at 98.8 MMbbl/day. Neither predict demand returning to 2019 levels until 2022 at the earliest.

Revised supply data for June indicates higher supply levels than last month's forecast, of the order of an additional 1 MMbbl/day. Revised supply data for July and August is in line with last month's forecast. The latest EIA data for August shows US production falling back slightly to 15.9 MMbbl/day, from 16.4 MMbbl/day in July. US supply is expected to recover in September, before stabilizing at about 15.5 MMbbl/day through to the end of the year. The US onshore oil rig count continues to rebound since appearing to bottom out in August at 156 units; rigs have been added steadily since September, reaching 210 units as of this report.

Supply is expected to average 91.8 MMbbl/day through the last quarter of the year against average demand of 94.9 MMbbl/day. The last month saw an unexpectedly strong rebound in Libyan production, with November production levels reported at 800,000 bbl/day. At the same time, production in Venezuela was reported to have fallen to just 300,000 bbl/day in June. At the time of writing, OPEC is considering whether to return 2 MMbbl/day of production to the market in January 2021 or extend their current production curbs.

WTI had fallen below the $40 per barrel mark by late October on news of mounting COVID-19 cases and expectations of further restrictions, only to rebound sharply when news started to break of progress on some effective vaccines. The market continues to hold above average supplies of crude in storage, a situation which is now expected to persist until 2023. With the current supply and demand balance, there is no reason to expect a sustained rebound in oil prices in the near term.

Long Oil Term Demand Forecast - Implications of Peak Oil Demand

The EIA published their 2020 international oil outlook last month, but this new edition does not include an update of their base demand forecast, instead it is focused on exploring electricity demand sensitivities. With all the major forecasting institutions having completed their updates it seems like a good time to consider the implications of those forecasts for the industry.

Following the discussion on the various oil demand trajectories and the social cost of carbon in last month's forecast[iii], it seems likely that oil demand will continue to rise for the next ten to twenty years, before plateauing and then beginning to decline. Some media coverage earlier this year suggested that the COVID-19 pandemic foreshadowed what this decline in demand would look like for the industry. As a reminder, if any were needed, April this year saw oil demand collapse by 12.4 MMbbl/day *month on month* at the same time as Saudi Arabia initiated a price war by adding 2 MMbbl/day to global supply. This doesn't seem a suitable analogue for structural demand decline, which is likely to be gradual and sustained over decades. It is likely that peak demand won't be recognized until several years after the event, and post plateau underlying demand decline rates of 1%-2%, of a similar magnitude to pre-plateau demand growth rates, seem more likely.

What are the implications for the industry under this scenario? The major international oil companies have consistently pointed out that the world will need oil, and new supplies of oil, for decades to come, which is consistent with the scenario outlined here. The emphasis has been on developing assets with low breakeven prices, so that when demand declines, those assets will remain competitive while assets with higher break evens will have their production pushed out of the market. This strategy makes intuitive sense. Does that mean that business will continue as normal?

Figure 1, below, is taken from a recent press release by Rystad Energy[iv]. This figure shows the breakeven price of oil supply, broken out by theme. Breakeven prices are on a point forward basis and it appears that averages are used rather than actual field data, as the legend indicates a 60% confidence interval around the average breakeven price presented.

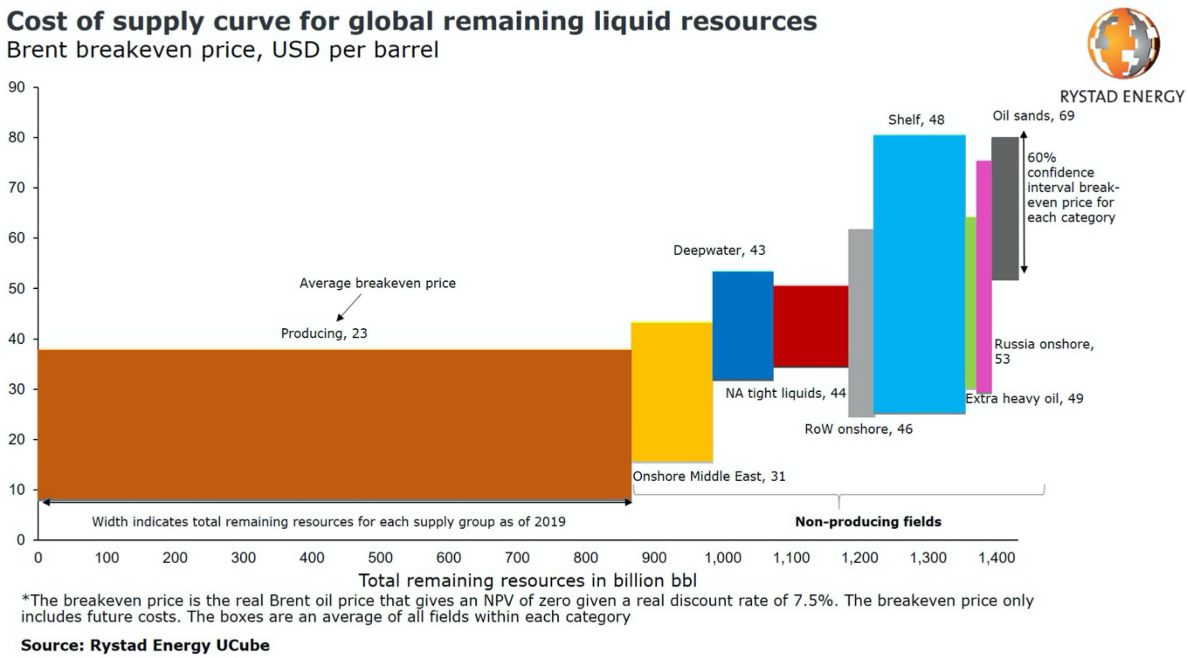

Figure 1 - Oil Supply Cost Curve

Figure 1 distinguishes between producing and non-producing fields and the key takeaway from this chart is that, using average costs on a point forward basis, there is no field development theme that can compete with existing production. Figure 1 is a simplification, within each theme there will obviously be a range of breakeven prices, which will change for each field over time as production declines with age. There will also be fields, in the middle east and perhaps deep water fields in places such as Guyana and Brazil, that can compete with existing production, even including their capital cost. Notwithstanding these points, broadly speaking non-producing fields will struggle to compete with producing fields on breakeven price. This conclusion makes intuitive sense, after all, non-producing fields still require capital investment to bring them on stream, whereas for producing fields, that is a sunk cost. This implies that new production from non-producing fields will not displace existing production from producing fields.

The second point of difference between existing production and non-producing fields is how operational and investment decisions are made. In a producing field, the decision on whether to continue or suspend production is made on the basis of whether the field can be operated profitably, together with a consideration of the value of deferring abandonment. Oil price risk can be transferred by hedging production over the next year or 18 months. Decisions are made over a short time horizon with high certainty. Compare this to a non-producing field. Even those fields that are ready to take a Final Investments Decision are years away from realizing first production, with the return on investment then being made over a further 15 to 30 year period. There is no way to transfer price risk by hedging. In contrast to existing production, decisions are taken over very long time horizons with high uncertainty. The investment case has worked historically because oil demand was rising. How can a company justify the risk associated with that kind of long term investment when demand declines?

The implication of this second point is that investment in new oil fields will cease once demand begins to decline. It won't, of course, stop everywhere at once, but it will taper down with the only the most profitable, short cycle fields continuing to attract investment, until eventually even those are considered to be too high risk.

What does this type of scenario mean for the industry today? In the first instance, the role of exploration in the oil and gas industry will change; it will shrink and shift in focus to infrastructure led opportunities that can be quickly monetized. BP has already announced that it is moving down this route, by abandoning exploration in new basins. Their timing may turn out to be prescient but given the assumption of another decade or two of demand growth, it seems a little early. There are still a lot of high value exploration opportunities available and enough time to monetize them.

This scenario also calls into question the industries current strategy of focusing on fields with low breakeven prices, at least for the next decade or so. Of course, low breakeven prices are always important to the extent that they are also a reflection of overall field profitability, but providing the field is sanctioned within the next decade or two, that production will not be displaced. Under this scenario, low operating costs will be more important over the long run than low lifecycle breakeven prices.

What does the future oil market look like under this kind of scenario? It is intuitive to think that a world in which oil demand declines would be characterized by consistently low prices. But a world in which demand declines at 1%-2% while underlying production declines at 5% and there is no material new investment, is a world in which oil prices would soar. This would be a world in which field redevelopment and infill drilling opportunities could become highly profitable, but they are unlikely to be enough to fill the void.

The kind of asset that would really win in this environment would be one that has no exploration risk, could be brought on stream in months rather than years and which realizes the bulk of its economic value over a time horizon where price risk can be transferred through hedging. If this description sounds familiar, it should. US shale is the ideal asset for a world where oil demand is declining as it has exactly those characteristics. It may turn out that the US shale revolution of the last decade was just a couple of decades early.

To summarize, the scenario presented here is one in which oil demand continues to rise for the next decade or two, plateauing and beginning a slow and steady decline. Once this occurs, investment in new oil and gas fields will quickly decline, resulting in price spikes as underlying field production declines outstrip the decline in supply. US shale becomes the asset of choice, given its short cycle times and the ability to realize most of the value within 18 months of investment.

The best strategy for an oil and gas company to pursue under this scenario is to invest in long life assets with low operating costs, not necessarily the assets with the lowest lifecycle breakeven prices. Maintain an active exploration program, including new basin exploration, and only begin to exit these positions when the projected first oil dates from these fields moves beyond 2035 – 2040. Take advantage of the currently depressed US shale industry to assemble a competitive shale position; a position that can be held over the long term with minimum work commitments. While this is an oil focused article, continuing to invest in profitable gas and renewable opportunities should also form part of this strategy.

Oil Market Balance and Storage

Revisions to supply and demand data mean that oil inventories are now thought to have begun to draw down in June by an estimated 137 MMbbl, as opposed to 166MMbbl in the October forecast and 174 MMbbl in the September forecast. Draws are forecast to continue at an average of roughly 82 MMbbl per month for the second half of 2020, as the OPEC+ supply curbs restrict supply and demand recovers. The latest forecast shows a market that is essentially balanced through 2021 and 2022, before demand outstrips supply again in 2023 and beyond, as demand continues its recovery, but supply stagnates. A supply and demand and surplus forecast is shown in Figure 2, below.

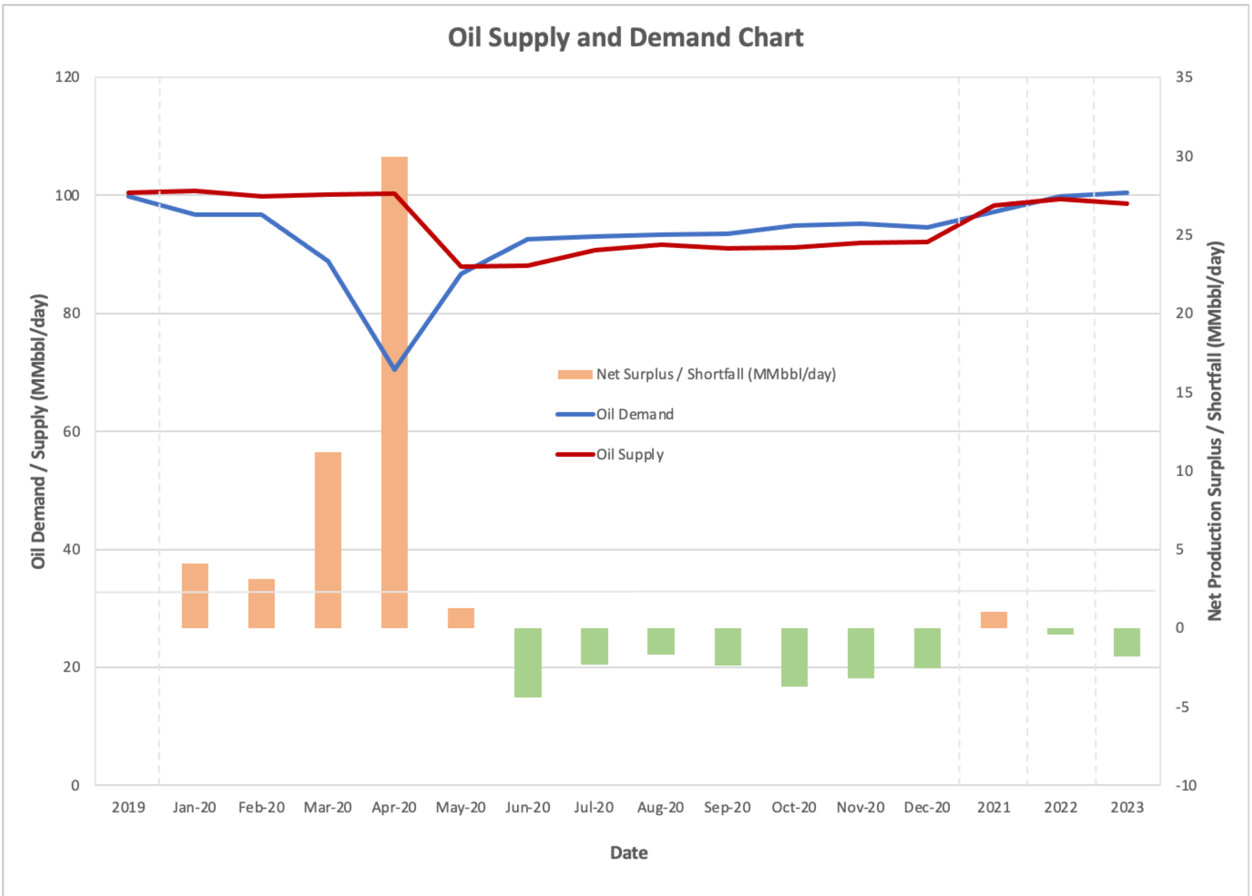

Figure 2 - Supply and Demand and Surplus Forecast

Figure 3 shows global storage capacity and inventories. Global inventories peaked in May at 4.4 billion barrels, nearly half a billion barrels short of the operational limit on global storage.

There have been several revisions to supply and demand data over the months since May, when global inventories peaked. The impact of all these small changes is that the peak in global crude inventories that occurred in May has been gradually adjusted down, but the rate at which the surplus is being worked off has also declined. The net effect is that we now expect to see 4 billion barrels of crude in storage by year end and then expect it to build back to almost 4.4 billion barrels in 2021.

As a consequence, global storage levels don't fall below long-term average until 2023, something that would be expected to further delay the recovery in crude pricing. OPEC has expressed growing concern about continued oversupply and are considering measures to extend their production curbs to prevent this. The near term global storage situation supports the view that supply curbs should be extended into 2021 to prevent this surplus building. Beyond 2023, the longer term storage picture continues to show a structural supply deficit.

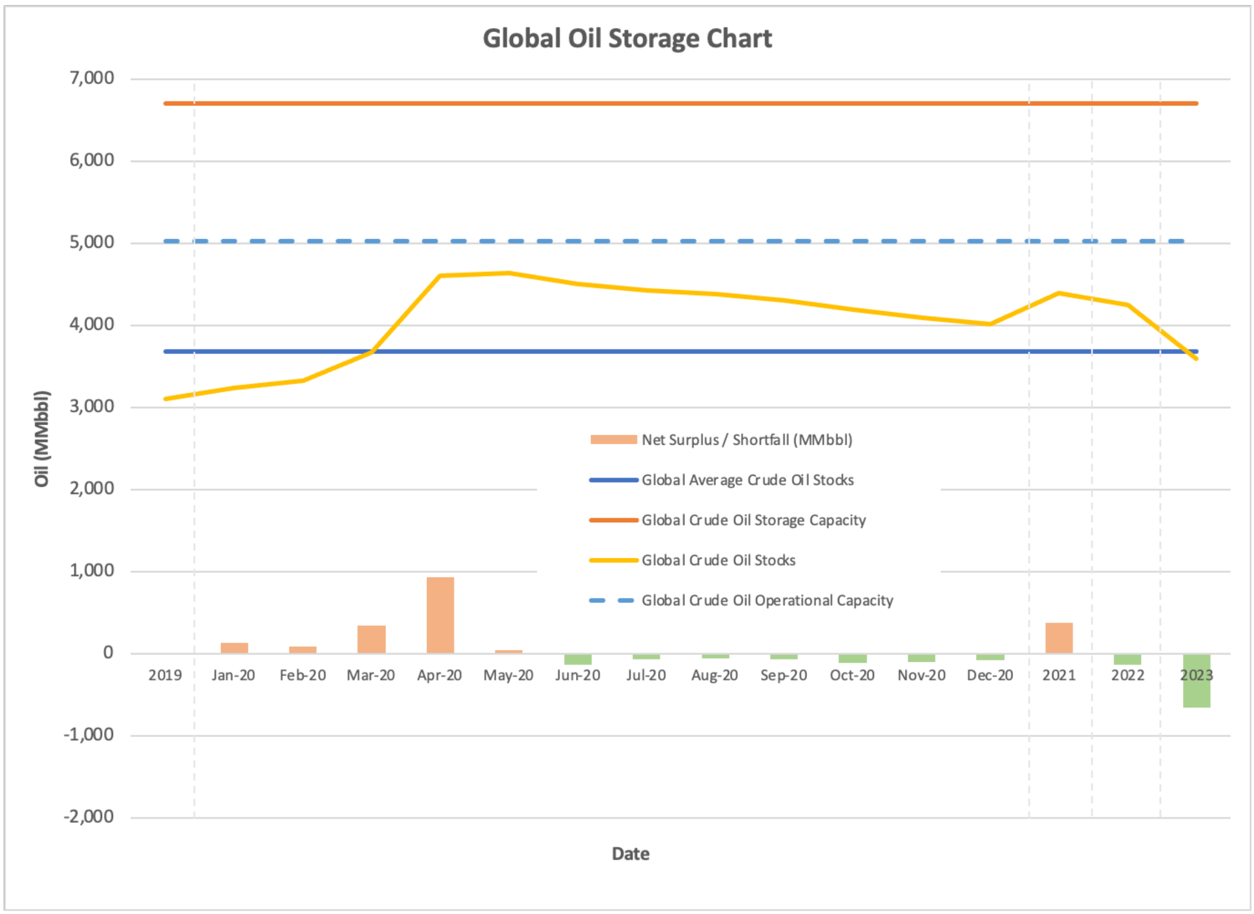

Figure 3 - Global Oil Storage Chart

Impact on US Investment and Oil Production

After a steep decline, the US land oil rig count appears to have bottomed out at 156 units in August and is now mounting a sustained recovery, rising to 210 at the time of this report. Historic and forecast rig count for the year is shown in Figure 4. Some early projections of 2021 US land drilling budgets indicated an increase in activity of 15%, which would suggest average 2021 oil land rig counts of 380.

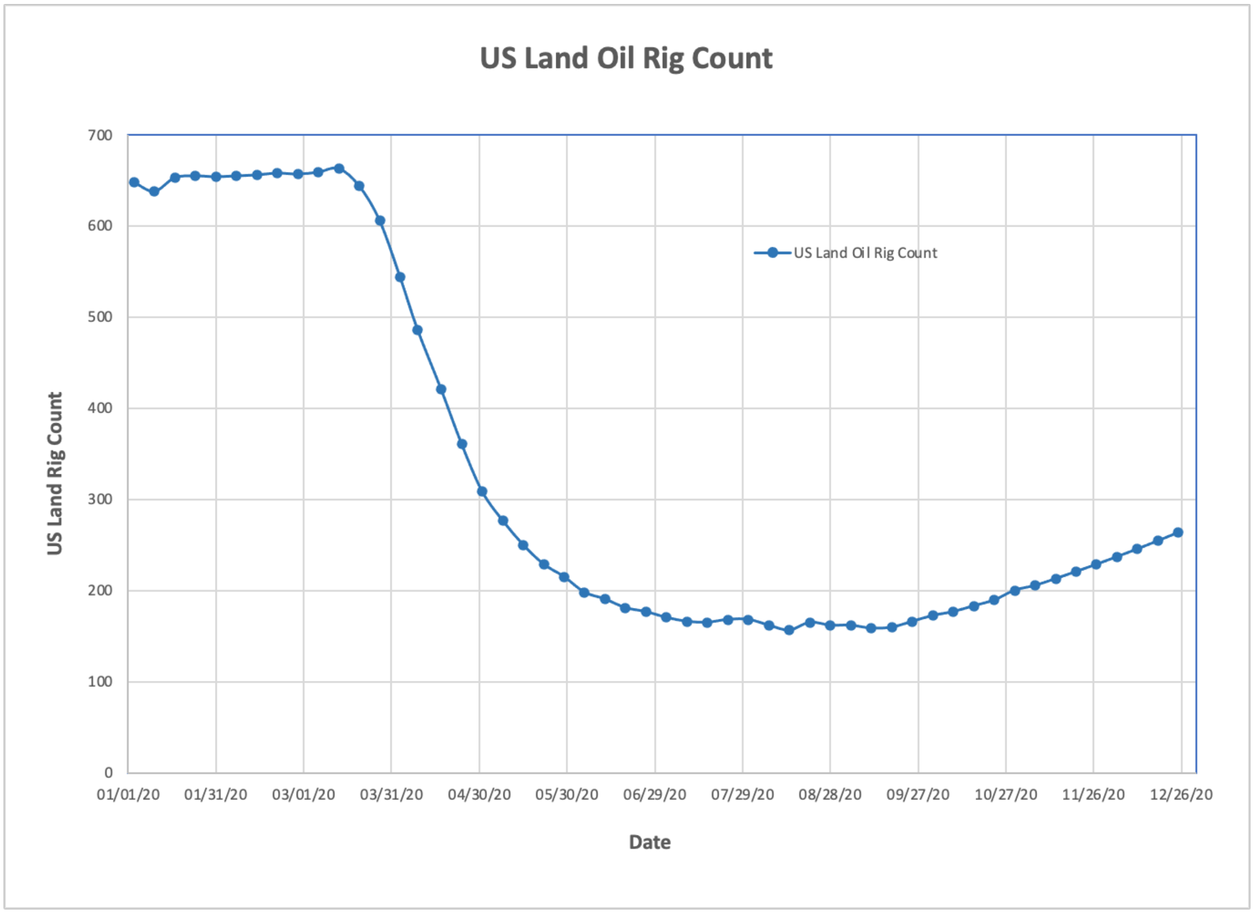

Figure 4 - US Land Oil Rig Count

While a rebound is undoubtedly occurring, the reason for this rebound isn't clear. While prices have recovered from their lows in the second quarter and economic conditions are improving, there is no basis to support a sustained rebound in oil prices over the next 12 months. Even using point forward economics, the average operator in the lowest cost play needs a WTI price of $46 to drill a new well[v]. On a lifecycle basis this is probably closer to $55 or $60. While there are some operators who can drill profitable wells at $30, again this is likely to be closer to $40 or $45 on a lifecycle basis.

One theory is that drilling activity is being spurred by concerns that an incoming Biden administration would curb development of Federal lands, and so the recent uptick in activity reflects a push to drill wells on Federal lands before regulations change. If this were the case, then we would expect to see a higher proportion of rigs active on Federal lands. Figure 5, below, shows US land oil rigs operating in New Mexico as a percentage of total US land oil rigs. As New Mexico has a high proportion of activity on Federal land, then we would expect to see the proportion of wells in New Mexico increase if the Biden hypothesis is correct. As Figure 5 shows, there has been a jump in the proportion of rigs active in New Mexico, from about 15% at the start of the year, to a peak of 30% mid-year. However, the proportion has since been trending down and it is more likely that this surge is caused by the relatively low breakeven prices in that part of the country.

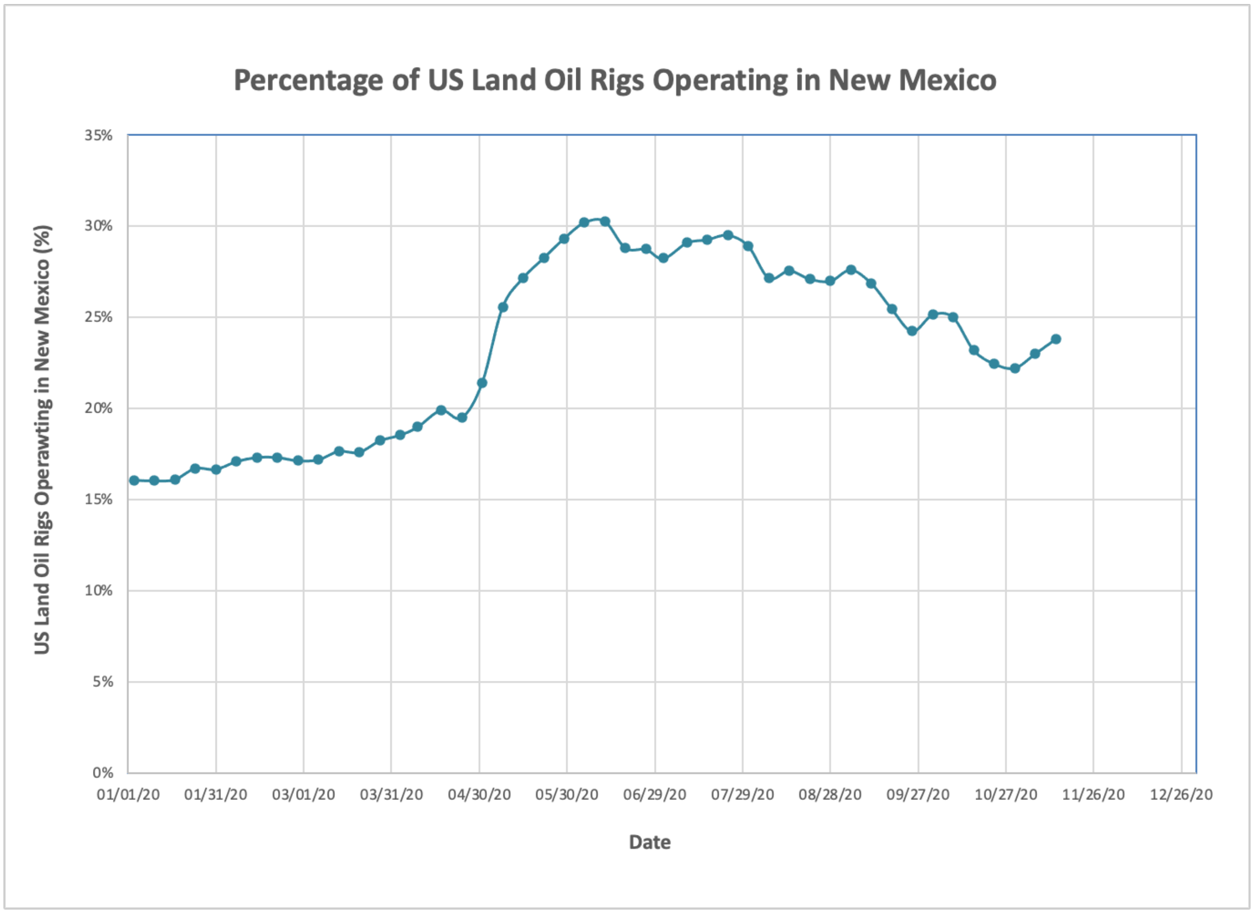

Figure 5 - Percentage of US Land Rigs Operating in New Mexico

---

[i] IEA (2020), Oil Market Report - November 2020, IEA, Paris
[ii] Short Term Energy Outlook (STEO), November 2020, U.S. Energy Information Administration.
[iii] "Oil Market Forecast – October 2020", Glenloch Energy LLC, October 2020
[iv] "Oil production costs reach new lows, making deep water one of the cheapest sources of novel supply", Rystad Energy, October 21st, 2020.
[v] "Energy Slideshow", Federal Reserve Bank of Dallas, November 5th, 2020