Energy Tidbits

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Supplying Asia with LNG got much costlier for the US, but strong demand brings export records

June 23, 2021

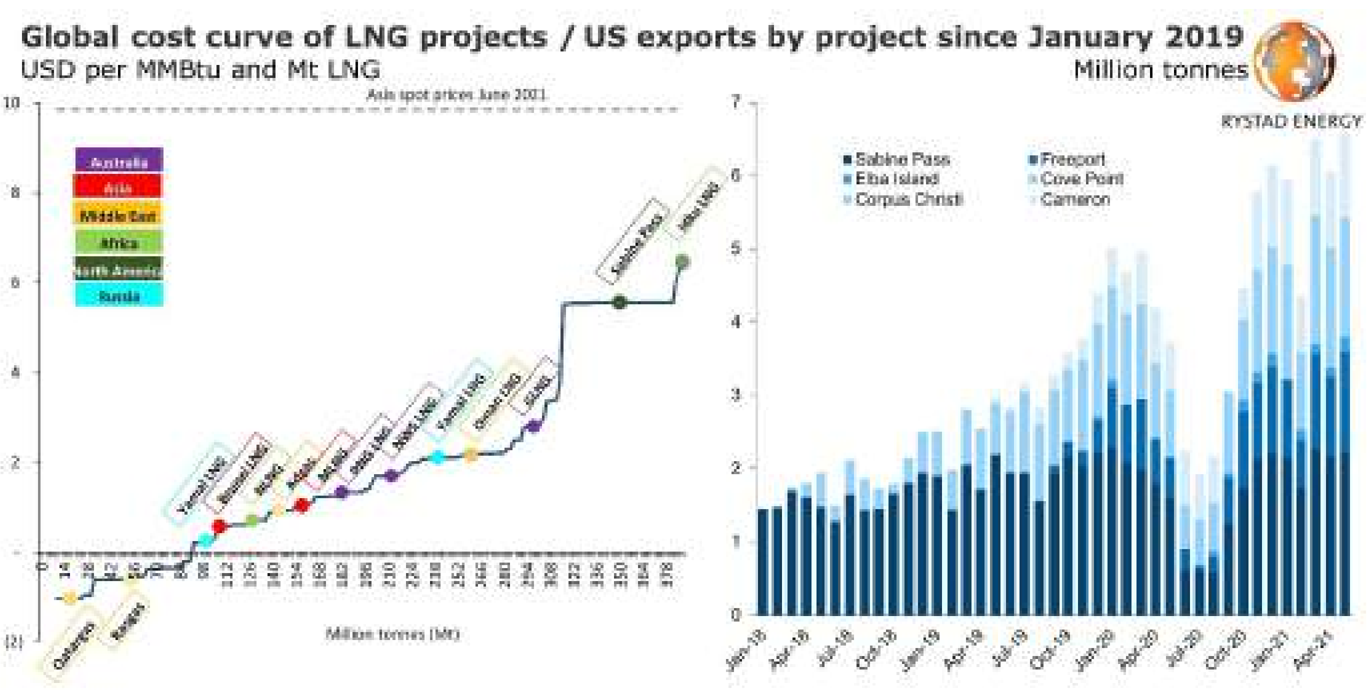
Supplying liquefied natural gas to the growing Asian market has become more expensive for US producers this year, a Rystad Energy report reveals. Even so, US exporters are unlikely to repeat last year's cost-related shut-ins as global demand has rebounded to strong levels. Instead, US LNG exports climbed to a record monthly high of 6.5 million tonnes in May and may keep rising to new peaks.

Rystad Energy estimates that the short-run marginal cost (SRMC) of US LNG exports to the Asian market has risen to about $5.60 per MMBtu as of June 2021, up 65% from $3.4 per MMBtu in mid-2020 and 30% higher than last year's average of $4.30 per MMBtu.

The SRMCs of currently operational liquefaction projects globally have risen this year due to a jump in transportation costs for LNG, driven by higher charter rates and fuel costs. On top of that, costs in the US have also been boosted by a recovery in domestic gas prices.

Despite the lower SRMC of LNG to Asia last year, the US was still the most expensive supplier globally. As the TTF gas prices in Europe and Asian spot LNG prices fell below $2 per MMBtu in mid-2020, US exports took the largest hit, resulting in shut-ins as buyers canceled cargoes. Rystad Energy estimates that about 12 Mt of US LNG exports were shut in last year as a result of the market crash.

"We do not see any signs of LNG shut-ins in 2021, but we do see a shift in the SRMC of global LNG and in the cost-of-supply curves. Instead, US LNG production will reach 72 Mt in 2021, its highest annual level on record, under an assumption of no shut-ins," says Sindre Knutsson, vice president on Rystad Energy's gas markets team.



Source: Rystad Energy GasMarketCube, Rystad Energy UCube, Refinitiv, Rystad Energy research and analysis

Learn more in Rystad Energy's GasMarketCube.

Despite the significant cost increase, the US is not the most expensive supplier to Asia this year, however. The comeback of Egyptian LNG to the market has seen the North African country assume the role as the marginal supplier of LNG, with an SRMC of about $6.30 per MMBtu. Still, the strong demand of 2021 is expected to absorb even these costs, as Asian spot LNG prices are around $12 per MMBtu.

Meanwhile, the high transportation costs also affect producers located closer to Asia. For instance, the average cost of transporting Qatari LNG to Tokyo, Japan, has increased to $0.90 per MMBtu in 2021 from about $0.75 per MMBtu in 2020. By comparison, delivery of US LNG to Tokyo has seen an increase in voyage costs to about $1.90 per MMBtu in 2021 from $1.45 last year (already included in the US SRMC).

Some LNG projects are profitable even if prices are zero

The SRMC of liquefaction projects is not the only important price increase to influence the LNG market of late. If pre-tax liquids revenue is accounted for, many integrated LNG projects have seen improved competitiveness during 2021 thanks to higher oil prices. Pre-tax liquids revenue is calculated as the pre-tax revenue from oil activity for the upstream assets that feed LNG plants, divided by LNG production.

In that way, the variable cost of LNG can be offset by oil production revenues. For example, Qatargas 1 LNG Train 1 has an estimated variable cost of LNG production of $1.60 per MMBtu. If the pre-tax liquids revenue from the oil production is considered, the costs are offset by oil revenues of about $2.60 per MMBtu, which brings net costs down to a negative $1 per MMBtu. That way, projects like Qatargas 1 LNG Train 1 would cover their costs even if LNG prices went down to zero.

Nevertheless, there are no signs of prices falling to zero this year, or even to levels around the SRMC of Egyptian LNG at $6.30 per MMBtu. The LNG market looks robust in the short term due to the recovery in Asian and European LNG demand, supported by high demand for restocking, high CO_2 prices and lower-than-expected Russian pipeline gas exports to Europe.

"Overall, the market is seeing many low-cost sources of LNG. Of the 393 Mt of LNG that we expect to be produced in 2021, over 300 Mt, or 75%, can be supplied at a cost below $3 per MMBtu, including delivery to Asia. Furthermore, 225 Mt can be delivered to the market at a price below $2 per MMBtu. This shows the diversity of the LNG market compared to other fuels, and also illustrates why LNG proved to be so robust during 2020 when Covid-19 hit the market with full force," Knutsson concludes.

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https://rbnenergy.com/big-gun-part-3-albertas-side-of-the-montney-natural-gas-play

Big Gun, Part 3 - Alberta's Side Of The Montney Natural Gas Play

Monday, 06/21/2021

Published by: Martin King

The immense Montney Formation in Western Canada is almost equally divided between the two provinces of Alberta and British Columbia. However, on either side of the provincial border there are stark differences in the number of wells drilled, well length, well productivity, and natural gas production. All these differences have resulted in Alberta being the much smaller player in the Montney gas story, with production from its side of the formation only helping to hold the line on Alberta's total gas output in the past few years. Today, we continue our Montney analysis by looking at gas well trends on the Alberta side of this prolific formation.

For nearly 100 years, Alberta has been the leading source of Western Canada's natural gas supplies. Previously supported for many decades by production from conventional shallow gas wells, the province's gas output has been steadily pivoting away from the shallow wells since the early 2000s, and toward wells that tap unconventional, gas-rich formations such as the Montney. These wells, which employ horizontal drilling and multi-stage completions to unlock their immense productivity and reserves, have come to play a growing role in Alberta's natural gas supply picture, and for Western Canada's gas supplies in general.

In Part 1, we provided a brief primer on the Montney, the massive formation spanning parts of Alberta and British Columbia (BC) and which covers about 50,000 square miles (yellow bordered area Figure 1), or roughly about two-thirds the size of the Permian Basin in Texas and New Mexico. The Montney's reserves as of 2019 were pegged at 576 Tcf, roughly split as 342 Tcf in BC and 224 Tcf in Alberta. The Montney's gas production trend has seen its output rise from zero in 2005 to more than 7 Bcf/d as of February 2021, or just over 45% of total gas production in Western Canada in that month. We also noted that the Montney has been the sole source of the increases in Western Canadian gas supply since 2014.

In Part 2, we turned our attention to the BC side of the Montney. The formation's output of natural gas has come to dominate BC's gas production, rising from zero in 2005 to 5.0 Bcf/d as of February 2021, a 90% share of all gas produced in the province. This incredible increase has been driven by a more than four-fold rise in the average peak productivity of BC's Montney gas wells, from less than 1 MMcf/d for wells drilled in 2005 to more than 4 MMcf/d for wells drilled in 2020. Similarly significant improvements have also been seen in long-term production from these wells, with average rates for wells still producing after five years rising to 1 MMcf/d from less than 0.3 MMcf/d. These production and productivity gains have been enabled by longer well bores and more fracks per well, a trend that appears to be continuing in 2021.

In today's blog we continue our Montney analysis by jumping over the provincial boundary to the Alberta side of the formation (dashed red rectangle in Figure 1) and consider similar wellhead metrics as those we discussed for BC's wells and compare the results. We also mentioned in Part 1 that while the Montney is gas-rich throughout its sprawling area, the nature of the geology on the Alberta side of the boundary leans toward liquids-rich gas, while dry gas wells dominate on the BC side of the formation. Neither side is necessarily better than the other — it's just that the geology, the happenstance of the provincial boundary, as well as pipeline access (more about this in Part 4) have contributed to the apparent differences.

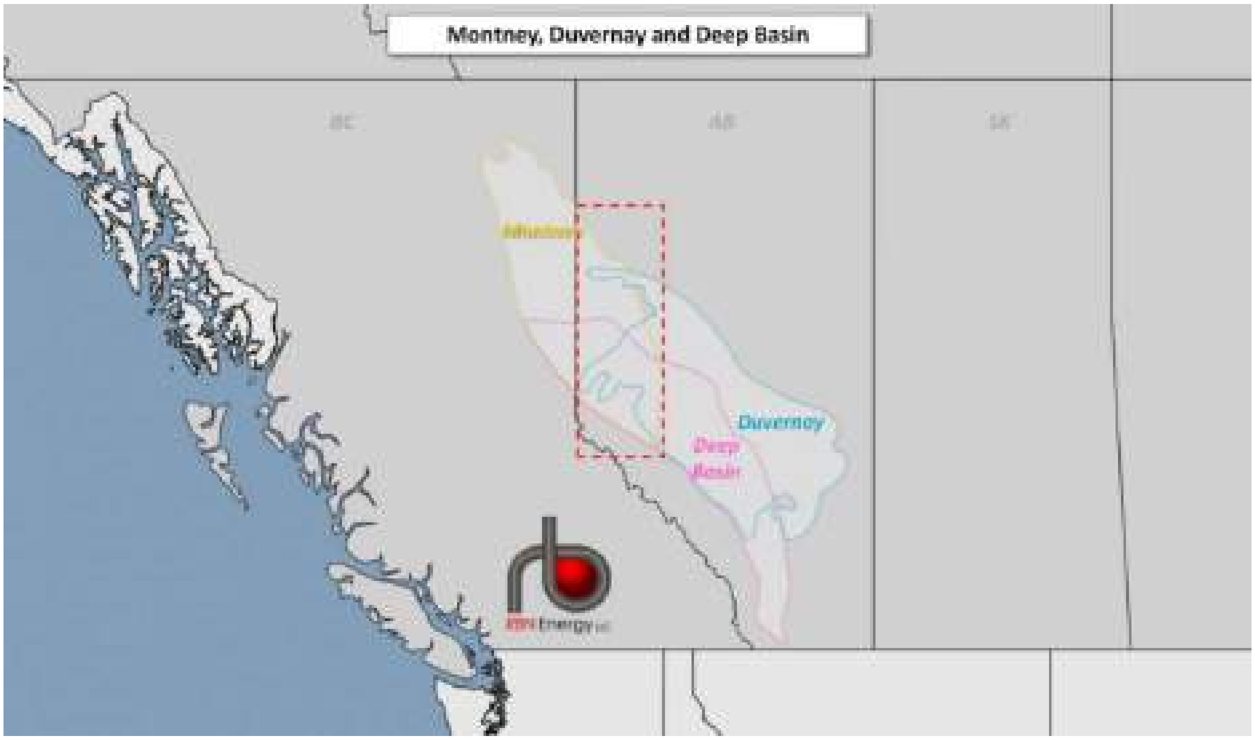


Figure 1. The Montney, the Duvernay and the Deep Basin. Source: RBN

According to data from the Alberta Energy Regulator (AER), Alberta's gas production from the Montney (blue bar segments and left axis in Figure 2) has been much smaller in scale and growth trajectory than that seen in BC. It also took a few more years for Alberta's part of the Montney to make significant contributions to the province's overall gas production profile. Rising from an average of 0.11 Bcf/d in 2009, Alberta Montney production averaged 2.03 Bcf/d in 2020, and through the first couple months of 2021, production has averaged 2.14 Bcf/d. Over this same 12-years-plus time span, the share of Montney gas in Alberta's total gas supply has risen from 2% to 21% (black line and right axis), while its share in total Western Canadian Sedimental Basin (WCSB) gas production has increased from a fractional 0.1% to just over 13% (green line and right axis). What is noteworthy is that Montney gas supply growth has been instrumental in holding overall Alberta gas production (combined red and blue bar segments) relatively stable around 10 Bcf/d since 2015.

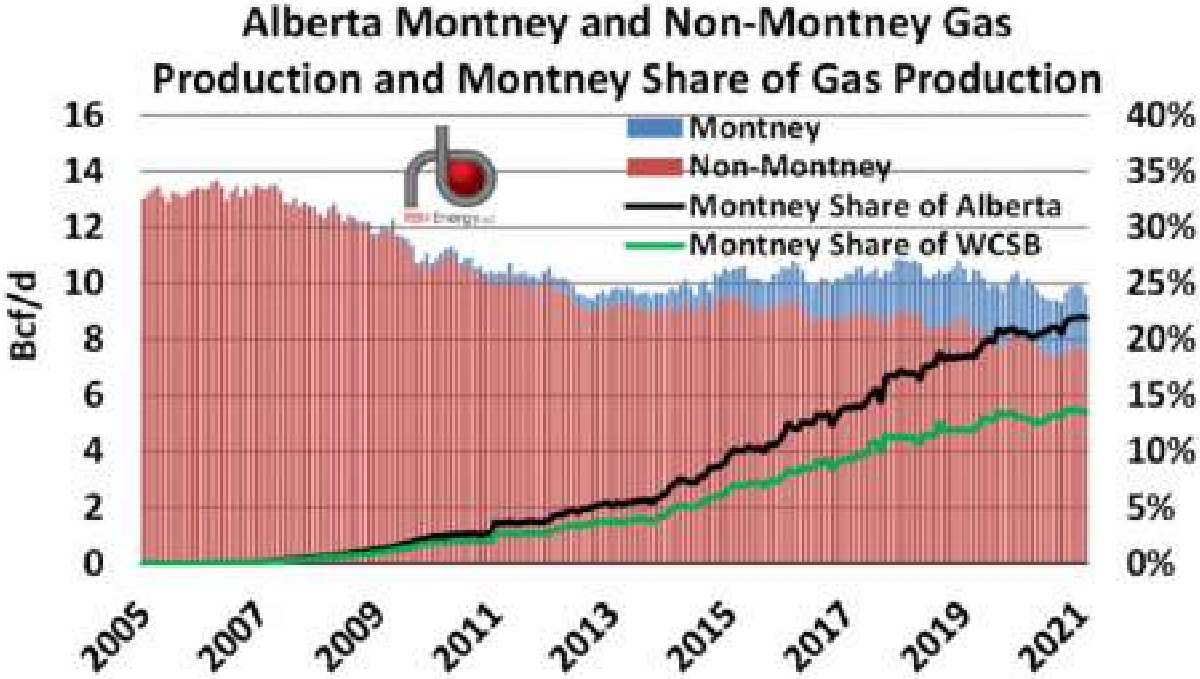


Figure 2. Alberta Montney and Non-Montney Gas Production and Montney's Share of Gas Production. Sources: AER, RBN's Canadian NATGAS Billboard.

Non-Montney gas supplies (red bar segments) have been declining modestly since 2015, but still provide a large majority of Alberta's overall gas supply profile. This is simply related to the fact that Alberta has more formations (e.g., Deep Basin and Duvernay) and older conventional and associated gas supplies on which it can rely than is the case in BC, where the Montney has effectively become the only game in town.

As for the average productivity of Alberta's Montney gas wells, there has been a general rising trend since 2005 (dashed pink oval in Figure 3). As we did for BC wells in Part 2, we have sorted Alberta's gas wells by the month and year in which they entered production, and averaged across all those wells for the first month for production, followed by the second month, etc. However, unlike in BC, the upward trend for Alberta Montney wells is not as consistent, with more recent wells appearing to peak at lower rates than in earlier years. Given the five-year increments we have chosen to focus on here, wells in 2015 and 2020 (orange and dark green arrows and dots) were about twice as productive (2 MMcf/d) as those that were producing in 2005 and 2010 (around 1 MMcf/d, blue and pink salmon arrows and dots). This is much less than BC wells, where productivity has been steadily rising to 2020 (more than 4 MMcf/d, on average) and more than four times as productive as wells drilled in 2005 (just under 1 MMcf/d).

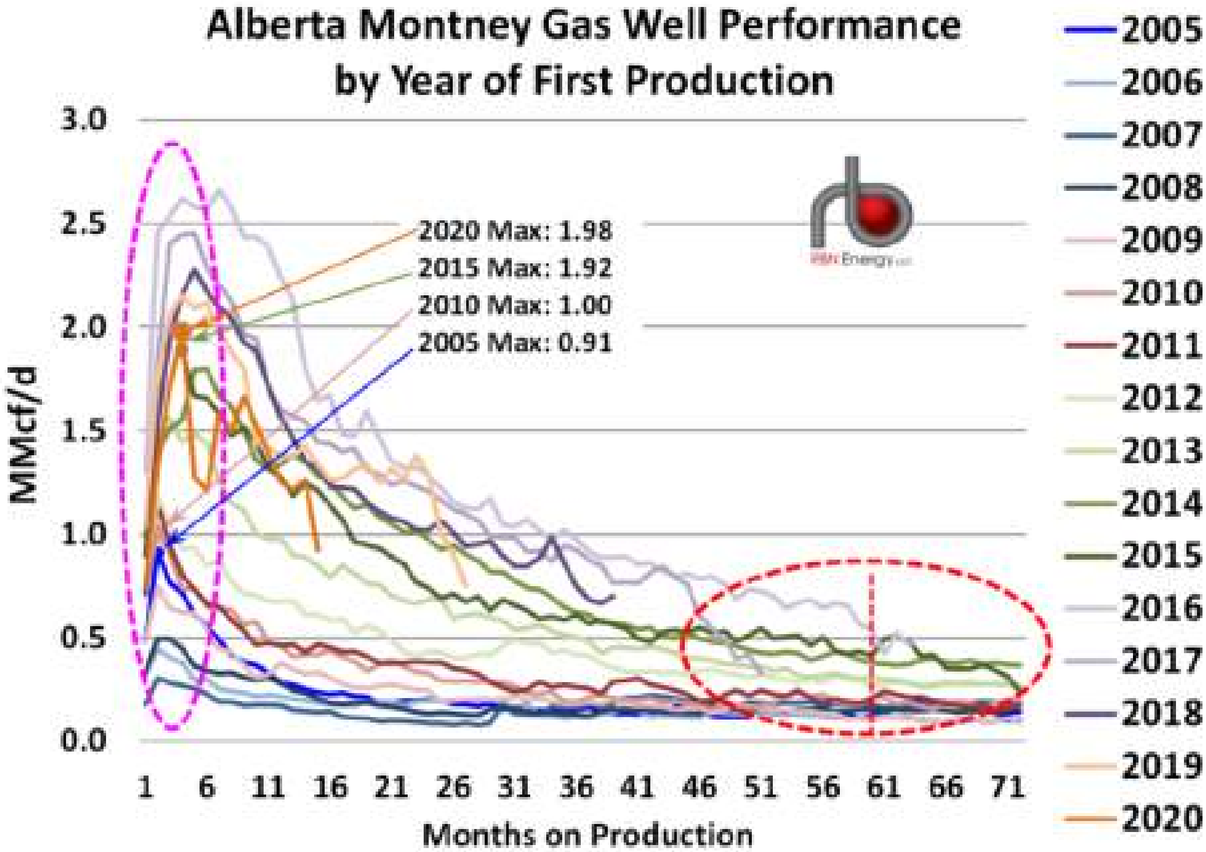
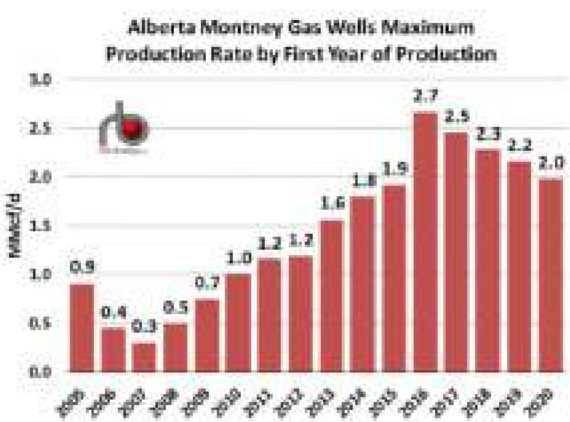


Figure 3. Alberta Montney Gas Well Performance by Year of First Production. Source: AER.

In fact, the average first-year peak production rate for Alberta's Montney gas wells has actually been on a downtrend since 2016 (red bars in left graph in Figure 4). After steadily rising from 2008 to 2016, with a more than four-fold productivity increase in that period, peak rates have declined from 2.7 MMcf/d in 2016 to 2 MMcf/d for wells drilled in 2020. This may reflect the different geology of the Montney on the Alberta side of the formation, as we mentioned earlier. With the more oily and NGL-saturated nature of Montney wells in Alberta, the focus of producers there since 2016 has been shifting more to liquids-rich wells that are producing natural gas as more of a by-product than drilling more gas-rich wells where the liquids are the by-product.



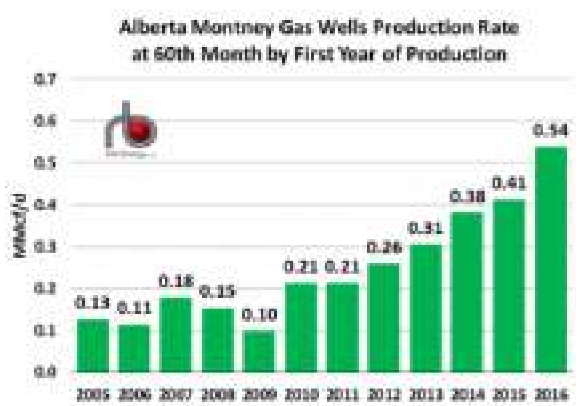


Figure 4. Alberta Montney Gas Wells' Peak Production and 60th-Month Production Rates. Source: AER

If we look at the production rate from wells still producing after 60 months (dashed red dashed oval and line in Figure 3), some productivity gains have been occurring (green bars in right graph in Figure 4). After remaining roughly stable between 0.1 MMcf/d and 0.2 MMcf/d from 2005 to 2011, longer-dated well productivity has increased to more than 0.5 MMcf/d for wells that were brought into production in 2016, the last year for which we had a full 60 months of production history. In contrast, 60th-month productivity from BC Montney wells has been steadily increasing since 2005 and was twice as much in 2016 (1 MMcf/d) than those in Alberta. When we took a quick look at Alberta's well productivity for more recent years and for shorter time spans, there does not seem to have been any noticeable further increase in productivity that we can detect. The reasons for the lower longer-term productivity and what may be a lack of further gains post-2016 may again be tied to the more liquids-focused nature of producers that are drilling the Alberta side of the Montney.

Just as we did for BC wells in Part 2, we have also looked at what has been happening to the average length of Alberta's Montney gas wells, defined as vertical depth plus horizontal length of the well bore (Figure 5). As you might expect, total well length has been increasing over time, and wells so far drilled in 2021 are twice as long as those drilled in 2005, and average almost 3.5 miles!

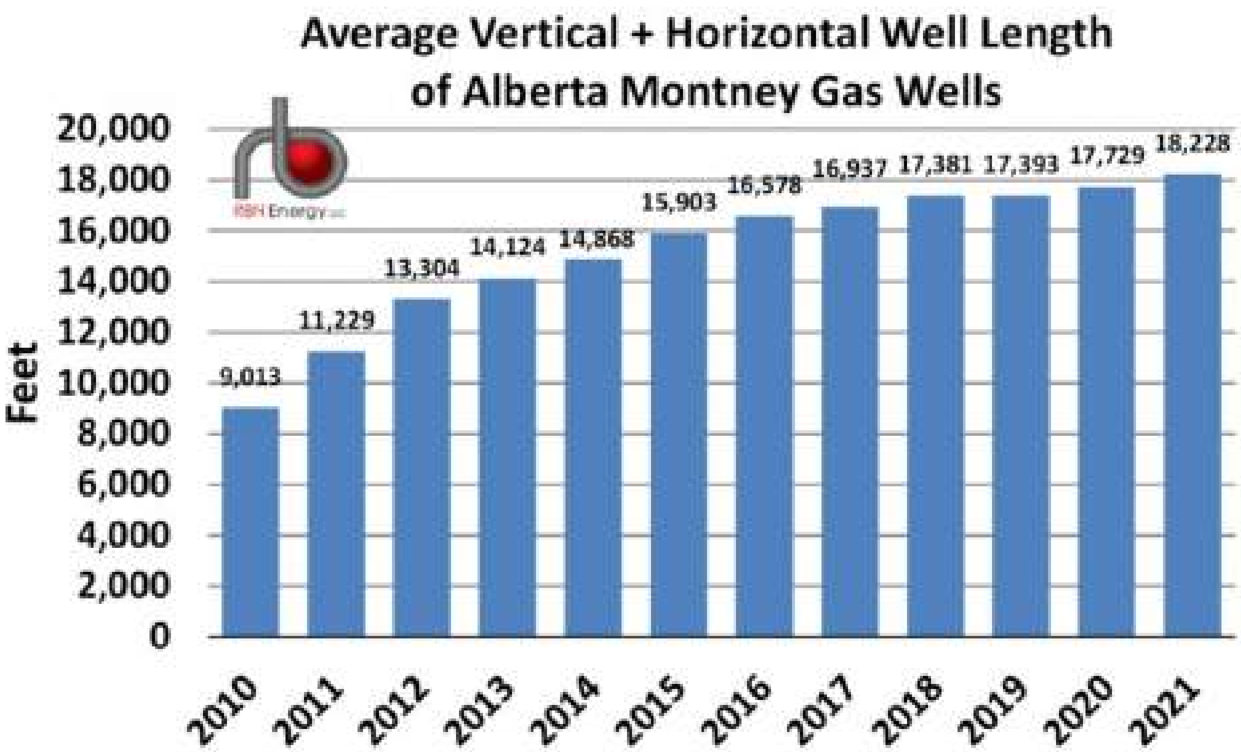


Figure 5. Average Vertical + Horizontal Well Length of Alberta Montney Gas Wells. Source: AER

Also noteworthy is that since 2013, the average length of Alberta Montney wells has been greater than those in the BC Montney, and they now average about 3,000 feet longer than their BC counterparts. Keep in mind that the productivity of these Alberta wells, as we just discussed, is roughly half of those in BC. As such, it may be a simple fact that to reach economic return thresholds, producers in Alberta are drilling longer wells simply because the wells are not as productive on a per-foot basis as those on the BC side of the formation. Moreover, if the Alberta wells are typically more liquids-rich, then additional economic return is being gained from the sale of the liquids, which may also be incentivizing the longer well bores.

Anecdotally, investor reports for producers that are more focused on the Alberta side of the Montney do routinely mention increasing well length and more frack stages per unit length of well bore, just as in the case for producers drilling the BC Montney. Unfortunately, our AER dataset does not have enough specific information to draw hard conclusions on this.

One final piece of data concerns the number of Montney wells in Alberta versus in BC. In Figure 6, we tallied the number of connected and flowing gas wells at the end of each calendar year since 2005 and by the year the well first entered production. The differences here could not be clearer. Over time, the number of new wells in BC has greatly exceeded those in Alberta by a wide margin, with the 16-year total (2005 through 2020) for BC wells being 4,795 versus Alberta's 2,088. Put simply, Alberta produces much less Montney-sourced gas than BC because it has less productive wells and fewer of them.

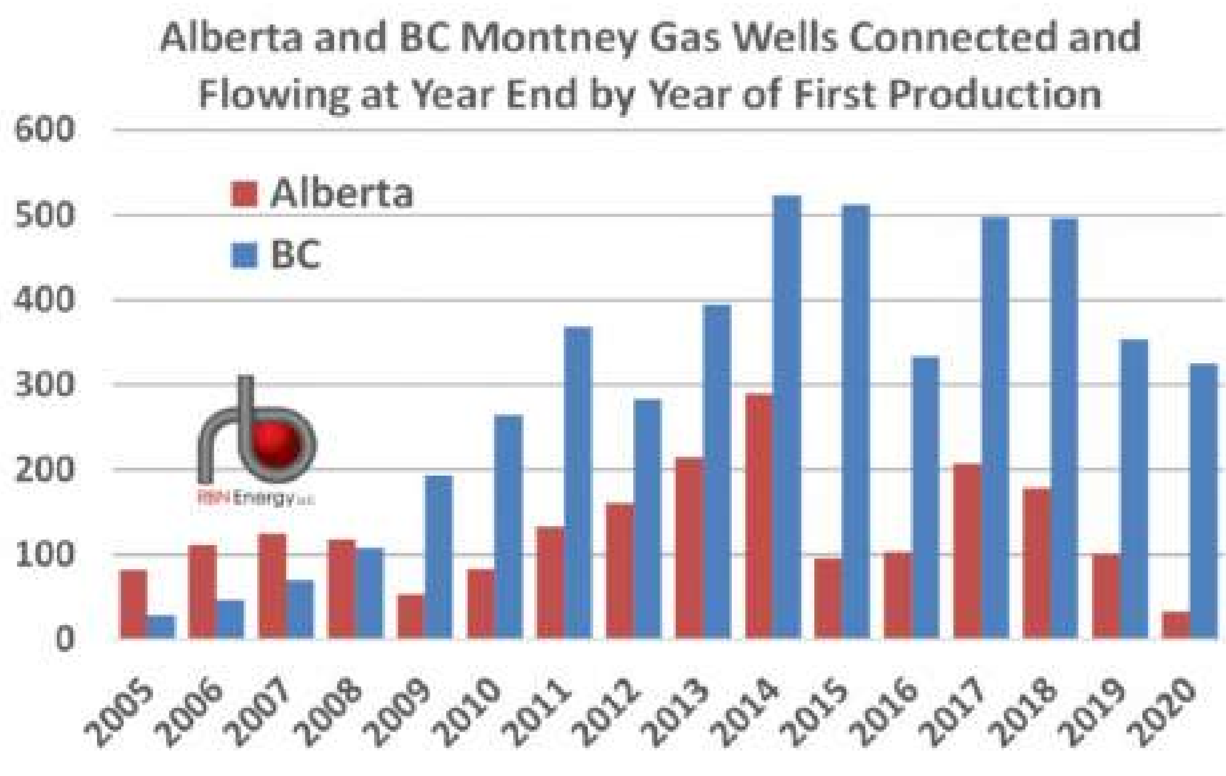


Figure 6. Alberta and BC Montney Gas Wells Connected and Flowing at Year-End by Year of First Production. Sources: BC Oil and Gas Commission, AER.

What general conclusions can we take away from our Alberta Montney analysis? Clearly, these wells are not as productive as those in the BC Montney, there are fewer of them, and we have provided some potential reasons as to why this may be the case. It also appears that although Montney-sourced gas production in Alberta has been growing slowly over the past few years, it has been growing at a rate that is just enough to mostly offset declines in formations in other parts of the province, explaining its nearly stable total gas production profile since 2015. As such, the Montney growth story and overall Western Canada gas growth story seems to be one with a definite BC bias.

This slant toward BC Montney production does present challenges for getting all of this gas to market via pipeline. We will investigate that angle in the next and final part of this blog series.

"Big Gun" was written by Malcolm Young, Angus Young, and Brian Johnson. Performed by AC/DC, it appears as the first track on the Last Action Hero: Music from the Original Motion Picture soundtrack album, released in June 1993. "Big Gun" was the first single from the LP, released in May 1993 to coincide with the movie's release. The film starred Arnold Schwarzenegger, who is also in the video for the song, which features AC/DC performing the tune at a mock concert setting. (Interestingly, the band has never performed the song live in a concert since.) The Rick Rubin-produced single went to #1 on the Billboard Mainstream Rock chart and #65 on the Billboard Hot 100 Singles chart. Personnel on the record were: Brian Johnson (lead vocals), Angus Young (lead guitar), Malcolm Young (rhythm guitar, backing vocals), Cliff Williams (bass, backing vocals), and Chris Slade (drums). "Big Gun" would later appear in the AC/DC boxset, Backtracks.

AC/DC is an Australian rock and roll band formed in Sydney in 1973 by brothers Angus and Malcolm Young. The band has released 17 studio albums, three live albums, two soundtrack albums, one EP, and 47 singles. They have sold over 200 million records worldwide, and have won one Grammy Award. So far, 21 members have passed through the ranks of AC/DC since its formation. Bon Scott died in 1980 and Malcolm Young in 2017. The band continues to record and tour. In a side note, Chris Slade, whose last duties with AC/DC as a drummer was the "Big Gun" single and video, is now back in the drummer throne after long-time drummer Phil Rudd decided not to tour with the band.

https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/062121-algerias-skikda-lng-shut-after-technical-issue-to-undergo-inspection-sonatrach

- 21 Jun 2021 | 09:02 UTC

Algeria's Skikda LNG shut after technical issue, to undergo inspection: Sonatrach

HIGHLIGHTS

Issue hit 4 million mt/year plant on June 11

Sonatrach to carry out 'necessary repairs'

Skikda was closed for six months in 2020

- Author Stuart Elliott

Algeria's Sonatrach has closed its 4 million mt/year capacity LNG plant at Skikda, it said June 19, after a technical fault was identified on June 11.

State-owned Sonatrach operates four LNG production facilities -- three at Arzew and one at Skikda -- with a total capacity of 24.7 million mt/year, according to recent comments from the company.

"A technical issue occurred on June 11 at the Skikda LNG complex and led to the shutdown of this complex," Sonatrach said in a statement June 19.

"The issue was caused by a sudden failure of a gas turbine control mechanism," it said.

"As a safety precaution, Sonatrach has decided to conduct a thorough inspection in order to carry out the necessary repairs," it said.

So far in 2020, Algeria has exported 6.22 million mt of LNG -- the equivalent of 8.56 Bcm of gas -- according to data from S&P Global Platts Analytics, or around 50% of its technical nameplate capacity.

In 2020, Algerian LNG exports -- which totaled 10.9 million mt -- were constrained because the Skikda plant was closed from January until July due to extended maintenance, although Sonatrach attempted to compensate for the loss by increasing exports from Arzew.

Skikda was closed for planned maintenance that was originally expected to last for two months, but an incident in February saw damage to a turbine at the plant.

Sonatrach decided then to repair the turbine -- rather than replace it which would have taken 18 months -- in order to bring Skikda LNG back to service as soon as possible, which led to the extended outage.

Highlights for the month

- The consumption of petroleum products during April-May 2021 with a volume of 32.1 MMT reported a growth of 30.1% compared to the volume of 24.7 MMT during the same period of the previous year. Except LPG, SKO and petcoke all the petroleum products reported a growth in consumption during April-May 2021 compared to the same period of the previous year. The consumption of petroleum products during May 2021 recorded a de-growth of 1.5% compared to the same period of the previous year.
- Ethanol blending with Petrol was 8.9% during May 2021 and cumulative during December 2020- March 2021 was 7.7%.
- Total consumption of natural gas (including internal consumption) for the month of May 2021 was 5247 MMSCM which was 4.3% higher than the corresponding month of the previous year. The cumulative consumption of 10485 MMSCM for the current year till May 2021 was higher by 23.7% compared with the corresponding period of the previous year.
- Indigenous crude oil and condensate production during May 2021 was lower by 6.3 % than that of May 2020 as compared to a de-growth of 2.1% during April 2021. OIL registered a de-growth of 1.3 % and ONGC registered a de-growth of 9.6 % during May 2021 as compared to May 2020. PSC registered growth of 0.7 % during May 2021 as compared to May 2020. De-growth of 4.2% was registered in the total crude oil and condensate production during April- May 2021 over the corresponding period of the previous year.
- Crude oil processed during May 2021 was 19.0 MMT, which was 16.0 % higher than May 2020 as compared to a growth of 34.9 % during April 2021. Growth of 25% was registered in the total crude oil processing during April- May 2021 over the corresponding period of the previous year.
- Production of petroleum products saw a growth of 15.5 % during May 2021 over May 2020 as compared to a growth of 30.9 % during April 2021. Growth of 22.8% was registered in the total POL production during April- May 2021 over the corresponding period of the previous year

•	Gross production of natural gas for the month of May 2021 was 2740 MMSCM which was higher by 19.1% compared with the corresponding month of the previous year. The cumulative gross production of natural gas of 5391 MMSCM for the current financial year till May, 2021 was higher by 21% compared with the corresponding period of the previous year.
•	Crude oil imports increased by 18.2% and 14% during May 2021 and April-May 2021 respectively as compared to the corresponding period of the previous year.
•	POL products imports decreased by 26.2% and 6.1% during May 2021 and April-May 2021 respectively as compared to the corresponding period of the previous year. Decrease in POL products imports during April-May 2021 was due to decrease in imports of petcoke, liquified petroleum gas (LPG) and high-speed diesel (HSD).
•	LNG import for the month of May, 2021(P) was 2587 MMSCM which was 9.2% higher than the corresponding month of the previous year. The cumulative import of 5242 MMSCM for the current year till May, 2021 was higher by 24.9% compared with the corresponding period of the previous year.
•	Exports of POL products decreased by 0.3% and 18.4% during May 2021 and April-May 2021 respectively as compared to the corresponding period of the previous year. Decrease in POL products exports during April-May 2021 (P) was due to decrease in exports of high-speed diesel (HSD), naphtha, petcoke/CBFS, fuel oil (FO), aviation turbine fuel (ATF) and LOBS/Lube oil.
•	The price of Brent Crude averaged $68.75/bbl during May, 2021 as against $64.70/bbl during April 2021 and $28.98/bbl during May 2020. The Indian basket crude price averaged $66.95/bbl during May 2021 as against $63.40/bbl during April 2021 and $30.61 /bbl during May 2020.

2. Crude oil, LNG and petroleum products at a glance									
	Details	Unit/ Base	2019-20	2020-21 (P)	May		April-May	
					2020-21 (P)	2021-22 (P)	2020-21 (P)	2021-22 (P)
1	Crude oil production in India#	MMT	32.2	30.5	2.6	2.4	5.1	4.9
2	Consumption of petroleum products*	MMT	214.1	194.6	15.3	15.1	24.7	32.1
3	Production of petroleum products	MMT	262.9	233.4	17.3	20.0	33.2	40.8
4	Gross natural gas production	MMSCM	31,184	28,672	2,300	2,740	4,461	5,391
5	Natural gas consumption	MMSCM	64,144	60,646	5,031	5,247	8,480	10,485
6	Imports & exports:							
	Crude oil imports	MMT	227.0	198.1	14.6	17.3	31.2	35.5
		$ Billion	101.4	62.7	2.3	8.3	5.3	16.8
	Petroleum products (POL) imports*	MMT	43.8	43.5	4.3	3.2	7.1	6.6
		$ Billion	17.7	14.2	0.9	1.1	1.7	2.5
	Gross petroleum imports (Crude + POL)	MMT	270.7	241.6	18.9	20.4	38.2	42.2
		$ Billion	119.1	76.9	3.2	9.4	7.0	19.3
	Petroleum products (POL) export	MMT	65.7	56.8	5.8	5.7	11.8	9.6
		$ Billion	35.8	21.4	1.3	3.3	2.5	5.5
	LNG imports*	MMSCM	33,887	32,861	2,370	2,587	4,198	5,242
		$ Billion	9.5	7.4	0.5	0.8	0.9	1.5
7	Petroleum imports as percentage of India's gross imports (in value terms)	%	25.1	19.8	14.4	24.4	17.8	22.9
8	Petroleum exports as percentage of India's gross exports (in value terms)	%	11.4	7.4	6.7	10.3	8.4	8.7
9	Import dependency of crude (on consumption basis)	%	85.0	84.4	83.7	84.4	80.7	85.4

#Includes condensate; *Jul 2020- May 2021 DGCIS data prorated

3. Indigenous crude oil production (Million Metric Tonnes)

Details	2019-20	2020-21 (P)	May			April-May		
			2020-21 (P)	2021-22 Target*	2021-22 (P)	2020-21 (P)	2021-22 Target*	2021-22 (P)
ONGC	19.2	19.1	1.6	1.7	1.5	3.2	3.3	3.0
Oil India Limited (OIL)	3.1	2.9	0.3	0.3	0.3	0.5	0.5	0.5
Private / Joint Ventures (JVs)	8.2	7.1	0.6	0.6	0.6	1.2	1.2	1.2
Total Crude Oil	**30.5**	**29.1**	**2.5**	**2.6**	**2.3**	**4.9**	**5.1**	**4.7**
ONGC condensate	1.4	1.1	0.1		0.1	0.2		0.2
PSC condensate	0.3	0.3	0.02		0.03	0.03		0.05
Total condensate	**1.6**	**1.4**	**0.1**		**0.1**	**0.2**		**0.2**
Total (Crude + Condensate) (MMT)	**32.2**	**30.5**	**2.6**	**2.6**	**2.4**	**5.1**	**5.1**	**4.9**
Total (Crude + Condensate) (Million Bbl/Day)	0.64	0.61	0.62		0.58	0.62		0.59

*Provisional targets inclusive of condensate.

4. Domestic oil & gas production vis-à-vis overseas production

Details	2019-20	2020-21 (P)	May		April-May	
			2020-21 (P)	2021-22 (P)	2020-21 (P)	2021-22 (P)
Total domestic production (MMTOE)	63.4	59.2	4.9	5.2	9.6	10.3
Overseas production (MMTOE)	24.5	21.9	1.9	1.8	3.8	3.7
Overseas production as percentage of domestic production	**38.7%**	**37.0%**	**37.9%**	**35.3%**	**40.0%**	**35.4%**

Source: ONGC Videsh, GAIL, OIL , IOCL, HPCL & BPRL

5. High Sulphur (HS) & Low Sulphur (LS) crude oil processing (MMT)

	Details	2019-20	2020-21 (P)	May		April-May	
				2020-21 (P)	2021-22 (P)	2020-21 (P)	2021-22 (P)
1	High Sulphur crude	192.4	161.3	12.1	14.0	22.8	29.0
2	Low Sulphur crude	62.0	60.5	4.2	5.0	8.3	9.8
Total crude processed (MMT)		**254.4**	**221.8**	**16.3**	**19.0**	**31.1**	**38.9**
Total crude processed (Million Bbl/Day)		5.09	4.45	3.87	4.49	3.74	4.67
Percentage share of HS crude in total crude oil processing		**75.6%**	**72.7%**	**74.1%**	**73.8%**	**73.2%**	**74.8%**

6. Quantity and value of crude oil imports

Year	Quantity (MMT)	$ Million	Rs. Crore
2019-20	227.0	1,01,376	7,17,001
2020-21 (P)	198.1	62,711	4,62,996

7. Self-sufficiency in petroleum products (Million Metric Tonnes)

Particulars		2019-20	2020-21 (P)	May		April-May	
				2020-21 (P)	2021-22 (P)	2020-21 (P)	2021-22 (P)
1	Indigenous crude oil processing	29.3	28.0	2.3	2.2	4.5	4.3
2	Products from indigenous crude (93.3% of crude oil processed)	27.3	26.1	2.2	2.0	4.2	4.0
3	Products from fractionators (Including LPG and Gas)	4.8	4.2	0.3	0.3	0.6	0.7
4	Total production from indigenous crude & condensate **(2 + 3)**	32.1	30.3	2.5	2.4	4.8	4.7
5	Total domestic consumption	214.1	194.6	15.3	15.1	24.7	32.1
% Self-sufficiency (4 / 5)		**15.0%**	**15.6%**	**16.3%**	**15.6%**	**19.3%**	**14.6%**

8. Refineries: Installed capacity and crude oil processing (MMTPA / MMT)

Company	Refinery	Installed capacity (1.6.2021) MMTPA	Crude oil processing (MMT)							
			2019-20	2020-21 (P)	May			April-May		
					2020-21 (P)	2021-22 (Target)	2021-22 (P)	2020-21 (P)	2021-22 (Target)	2021-22 (P)
IOCL	Barauni (1964)	6.0	6.5	5.5	0.3	0.6	0.5	0.6	1.1	1.0
	Koyali (1965)	13.7	13.1	11.6	0.8	1.2	1.0	1.3	2.4	2.0
	Haldia (1975)	8.0	6.5	6.8	0.3	0.7	0.6	0.6	1.4	1.3
	Mathura (1982)	8.0	8.9	8.9	0.7	0.8	0.7	1.2	1.5	1.5
	Panipat (1998)	15.0	15.0	13.2	0.9	1.3	1.2	1.4	2.6	2.5
	Guwahati (1962)	1.0	0.9	0.8	0.02	0.0	0.0	0.02	0.0	0.1
	Digboi (1901)	0.65	0.7	0.6	0.06	0.06	0.06	0.1	0.1	0.1
	Bongaigaon(1979)	2.35	2.0	2.5	0.2	0.2	0.2	0.4	0.4	0.5
	Paradip (2016)	15.0	15.8	12.5	1.0	1.3	1.0	1.7	2.6	2.4
	IOCL-TOTAL	**69.7**	**69.4**	**62.4**	**4.3**	**6.3**	**5.4**	**7.4**	**12.3**	**11.4**
CPCL	Manali (1969)	10.5	10.2	8.2	0.4	0.5	0.6	0.7	1.0	1.4
	CBR (1993)	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CPCL-TOTAL	**11.5**	**10.2**	**8.2**	**0.4**	**0.5**	**0.6**	**0.7**	**1.0**	**1.4**
BPCL	Mumbai (1955)	12.0	15.0	12.9	0.9	1.2	1.2	1.7	2.5	2.4
	Kochi (1966)	15.5	16.5	13.3	0.7	1.5	0.9	1.5	2.8	2.3
BORL	Bina (2011)	7.8	7.9	6.2	0.4	0.6	0.5	0.8	1.2	1.2
NRL	Numaligarh (1999)	3.0	2.4	2.7	0.2	0.2	0.2	0.4	0.4	0.4
	BPCL-TOTAL	**38.3**	**41.8**	**35.1**	**2.2**	**3.5**	**2.8**	**4.3**	**6.9**	**6.3**

Company	Refinery	Installed capacity (1.6.2021) (MMTPA)	Crude oil processing (MMT)							
			2019-20	2020-21 (P)	April			Apr-May		
					2020-21 (P)	2021-22 (Target)	2021-22 (P)	2020-21 (P)	2021-22 (Target)	2021-22 (P)
ONGC	Tatipaka (2001)	0.066	0.087	0.081	0.006	0.003	0.007	0.008	0.009	0.014
MRPL	Mangalore (1996)	15.0	14.0	11.5	0.6	1.0	1.0	1.2	2.1	2.1
	ONGC-TOTAL	**15.1**	**14.0**	**11.6**	**0.6**	**1.0**	**1.0**	**1.2**	**2.1**	**2.1**
HPCL	Mumbai (1954)	7.5	8.1	7.4	0.5	0.28	0.12	1.1	0.3	0.2
	Visakh (1957)	8.3	9.1	9.1	0.7	0.8	0.7	1.5	1.6	1.6
HMEL	Bathinda (2012)	11.3	12.2	10.1	0.7	0.9	1.1	1.2	1.8	2.2
	HPCL- TOTAL	**27.1**	**29.4**	**26.5**	**1.9**	**2.0**	**2.0**	**3.8**	**3.8**	**3.9**
RIL	Jamnagar (DTA) (1999)	33.0	33.0	34.1	2.8	2.8	2.8	5.6	5.6	5.6
	Jamnagar (SEZ) (2008)	35.2	35.9	26.8	2.5	2.5	2.7	5.1	5.1	4.9
NEL	Vadinar (2006)	20.0	20.6	17.1	1.6	1.6	1.7	3.0	3.0	3.3
All India (MMT)		**249.9**	**254.4**	**221.8**	**16.3**	**20.2**	**19.0**	**31.1**	**39.7**	**38.9**
All India (Million Bbl/Day)		**5.02**	**5.09**	**4.45**	**3.87**		**4.49**	**3.74**		**4.67**

Note: Provisional Targets; Some sub-totals/ totals may not add up due to rounding off at individual levels.

9. Major crude oil and product pipeline network (as on 01.06.2021)

Details		ONGC	OIL	Cairn	HMEL	IOCL	BPCL	HPCL	Others*	Total
Crude Oil	Length (KM)	1,283	1,193	688	1,017	5,301	937			**10,419**
	Cap (MMTPA)	60.6	9.0	10.7	11.3	48.6	7.8			**147.9**
Products	Length (KM)		654			9,400	2,241	3,775	2,395	**18,465**
	Cap (MMTPA)		1.7			47.5	19.5	34.1	9.4	**112.2**

*Others include GAIL and Petronet India. HPCL and BPCL lubes pipeline included in products pipeline data

12. Production and consumption of petroleum products (Million Metric Tonnes)												
Products	**2019-20**		**2020-21 (P)**		**May 2020**		**May 2021 (P)**		**Apr-May 2020 (P)**		**Apr-May 2021 (P)**	
	Prod	**Cons**	**Prod**	**Cons**	**Prod**	**Cons**	**Prod**	**Cons**	**Prod**	**Cons**	**Prod**	**Cons**
LPG	12.8	26.3	12.1	27.6	1.0	2.3	1.0	2.2	1.9	4.4	2.0	4.3
MS	38.6	30.0	35.8	28.0	2.4	1.8	3.2	2.0	4.4	2.7	6.4	4.4
NAPHTHA	20.6	14.3	19.4	14.3	1.4	1.0	1.6	1.2	2.9	1.8	3.3	2.5
ATF	15.2	8.0	7.1	3.7	0.4	0.1	0.8	0.3	0.9	0.2	1.5	0.7
SKO	3.2	2.4	2.3	1.8	0.2	0.2	0.2	0.1	0.4	0.3	0.3	0.2
HSD	111.1	82.6	100.4	72.7	7.4	5.5	8.3	5.5	14.0	8.7	17.1	12.2
LDO	0.6	0.6	0.7	0.8	0.03	0.07	0.06	0.08	0.1	0.1	0.1	0.2
LUBES	0.9	3.8	1.1	3.5	0.1	0.2	0.1	0.3	0.1	0.3	0.2	0.5
FO/LSHS	9.3	6.3	8.2	6.0	0.8	0.5	0.7	0.5	1.5	0.8	1.2	1.0
BITUMEN	4.9	6.7	4.9	7.1	0.4	0.6	0.4	0.5	0.4	0.8	0.9	1.2
PET COKE	14.6	21.7	12.0	18.3	1.0	2.5	1.0	1.6	2.0	3.3	2.2	3.2
OTHERS	31.0	11.4	29.5	10.8	2.4	0.7	2.7	0.9	4.5	1.3	5.6	1.8
ALL INDIA	**262.9**	**214.1**	**233.4**	**194.6**	**17.3**	**15.3**	**20.0**	**15.1**	**33.2**	**24.7**	**40.8**	**32.1**
Growth (%)	**0.2%**	**0.4%**	**-11.2%**	**-9.1%**	**-21.3%**	**-20.2%**	**15.5%**	**-1.5%**	**-22.7%**	**-34.2%**	**22.8%**	**30.1%**

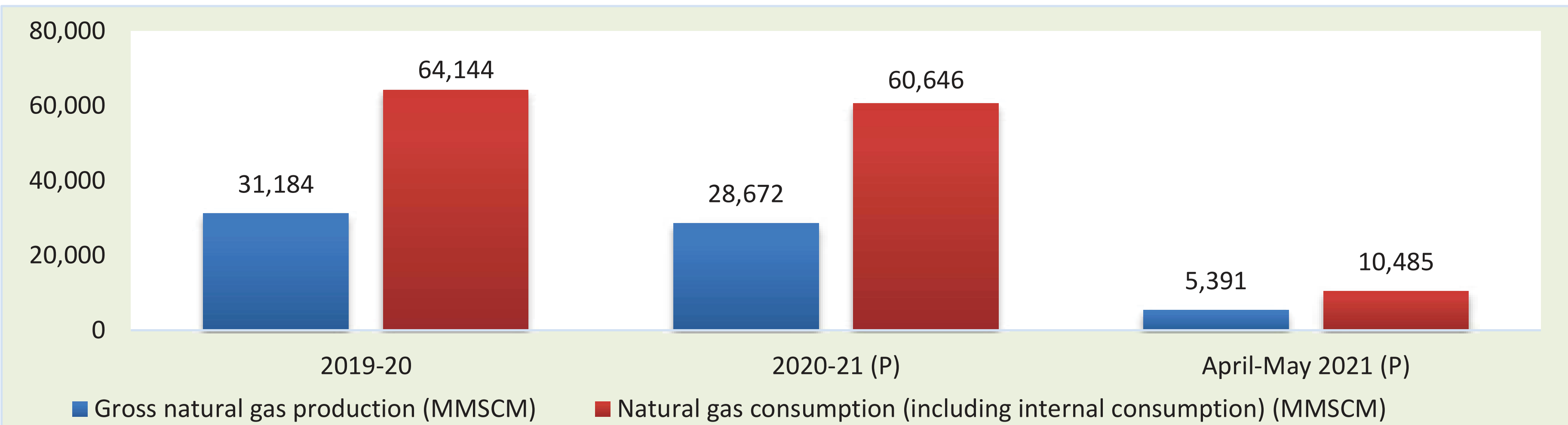
Note: Prod - Production; Cons - Consumption

19. Natural gas at a glance

(MMSCM)

Details	2019-20	2020-21 (P)	May 2020-21 (P)	May 2021-22 (Target)	May 2021-22 (P)	April-May 2020-21 (P)	April-May 2021-22 (Target)	April-May 2021-22 (P)
(a) Gross production	31,184	28,672	2,300	2,857	2,740	4,461	5,536	5,391
- ONGC	23,746	21,872	1,806	1,890	1,642	3,532	3,695	3,368
- Oil India Limited (OIL)	2,668	2,480	228	251	230	430	490	445
- Private / Joint Ventures (JVs)	4,770	4,321	266	716	868	499	1,350	1,579
(b) Net production (excluding flare gas and loss)	30,257	27,785	2,661		2,660	4,281		5,244
(c) LNG import#	33,887	32,861	2,370		2,587	4,198		5,242
(d) Total consumption including internal consumption (b+c)	64,144	60,646	5,031		5,247	8,480		10,485
(e) Total consumption **(in BCM)**	64.1	60.6	5.0		5.2	8.5		10.5
(f) Import dependency based on consumption (%), {c/d*100}	52.8	54.2	47.1		49.3	49.5		50.0

#Jul 2020-May 2021 DGCIS data prorated



20. Coal Bed Methane (CBM) gas development in India

Prognosticated CBM resources		91.8	TCF
Established CBM resources		10.4	TCF
CBM Resources (33 Blocks)		62.8	TCF
Total available coal bearing areas (India)		32760	Sq. KM
Total available coal bearing areas with MoPNG/DGH		21659	Sq. KM
Area awarded		16613	Sq. KM
Blocks awarded (ST CBM Block awarded twice in CBM Round II and Round IV)		32	Nos.
Exploration initiated (Area considered if any boreholes were drilled in the awarded block)		10669.55	Sq. KM
Production of CBM gas	April-May 2021 (P)	115.39	MMSCM
Production of CBM gas	May 2021 (P)	58.88	MMSCM

21. Natural gas pipeline network as on 31.12.2020

Nature of pipeline		GAIL	GSPL	PIL	IOCL	AGCL	RGPL	GGL	DFPCL	ONGC	GIGL	GITL	Others*	Total
Operational	Length	8,241	2,265	1,460	132	105	312	73	42	24				**12,654**
	Capacity	171.6	43.0	85.0	20.0	2.4	3.5	5.1	0.7	6.0				**337.3**
Partially commissioned#	Length	3,643			23						442	364		**4,472**
	Capacity	-			-						-	-		**-**
Total operational length		**11,884**	**2,265**	**1,460**	**155**	**105**	**312**	**73**	**42**	**24**	**442**	**364**	**0**	**17,126**
Under construction	Length	6,242			1,398						2,335	1,678	3,780	**15,433**
	Capacity	23.2			-						-	-	157.7	**-**
Total length		**18,126**	**2,265**	**1,460**	**1,553**	**105**	**312**	**73**	**42**	**24**	**2,777**	**2,042**	**3,780**	**32,559**

Source: PNGRB; Length in KMs ; Authorized Capacity in MMSCMD; *Others-APGDC, HEPL, IGGL, IMC, Consortium of H-Energy

22. Existing LNG terminals

Location	Promoters	Capacity as on 01.06.2021	% Capacity utilisation (April 2021)
Dahej	Petronet LNG Ltd (PLL)	17.5 MMTPA	80.2
Hazira	Shell Energy India Pvt. Ltd.	5 MMTPA	36.9
Dabhol	Konkan LNG Limited	*5 MMTPA	146.0
Kochi	Petronet LNG Ltd (PLL)	5 MMTPA	27.0
Ennore	Indian Oil LNG Pvt Ltd	5 MMTPA	17.0
Mundra	GSPC LNG Limited	5 MMTPA	27.4
Total Capacity		**42.5 MMTPA**	

* To increase to 5 MMTPA with breakwater. Only HP stream of capacity of 2.9 MMTPA is commissioned

https://qp.com.qa/en/MediaCentre/Pages/ViewNews.aspx?NType=News

Qatar Petroleum has received offers for double the equity available in the North Field East project (NFE)"

DOHA, Qatar • 23 June 2021 – His Excellency Mr. Saad Sherida Al-Kaabi, Minister of State for Energy Affairs, The President and CEO of Qatar Petroleum, said Qatar Petroleum has received offers for double the equity available to potential partners in the bidding process for the North Field East project.

His Excellency Al-Kaabi stated that Qatar Petroleum was in the process of evaluating commercial offers received for participation in the largest LNG development in the world with a capacity of 32 million tons per annum of LNG, and that Qatar Petroleum had received offers that cover double the offered equity stake. His Excellency Al-Kaabi also noted that as part of the same process, Qatar Petroleum had received offtake commitments/ sales and purchase agreements for double the 32 million tons per annum volume on offer.

The NFE project is unique in the LNG world because of its advanced environmental characters, including significant carbon capture and sequestration capacity.

These remarks were made during a Qatar Economic Forum session on “Energy Shifts” in which His Excellency Al-Kaabi was a panelist along with Mr. Ben van Beurden, the CEO of Royal Dutch Shell, Mr. Patrick Pouyanné, the Chairman and CEO of TotalEnergies and Mr. Darren Woods, the Chairman and CEO of ExxonMobil.

The session, which was also broadcast on Bloomberg TV and its media platforms, focused on the energy transition and the underlying climate change concerns driving net zero emissions targets.
In discussing the ongoing energy transition, His Excellency Al-Kaabi said “We see natural gas and the energy transition - joined at the hip- and gas/ LNG is part of the solution for a longer term transition. We are investing the majority of our CAPEX in LNG, but we are also investing in renewables such as solar, here in Qatar but also worldwide.”

However, His Excellency Al-Kaabi voiced concern that during the global discussion on energy transition, there is a lack of investment in oil and gas projects, which could drive energy prices higher by stating that “while gas and LNG are important for the energy transition, there is a lack of investments that could cause a significant shortage in gas between 2025-2030, which in turn could cause a spike in the gas market.”

On Carbon Capture and Sequestration, His Excellency Al-Kaabi highlighted the fact that Qatar started decarbonizing its LNG a while ago, and that it currently captures and sequesters two million tons per annum of CO_2, which will grow to 9 million tons by 2030. “We are doing it very responsibly and we will be part of the solution for the long term,” Minister Al-Kaabi added.

The panelists warned that energy transition is not only about the producers, but also about end users and their consuming behaviors. His Excellency Al-Kaabi also highlighted the fact that the energy transition needs to take into consideration the requirements of the developing world, including the 0.8-1.0 billion people who are deprived of electricity and basic fuels today to ensure a balanced approach that takes human development and economic growth in these developing nations into account, and that actions taken need to be responsible for the collective wellbeing of all of humanity.

In concluding his remarks, His Excellency Al-Kaabi said that in the effort to put policies in place to reduce CO_2 level, there is a challenge represented by the bill that has to be paid to bridge that gap, and called for collective work for a carbon pricing mechanism that is fair and equitable and that can be applied seamlessly on a global basis.

The Qatar Economic Forum, Powered by Bloomberg, brings together some of the world’s leaders and the most influential thinkers, executives, and policy makers to prepare a blueprint for the next stage of global growth. Discussion themes during the Qatar Economic Forum cover issues such as leadership in a post-pandemic world, changes to the human-technology nexus, a more sustainable global economy, markets and investing, power and trade flows, and the future of commerce.
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https://www.thehindubusinessline.com/companies/lngs-share-of-indian-gas-demand-to-rise-to-70-by-2030-petronet-ceo/article34845886.ece

LNG's share of Indian gas demand to rise to 70% by 2030: Petronet CEO

Reuters NEW DELHI | Updated on June 18, 2021

Replacing about 30% of the country's crude oil imports with LNG would save $10 billion at current global oil price of $74/barrel, he said

The share of liquefied natural gas (LNG) in India's gas consumption could rise to 70% from the current 50% in 10 years, and new import terminals are needed, the chief executive of the country's top gas importer said.

Prime Minister Narendra Modi has set a target to raise the share of natural gas in the country's energy mix to 15% by 2030 from the current 6.3% to cut its carbon footprint.

To meet that target India's gas consumption needs to rise to 640 million standard cubic metres a day (mmscmd) from the current 155 mmscmd, AK Singh, chief executive of Petronet LNG, said at ET Energy Leadership summit.

Huge invesments by Indian cos

Indian companies are investing billions of dollars to strengthen gas infrastructure, including laying 15,000-kilometer pipelines to supply cleaner fuel to households and industries. India currently has 17,000 kms of gas pipeline network.

Also, LNG projects of 19 million tonnes per annum (mtpa) capacity are under construction and plans are afoot to increase use of LNG in trucks and buses.

"With limited increase in domestic gas supply LNG will play a major role in catering to this incremental demand and share of LNG in natural gas consumption is likely to increase from the present 55% to 70% in coming 9-10 years," Singh said.

Petronet operates two LNG terminals in India accounting for about 53% of the nation's existing 42.5 mtpa import capacity.

Singh said India needed to increase its LNG import capacity to 155 mtpa "considering 80% utilisation" to boost use of the cleaner fuel.

India imports about 85% of its oil needs. He said replacing about 30% of the country's crude oil imports with LNG would save $10 billion at current global oil price of $74/barrel.

Published on June 18, 2021

Finally, Some Visibility That India Is Moving Towards Its Target For Natural Gas To Be 15% Of Its Energy Mix By 2030

Posted: Wednesday October 23, 2019. 3:45pm MT

It's taking longer than expected, but we are finally getting visibility that India is investing significantly towards its goal to have natural gas be 15% of its energy mix by 2030. Earlier in Oct, India Oil Minister Dharmendra Pradhan said that there are $60 billion of natural gas infrastructure and LNG import terminals that are "under execution". He said "*I am not talking about potential investment. This number relates to the project that are under execution".* Natural gas consumption in India is only now back to 2011 levels at 5.6 bcf/d and represents only 6.2% of its energy mix. If India hits its 15% target of its energy mix by 2030, it would add natural gas demand, on average, of >1.5 bcf/d per year. At the same time India's domestic natural gas production peaked in 2010 at 4.6 bcf/d, but has been flat from 2014 thru 2018 at ~2.7 bcf/d, which means the big winner will be LNG. The most important factor driving this expectation for natural gas consumption growth is likely price. Asian LNG landed prices are down about 50% YoY and, more significantly, the expectation is for future Asian LNG prices to be at lower levels than prior cycles. India, by itself, may not be a LNG global game changer, but it is another positive support for why we believe LNG markets will rebalance sooner than expected ie. in 2022/2023. We see mid term Asian LNG landed prices lower than prior cycles in a rebalanced market (ie. +/- $8), which means that low capital costs will be critical for future LNG projects. We believe that BC's LNG key potential projects (LNG Canada Phase 2 and Chevron Kitimat LNG) can compete in this price environment as they have the potential for brownfield capital costs if they move to a continuous construction cycle following in lockstep to LNG Canada Phase 1, much like Cheniere does for its LNG projects in the Gulf Coast.

India has a pollution crisis. We don't think it is unfair to say India has a pollution crisis. In every pollution ranking, India has several cities among the most polluted cities. The 2018 World Air Quality Report (AirVisual) list of the World's Most Polluted Cities 2018 has 20 of the world's 25 most polluted cities being in India. India has all of the top 25 most polluted cities other than #3 Faisalabad (Pakistan), #7 Hotan (China), #10 Lahore (Pakistan), #17 Dhaka (Bangladesh), and #19 Kashgar (China). Like us, many people have been to Beijing on business and believe Beijing's reputation as a very polluted city is deserved. But to put in perspective, Beijing's ranking isn't even close to the 15 most polluted cities in China, let alone the world. Beijing's score on their scale is 50.9 vs the other Chinese cities #7in the world, Hotan at 116.0, and #19 Kashgar at 95.7, and the world's most polluted city #1 Gurugram (India) at 135.8 .

World's Most Polluted Cities 2018

Rank	City	Country	Rank	City	Country
1	Gurugram	India	14	Varanasi	India
2	Ghaziabad	India	15	Moradabad	India
3	Faisalabad	Pakistan	16	Agra	India
4	Faridabad	India	17	Dhaka	Bangladesh
5	Bhiwadi	India	18	Gaya	India
6	Noida	India	19	Kashgar	China
7	Patna	India	20	Jind	India
8	Hotan	China	21	Kanpur	India
9	Lucknow	India	22	Singrauli	India
10	Lahore	Pakistan	23	Kolkata	India
11	Delhi	India	24	Pali	India
12	Jodhpur	India	25	Rohtak	India
13	Muzaffarpur	India	26	Mandi Gobindgarh	India

Source: Airvisual

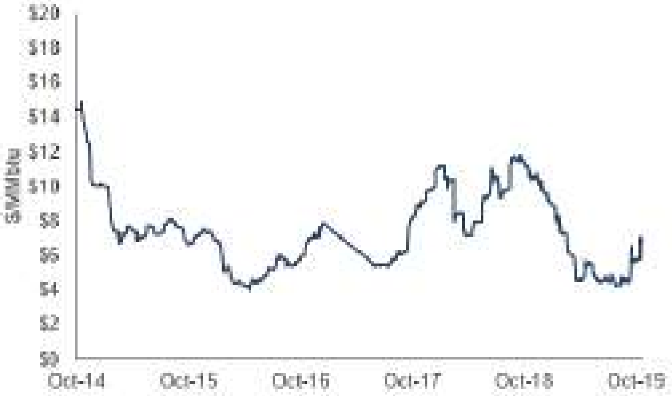
India natural gas consumption is only now back to 2011 levels. For the past couple years, we have been highlighting that the growth in India's natural gas consumption (and linked LNG imports) has been very low due to the slow buildout of domestic natural gas infrastructure and LNG import facilities. BP data shows India's natural gas consumption was 5.6 bcf/d in 2018, and this compares to its peak of 5.8 bcf/d in 2011. To put in perspective, China's natural gas consumption in 2011 was 13.1 bcf/d and reached 27.4 bcf/d in 2018.

India's Natural Gas Consumption (bcf/d)

Source: BP

<u>Perhaps the best reason why there is better visibility – LNG prices are expected lower than prior cycles</u>. A key reason for this lack of growth has been the price of LNG relative to coal. Our June 17, 2018 Energy Tidbits [LINK] highlighted comments from the Q&A from BP's Chief Economist speech "*Energy in 2017: two steps forward, one step back*" on this relative cost concept. We then wrote on the BP Chief Economist comments from an India company on why there isn't more natural gas and why coal is still going up. He said that the Indian executive said it was because the cost of natural gas was significantly more expensive than domestic coal and that the push in India is to get more power to more poorer people, but if natural gas is significantly higher, it can't be done, they have to rely on coal. What has happened since the BP Chief Economist June 2018 comment is that Asian LNG prices are down 50% and the expectation going forward is that future LNG prices are not expected to be at prior cycle highs. But the other question is what does it mean for LNG prices. There is an increasing supply of reasonable priced LNG around the world, whether it from Qatar, Papua New Guinea, the Gulf of Mexico and even Canada. And each of these areas has anchor projects to support future brownfield development. Couple that with increasing linkage of LNG prices away from oil indexed contracts, we believe this means that a balanced LNG market going forward is going is not going to see sustained high Asian LNG prices from prior cycles, but around more costs related more to lower LNG supply basins ie. LNG prices around mid to long term +/- $8 landed Asian LNG prices, and not the prior $10 - $12 range. As the BP Chief Economist highlights, price is a huge issue for India and it is likely that the expectation for lower LNG prices than prior cycles is the most important reason to push India to increased natural gas consumption.

Japan/Korea Marker (JKM) LNG Price



Source: Bloomberg

India is now getting serious about increasing natural gas consumption, has $60b of projects under execution. We follow the key India news as part of our weekly news scan for our Energy Tidbits memos and there is no question that the India government and its people realize they have to deal with this increasing pollution problem. And perhaps most of all, India is now taking specific, significant action to set the stage for increasing natural gas consumption and LNG imports. Earlier in Oct, Japan Times picked up a Reuters story "*India investing $60 billion on gas grid to link up nation by 2024*" [LINK]. The story notes "*India, one of the world's largest consumers of oil and coal, is investing $60 billion to build a national gas grid and import terminals by 2024 in a bid to cut its carbon emissions, the oil minister said on Sunday. India has struggled to boost its use of gas, which produces less greenhouse gas emissions than coal and oil, because many industries and towns are not linked to the gas pipeline network. Gas consumption growth was running at 11 percent in 2010 but growth slid to just 2.5 percent in the financial year 2018/19.*" The most significant part of this story is that this is $60 billion of projects under execution, not planned or potential projects. The story quotes Oil Minister Dharmendra Pradhan "*I am not talking about potential investment. This number relates to the project that are under execution*". The critical natural gas infrastructure requirement is a domestic natural gas pipeline network to deliver gas throughout India. The India Ministry of Petroleum & Natural Gas Oct 3, 2019 release [LINK] said "*On the issue of moving towards the gas economy, Shri Pradhan said that over 16,000 km of gas pipeline has been built and an additional 11,000 km is under construction. With the tenth bid round for City Gas Distribution completed, it will cover over 400 districts and will extend coverage to 70 percent of our population".* Progress is being made. Plus LNG regasification projects continue to be completed. Below is our updated table of India LNG projects that are estimated to come on stream in 2019 and 2020. We haven't included the projects beyond 2020, but there are several planned projects already on the books.

India Current/Planned LNG Regasification Projects Est. In Service In 2019/2020

	State	Coast	Operator	Capacity (mtpa)	Capacity (bcf/d)	Expected Timelines
Existing Terminals						
Dahej	Gujarat	West	Petronet LNG	10.00	1.32	Operating
Dahej Phase 2	Gujarat	West	Petronet LNG	5.00	0.66	Operating
Hazira	Gujarat	West	Shell	5.00	0.66	Operating
Dabhol RGPPL	Maharashtra	West	GAIL & NTPC JV	5.00	0.66	Operating
Kochi	Kerela	West	Petronet LNG	5.00	0.66	Operating
Ennore Phase 1	Tamil Nadu	East	IOCL	5.00	0.66	Operating
Total Existing				**35.00**	**4.61**	
Upcoming Terminals						
Mundra	Gujarat	West	Adani & GSPC	5.00	0.66	2019
Jaigarh	Maharashtra	West	H-Energy Gateway Pvt. Limited	4.00	0.53	2019
Dahej Phase 3	Gujarat	West	PLL	2.50	0.33	2019
Mundra	Gujarat	West	Adani	5.00	0.66	2020
Digha FSRU	Odisha	East	H-Energy	4.00	0.53	2020
Ennore Phase 2	Tamil Nadu	East	IOCL	1.75	0.23	2020
Jafrabad	Gujarat	West	Swan Energy	5.00	0.66	2020
Total Upcoming				**27.25**	**3.59**	

Source: Bloomberg, Company Reports, Street Reports

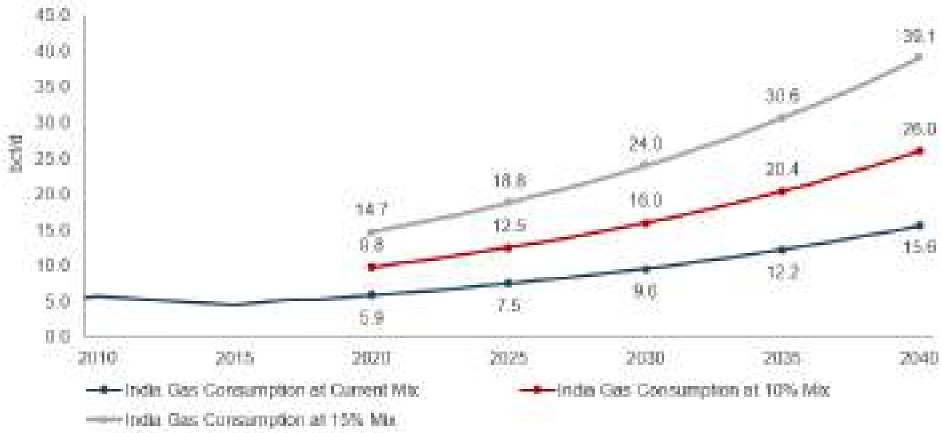
It reminds us of when China got really serious about natural gas in 2018. We should be clear that we do not consider India anywhere near as significant to global LNG markets as China. But conceptually, India getting serious about increasing natural gas consumption reminds us of what we were seeing in China in 2016/2017. India is probably more like China in 2016 as opposed to the summer of 2017, when it seemed clear that China was on the cusp of a major push in natural gas consumption and LNG would be the winner in 2018. India's impact should start to play out by year end 2020 as opposed to this winter. We first outlined the China LNG thesis in our Sept 20, 2017 blog "*China's Plan To Increase Natural Gas To 10% Of Its Energy Mix Is A Global Game Changer Including For BC LNG*" [LINK]. Our Sept 20, 2017 blog wrote "*The news flow from China this summer on its increasing fight and urgency to fight pollution supports China's plan to increase natural gas to 10% of its energy mix in 2020 and 15% of its energy mix in 2030. This is a game changer to global natural gas markets and, by itself, can bring LNG to undersupply 2 to 3 years earlier than expected. China's natural gas consumption increased by ~15% per year from 2005 thru 2016 and ~1.5 bcf/d per year vs China's 8.5%*

growth rate in energy in total. Yet natural gas only got to 5.9% of China's energy mix. If China is to hit 10% by 2020, it will need to increase natural gas consumption by 4 to 5 bcf/d per year. Assuming China continues to grow its domestic natural gas production by 0.6 bcf/d per year (its growth rate for last five years), China will need to import an additional ~3.5 to ~4.5 bcf/d per year. This is "per year"! And if so, we believe BC LNG will be back and there is a higher probability than ever before for a Shell FID on its BC LNG project in 2018." As it turned out, Shell did FID its LNG Canada project on Oct 1, 2018.

Natural gas is only 6.2% of India's energy mix vs its target of 15% in 2030. India, similar to China, has a target to have natural gas to be 15% of its total energy mix by 2030. This is not a new target, rather it has been in place and we first highlighted India's 15% target of its energy mix in our Nov 23, 2018 blog "*"India's Natural Gas Consumption Would Be Up ~1.3 Bcf/D Per Year If Its To Reach Its Target Of 15% Of Its Energy Mix By 2030*" [LINK] At that time, we noted some specific steps that were happening in 2019 and 2020 to put them on that long term plan. The impact to get to 15% of energy mix is significant to world LNG markets. This is a big increase from natural gas being 6.2% of India's energy mix in 2018. To put in perspective, in 2018, natural gas was 30.5% of US energy mix, 21.9% of Japan's energy mix, 16.0% of South Korea's energy mix, and 7.4% of China's energy. Note, China is up from 6.6% in 2017.

Hitting 15% of its energy mix would increase India's natural gas consumption by >1.5 bcf/d per year. We projected how much India's natural gas consumption would increase if it can hit its target of 15% of total energy mix in 2030. BP data shows India's natural gas consumption in 2018 was 5.6 bcf/d and natural gas was only 6.2% of total energy mix. BP also estimates India's total energy consumption grew at a rate of 5.2% per year for the 2007 – 2017 period, but energy consumption growth increased to +7.9% in 2018 YoY vs 2017 But if we only assume a 5% growth in total energy mix to 2030, then if natural gas is 15% of India's energy mix, it would be 18.8 bcf/d in 2025 and 24.0 bcf/d in 2030 ie. growth of +13.2 bcf/d to 2025 and +18.4 bcf/d to 2030. India's domestic natural gas production peaked in 2010 at 4.6 bcf/d, but has been flat from 2014 thru 2018 at +/- 2.7 bcf/d. We expect there to be some increased focus to at least return India to modest domestic natural gas production. But, until then, any growth in natural gas consumption will be met with LNG. Our model forecasts of >1.5 bcf/d per year, on average, in consumption is the equivalent of 2.5 Cheniere LNG trains per year.

India's Projected Natural Gas Consumption @15% Of Energy Mix (bcf/d)



Source: BP, SAF

India may not be a LNG global game changer by itself like China, but does support the call that LNG markets rebalance sooner than expected. We had our SAF Group 2020 Energy Market Outlook on Monday Oct 7. A replay of the call and the supporting slide presentation are available on our website at [LINK]. Two of our key off consensus calls were on LNG including our view LNG market would balance earlier than expected ie. 2022/2023. We noted that we agree with markets that LNG will be oversupplied thru 2021, but where we disagree is that we see LNG markets balancing in 2022 or 2023. Our presentation reminded that LNG supply capacity needs to be in excess of demand to provide for turnarounds and allowance such that suppliers can deliver contract volumes. We also expect the required over capacity of supply is increasing as contract mix shifts away from historical oil indexed take or pay contracts with destination clauses to an increase share of portfolio contracts. There is no firm number, but we believe the required excess supply capacity relative to demand has increased from approx. 5% to 10% to +/-15% ie. LNG markets are effectively balanced when LNG supply capacity is >10% of demand. As a result, we believe that LNG markets rebalance in 2022/2023, a view which is similar to Total's Sept 25, 2019 Investor Day [LINK] (see below graphs). We should note that our view of balanced LNG markets doesn't mean a return to $12 or more Asian landed LNG prices, rather, we see the emergence of anchor LNG projects in areas with brownfield expansion potential means that a planning case for mid term Asian LNG price is in the $8 range. Our outlook presentation also includes our view that BC's LNG key potential projects (LNG Canada Phase 2 and Chevron Kitimat LNG) can compete in this price environment as they have the potential for brownfield capital costs if they move to a continuous construction cycle following in lockstep to LNG Canada Phase 1, much like Cheniere does for its LNG projects in the Gulf Coast. Our outlook call did not specifically work in the India Energy Minister's comment on in execution projects, but, if anything, it provides us with more confidence for the call for LNG markets to rebalance in 2022/2023.

Total's Medium And Long Term LNG Supply & Demand

Source: Total Sept 25, 2019 Investor Day

Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

Posted Wednesday April 28, 2021. 9:00 MT

The next six months will determine the size and length of the new LNG supply gap that is hitting harder and faster than anyone expected six months ago. Optimists will say the Mozambique government will bring sustainable security and safety to the northern Cabo Delgado province and provide the confidence to Total to quickly get back to LNG development such that its LNG in-service delay is a matter of months and not years. We hope so for Mozambique's domestic situation, but will it be that easy for Total's board to quickly look thru what just happened? Total suspended LNG development for 3 months, restarted development on March 25, but then 3 days of violence led it to suspend development again on March 28, and announce force majeure on Monday April 26. Even if the optimists are right, Mozambique LNG is counted on for LNG supply and the major LNG supply project that are in LNG supply forecasts are now all delayed – Total Phase 1 of 1.7 bcf/d and its follow on Phase 2 of 1.3 bcf/d, and Exxon's Rozuma Phase 1 of 2.0 bcf/d. It is important to remember this 5.0 bcf/d of major LNG supply is being counted in LNG supply forecasts and starting in 2024. At a minimum, we think the more likely scenario is a delay of at least 2 years in this 5.0 bcf/d from the pre-Covid timelines. And this creates a much bigger and sooner LNG supply gap starting ~2025 and stronger outlook for LNG prices. Thermal coal in Asia will play a role in keeping a lid on LNG prices. But there will be the opportunity for LNG suppliers to at least review the potential for brownfield LNG projects to fill the growing supply gap. The thought of increasing capex was a non-starter six months ago, but there is a much stronger outlook for global oil and gas prices. Oil and gas companies are pivoting from cutting capex to small increases in 2021 capex and expecting for higher capex in 2022. We believe this sets the stage for looking at potential FID of brownfield LNG projects before the end of 2021 to be included in 2022 capex budgets. Mozambique is causing an LNG supply gap that someone will try to fill. And if brownfield LNG is needed, what about Shell looking at 1.8 bcf/d brownfield LNG Canada Phase 2? Cdn natural gas producers hope so as this would mean more Cdn natural gas will be tied to Asian LNG markets and not competing in the US against Henry Hub.

<u>Total declares force majeure on Mozambique LNG,</u> Yesterday, Total announced [LINK] "*Considering the evolution of the security situation in the north of the Cabo Delgado province in Mozambique, Total confirms the withdrawal of all Mozambique LNG project personnel from the Afungi site. This situation leads Total, as operator of Mozambique LNG project, to declare force majeure. Total expresses its solidarity with the government and people of Mozambique and wishes that the actions carried out by the government of Mozambique and its regional and international partners will enable the restoration of security and stability in Cabo Delgado province in a sustained manner".* Total is working Phase 1 is ~1.7 bcf/d (Train 1 + 2, 6.45 mtpa/train) and was originally expected to being LNG deliveries in 2024. There was no specific timeline for Phase 2 of 1.3 bcf/d (Train 3 + 4, 5.0 mtpa/train), but was expected to follow Phase 1 in short order to keep capital costs under control with a continuous construction process with a potential onstream shortly after 2026.

Total Mozambique Phase 1 and 2

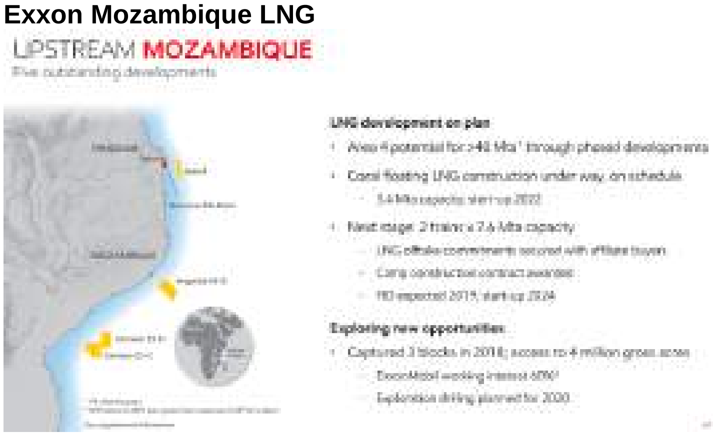
Source: Total Investor Day September 24, 2019

Total's Mozambique force majeure is no surprise, especially the need to the restoration of security and stability "in a sustained manner". Yesterday, Total announced [LINK] "*Considering the evolution of the security".* No one should be surprised by the force majeure or the sustained manner caveat. SAF Group posts a weekly Energy Tidbits research memo [LINK], wherein we have, in multiple weekly memos, that Total had shut down development in December for 3 months due to the violent and security risks. It restarted development on Wed March 24, violence/attacks immediately resumed for 3 consecutive days, and then Total suspended development on Sat March 27. Local violence/attacks shut development down in Dec, the situation gets settled enough for Total to restart in March, only to be shut down 3 days thereafter. No one should be surprised especially with Total's need to see security and stability "in a sustained manner".

Does anyone really think Total will risk another quick 2-3 month restart or even in 2021? The Mozambique government will be working hard to convince Total to restart soon. We just find it hard to believe Total board will risk a replay of March 24-27 in 2021. Unfortunately, Mozambique has had internal conflict for years. It reached a milestone to the positive in August 2019. Our SAF Group August 11, 2019 Energy Tidbits memo [LINK] highlighted the signing of a peace pact between Mozambique President Nyusi and leader of the Renamo opposition Momade. This was the official end to a 2013 thru 2016 conflict following a failure to hold up the prior peace pact. At that time, FT reported [LINK] "Mr Nyusi has said that "*the government and Renamo will come together and hunt" rebels who fail to disarm. The government has struggled to stem the separate insurgency in the north, which has killed or displaced hundreds near the gas-rich areas during the past two years. While the roots of the conflict remain murky, it is linked to a local Islamist group and appears to be drawing on disaffection over sharing gas investment benefits, say analysts*." This is just a reminder this is not a new issue. LNG is a game changer to Mozambique's economic future. It is, but also has been, a government priority to have the security and safety for Total and Exxon to move on their LNG developments. Its hard to believe the Mozambique government will be able to quickly convince Total and Exxon boards that they can be comfortable there is a sustained security/safety situation and they can send their people back in to develop the LNG. Total's board would allow any resumption of development before year end 2021. The last thing Total wants is a replay of March 24-27. The first question is how long will it take before the Total board is convinced its safe to restart. Could you imagine them doing a replay of what just happened? Wait three months, restart development and have to stop again right away? We have to believe that could lead the Total board to believe it is unfixable for years. We just don't think they are to prepared to risk that decision in 3 months. Its why we have to think there isn't a restart approval until at least in 2022 at the earliest ie. why we think the likely scenario is a delay of 2-3 years, and not a matter of months.

Mozambique's security issues pushes back 5.0 bcf/d of new LNG supply at least a couple years. The global LNG issue is that 5 bcf/d of new Mozambique LNG supply (apart from the Eni Coral FLNG of 0.45 bcf/d) won't start up in 2024 and continuing thru the 2020s. And we believe all LNG forecasts included this 5.0 bcf/d to be in service in the 2020s as Mozambique had been considered the best positioned LNG supply to access Asia after Australia and Papua New Guinea. (i) Eni Coral Sul (Rovuma Basin) FLNG of 0.45 bcf/d planned in service in 2022. [LINK] This is an offshore floating LNG vessel that is still expected to be in service in 2022. (ii) Total Phase 1 to add 1.7 bcf/d with an in service originally planned for 2024. We expect the in service data to be pushed back to at least 2026 assuming Total gives a development restart approval in Dec 2021. In theory, this would only be a 1 year loss of time. However, Total has let services go, the project will be idle for 9 months, it isn't clear if the need to get people out quickly let them do a complete put the project on hold, and how many people will be on site maintaining the status of the development during the force majeure. Also what new procedures and safety will be put in place for a restart. These all mean there will be added time needed to get the project back to where it was when force majeure was declared ie. why we think a 12 month time delay will be more like an 18 month project delay. (iii) Exxon's Rozuma Phase 1 LNG will add 2.0 bcf/d and, pre-Covid, was expected to be in service in 2025. We believe the delays related to security and safety at Total are also going to impact Exxon. We find it highly unlikely the Exxon board would take a different security and safety decision than Total. Pre-pandemic, Exxon's March 6, 2019 Investor Day noted their operated Mozambique Rovuma LNG Phase 1 was to be 2 trains each with 1.0 bcf/d capacity for total initial capacity of 2.0 bf/d with FID expected in 2019 and first LNG deliveries in 2024. The 2019 FID expectation was later pushed to be expected just before the March 2020 investor day. But the pandemic hit, and on March 21, 2020, we tweeted [LINK] on the Reuters story "*Exclusive: Coronavirus, gas slump put brakes on Exxon's giant Mozambique LNG plan"* [LINK] that noted Exxon was expected to delay the Rovuma FID. There was no timeline, but the expectation was that FID would now be in 2022 (3 years later than original timeline0 and that would push first LNG likely to 2027. (iv) Total Phase 2 was to add 1.3 bcf/d. There was no firm in service date but it was expected to follow closely behind Phase 1 to maintain services. That would have put it originally in the 2026/2027 period. But if Phase 1 is pushed back 2 years, so will Phase 2 so more likely 2028/2029.. (v) Total Phase 1 + 2 and Exxon Rozuma Phase 1 total 5.0 bcf/d and would have been (and still are) in all LNG supply forecasts for the 2020s. (vi) We aren't certain if the LNG supply forecasts include Exxon Rozuma Phase 2 ,which would be an additional 2.0 bcf/d on top of the 5.0 bcf/d noted above. Exxon Rozuma has always been expected to be at least 2 Phases. This has been the plan since the Anadarko days given the 85 tcf size of the resource on Exxon's Area 4. There was no firm in service data for Phase 2, but it was expected they would also closely follow Phase 1 to maintain services. We expect that original timeline would have been 2026/2027 and that would not be pushed back to 2029/2030. (vii) It doesn't matter if its only 5 bcf/ of Mozambique that is delayed 2 to 3 years, it will cause a bigger LNG supply gap and sooner. The issue for LNG markets is this is taking projects that are in development effectively out of the queue for some period.

Exxon Mozambique LNG



Source: Exxon Investor Day March 6, 2019

<u>Won't LNG and natural gas get hit by Biden's push for carbon free electricity?</u> Yes, in the US. For the last 9 months, we have warned on Biden's climate change plan that were his election platform and now form his administration's energy transition map. We posted our July 28, 2020 blog "*Biden To Put US On "Irreversible Path to Achieve Net-Zero Emissions, Economy-Wide" Is a Major Negative To US Natural Gas in 2020s* "[LINK] on Biden's platform "*The Biden Plan to Build a Modern, Sustainable Infrastructure and an Equitable Clean Energy Future*" [LINK]. Biden's new American Jobs Plan

[LINK] lines up with his campaign platform including to put the US "*on the path to achieving 100 percent carbon-free electricity by 2035*.". Our July 28, 2020 blog noted that it would require replacing ~60% of US electricity generation with more renewable and it could eliminate ~40% (33.5 bcf/d) of 2019 US natural gas consumption. If Biden is 25% successful by 2030, it would replace ~6.3 bcf/d of natural gas demand. It would be a negative to US natural gas and force more US natural gas to export markets. The wildcard when does US natural gas start to decline if producers are faced with the reality of natural gas being phased out for electricity. The other hope is that when Biden says "carbon-free", its not what ends up in the details of any formal policy statement ie. carbon electricity will be allowed with Biden's push for CCS.

<u>Will Cdn natural gas be similarly hit by if Trudeau move to "emissions free" and not "net zero emissions" electricity?</u> Yes and No. Our SAF Group April 25, 2021 Energy Tidbits memo [LINK] was titled ""*Bad News For Natural Gas, Trudeau's Electricity Goal is Now 100% "Emissions Free" And Not "Net Zero Emissions*". On Thursday, PM Trudeau spoke at Biden's global climate summit [LINK] and looks like he slipped in a new view on electricity than was in last Monday's budget and his Dec climate plan. Trudeau said "*In Canada, we've worked hard to get to over 80% emissions-free electricity, and we're not going to stop until we get to 100%."* Speeches, especially ones made on a global stage are checked carefully so this had to be deliberate. Trudeau said "*emissions free*" and not net zero emissions electricity. It seems like this language is carefully written to exclude any fossil fuels as they are not emissions free even if they are linked to CCS. Recall in Liberals big Dec 2020 climate announcement [LINK], Liberals said ""*Work with provinces, utilities and other partners to ensure that Canada's electricity generation achieves net-zero emissions before 2050*." There is no way Trudeau changed the language unless he meant to do so. And this is a major change as it would seem to indicate his plan to eliminate all fossil fuels used for electricity. If so this would be a negative to Cdn natural gas that would be stuck within Western Canada and/or continuing to push into the US when Biden is trying to switch to carbon free electricity. We recognize that there is still some ambiguity in what will be the details of policy and the Liberals aren't changing to no carbon sourced electricity at all. Let's hope so. But let's also be careful that politicians don't change language without a reason or at least with a view to setting up for some future hit. Plus Trudeau had a big warning in that same speech saying "*we will make it law to respect our new 2030 target and achieve net-zero emissions by 2050*". They plan to make it the law that Canada has to be on track for the Liberals 2030 emissions targets. This means that the future messaging will be that the Liberals have no choice but to take harder future emissions actions as it is the law. They will be just obeying the law as they will be obligated to obey the law. Everyone knows the messaging will be we have to do more get to Net Zero, that in itself will inevitably mean it will be the law if he actually does move to eliminate any carbon based electricity. So yes it's a negative, that is unless more Cdn natural gas can be exported via LNG to Asia. We believe this would be a plus to be priced against global LNG instead of Henry Hub.

<u>Biden's global climate summit reminded there is too much risk to skip over natural gas as the transition fuel.</u> Apart from the US and Canada, we haven't seen a sea shift to eliminating natural gas for power generation, especially from energy import dependent countries. There is a strong belief that hydrogen and battery storage will one day be able to scale up at a competitive cost to lead to the acceleration away from fossil fuels. But that time isn't yet here, at least not for energy import dependent countries. One of the key themes from last week's leader's speeches at the Biden global climate summit – to get to Net Zero, the world is assuming there wilt be technological advances/discoveries that aren't here today and that have the potential to immediately ramp up in scale. IEA Executive Director Faith Birol was blunt in his message [LINK] saying "*Right now, the data does not match the rhetoric – and the gap is getting wider*." And "*IEA analysis shows that about half the reductions to get to net zero emissions in 2050 will need to come from technologies that are not yet ready for market. This calls for massive leaps in innovation. Innovation across batteries, hydrogen, synthetic fuels, carbon capture and many other technologies.* US Special Envoy for Climate John Kerry said a similar point that half of the emissions reductions will have to come from technologies that we don't yet have at scale. UK PM Johnson [LINK] didn't say it specifically, but points to this same issue saying "*To do these things we've got to be constantly original and optimistic about new technology and new solutions whether that's crops that are super-resistant to drought or more accurate weather forecasts like those we hope to see from the UK's new Met Office 1.2bn supercomputer that we're investing in*." It may well be that the US and other self sufficient energy countries are comfortable going on the basis of assuming technology developments will occur on a timely basis. But, its clear that countries like China, India, South Korea and others are not prepared to do so. And not prepared to have the confidence to rid themselves of coal power generation. This is why there hasn't been any material change in the LNG demand outlook

We expect the IEA's blunt message that the gap is getting wider will be reinforced on May 18. We have had a consistent view on the energy transition for the past few years. We believe it is going to happen, but it will take longer, be a bumpy road and cost more than expected. This is why we believe the demise of oil and natural gas won't be as easy and fast as hoped for by the climate change side. The IEA's blunt warning on the gap widening should not be a surprise as they warned on this in June 2020. Birol's climate speech also highlighted that the IEA will release on May 18 its roadmap for how the global energy sector can reach net zero by 2050. Our SAF Group June 11, 2020 blog "*Will The Demise Of Oil Take Longer, Just Like Coal? IEA and Shell Highlight Delays/Gaps To A Smooth Clean Energy Transition*" [LINK] feature the IEA's June 2020 warning that the critical energy technologies needed to reduce emissions are nowhere near where they need to be. In that blog, we said "there was an excellent illustration of the many significant areas, or major pieces of the puzzle, involved in an energy transition by the IEA last week. The IEA also noted the progress of each of the major pieces and the overall conclusion is that the vast majority of the pieces are behind or well behind where they should be to meet a smooth timely energy transition. It is important to note that these are just what the IEA calls the "*critical energy technologies*" and does not get into the wide range of other considerations needed to support the energy transition. The IEA divides these "critical energy technologies "into major groupings and then ranked the progress of each of these pieces in its report "*Tracking Clean Energy Progress"* [LINK] by on track, more efforts needed, or not on track". Our blog included the below IEA June 2020 chart.

IEA's Progress Ranking For "Critical Energy Technologies" For Clean Energy Transition

🔴 Power	🟡 Renewable Power	🔴 Geothermal
	🟢 Solar PV	🔴 Ocean Power
	🟡 Onshore Wind	🔴 Nuclear Power
	🟡 Offshore Wind	🟡 Natural Gas-Fired Power
	🟡 Hydropower	🔴 Coal-Fired Power
	🟢 Bioenergy Power Generation	🔴 CCUS in Power
	🔴 Concentrating Solar Power	
🔴 Fuel Supply	🔴 Methane Emissions from O&G	🔴 Flaring Emissions
🟡 Industry	🟡 Chemicals	🟡 Pulp and Paper
	🟡 Iron and Steel	🟡 Aluminum
	🟡 Cement	🔴 CCUS in Industry and Transformation
🟡 Transport	🟢 Electric Vehicles	🔴 Transport Biofuels
	🟢 Rail	🟡 Aviation
	🔴 Fuel Consumption of Cars and Vans	🟡 International Shipping
	🟡 Trucks and Busses	
🔴 Buildings	🔴 Building Envelopes	🟢 Lighting
	🔴 Heating	🟡 Appliances and Equipment
	🟡 Heat Pumps	🟢 Data Centres and Data Transmission Networks
	🟡 Cooling	
🟡 Energy Integration	🟡 Energy Storage	🟡 Demand Response
	🟡 Hydrogen	🟡 Direct Air Capture
	🟡 Smart Grids	

Source: IEA

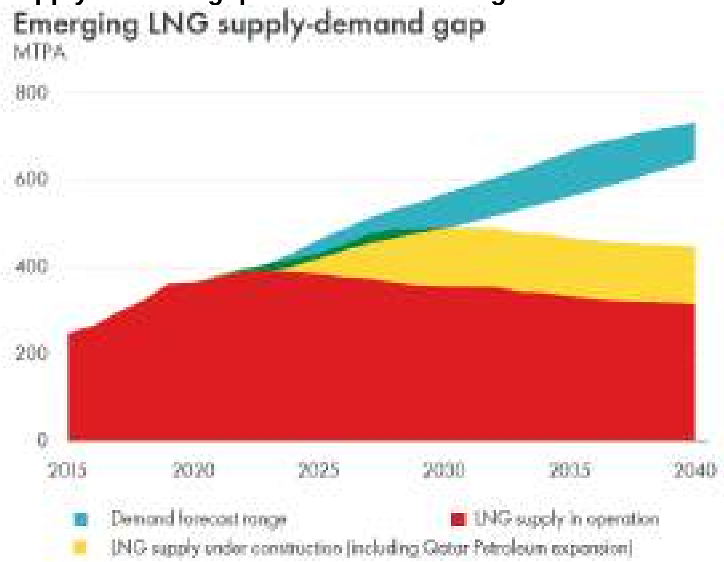
🟢 On Track 🟡 More Efforts Needed 🔴 Not on Track

Source: IEA Tracking Clean Energy Progress, June 2020

We are referencing Shell's long term outlook for LNG We recognize there are many different forecasts for LNG, but are referencing Shell' LNG Outlook 2021 from Feb 25, 2021 for a few reasons. (i) Shell's view on LNG is the key view for when and what decision will be made for LNG Canada Phase 2. (ii) Shell is one of the global leaders in LNG supply and trading. (iii) Shell provides on the record LNG outlooks every year so there is the ability to compare and make sure the outlook fits the story. It does. (iv) Shell, like other supermajors, has had to make big capex cuts post pandemic and that certainly wouldn't put any bias to the need for more capex.

Shell's March 2021 long term outlook for LNG demand was basically unchanged vs 2020 and leads to a LNG supply gap in mid 2020s Shell does not provide the detailed numbers in their Feb 25, 2021 LNG forecast. We would assume they would have reflected some delay, perhaps 1 year, at Mozambique but would be surprised if they put a 2-3 year delay in for the 5 bcf/d from Total Phase 1 +2 and Exxon Rozuma Phase 1. Compared to their LNG Outlook 2020, it looks like there was no change for their estimate of global natural gas demand growth to 2040, which looked relatively unchanged at approx. 5,000 bcm/yr or 484 bcf/d. Similarly, long term LNG demand looked unchanged to 2040 of ~700 mm tonnes (92 bcf/d) vs 360 mm tonnes (47 bcf/d) in 2020. In the 2021 outlook, Shell highlighted that the pandemic delayed project construction timelines and that the "*lasting impact expected on LNG supply not demand"*. And that Shell sees a LNG "*supply-demand gap estimated to emerge in the middle of the current decade as demand rebounds*". Comparing to 2020, it looks like the supply-demand gap is sooner.

Supply-demand gap estimated to emerge in the middle of the current decade



Source: Shell LNG Outlook 2021, Feb 25, 2021

<u>Mozambique delays are redefining the LNG markets for the 2020s: Delaying 5 bcf/d of Mozambique new LNG supply 2-3 years means a much bigger supply gap starting in 2025..</u> Even if the optimists are right, there are now delays to all major Mozambique LNG supply from LNG supply forecasts. We don't have the detail, but we believe all LNG forecasts, including Shell's LNG Outlook 2021, would have included Total's Phase 1 and Phase 2 and Exxon Rozuma Phase 1. As noted earlier, we believe that the likely impact of the Mozambique security concerns is that these forecasts would likely have to push back 1.7 bcf/d from Total Phase 1 to at least 2026, 2.0 bcf/d Exxon Rozuma Phase 1 to at least 2027, and 1.3 bcf/d Total Phase 2 to at least 2028/2029 with the real risk these get pushed back even further. 5.0 bcf/d is equal to 38 mtpa. These delays would mean there is an increasing LNG supply gap in 2025 and increasingly significantly thereafter. And even if a new greenfield LNG project is FID's right away, it wouldn't be able to step in to replace Total Phase 1 prior startup timing for 2024 or likely the market at all until at least 2027. Its why the decision on filling the gap will fall on brownfield LNG projects.

<u>And does this bigger, nearer supply gap force LNG players to look at what brownfield LNG projects they could advance?</u> A greenfield LNG project would likely take at least until 2027 to be in operations. Its why we believe the Mozambique delays will effectively force major LNG players to look to see if there are brownfield LNG projects they should look to advance. Prior to the just passed winter, no one would think Shell or other major LNG players would be considering any new LNG FIDs in 2021. All the big companies are in capital reduction mode and debt reduction mode. But Brent oil is now solidly over $60 and LNG prices hit record levels in Jan and the world's economic and oil and gas demand outlook are increasing with vaccinations. And we are starting to see companies move to increasing capex with the higher cash flows. We would not expect any major LNG players to move to FID right away. But we see them watching to see if 2021 plays out to still support this increasing LNG supply gap. And unless new mutations prevent vaccinations from returning the world to normal, we suspect that major LNG players, like other oil and gas companies, will be looking to increase

capex as they approve 2022 budgets. The outlook for the future has changed dramatically in the last 5 months. The question facing Shell and others, should they look to FID new LNG brownfield projects in the face of an increasing LNG supply gap that is going to hit faster and harder than expected a few months ago. We expect these decisions to be looked at before the end of 2021. LNG prices will be stronger, but we expect the limiting cap in Asia will be that thermal coal will be used to mitigate some LNG price pressure.

Back to Shell, does increasing LNG supply gap provide the opportunity to at least consider a LNG Canada Phase 2 FID over the next 9 months? Shell is no different than any other major LNG supplier in always knowing the market and that the oil and gas outlook is much stronger than 6 months ago. No one has been or is talking about this Mozambique impact and how it will at least force major LNG players to look at if they should FID new brownfield LNG projects to take advantage of this increasing supply gap. We don't have any inside contacts at Shell or LNG Canada, but that is no different than when we looked at the LNG markets in September 2017 and saw the potential for Shell to FID LNG Canada in 2018. We posted a September 20, 2017 blog *"China's Plan To Increase Natural Gas To 10% Of Its Energy Mix Is A Global Game Changer Including For BC LNG*" [LINK]. Last time, it was a demand driven supply gap, this time, it's a supply driven supply gap. We have to believe any major LNG player, including Shell, will be at least looking at their brownfield LNG project list and seeing if they should look to advance FID later in 2021. Shell has LNG Canada Phase 2, which would add 2 additional trains or approx. 1.8 bcf/d. And an advantage to an FID would be that Shell would be able to commit to its existing contractors and fabricators for a continuous construction cycle following on LNG Canada Phase 1 ie. to help keep a lid on capital costs. No one is talking about the need for these new brownfield LNG projects, but, unless Total gets back developing Mozambique and keeps the delay to a matter of months, its inevitable that these brownfield LNG FID internal discussions will be happening in H2/21. Especially since the oil and gas price outlook is much stronger than it was in the fall and companies will be looking to increase capex in 2022 budgets

A LNG Canada Phase 2 would be a big plus to Cdn natural gas. A LNG Canada Phase 2 FID would be a big plus for Cdn natural gas. It would allow another ~1.8 bcf/d of Cdn natural gas to be priced against Asian LNG prices and not against Henry Hub. And it would provide demand offset versus Trudeau if he moves to make electricity "emissions free" and not his prior "net zero emissions". Mozambique may be in Africa, but, unless sustained peace and security is attained, it is a game changer to LNG outlook creating a bigger and sooner LNG supply gap. And with a stronger tone to oil and natural gas prices in 2021, the LNG supply gap will at least provide the opportunity for Shell to consider FID for its brownfield LNG Canada Phase 2 and provide big support to Cdn natural gas for back half of the 2020s. And perhaps if LNG Canada is exporting 3.6 bcf/d from two phases, it could help flip Cdn natural gas to a premium to US natural gas especially if Biden is successful in reducing US domestic natural gas consumption for electricity. The next six months will be very interesting to watch for LNG markets.

India’s Return to LNG Spot Market Hints at Post-Virus Recovery
2021-06-21 03:56:48.497 GMT

By Stephen Stapczynski
(Bloomberg) -- India started buying prompt shipments of liquefied natural gas from the spot market after a two-month absence, indicating a rebound in demand as the nation exits a deadly phase of the Covid-19 pandemic.
Petronet LNG Ltd. and Indian Oil Corp. awarded tenders for delivery over the next few months, the first spot purchases since March, according to traders with knowledge of the matter. Both cargoes cost more than $11 per million British thermal units, an unusually high level for Indian buyers able to turn to alternatives such as fuel oil and liquefied petroleum gas.
Global energy use is quickly recovering from the devastation wrought by the pandemic, and the positive signal from India will help to push natural gas prices higher, though the nation’s demand recovery is still uneven and not all buyers there are eager to boost purchases. LNG spot prices for North Asia have rallied due to robust Chinese demand and supply issues, and been further bolstered by a surge in European gas benchmarks to near their highest in almost 13 years help.
India is emerging from the Covid-19 wave that overwhelmed healthcare infrastructure and triggered localized lockdowns, causing a slump in natural gas consumption in the transport, commercial and industrial sectors. Now, daily cases have sunk back below 60,000 from more than 400,000 at the outbreak’s peak, and curbs are being eased.
Read: India’s Fuel Sales Rebound From Virus Hit in Boost for Oil Bulls
India’s return to the spot market is in stark contrast to just last month, when companies were seeking to cancel and divert shipments due to a glut at import facilities.

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https://www.reuters.com/business/sustainable-business/china-use-more-natural-gas-energy-mix-2035-cnpc-2021-06-24/?taid=60d4499fb9a1150001df07b3&utm_campaign=trueAnthem:+Trending+Content&utm_medium=trueAnthem&utm_source=twitter

June 23, 202110:24 PM MDTLast Updated 7 hours ago

Sustainable Business

China to use more natural gas in energy mix to 2035 - CNPC

Reuters

BEIJING, June 24 (Reuters) - China National Petroleum Corp (CNPC) expects China to cut its coal use to 44% of energy consumption by 2030 and 8% by 2060 as the country aims to use more natural gas to achieve its climate change goals.

China, the world's biggest coal consumer, is expected to increase the use of natural gas in its primary energy mix to 12% in 2030 from 8.7% in 2020, said Zhu Xingshan, senior director, Planning Department CNPC at a conference on Thursday.

He added that the share of natural gas in energy consumption is expected to increase "significantly" from 2030 to 2035.

China, the world's largest energy consumer and biggest emitter of climate warming greenhouse gases, has vowed to bring its total carbon emissions to a peak before 2030 and to be carbon neutral by 2060.

Natural gas is expected to be a key bridge fuel over the next two decades, CNPC has said. read more

The energy giant expects coal to make up 44%, petroleum at 18%, natural gas at 12% and non-fossil fuel to make up 26% of the total energy mix in 2030.

The estimates for 2060 were coal at 8%, petroleum at 6%, natural gas at 11% and non-fossil fuel at 75% of the total energy mix.

China lowered the share of coal use in its primary energy mix to 56.8% in 2020, from around 68% at the beginning of the previous decade and expects this share to fall to below 56% in 2021. read more

Reporting by Emily Chow; Writing by Shivani Singh; Editing by Stephen Coates

China's Plan To Increase Natural Gas To 10% Of Its Energy Mix Is A Global Game Changer Including For BC LNG

Posted: Sept 20, 2017

The news flow from China this summer on its increasing fight and urgency to fight pollution supports China's plan to increase natural gas to 10% of its energy mix in 2020 and 15% of its energy mix in 2030. This is a game changer to global natural gas markets and, by itself, can bring LNG to undersupply 2 to 3 years earlier than expected. China's natural gas consumption increased by ~15% per year from 2005 thru 2016 and ~1.5 bcf/d per year vs China's 8.5% growth rate in energy in total. Yet natural gas only got to 5.9% of China's energy mix. If China is to hit 10% by 2020, it will need to increase natural gas consumption by 4 to 5 bcf/d per year. Assuming China continues to grow its domestic natural gas production by 0.6 bcf/d per year (its growth rate for last five years), China will need to import an additional ~3.5 to ~4.5 bcf/d per year. This is "per year"! And if so, we believe BC LNG will be back and there is a higher probability than ever before for a Shell FID on its BC LNG project in 2018.

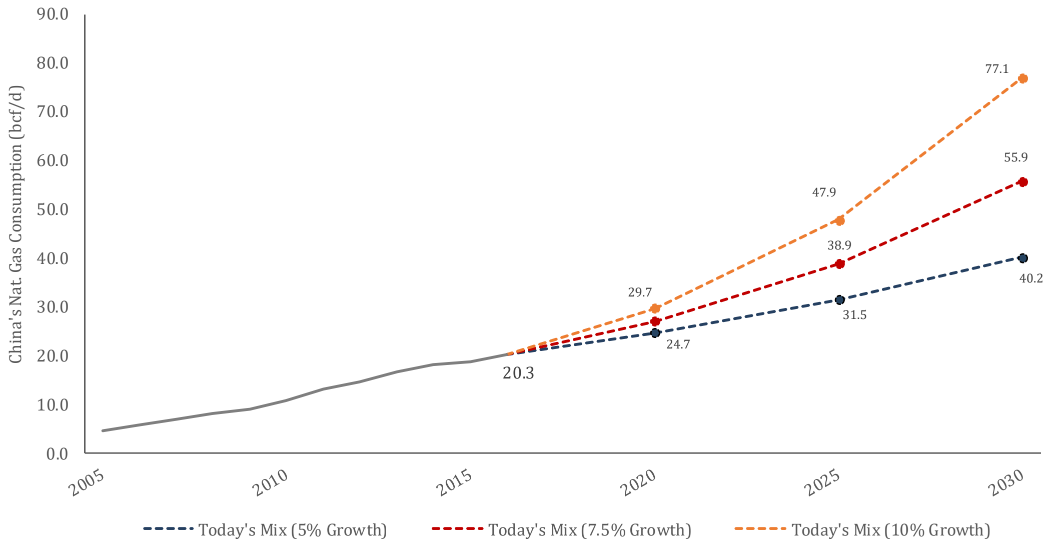
<u>China has had strong growth in natural gas demand to date.</u> China's natural gas consumption has increased by 15% per year from 2005 thru 2016. This was from a small base as China's natural gas consumption was only 4.7 bcf/d in 2005. But it reached 20.3 bcf/d in 2016, or approx. 1.5 bcf/d increase per year. To put in perspective, US natural gas consumption was ~75 bcf/d in 2016 and Canada was ~11 bcf/d in 2016. Natural gas consumption increase of ~15% was almost twice China's growth rate in energy consumption of ~8.5%. But even still, at 20.3 bcf/d in 2016, natural gas was still only 5.9% of China's total energy mix.

<u>There seems to be a greater urgency to switch from coal to natural gas before the winter to fight pollution.</u> This is what got our attention over the summer and caused us to focus on China's plan to increase natural gas in its energy mix. There has been an increasing flow of news this summer on actions to fight pollution. Anyone who has been to Beijing can tell you that the pollution issue is only getting worse. But what caught our attention was the Sat Sept 16 news reports in the South China Morning Post [LINK] and Xinhua news [LINK] on new actions to immediately switch from coal to natural gas for this winter. Hebei province is switching 1.8 million households to natural gas by Oct 31! SCMP reported that the Hebei province "*announced on its website on Friday that 1.8 million households would switch to natural gas from coal for fuel and heating in order to improve air quality*" and "*Meanwhile, the Hebei authorities said 1.8 million households in the province would make the switch to natural gas by the end of October so that it can meet air quality targets*". Xinhua reported that "*China has regulated use of cleaner fuel for heating in north China, where coal burning in winter is a major source of pollution. In the Beijing-Tianjin-Hebei region and nearby areas, 28 cities will now use only natural gas, electricity and renewable energy for heating".*

<u>China's domestic natural gas production has grown by 0.6 bcf/d per year for last 5 years.</u> BP Amoco estimates for China's domestic natural gas production was 5.9 bcf/d in 2006, reached 10.5 bcf/d in 2011 and finally 13.4 bcf/d in 2016. This is annual growth rate of 0.6 bcf/d for the last five years and 0.75 bcf/d for the last 10 years. The largest annual increases were 1.1 bcf/d in each of 2008 and again in 2010, whereas the smallest annual increase was 0.2 bcf/d in 2016.

<u>China's natural gas imports should increase by ~1.9 bcf/d per year assuming no change to a 5.9% share of the energy mix,</u> As a reminder, China's natural gas consumption has grown by ~15% per year and its total energy consumption by ~8.5% per year. We projected China's natural gas consumption starting from the current 20.3 bcf/d and 5.9% share of energy mix, and grew it by 5%, 7.5% or 10%. The mid case being generally in line with China's historical energy growth. In other words, we aren't assuming any major increase in the 5.9% share of total energy. Under the 7.5% growth case, China's natural gas consumption would increase by ~2.5 bcf/d per year, and natural gas imports by ~1.9 bcf/d per year assuming China's production growth is 0.6 bcf/d per year. It's a strong growth case for China and slightly higher than its historical 1.5 bcf/d per year growth in natural gas consumption. But remember, it doesn't increase natural gas from its current 5.9% share of the energy mix. .

China's Natural Gas Consumption Based On Current 5.9% Share Of Energy Mix

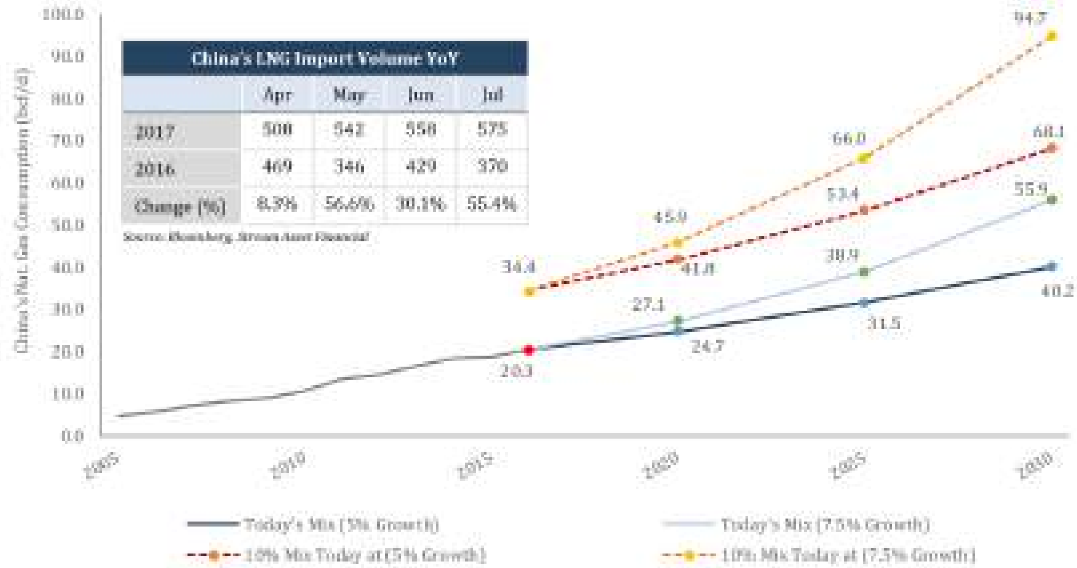


Source: BP Amoco, Stream Asset Financial

<u>However, a shift to a 10% share of energy would increase China's natural gas imports by ~3.5 bcf/d to ~4.5 bcf/d per year.</u> As good as China's natural gas demand growth has been, Its only going to get bigger as China moves to its target that natural gas would be 10% of its energy share in 2020 and 15% in 2030. This may not seem like much, but the math says to hit a 10% target, let alone a 15% share target, China will need to increase natural gas demand by 4 to 5 bcf/d per year and its imports by ~3.5 to ~4.5 bcf/d per year.

We took the above graph and added a line to show where China's natural gas consumption wouild be if it was already at 10% of the energy mix. If so, it would be at 34.4 bcf/d instead of its current 20.3 bcf/d. We used that point to project where natural gas consumption will be at a 10% share of energy mix and assuming energy growth is increased by 5% or 7.5% per year. Remember that energy use has increased by 8.5% per year, and that we did not put in a 15% of total energy case which is China's target for 2030. It means that to get to 10% of the energy mix in 2020 and a 7.5% total energy growth, natural demand would need to go from 20.3 bcf/d to 45.9 bcf/d in 2020 (+6.4 bcf/d per year) and 66.0 bcf/d in 2025 (+5.1 bcf/d per year). Under a 5% energy growth rate case, natural gas demand would need to go from 20.3 bcf/d to 41.8 bcf/d in 2020 (+5.4 bcf/d per year) and to 53.4 bcf/d in 2025 (+3.7 bcf/d per year). If we are conservative and use 4 to 5 bcf/d per year increase in natural gas consumption, this would mean an increase in natural gas imports of ~3.5 to ~4.5 bcf/d per year. This is a WOW! and even before we even think about natural gas moving to 15% of the energy mix in 2030.

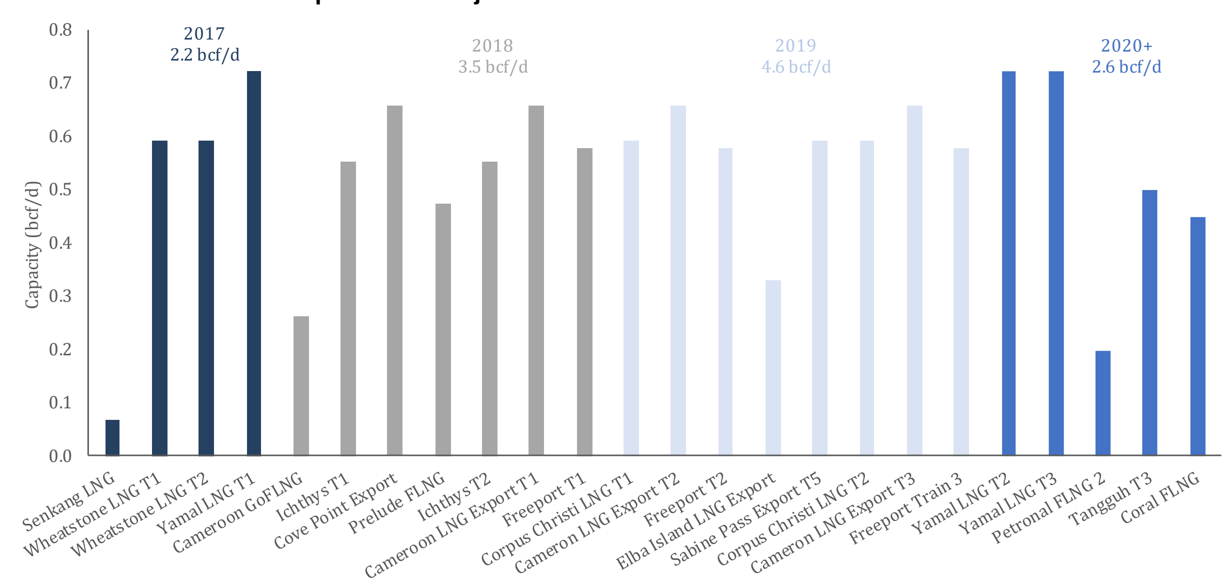
China's Natural Gas Consumption Based On Moving To 10% Share Of Energy Mix



Source: BP Amoco, Stream Asset Financial

<u>This is why we see the market being able to absorb quickly the 8.1 bcf/d of new LNG supply in 2018/2019.</u> As noted in our earlier blog today, the big test is coming up with under construction LNG supply projects expected to add 3.5 bcf/d in 2018 and 4.6 bcf/d in 2019. Then new LNG supply goes down to 2.6 bcf/d in 2020. If China is to get natural gas consumption to 10% of its energy mix by 2020, it is going to have to increase natural gas imports by ~3.5 bcf/d to ~4.5 bcf/d. It is why we see any oversupply caused by timing of supply additions vs demand growth should be temporary and be fixed quickly.

Under Construction LNG Liquefaction Projects



Source: Company Reports, Stream Asset Financial

<u>If China can move to natural gas to 10% of its energy mix, it can move LNG markets to undersupply closer to 2020 than the conventional wisdom of closer to 2025.</u> We recognize this is a major difference in the conventional wisdom views. Its not that we are trying to be bold, but the urgency we are seeing in China this summer to fight pollution

makes us think that their plan to increase natural gas to 10% of its energy mix is a logical plan that they are working to attain. The math suggests that the conventional wisdom of LNG being oversupplied until close to 2025 is off by a few years and it will be fixed closer to 2020. Under construction US LNG projects are expected to add 4.6 bcf/d of new capacity thru 2020 and this provides increasing linkage of HH prices to global markets. It also is why we see HH gas prices potentially being ~40% above long dated strips post 2019. Cdn gas prices will be dragged up with HH prices, but we expect the 2018 and 2019 valuations and tone to Cdn natural gas to reflect this natural gas demand surge.

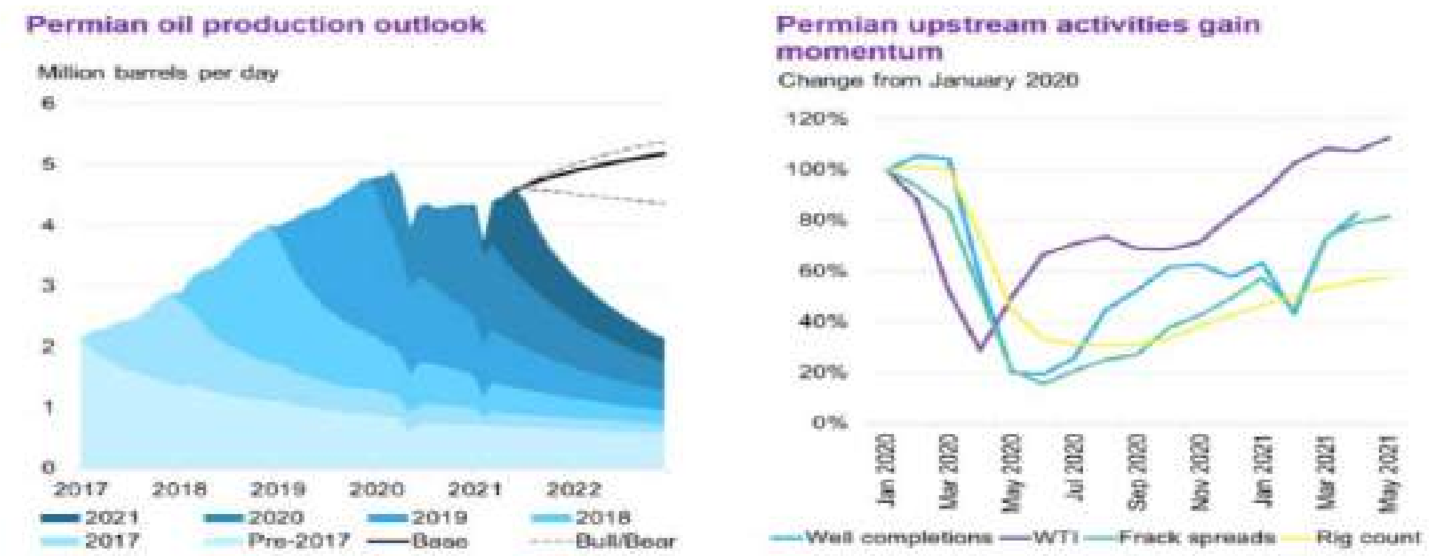
<u>And it means that BC LNG will be back.</u> We recognize that CNOOC just stopped pursing its BC LNG Aurora project and that the new BC NDP government isn't viewed as being LNG friendly. And it will surprise long term readers of Energy Tidbits who know we have never believed BC LNG would happen. We always believed it had no hope, or at least we did up until the last two months. But that was before we saw the urgency and seriousness of China's move to increase natural gas at the cost of coal and that China's LNG imports were up 38% YoY in H1/17. The math that shows China will need to increase its natural gas imports by ~3.5 bcf/d to ~4.5 bcf/d per year means that BC LNG has to be back on the map. Shell has always been the higher probability of being the first BC LNG player. BC LNG will have to be cost competitive, but it also gives Shell more diversity to its LNG supply - a good thing for a global supplier of LNG. Especially with the increasing risk of North Korea and separately China's increasing territorial claim to the South China Sea shipping lanes from its island building. So, it may be a wildcard, but why we said earlier Cdn investors need to pay attention to what China is doing to increase natural gas share of its energy mix. For Canada, this should impact natural gas valuations in 2018 and 2091. And perhaps most of all for Canada, its why we see a better chance than ever to see a Shell FID on its BC LNG in 2018.

Excerpt Bloomberg TOPLive coverage of EIA weekly oil inventory data

06/23 10:24

Crude oil production rose by 200,000 barrels per day, according to last week's EIA data. While that could just be noise, we do see some positive signs coming out of the Permian Basin. According to BloombergNEF analyst Tai Liu:

The Permian is the U.S. shale play most likely to meaningfully increase oil output in the next 18 months. It is set to surpass its pre-pandemic levels of 4.9 million barrels by 2022. The Permian is attractive due to its low break-even prices and plentiful quality drill sites. As a result, many multi-basin operators plan to direct most of their capital towards Permian acreage. This is only moderately optimistic for total U.S. output, though, as it will barely offset expected declines from the other shale basins.



Source: Enverus, Energy Information Administration, BloombergNEF estimates

For more details on Permian and other basin outlooks, see the full report here.

Anastacia Dialynas BNEF Analyst

https://www.rystadenergy.com/newsevents/news/press-releases/a-record-cash-flow-is-brewing-for-the-worlds-public-eps-in-2021-as-us-shale-delivers-super-profits/

A record cash flow is brewing for the world’s public E&Ps in 2021 as US shale delivers super-profits

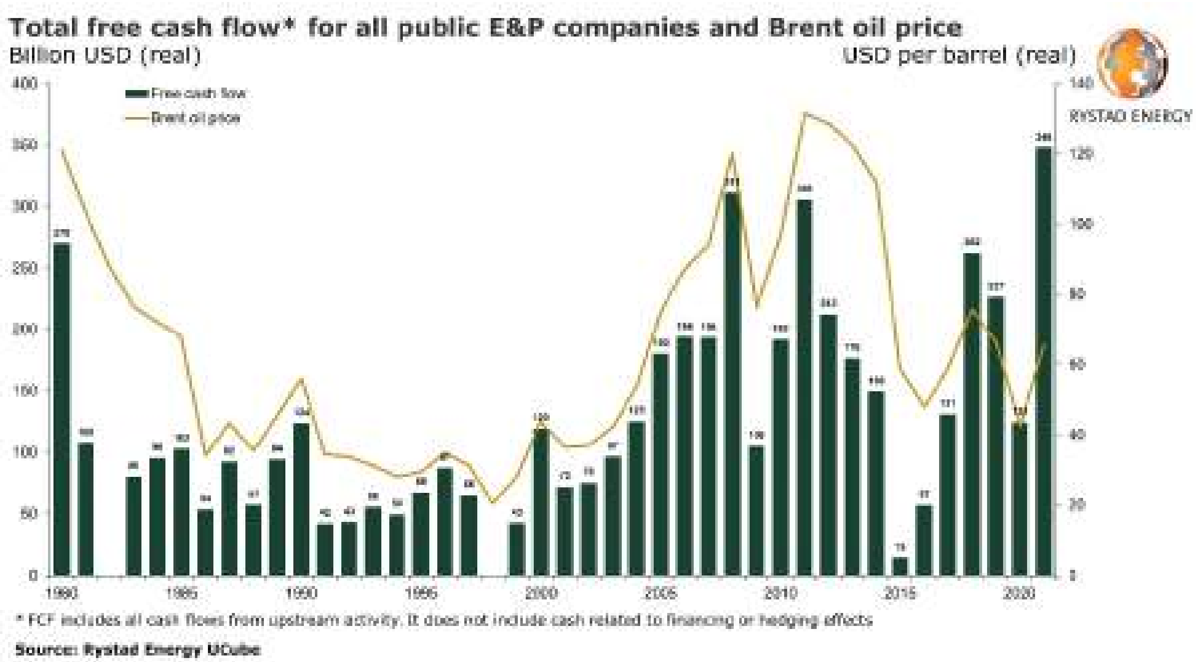
June 23, 2021

With oil trading above $70 per barrel while investment activity remains low, the world’s publicly traded exploration and production (E&P) companies are set to generate record-breaking free cash flows in 2021, a Rystad Energy report projects. Their combined FCF* is expected to surge to $348 billion this year, with the previous high being $311 billion back in 2008.

Rystad Energy estimates that total gross revenue for all public upstream companies is expected to increase by almost $500 billion in 2021, or 55% compared to last year (excluding hedging effects). At the same time, the investment level of these companies is only expected to grow by around 2% in 2021, resulting in significantly higher profits.

A key reason for the all-time-high FCF is the turnaround in the US tight oil industry. Historically, this industry has struggled to generate positive returns, but this could change in 2021. We estimate that all public tight oil companies will to make close to $60 billion in FCF this year, before hedging effects.

The conventional onshore supply segment is in line to earn the highest level of FCF this year at close to $160 billion – but is still behind the record touched in 2011. Both deepwater and offshore shelf are recovering this year, each ending up with close to $60 billion in FCF. However, tight oil is expected to surpass both these offshore segments in 2021.



Learn more in Rystad Energy’s UCube.

“Oil demand has gradually increased after the initial shock of the Covid-19 pandemic, and OPEC+ continues to hold back volumes from the market. The consequent high price movement has been further supported by a slow ramp-up in US tight oil activity. In conjunction with the persisting low investment environment, E&Ps are enjoying super-profits," says Espen Erlingsen, head of upstream research at Rystad Energy.

The FCF comeback means more surplus cash for E&P companies and historically there has been a strong link between FCF and activity levels. Merger and acquisition (M&A) activity has recovered in 2021, with transaction values increasing by around 30% compared to 2020. New projects are also making a comeback: The amount of greenfield investment that has been sanctioned as of June has already matched the full year 2020 total, and we expect the full 2021 level to be double that of last year.

**FCF includes all cash flows from upstream activity. It does not include cash from financing or hedging effects*

For more analysis, insights and reports, clients and non-clients can apply for access to Rystad Energy's Free Solutions and get a taste of our data and analytics universe.

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Sporadic Gasoline Shortages Are Surfacing Across Six U.S. States
2021-06-24 18:26:48.110 GMT

By Jeffrey Bair
(Bloomberg) -- Some gasoline stations in at least six U.S. states are experiencing temporary fuel shortages because there aren't enough tanker-truck drivers to deliver the fuel just as summer demand rises, according to an OPIS by IHS Markit report.
Fuel-hauling companies that reduced staff during the pandemic are struggling to hire back drivers that found jobs elsewhere, leaving Florida, Iowa, Ohio, Washington, Oregon and Colorado with cases of bagged pumps and outages of regular and premium gasoline in some filling stations, OPIS said Thursday.
The supply woes are happening as demand for gasoline has risen to levels last seen before the pandemic, with the U.S. reopening after months of lockdowns. Consumption could rise above 9.7 million barrels a day in July or August, according to the report, up from about 9.4 million last week.
For now, the supply constraints have only been a cause of inconvenience for some drivers and have not yet reached the level of a crisis, OPIS said.
But the driver shortage will likely affect fuel deliveries for another 12 months, OPIS said, citing Holly McCormick, chair of workforce committee for industry group National Tank Truck Carriers.
U.S. gasoline stockpiles, meanwhile, declined last week after recent additions.

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https://www.whitehouse.gov/briefing-room/statements-releases/2021/06/24/fact-sheet-president-biden-announces-support-for-the-bipartisan-infrastructure-framework/

FACT SHEET: President Biden Announces Support for the Bipartisan Infrastructure Framework

JUNE 24, 2021•STATEMENTS AND RELEASES

Today, President Biden and Vice President Harris announced their support for the Bipartisan Infrastructure Framework, the largest long-term investment in our infrastructure and competitiveness in nearly a century – an investment that will make our economy more sustainable, resilient, and just.

The President came into office promising to find common ground to get things done – and he's delivering on that promise.

The $1.2 trillion Bipartisan Infrastructure Framework is a critical step in implementing President Biden's Build Back Better vision. The Plan makes transformational and historic investments in clean transportation infrastructure, clean water infrastructure, universal broadband infrastructure, clean power infrastructure, remediation of legacy pollution, and resilience to the changing climate. Cumulatively across these areas, the Framework invests two-thirds of the resources that the President proposed in his American Jobs Plan.

President Biden believes that we must invest in our country and in our people, creating good-paying union jobs, tackling the climate crisis, and growing the economy sustainably, and equitably for decades to come. The Bipartisan Infrastructure Framework is a critical step in accomplishing these objectives.

President Biden believes that we are at inflection point between democracy and autocracy. At this moment in our history, President Biden believes we must demonstrate to the world that American democracy can deliver for the American people. Today, the President is showing that democracy can deliver results. The Framework will position American workers, farmers, and businesses – small and large alike – to compete and win in the 21st century.

Still, there is more work to do – to grow our economy, create jobs, improve living standards, reduce climate pollution, and ensure more Americans can participate fully and equally in our economy. President Biden remains committed to the comprehensive agenda laid out in the American Jobs Plan and American Families Plan. He will work with Congress to build on the Bipartisan Infrastructure Framework in legislation that moves in tandem, and he is encouraged that both the House and Senate are working on budget plans that would do so. But democracy requires compromise. The historic Bipartisan Infrastructure Framework will make life better for millions of Americans, create a generation of good-paying union jobs and economic growth, and position the United States to win the 21st century, including on many of the key technologies needed to combat the climate crisis. That's what President Biden and Vice President Harris were elected to do.

The President calls on Congress to pass the Bipartisan Infrastructure Framework and send it to his desk, and pass a budget resolution and legislation that makes his full Build Back Better vision a reality.

The Bipartisan Infrastructure Framework will:

- Improve healthy, sustainable transportation options for millions of Americans by modernizing and expanding transit and rail networks across the country, while reducing greenhouse gas emissions. The Plan is the largest federal investment in public transit in history and is the largest federal investment in passenger rail since the creation of Amtrak.

- Repair and rebuild our roads and bridges with a focus on climate change mitigation, resilience, equity, and safety for all users, including cyclists and pedestrians. The Bipartisan Infrastructure Framework is the single largest dedicated bridge investment since the construction of the interstate highway system.

- Build a national network of electric vehicle (EV) chargers along highways and in rural and disadvantaged communities. The largest investment in EV infrastructure in history, the Bipartisan Infrastructure Framework will accomplish the President's goal of building 500,000 EV chargers.

- Electrify thousands of school and transit buses across the country to reduce harmful emissions and drive domestic manufacturing of zero emission vehicles and components.

- Eliminate the nation's lead service lines and pipes, delivering clean drinking water to up to ten million American families and more than 400,000 schools and child care facilities that currently don't have it, including in Tribal nations and disadvantaged communities. The Plan is the largest investment in clean drinking water and waste water infrastructure in American history.

- Connect every American to reliable high-speed internet, just as the federal government made a historic effort to provide electricity to every American nearly one hundred years ago. The Framework will also drive down prices for internet service and close the digital divide.

- Upgrade our power infrastructure, including by building thousands of miles of new, resilient transmission lines to facilitate the expansion of renewable energy, including through a new Grid Authority. The Plan is the single largest investment in clean energy transmission in American history.

- Create a first of its kind Infrastructure Financing Authority that will leverage billions of dollars into clean transportation and clean energy.

- Make the largest investment in addressing legacy pollution in American history, a cleanup effort that will create good-paying union jobs and advance environmental justice.

- Prepare more of our infrastructure for the impacts of climate change, cyber attacks, and extreme weather events. The Framework is the largest investment in the resilience of physical and natural systems in American history.

The Framework, which will generate significant economic benefits and returns, is financed through a combination of closing the tax gap, redirecting unspent emergency relief funds, targeted corporate user fees, and the macroeconomic impact of infrastructure investment.

Bipartisan Infrastructure Framework

	Amount (billions)
Total	**$579**
Transportation	**$312**
Roads, bridges, major projects	$109
Safety	$11
Public transit	$49
Passenger and Freight Rail	$66
EV infrastructure	$7.5
Electric buses / transit	$7.5
Reconnecting communities	$1
Airports	$25
Ports & Waterways	$16
Infrastructure Financing	$20
Other Infrastructure	**$266**

Water infrastructure	$55
Broadband infrastructure	$65
Environmental remediation	$21
Power infrastructure incl. grid authority	$73
Western Water Storage	$5
Resilience	$47

**New spending + baseline (over 5 years) = $973B*

**New spending + baseline (over 8 years) = $1,209B*

Proposed Financing Sources for New Investment

- Reduce the IRS tax gap
- Unemployment insurance program integrity
- Redirect unused unemployment insurance relief funds
- Repurpose unused relief funds from 2020 emergency relief legislation
- State and local investment in broadband infrastructure
- Allow states to sell or purchase unused toll credits for infrastructure
- Extend expiring customs user fees
- Reinstate Superfund fees for chemicals
- 5G spectrum auction proceeds
- Extend mandatory sequester

- Strategic petroleum reserve sale
- Public-private partnerships, private activity bonds, direct pay bonds and asset recycling for infrastructure investment
- Macroeconomic impact of infrastructure investment

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https://www.theglobeandmail.com/politics/article-us-army-corps-of-engineers-opts-for-more-comprehensive-review-of-line/?ref=premium

U.S. Army Corps of Engineers opts for more comprehensive review of Line 5 tunnel

STEVEN CHASESENIOR PARLIAMENTARY REPORTER

PUBLISHED JUNE 23, 2021UPDATED 8 HOURS AGO.

DALE G. YOUNG/THE ASSOCIATED PRESS

The U.S. Army Corps of Engineers said Wednesday that it has opted to conduct an extensive review of Enbridge Inc.'s proposed Line 5 tunnel under the Great Lakes, which could significantly delay a solution the company has offered to avert a full shutdown of the pipeline.

It has chosen to prepare an environmental-impact statement, a more wide-ranging study than an environmental assessment, which was the other option available. The Army Corp's website explains that the impact statement is "the most thorough and comprehensive level of National Environmental Policy Act (NEPA) documentation used to assist in making a decision."

Enbridge Line 5 is a key petroleum conduit for Ontario and Quebec that has run through the Great Lakes region for close to 70 years. However, the state of Michigan is trying to stop it from operating because of fears that oil could leak into Lake Michigan and Lake Huron where the pipeline crosses the Straits of Mackinac.

Michigan's Department of Environment, Great Lakes and Energy has issued a permit for the tunnel, but approval from the Army Corps is also needed. The federal agency would consider potential effects on the straits and adjacent wetlands.

Enbridge defies Michigan governor, continues operating Line 5 pipeline as state seeks court order for shutdown

Line 5 pipeline: What you need to know about the Enbridge route now at the centre of a U.S.-Canada legal dispute

Last fall, Michigan Governor Gretchen Whitmer revoked an easement permit first granted in 1953 that allows Line 5 to cross the Straits of Mackinac waterway between the state's upper and lower peninsulas, citing the risk of oil spills and calling it a "ticking time bomb." She gave Enbridge until May 12 of this year to comply and warned the company that it would be breaking the law after that.

Calgary-based Enbridge has challenged these actions in U.S. federal court, arguing that only the federal government can pass judgment on the safety of a pipeline. And the company has defied Ms. Whitmer, saying it would not shut the line down unless ordered to do so by a judge. The state is seeking to have the matter sent back to state-level court. Enbridge and the Michigan state government are now in court-ordered mediation talks.

Enbridge has proposed a US$500-million tunnel that would run deep under the Straits of Mackinac and which the company said would shield the Great Lakes from spills. The company had previously estimated it would take three years to build the tunnel but has been awaiting regulatory approval.

The U.S Army Corps' environmental-impact statement represents a lengthier regulatory review. Jaime A. Pinkham, acting assistant secretary of the Army for civil works, announced Wednesday that it is necessary "because of the potential for impacts significantly affecting the quality of the human environment."

He said the Army Corps of Engineers "will ensure all potential impacts and reasonable alternatives associated with this project are thoroughly analyzed and will ultimately support a decision on the permit application."

Mr. Pinkham said his organization "received thousands of public comments" on the proposed project "which warrant further review," including "impacts to navigation" in the Great Lakes.

He said the Army Corps will also be conducting consultations with Indigenous people, in accordance with instructions laid out by President Joe Biden in January: the "Memorandum on Tribal Consultation and Strengthening Nation-to-Nation Relationships."

In a statement, Enbridge said Wednesday's development would push back the timeline for constructing a tunnel.

"Project permitting continues to be the driver of project timing. The decision by the U.S. Army Corps of Engineers to complete an environmental-impact statement instead of an environmental assessment for the Great Lakes Tunnel project will lead to a delay in the start of construction on this important project," company spokesman Jesse Semko said in a statement.

"Enbridge will continue to work with the U.S. Army Corps of Engineers on its review of our application and towards a successful conclusion to this process, which began when we filed our permit application in April 2020."

Mr. Semko said Enbridge believes that a majority of Michiganders back the Great Lakes Tunnel project. "To date, the company has spent more than [US]$100-million on the project. Enbridge remains intensely focused on project permitting and the sustained and safe operation of Line 5 until the tunnel is completed," he said.

Line 5 carries up to 540,000 barrels a day from Alberta and Saskatchewan through two Great Lakes states before re-entering Canada at Sarnia, Ont. The Canadian government has warned that a shutdown would represent a threat to this country's energy security.

Enbridge says Line 5 has never leaked into the Straits of Mackinac, but critics note that it has leaked elsewhere along the route.

They also point to 2010, when another pipeline operated by Enbridge, Line 6B, ruptured and released 3.3 million litres of oil into a tributary of the Kalamazoo River. That became one of the largest inland oil spills in U.S. history and took five years to clean up.

Table 1. Number and Capacity of Operable Petroleum Refineries by PAD District and State as of January 1, 2021

PAD District and State	Number of Operable Refineries			Atmospheric Crude Oil Distillation Capacity					
				Barrels per Calendar Day			Barrels per Stream Day		
	Total	Operating	Idle [a]	Total	Operating	Idle [b]	Total	Operating	Idle [b]
PAD District I	**7**	**7**	**0**	**817,800**	**817,800**	**0**	**869,900**	**869,900**	**0**
Delaware	1	1	0	171,000	171,000	0	180,000	180,000	0
New Jersey	2	2	0	358,500	358,500	0	377,100	377,100	0
Pennsylvania	3	3	0	266,000	266,000	0	289,800	289,800	0
West Virginia	1	1	0	22,300	22,300	0	23,000	23,000	0
PAD District II	**25**	**24**	**1**	**4,188,265**	**4,150,265**	**38,000**	**4,415,124**	**4,365,124**	**50,000**
Illinois	4	4	0	1,040,065	1,040,065	0	1,097,200	1,097,200	0
Indiana	2	2	0	463,800	463,800	0	470,800	470,800	0
Kansas	3	3	0	403,800	403,800	0	415,930	415,930	0
Kentucky	1	1	0	291,000	291,000	0	306,000	306,000	0
Michigan	1	1	0	140,000	140,000	0	147,000	147,000	0
Minnesota	2	2	0	438,000	438,000	0	483,000	483,000	0
North Dakota	1	1	0	71,000	71,000	0	74,000	74,000	0
Ohio	4	4	0	600,800	600,800	0	627,000	627,000	0
Oklahoma	5	5	0	521,800	521,800	0	559,194	559,194	0
Tennessee	1	1	0	180,000	180,000	0	185,000	185,000	0
Wisconsin	1	0	1	38,000	0	38,000	50,000	0	50,000
PAD District III	**56**	**52**	**4**	**9,751,400**	**9,444,900**	**306,500**	**10,322,345**	**10,001,845**	**320,500**
Alabama	3	3	0	139,600	139,600	0	145,600	145,600	0
Arkansas	2	2	0	90,500	90,500	0	92,700	92,700	0
Louisiana	16	14	2	3,165,031	2,949,531	215,500	3,312,295	3,092,295	220,000
Mississippi	3	2	1	393,940	382,940	11,000	415,000	402,500	12,500
New Mexico	1	1	0	110,000	110,000	0	124,000	124,000	0
Texas	31	30	1	5,852,329	5,772,329	80,000	6,232,750	6,144,750	88,000
PAD District IV	**15**	**15**	**0**	**656,664**	**647,064**	**9,600**	**702,700**	**692,700**	**10,000**
Colorado	2	2	0	103,000	103,000	0	111,700	111,700	0
Montana	4	4	0	224,100	214,500	9,600	232,900	222,900	10,000
Utah	5	5	0	203,714	203,714	0	214,200	214,200	0
Wyoming	4	4	0	125,850	125,850	0	143,900	143,900	0
PAD District V	**26**	**26**	**0**	**2,713,571**	**2,659,571**	**54,000**	**2,850,400**	**2,793,400**	**57,000**
Alaska	5	5	0	164,200	164,200	0	178,500	178,500	0
California	14	14	0	1,748,171	1,748,171	0	1,842,400	1,842,400	0
Hawaii	1	1	0	147,500	93,500	54,000	152,000	95,000	57,000
Nevada	1	1	0	2,000	2,000	0	5,000	5,000	0
Washington	5	5	0	651,700	651,700	0	672,500	672,500	0
U.S. Total	**129**	**124**	**5**	**18,127,700**	**17,719,600**	**408,100**	**19,160,469**	**18,722,969**	**437,500**
Virgin Islands	1	1	0	176,400	176,400	0	180,000	180,000	0

Table 1. Number and Capacity of Operable Petroleum Refineries by PAD District and State as of January 1, 2021

PAD District and State	Downstream Charge Capacity (Barrels per Stream Day)							
	Vacuum Distillation	Thermal Cracking	Catalytic Cracking		Catalytic Hydro-Cracking	Catalytic Reforming	Hydrotreating/ Desulfurization	Fuels Solvent Deasphalting
			Fresh	Recycled				
PAD District I	**387,200**	**54,500**	**305,000**	**5,000**	**47,000**	**150,900**	**708,800**	**22,000**
Delaware	104,600	54,500	82,000	4,000	24,000	43,000	180,300	0
New Jersey	161,000	0	145,000	0	0	37,000	252,100	22,000
Pennsylvania	113,000	0	78,000	1,000	23,000	66,200	252,300	0
West Virginia	8,600	0	0	0	0	4,700	24,100	0
PAD District II	**1,843,442**	**608,785**	**1,358,935**	**15,800**	**379,700**	**902,958**	**4,160,924**	**22,350**
Illinois	476,400	212,850	324,300	0	101,200	250,100	970,110	0
Indiana	290,700	102,000	185,600	7,200	0	73,500	610,200	0
Kansas	161,000	78,050	104,000	500	43,000	84,000	406,400	0
Kentucky	134,000	0	104,000	0	0	58,000	275,500	13,000
Michigan	89,000	36,500	44,000	0	0	21,500	133,500	0
Minnesota	284,000	82,000	126,500	2,500	67,000	73,800	446,500	4,500
North Dakota	0	0	27,000	3,600	0	12,500	60,300	0
Ohio	164,500	59,000	208,300	0	109,800	170,800	519,900	0
Oklahoma	220,342	38,385	153,912	2,000	32,200	113,458	569,014	4,850
Tennessee	0	0	70,000	0	26,500	36,000	129,000	0
Wisconsin	23,500	0	11,323	0	0	9,300	40,500	0
PAD District III	**4,768,195**	**1,693,707**	**2,970,690**	**18,500**	**1,379,000**	**1,882,270**	**9,305,050**	**265,900**
Alabama	54,000	34,000	0	0	20,500	37,300	125,100	0
Arkansas	48,850	0	21,000	0	0	15,300	98,750	7,400
Louisiana	1,645,170	596,000	1,048,500	5,500	456,900	617,890	2,846,180	72,000
Mississippi	354,875	104,000	88,000	0	119,000	101,600	307,300	0
New Mexico	34,300	0	30,000	0	18,000	24,000	118,000	18,000
Texas	2,631,000	959,707	1,783,190	13,000	764,600	1,086,180	5,809,720	168,500
PAD District IV	**249,000**	**74,270**	**206,660**	**1,990**	**61,200**	**120,000**	**565,950**	**6,000**
Colorado	33,500	0	30,000	500	0	21,900	87,430	0
Montana	129,600	44,270	66,660	990	30,200	35,700	218,820	0
Utah	34,900	10,000	70,000	0	15,000	37,500	145,800	6,000
Wyoming	51,000	20,000	40,000	500	16,000	24,900	113,900	0
PAD District V	**1,462,106**	**562,400**	**758,900**	**16,600**	**550,100**	**549,500**	**2,450,000**	**80,000**
Alaska	26,000	0	0	0	13,000	13,500	24,500	0
California	1,043,256	464,600	611,500	13,600	452,100	382,000	1,890,000	56,000
Hawaii	71,000	11,000	0	0	20,000	13,500	13,000	0
Nevada	2,750	0	0	0	0	0	0	0
Washington	319,100	86,800	147,400	3,000	65,000	140,500	522,500	24,000
U.S. Total	**8,709,943**	**2,993,662**	**5,600,185**	**57,890**	**2,417,000**	**3,605,628**	**17,190,724**	**396,250**
Virgin Islands	90,000	62,000	0	0	0	46,000	282,000	0

[a] Refineries where distillation units were completely idle but not permanently shutdown on January 1, 2021.
[b] Includes capacity from refineries that are either completely or partially idle.

Source: Energy Information Administration (EIA), Form EIA-820, "Annual Refinery Report."

Table 2. Production Capacity of Operable Petroleum Refineries by PAD District and State as of January 1, 2021

(Barrels per Stream Day, Except Where Noted)

PAD District and State	Production Capacity							
	Alkylates	Aromatics	Asphalt and Road Oil	Isomers	Lubricants	Marketable Petroleum Coke	Hydrogen [a] (MMcfd)	Sulfur (short tons/day)
PAD District I	**47,800**	**5,191**	**44,260**	**19,280**	**20,945**	**13,620**	**109**	**1,074**
Delaware	12,500	5,191	0	6,000	0	13,620	65	596
New Jersey	18,800	0	21,000	4,000	12,000	0	31	320
Pennsylvania	16,500	0	22,560	9,280	2,945	0	10	157
West Virginia	0	0	700	0	6,000	0	3	1
PAD District II	**288,336**	**112,600**	**290,514**	**167,000**	**9,900**	**193,824**	**633**	**8,732**
Illinois	86,400	17,200	43,100	16,000	0	74,690	202	2,380
Indiana	34,200	16,800	33,200	31,100	0	30,000	0	1,913
Kansas	33,500	0	4,000	32,300	0	23,064	120	831
Kentucky	21,500	2,500	35,400	17,000	0	0	0	448
Michigan	7,500	0	32,000	0	0	12,320	0	460
Minnesota	20,500	0	59,600	33,500	0	28,400	209	1,339
North Dakota	4,800	0	0	0	0	0	0	15
Ohio	29,950	20,000	23,800	23,200	0	16,300	0	922
Oklahoma	35,586	21,000	43,414	13,900	9,900	9,050	72	275
Tennessee	12,700	29,000	0	0	0	0	30	116
Wisconsin	1,700	6,100	16,000	0	0	0	0	33
PAD District III	**697,571**	**207,865**	**186,625**	**317,010**	**192,900**	**501,582**	**742**	**24,265**
Alabama	0	0	25,000	5,350	0	7,120	40	228
Arkansas	5,000	0	21,300	7,500	6,000	0	13	157
Louisiana	247,500	49,900	63,000	109,220	66,000	173,152	118	6,178
Mississippi	21,500	15,600	16,125	0	48,000	35,500	242	1,264
New Mexico	9,500	0	7,000	0	0	0	38	224
Texas	414,071	142,365	54,200	194,940	72,900	285,810	291	16,214
PAD District IV	**45,000**	**0**	**67,300**	**16,068**	**0**	**23,780**	**223**	**911**
Colorado	0	0	13,200	0	0	0	22	116
Montana	17,200	0	44,300	6,750	0	15,480	149	489
Utah	21,500	0	1,800	9,318	0	2,500	0	93
Wyoming	6,300	0	8,000	0	0	5,800	52	213
PAD District V	**235,062**	**1,500**	**53,350**	**225,000**	**39,800**	**161,173**	**1,186**	**5,596**
Alaska	0	0	12,500	5,000	0	0	13	25
California	192,862	1,500	30,550	180,100	39,800	137,523	969	4,728
Hawaii	0	0	0	0	0	0	18	38
Nevada	0	0	1,600	0	0	0	0	0
Washington	42,200	0	8,700	39,900	0	23,650	186	805
U.S. Total	**1,313,769**	**327,156**	**642,049**	**744,358**	**263,545**	**893,979**	**2,893**	**40,578**
Virgin Islands	0	0	0	0	0	13,800	0	380

[a] Includes hydrogen production capacity of hydrogen plants on refinery grounds and operated by the refinery operator.

MMcfd = Million cubic feet per day.

Source: Energy Information Administration (EIA), Form EIA-820, "Annual Refinery Report."

Phillips 66 Ferndale Has Sole FCC Shut for Unplanned Repairs
2021-06-23 17:35:56.692 GMT

By Barbara Powell
(Bloomberg) -- Phillips 66 Ferndale, Wash., refinery was forced to shut its FCC late last week for unplanned repairs, people familiar with operations say.
* Repairs are in progress and are expected to be complete by as soon as early next week and the 38k b/d FCC restarted
* FCC, the main gasoline production unit at Ferndale, supplies the fuel by barge and pipeline to markets in the Pacific Northwest
* No immediate reply to email sent to co. seeking comment
* Ferndale, located on Puget Sound, has a crude processing capacity of 105k b/d: data from EIA
** Refinery processes a variety of domestic and foreign crude oils, including Alaskan North Slope, Canadian and U.S. shale crudes

--With assistance from Andrew Stewart.

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https://www.neste.com/releases-and-news/oil-products/major-turnaround-nestes-porvoo-refinery-completed

24 June 2021

Major turnaround at Neste's Porvoo refinery is completed

Neste Corporation, Press Release, 24 June 2021 at 10.00 a.m. (EET)

The scheduled maintenance i.e. the major turnaround at Neste's Porvoo refinery in Finland is now successfully completed and production has started at the refinery.

The major turnaround is a significant investment to secure safety, availability and competitiveness of the refinery. The total investment of the Porvoo refinery major turnaround was approximately EUR 630 million, of which approximately EUR 330 million was realized in the major turnaround in 2021. In 2020, only the most critical maintenance work was executed at the refinery as the corona pandemic delayed the turnaround by a year.

“We executed a large number of regulatory inspections, maintenance works and asset improvement initiatives at the Porvoo refinery to ensure the safety and reliability of the refinery. The turnaround works focused on, among other things, process equipment and pipelines, and we also extensively renewed the refinery's electrification and automation systems. During the major turnaround, we also executed preparatory measures for the processing of renewable and circular raw materials at the Porvoo refinery,” says Jori Sahlsten, Vice President, Production at the Neste Porvoo refinery.

During the major turnaround, the Porvoo refinery was one of the largest construction sites in Finland. In total, some 6,000 persons took part in the turnaround works and over 1.5 million working hours were completed.

In order to manage the pandemic situation during the major turnaround, a detailed health security plan was prepared with extensive measures to mitigate the impacts of the coronavirus. Neste worked closely with authorities, nearby municipalities and cities as well as health care professionals throughout the turnaround.

Thanks to the comprehensive precautionary measures, the corona situation at the refinery remained calm. Regular corona tests were done to every person working in the turnaround. All in all approximately 61,000 corona tests were taken, out of which 97 infections were identified.

“We would like to thank our partners for the seamless cooperation, their expertise and active dialogue. Extensive preparation and close cooperation, as well as common rules at the turnaround site, played a key role in the successful execution of the major turnaround at the Porvoo refinery. Thanks to versatile measures and effective tracing executed in cooperation with the health authorities, asymptomatic cases of infection and potential exposures were identified and spreading of the virus and chains of infection on the site were prevented,” explains, Hannele Jakosuo-Jansson, Senior Vice President, HR, HSSEQ and Procurement at Neste.

The major turnaround did not affect the product deliveries to Neste's customers. The Neste harbour and distribution terminal in Porvoo have been operating normally during the major turnaround.

https://www.state.gov/u-s-eu-canada-joint-statement-on-venezuela/

U.S.-EU-Canada: Joint Statement on Venezuela

MEDIA NOTE **OFFICE OF THE SPOKESPERSON**

JUNE 25, 2021

The following statement was released by Secretary of State Antony J. Blinken, the EU High Representative for Foreign Affairs and Security Policy Josep Borrell, and Canadian Minister of Foreign Affairs Marc Garneau.

Begin text:
We remain deeply concerned about the ongoing crisis in Venezuela and its regional and global impact.

The peaceful solution to that deep political, social, and economic crisis has to come from the Venezuelan people themselves through Venezuelan-led, comprehensive negotiations with participation from all stakeholders. A time-bound and comprehensive negotiation process should restore the country's institutions and allow for all Venezuelans to express themselves politically through credible, inclusive and transparent local, parliamentary, and presidential elections.

We call for the unconditional release of all those unjustly detained for political reasons, the independence of political parties, freedom of expression including for members of the press, and an end to human rights abuses.

We welcome substantive, credible advancements to restore core democratic processes and institutions in Venezuela and are willing to review sanctions policies based on meaningful progress in a comprehensive negotiation.

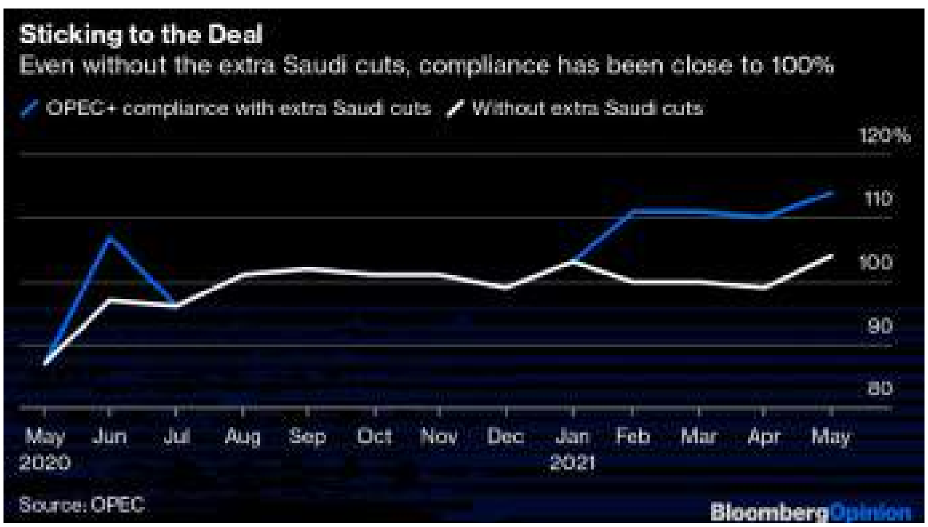
We call for electoral conditions that abide by international standards for democracy, beginning with the local and regional elections scheduled for November 2021.

We remain committed to addressing the dire humanitarian crisis inside Venezuela and welcome further agreement among all political actors in Venezuela to allow for unfettered access to humanitarian assistance, to include food, medicine, and critical COVID-19 relief supplies.

End text.

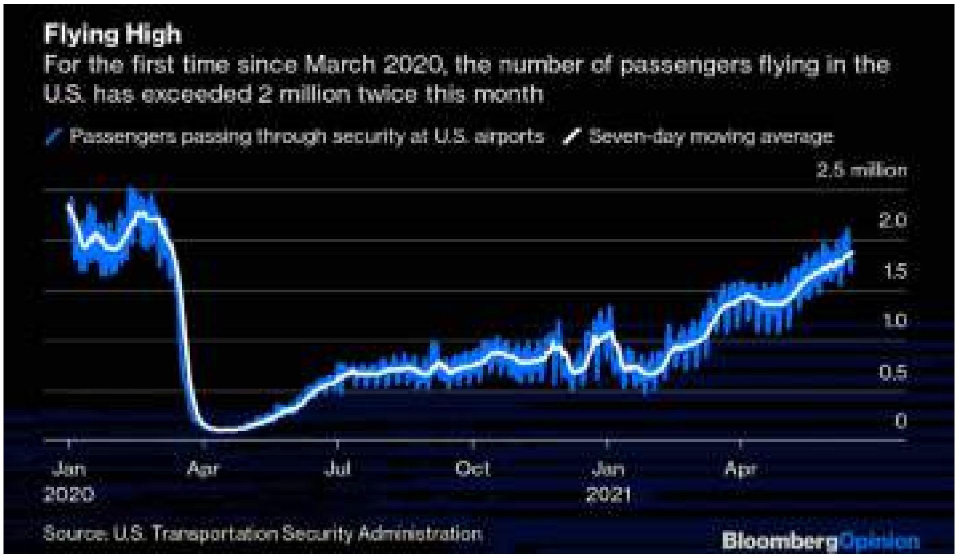
Oil Shifts From Lack of Demand to Lack of Supply: Julian Lee
2021-06-20 05:00:16.991 GMT

By Julian Lee
(Bloomberg Opinion) -- The oil market is rapidly shifting from a period of over-supply during the height of the pandemic to one of potential shortage. Producers who managed the slump now need to be diligent in managing the recovery.
The oil producing countries in the OPEC+ group — led by Saudi Arabia and Russia — have done an amazing job at managing oil supplies as demand has crawled its way back from the biggest collapse in history.
Sure, they got off to a shaky start. Instead of slashing supply as demand cratered in April 2020, they boosted it in a production free-for-all after their previous cooperation fell apart. The deal that emerged when they eventually got together took days to form and almost foundered on the unwillingness of Mexico to play its part.
But after some vague pledge from President Donald Trump that the U.S. would make up the cuts that Mexico refused, the producer group announced a record output reduction of almost 10 million barrels a day. And, for the most part, it has stuck by what it promised.



As always, there are those who haven't done all they pledged. Some, most notably Russia, have been given a free pass. Others, like Iraq, Nigeria and most visibly the United Arab Emirates, have been called out and persuaded to compensate with even deeper cuts. Saudi Arabia twice made additional unilateral reductions to its production to speed up the process of market rebalancing.
Demand is now well on the road to recovery — literally. Highway traffic is back at, or even above, pre-pandemic levels in the U.S., China and large parts of Europe. Domestic and regional aviation is also picking up. The number of passengers passing through security at U.S. airports surpassed 2 million a

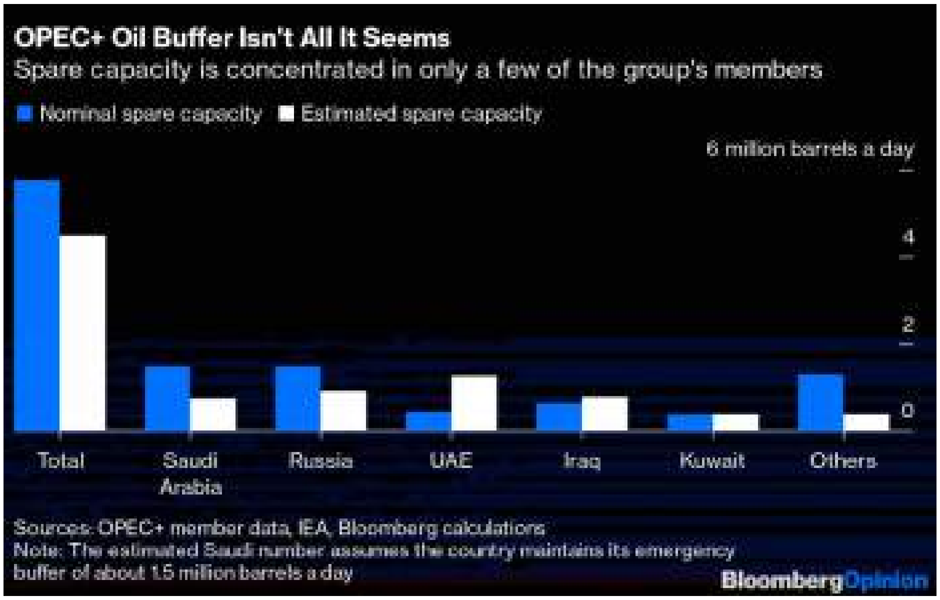
day for the first time since March 2020, while European air traffic has risen by one-third in the past month. The remaining weak spot is long-haul flying, which is still constrained by restrictions on incoming passengers in many parts of the world.



As the story has switched from collapsing demand to recovery, however, it's now supply that is lagging. That's partly because the OPEC+ producers want to keep draining stockpiles, deliberately pumping less than their customers are using to whittle away the excess inventory built up during their slow response to the onset of the pandemic. But it's also because oil companies aren't investing in new production. That's not yet a serious problem, but it could become one.

Some of the companies' reluctance is due to pressure from shareholders, who are either pushing for more environmentally conscious business models or seeking better returns on their investments. Some is simply due to oil incomes getting hit hard in 2020, which forced companies to slash budgets.

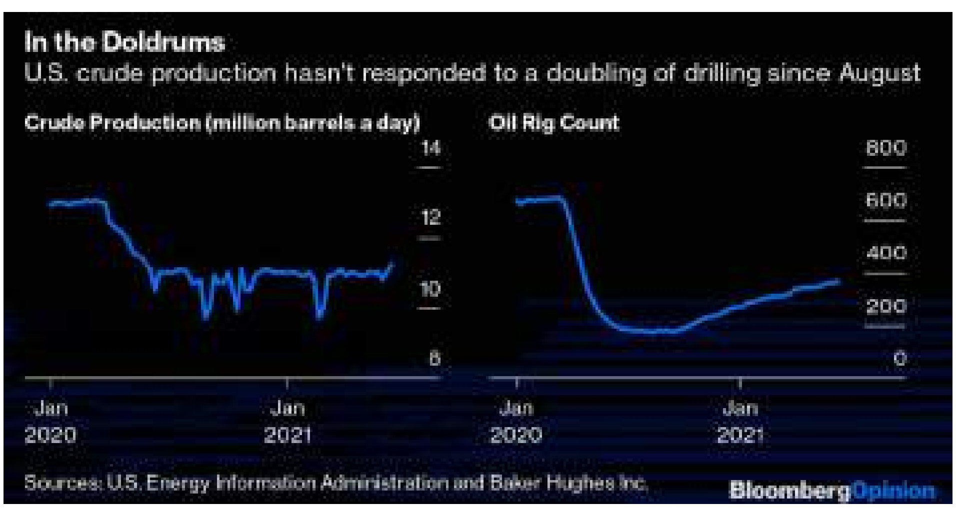
The OPEC+ countries have the capacity to raise output quickly, although maybe not by as much as we've been led to believe. Spare capacity is concentrated in just a few of the 23 countries, and the two biggest probably have less of it than the numbers used in the production cut deal indicate.



One reason for this is that the reference production levels used for the two biggest producers, Saudi Arabia and Russia, were arbitrarily set at 11 million barrels a day when the deal was first struck in April 2020. That allowed Russia to claim a bigger cut than it actually made and is more than it can pump. It is also more than Saudi Arabia has produced at any time except during its April 2020 production surge. Other countries, most notably Angola, have seen production capacity slump as investment has stalled.

The true production uplift available is probably closer to 4.5 million barrels a day, rather than the 5.8 million barrels suggested by the numbers in the deal.

The U.S. shale patch isn't yet responding to higher prices with increased activity, at least not on a scale that's big enough to do more than offset declines from already operating wells. Production has been stuck at around 11 million barrels a day for a year, even though the number of rigs drilling for oil has doubled since August.



While the OPEC+ countries have been raising output in the past couple of months, they currently have no plans to do so

after July until their current deal expires next May.
That will have to change. The group is due to meet on July 1, and to continue meeting monthly thereafter. It will need to act to prevent oil prices from rising high enough to choke off the recovery.
Saudi Energy Minister Prince Abdulaziz Bin Salman said last week that it is his job, along with others, to ensure that a new super cycle in global oil prices doesn't happen. To do that he's going to have to manage the return of OPEC+ production just as carefully as he's managed its reduction — and perhaps ease up on the caution for which he's now known.

--With assistance from Grant Smith.

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SAF Group Created Transcript from Bloomberg Daybreak: Europe interview with Saad Rahim, Chief Economist at Trafigura Pte Ltd. June 22, 2021 https://www.bloomberg.com/news/videos/2021-06-22/market-is-hungry-for-oil-trafigura-s-rahim-video

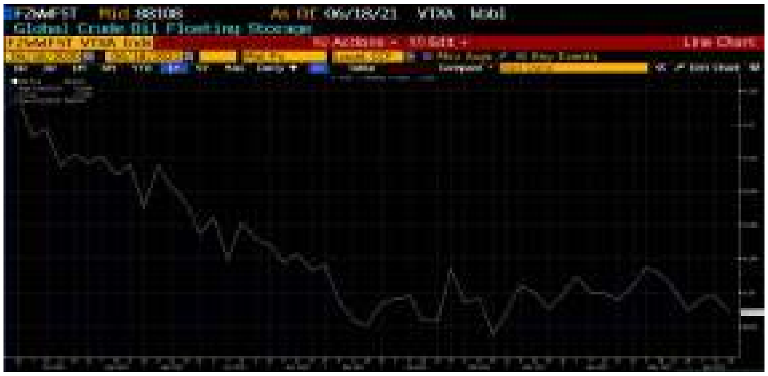
Items in "*italics*" are SAF Group created transcript

Bloomberg Manus Cranny "… *we've only seen this backwardation, this is tight as you can be, over a buck, we've only seen it twice and on each of those occasions, it made $100 oil. Saad, your CEO calls $100 oil, when will we hit $100 oil and is the market tight enough to achieve that?"*

Rahim *".. as you said, the current structure of the market is absolutely telling you the market is hungry for oil. We've moved from a situation where the recovery really was China led, manufacturing led, and goods led and now we are moving into something that is more US led, Europe led, more services led and more experiences led. So everyone is out there hitting the road, taking to the skies again, you are seeing a very strong demand recovery. And I think some of the real issues that were in the market that we were talking about the three big "I's" – India, Iran, Inflation. India has really started to recover there, you're starting to see demand, mobility indicators start to pick up. Iran at least seems to be absorbed by the market and then of course we have had all the talk about inflation and but even that seems to have been absorbed by the market. so going to where we think we could hit $100 oil. For us, this has really been a question of structural underinvestment that you have been seeing now, since 2014. So this has now been going for a better part of a decade. And to me, this is something where the market is slowly realizing that, even with all the spare capacity that OPEC currently has off the market, that eventually you are going to be in a situation where demand has not only recovered, but that is stronger than where it was. and you don't have that capacity anymore that you are really going to need other than maybe as a little bit of a buffer. And in some sense its going to be like Hemingway said about bankruptcy, which is its going to happen gradually, then suddenly. And all of a sudden I think the market is going to wake up and realize we have lost significant production from a lot of the smaller producers that people don't talk about – Angola, Mexico, Colombia, Vietnam just to name a few, and that production really needs a much higher price, not just in the front but in the back to really incentivize new production to start to come on.*"

Bloomberg Dani Burger "… *when do we get exactly that $100 a barrel oil?"*

Rahim "*I think the demand recovery that we are looking at. I think that the amount of stimulus that's gone into the system, I think the liquidity that's there. I think it is something you could see potentially next year, assuming we don't see any real movement on rates or anything else that will slow down this economy. It is something where you will quite quickly run out of spare capacity as that demand recovers back to pre pandemic levels. So given the conditions that we are seeing, so given how quickly quite frankly we come from $35 back up to $70, to $75, this is something you could see in the next 12 to 18 months, but again conditions have to be really ripe for that*"



Crude Oil in Floating Storage Falls 9.6% in Past Week: Vortexa
2021-06-21 07:00:01.450 GMT

By Bloomberg Automation
(Bloomberg) -- The amount of crude oil held around the world on tankers that have been stationary for at least 7 days fell to 88.11m bbl as of June 18, Vortexa data show.
* That's the lowest since February, and down 9.6% from 97.51m bbl on June 11
* Asia Pacific down 4.8% w/w to 58.44m bbl
* Middle East down 16% w/w to 5.93m bbl
* Europe down 30% w/w to 4.56m bbl
* West Africa down 23% w/w to 4.17m bbl
* North Sea up 115% w/w to 2.63m bbl
* U.S. Gulf Coast down 19% w/w to 677.00k bbl
* Company Exposure:
** Asia: Cosco Shipping Energy Transportation Co., HMM Co. Ltd., Mitsui O.S.K. Lines Ltd., Nippon Yusen KK
** Europe: Euronav NV, Frontline, Vopak
** U.S.: DHT Holdings, International Seaways, Nordic American Tankers, Teekay Tankers, Tsakos Energy Navigation
* NOTE:
** Vortexa data exclude FPSO units, oil products and Iranian condensate
** Crude oil transferred by STS isn't included until that volume has been stationary on receiving vessel for 7 days
** Data don't include vessels booked for floating storage until they are actually stationary for the minimum period
** See VTXA or DATA FLOAT for more data, which is subject to revisions, and see NI TANTRA for all tanker-tracking stories
** See SPOT FREIGHT for freight rate assessments using shipbroker data

To contact Bloomberg News for this story:
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OIL DEMAND MONITOR: Jet Fuel Demand Recovery Under Way in Europe
2021-06-23 07:38:50 GMT

- **Portugal data shows rising demand for aviation fuels: ENSE**
- **U.S. airport passenger count regularly topping 2 million a day**

By Stephen Voss

Airline flight numbers and seat capacity data have been showing a recovery in European activity for several weeks now, a revival that's also borne out in jet fuel consumption data for countries such as Portugal. Flights in the European air zone have risen steadily since early May and have now narrowed the deficit to 2019 levels to less than 50% for the first time since a brief period just before Christmas, according to Eurocontrol, an agency that helps coordinate traffic.

Portuguese demand for aviation fuel rose by 39% in May versus April, the third consecutive monthly gain, according to ENSE, a national agency that manages reserves. While demand is still 68% below the May 2019 level, a much larger gap than the 16% for gasoline, and it's normal to see a rising pattern of jet consumption during the first half of the year to a peak in July or August, the data is nevertheless an encouraging affirmation that a recovery is under way.

In the U.S., the number of passengers passing through security turnstiles at airports has surpassed 2 million a day on six days so far in June, including the most recent Sunday and Monday. Prior to those peaks, the daily count had been below 2 million since March 2020.

Flight activity in the U.K. has lagged the recovery in continental Europe, according to seat capacity data from OAG Aviation that shows the nation still 78% below 2019 levels while France is down 54% and the U.S. only 19% lower. That may be about to change as the U.K. government is preparing to allow Britons who have been fully vaccinated against coronavirus to travel to more than 150 countries without the need to quarantine on their return to England later this summer.

The OAG data has consistently shown China having the least impact from coronavirus, with the latest seat capacity estimate down only 0.3% from the same time in 2019.

Global Flights

Tracking the total number of commercial flights worldwide, data from FlightRadar24 show the seven-day moving average volume on Tuesday was just 29% below two years earlier, as the gap to a normal year continues to shrink. When one adds in helicopters, government, military and private flights and any other business flights not already counted as "commercial," then the gap between the latest moving average data for total flights and its 2019 equivalent, is much smaller, at just 7%, and narrowed to as little as 3.6% on June 18.

Parisian Streets

Among Western Europe's five biggest cities, Paris had the most road congestion on Monday morning. Commuters took an additional 44 minutes on top of a road journey that would normally take 1 hour on empty roads in the French capital at 8 a.m. Monday, according to data collected by navigation technology company TomTom NV. That's the same as the typical congestion time in 2019, and more than 10 other major world cities regularly studied in this monitor.

London was next, down 3% from the pre-pandemic level while Tokyo and Rome were both down 26%. New York congestion was 48% lower.

As nations relax mobility restrictions, demand for public transport is rising, and in many places exceeding previous peaks set in September and October, according to Moovit App Global Ltd. The company measures usage of its urban transport options app each day and compares it with typical levels before the Covid-19 outbreak began.

Traffic volumes on European toll motorways have slipped back from where they were a few weeks ago, when using comparisons against the equivalent period of 2019, according to road operator Atlantia Group. The figure for Spain was between 6.8% and 11.3% below year earlier levels during each of the three weeks ended June 13, after notching up a decline of only 0.2% in the week ended May 23. Even so, in general, May and early June represent a vast improvement from April when Italy, Spain and France were all showing volumes down by about 40% versus 2019.

The Bloomberg weekly oil-demand monitor uses a range of high-frequency data series to help identify trends that may become clearer later in more comprehensive monthly figures.

Following are the latest indicators, in the four tables below. The first two show fuel demand and mobility, the next shows air travel globally and the last is refinery activity:

Measure	Location	% y/y	% vs 2019	% m/m	Freq.	Latest as of Date	Latest Value	Source
Gasoline demand	U.S.	+19	-5.7	+1.5	w	June 11	9.36m b/d	EIA
Distillates demand	U.S.	+22	+6.8	+6.9	w	June 11	4.34m b/d	EIA
Jet fuel demand	U.S.	+60	-25	+6.1	w	June 11	1.26m b/d	EIA
Total oil products demand	U.S.	+19	-1.2	+6.7	w	June 11	20.6m b/d	EIA
All vehicles miles traveled	U.S.		-2		w	June 13	16.8b miles	DoT
Passenger car VMT	U.S.		-4		w	June 13	n/a	DoT
Truck VMT	U.S.		+8		w	June 13	n/a	DoT
All motor vehicle use index	U.K.	+34	-1	+3.1	d	June 14	99	DfT
Car use	U.K.	+36	-5	+4.4	d	June 14	95	DfT
Heavy goods vehicle use	U.K.	+18	+9	unch	d	June 14	109	DfT
Gasoline (petrol) avg sales per filling station	U.K.	+55	-6.2	+9.6	w	June 13	6,810 liters/d	BEIS
Diesel avg sales per station	U.K.	+35	-7.3	+1.9	w	June 13	9,665 liters/d	BEIS
Total road fuels sales per station	U.K.	+42	-6.9	+5	w	June 13	16,474 liters/d	BEIS
Gasoline	India	-3.5	-21	+13	2/m	June 1-15	905k tons	Bberg
Diesel	India	-7.5	-21	+12	2/m	June 1-15	2.48m tons	Bberg
Jet fuel	India	+13	-66	-17	2/m	June 1-15	107k tons	Bberg
Total Products	India	-1.5	-21	-11	m	May 2021	15.11m tons	PPAC
Passenger car traffic	Poland	+12	+3	+9.2	w	June 20	23,946	GDDKiA
Heavy goods traffic	Poland	+13	+12	+2.1	w	June 20	4,873	GDDKiA
Toll roads volume	France	+23	-11		w	June 13	n/a	Atlantia
Toll roads volume	Italy	+21	-11		w	June 13	n/a	Atlantia
Toll roads volume	Spain	+96	-6.8		w	June 13	n/a	Atlantia

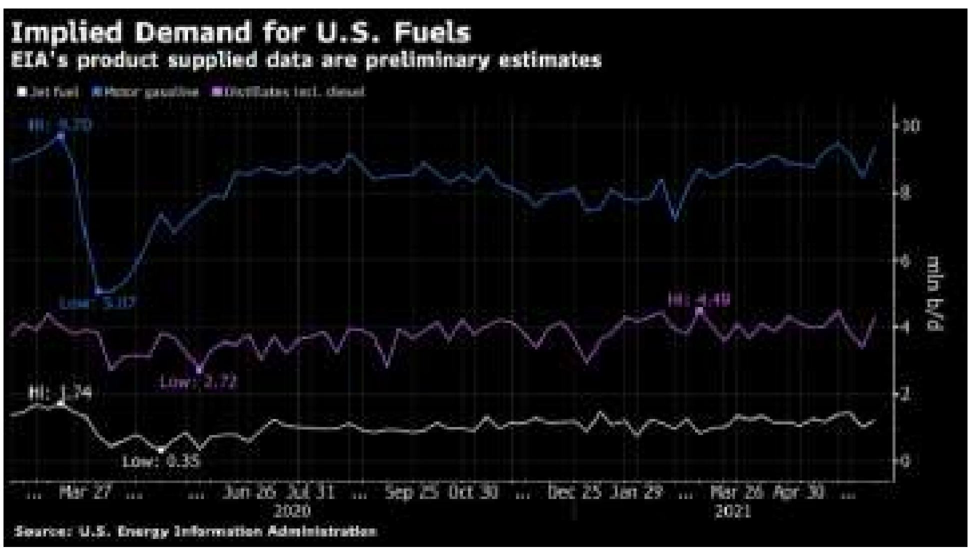
Toll roads volume	Brazil	+19	+2.4		w	June 13	n/a	Atlantia
Toll roads volume	Chile	+96	-7.6		w	June 13	n/a	Atlantia
Toll roads volume	Mexico	+32	+4.1		w	June 13	n/a	Atlantia
All vehicles traffic	Italy	+58		+25	m	May	n/a	Anas
Heavy vehicle traffic	Italy	+23		+1.6	m	May	n/a	Anas
Gasoline	Portugal	+28	-16	+5.1	m	May	79k tons	ENSE
Diesel	Portugal	+12	-12	-0.1	m	May	380k tons	ENSE
Jet fuel	Portugal	+298	-68	+39	m	May	46k tons	ENSE

The frequency column shows d for data updated daily, w for weekly, 2/m for twice a month and m for monthly.

* In DfT U.K. data, the column showing versus 2019 is actually showing the change versus the first week of February 2020, to represent the pre-Covid era.

** In BEIS U.K. data, the column showing versus 2019 is actually showing the change versus the average of Jan. 27-March 22, 2020, to represent the pre-Covid era.

*** Polish GDDKiA weekly data is compared against appropriate prior-year weeks that also contained the Corpus Christi national holiday.

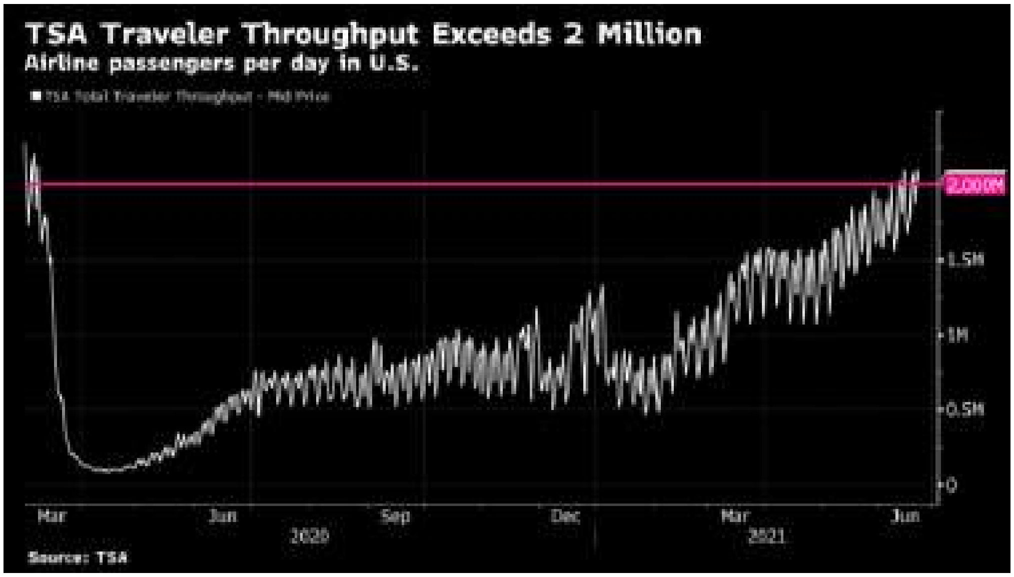


Measure	Location	% chg vs 2019	% chg m/m	June 21	Jun. 14	Jun. 7	May 31	May 24	May 17	May 10	May 3	Apr. 26	Apr. 19
		(June 21)			Minutes of congestion at 8am local time								
Congestion	Tokyo	-26	-4	28	30	27	26	29	31	28	7	32	30
Congestion	Mumbai	-87	+167	5	4	4	2	2	3	2	1	2	2
Congestion	New York	-48	-21	16	22	23	2	20	17	19	20	20	20
Congestion	Los Angeles	-56	-26	16	19	20	3	21	19	19	20	18	20
Congestion	London	-3	-10	37	39	40	3	41	40	41	2	44	38
Congestion	Rome	-26	-5	36	34	49	24	38	34	40	29	37	37
Congestion	Madrid	-49	-21	18	22	27	22	23	19	24	1	28	20
Congestion	Paris	unch	+1380	44	42	42	37	3	32	31	29	23	13
Congestion	Berlin	-16	+840	28	28	28	26	3	25	24	23	28	26
Congestion	Mexico City	-57	-8	21	26	24	22	23	23	14	20	23	20
Congestion	Sao Paulo	-40	+10	26	23	26	28	23	22	22	24	22	22

Source: TomTom. Note: M/m comparison is June 21 vs May 24. TomTom has been unable to provide Chinese data since late April. The Pentecost Monday holiday probably reduced traffic levels in Paris and Berlin on May 24, the month-ago date.

Air Travel:

Measure	Location	% chg y/y	% chg vs 2019	% chg m/m	Freq.	Latest as of Date	Latest Value	Source
Airline passenger throughput	U.S.	+234	-22	+16	d	June 21	2.03m people	TSA
Commercial flights	Worldwide	+83	-29	+12	d	June 22	86,677	FlightRadar24
Air traffic (flights)	Europe		-49	+38	d	June 22	17,152	Eurocontrol
Seat capacity	Worldwide	+81	-38		w	June 21	72.41m	OAG
Seat cap.	China	+35	-0.3		w	June 21	16.06m	OAG
Seat cap.	U.S.	+137	-19		w	June 21	18.96m	OAG
Seat cap.	India	+79	-49		w	June 21	2.02m	OAG
Seat cap.	Japan	-23	-59		w	June 21	1.71m	OAG
Seat cap.	Australia	+336	-36		w	June 21	1.32m	OAG
Seat cap.	Brazil	+243	-44		w	June 21	1.36m	OAG
Seat cap.	France	+197	-54		w	June 21	1.18m	OAG
Seat cap.	Germany	+115	-67		w	June 21	1.13m	OAG
Seat cap.	U.K.	+43	-78		w	June 21	859k	OAG



Refineries:

Measure	Location	y/y chg	m/m chg	Latest as of Date	Latest Value	Source
Crude intake	U.S.	+20%	+8.1%	June 11	16.3m b/d	EIA
Utilization	U.S.	+19 ppt	+6.3 ppt	June 11	92.6 %	EIA
Utilization	Gulf Coast U.S.	+14 ppt	+5 ppt	June 11	93 %	EIA
Utilization	East Coast U.S.	+42 ppt	+3.4 ppt	June 11	90.6 %	EIA
Utilization	Midwest U.S.	+21 ppt	+13 ppt	June 11	97.3 %	EIA
Apparent Oil Demand	China	-0.9%	+4.8%	May 2021	13.58m b/d	NBS
Indep. refs run rate	Shandong, China	-0.5 ppt	+7.9 ppt	June 18	74.6 %	SCI99
State refs run rate	East China	-2.3 ppt	+1.3 ppt	June 17	76.6 %	SCI99
State refs run rate	South China	-2.1 ppt	+8.5 ppt	June 17	83.8 %	SCI99

NOTE: All of the refinery data is weekly, except for SCI99 state refineries, which is twice per month, and the NBS apparent demand, which is usually monthly.

--With assistance from Jack Wittels and Julian Lee.

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Headlines

- 18,094 flights (51% of 2019 levels) on Wed 23 June 2021, increase (+16%) over 2 weeks.
- Continuous traffic increase (2-digit) as of early June. Record number on 18 June with 19,826.
- Ryanair, busiest operator, with about 1,000 additional flights per day since start of June. Five Low cost airlines are now back in the top 10 airlines.
- High increase for many States: Spain (+21%), Turkey (+26%), Germany (+15%), France (+15%), Greece (+41%), Italy (+21%) and Morocco (+275%, authorities facilitated return for nationals).
- High increase for domestic flows and flows between Southern and Northern European States. Noticeable increases on flows between Europe and Morocco as well as Russia-Turkey.
- Domestic traffic vs 2019: Europe (-49%), US (-19%), China (-7%) (recent decline due to lockdown in the Guanghzou area), Middle-East (-32%).

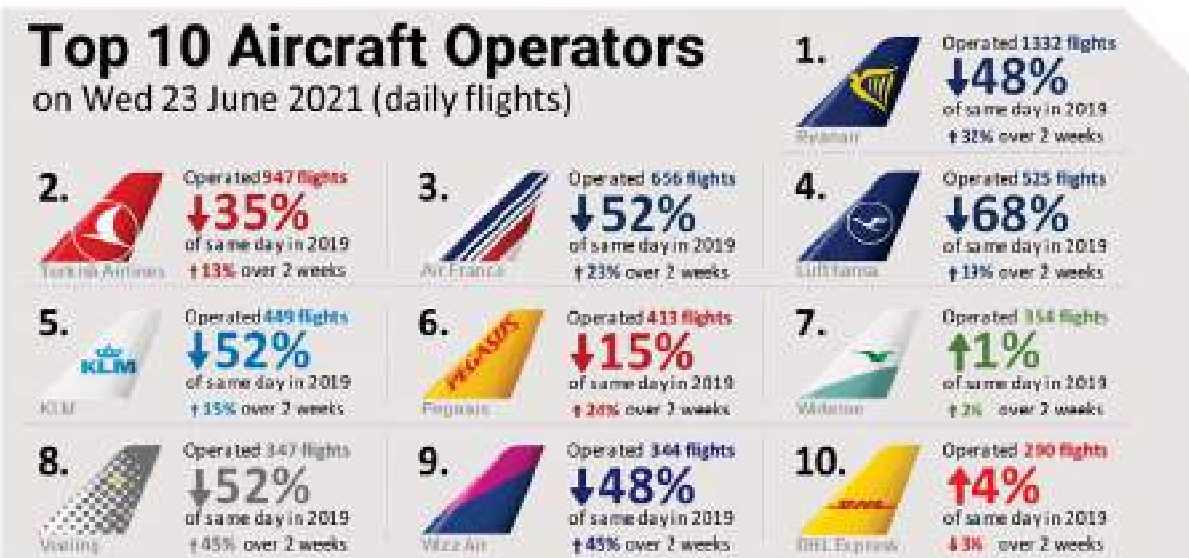
Traffic Situation

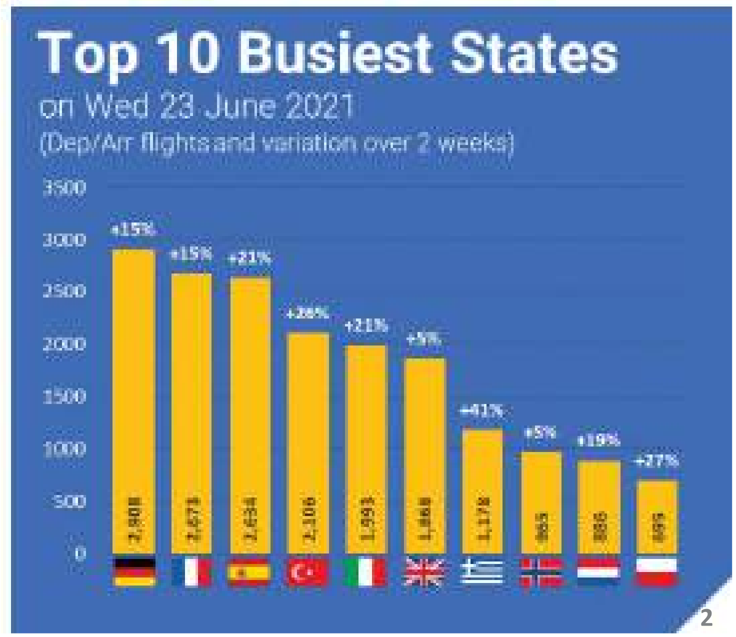
Daily flights (including overflights)

Traffic over the last 7 days is

↓48%

Compared to equivalent days in 2019





Top 10 Busiest Airports

7-day average Dep/Arr flights on 17-23 June, compared to 2019

Top 10 Airports	Average flights per day (week 17-23/6)	Average flights per day (week 17-23/6) vs 2019
IGA Istanbul Airport	734	-42%
Amsterdam	710	-53%
Frankfurt	691	-55%
Paris/Charles-De-Gaulle	652	-57%
Madrid/Barajas	608	-52%
Istanbul/Sabiha Gokcen	553	-18%
Athens	543	-30%
Barcelona	482	-56%
Palma De Mallorca	472	-47%
London/Heathrow	462	-66%

Market Segments

On 23 Jun, compared to 2019

↓60% Low cost

↓57% Traditional

↑ 3% Business Aviation

↓29% Non-Scheduled/ Charter

↑10% All Cargo

Traffic Flow

On 23 June, the **intra-European** traffic flow was

14,353 flights

+ 15% over **past 2 weeks**

-49% Compared **to 2019**

Route charges

(May 2021)

Amount billed

€ 234 million

Jan-May 2021 amount billed **€ 980 million** vs. Jan-May 2019 **(-67%)**

Economics

(18 June 2021)

Fuel price

185 Cents/gallon

compared to **184 cents/gallon on 11 June 2021**

Source: IATA/Platts

Passengers

(03 June 2021)

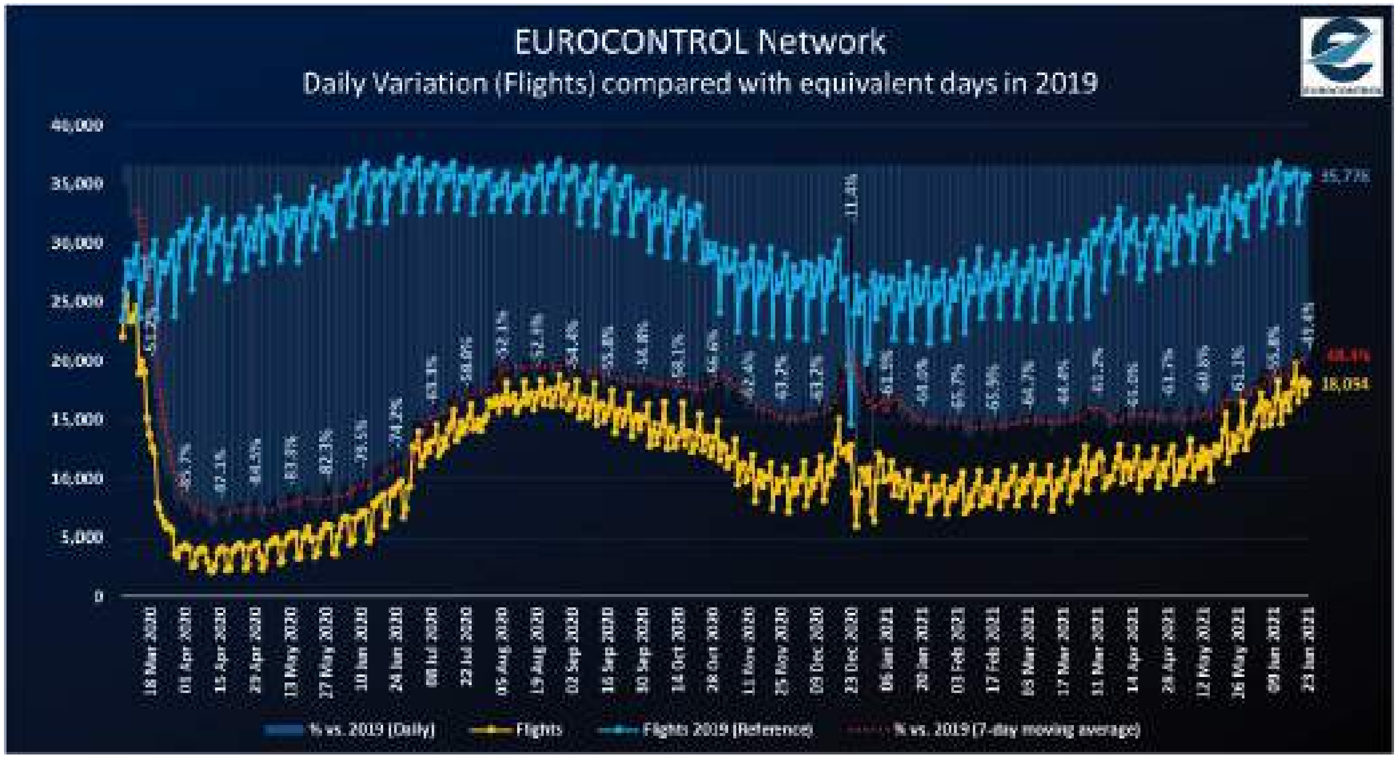
2 million pax

-5.3 million

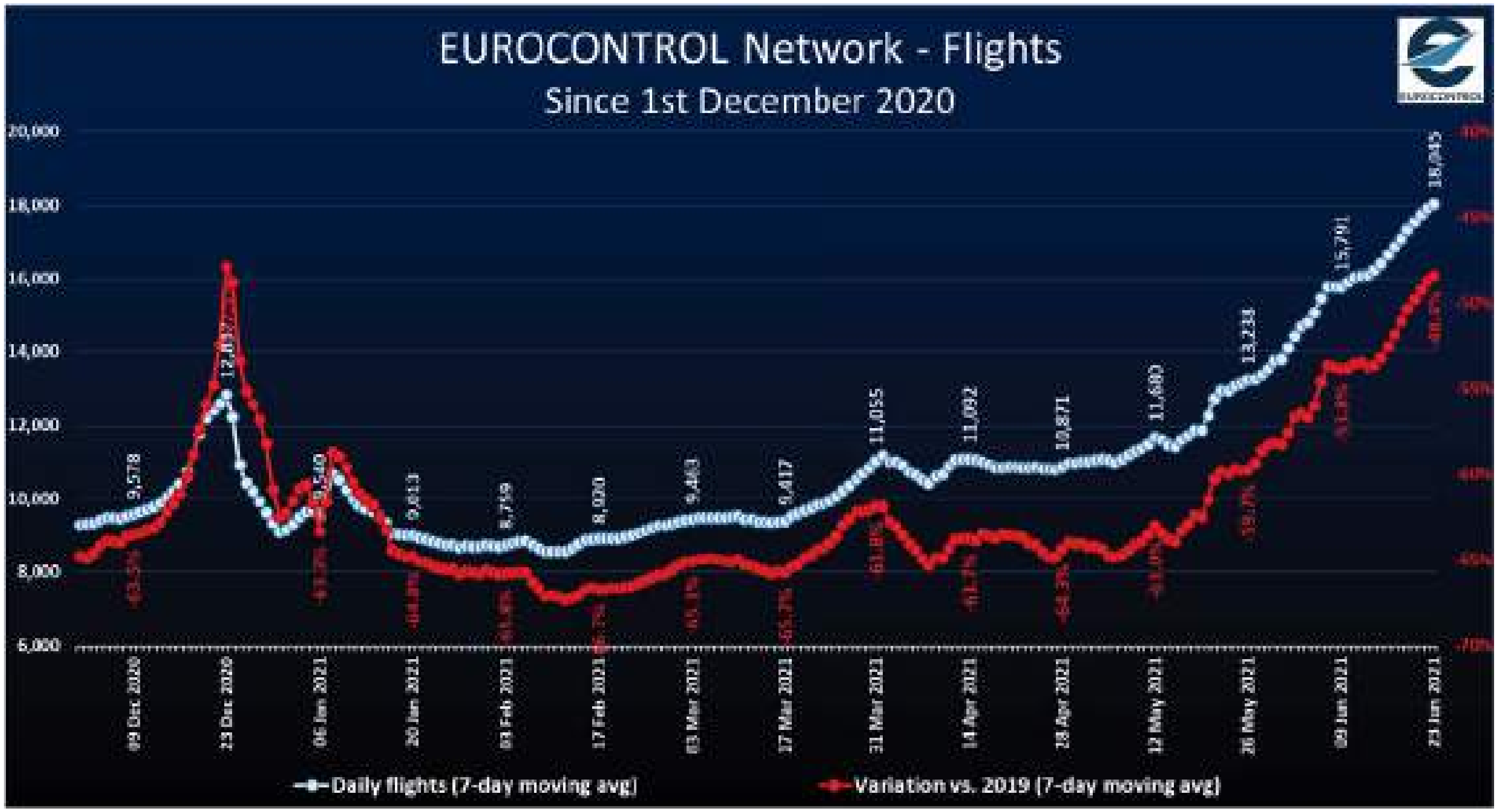
vs. 2019 **(-73%)**

Overall traffic situation at network level

- **18,094 flights** on Wednesday 23 June.
- **+16%** with **+2,510 flights** over 2 weeks (from Wed 3 Jun).
- **4%** with **+742 flights** over 1 week (from Wed 16 June).
- **51%** of 2019 traffic levels on Wednesday 23 June.



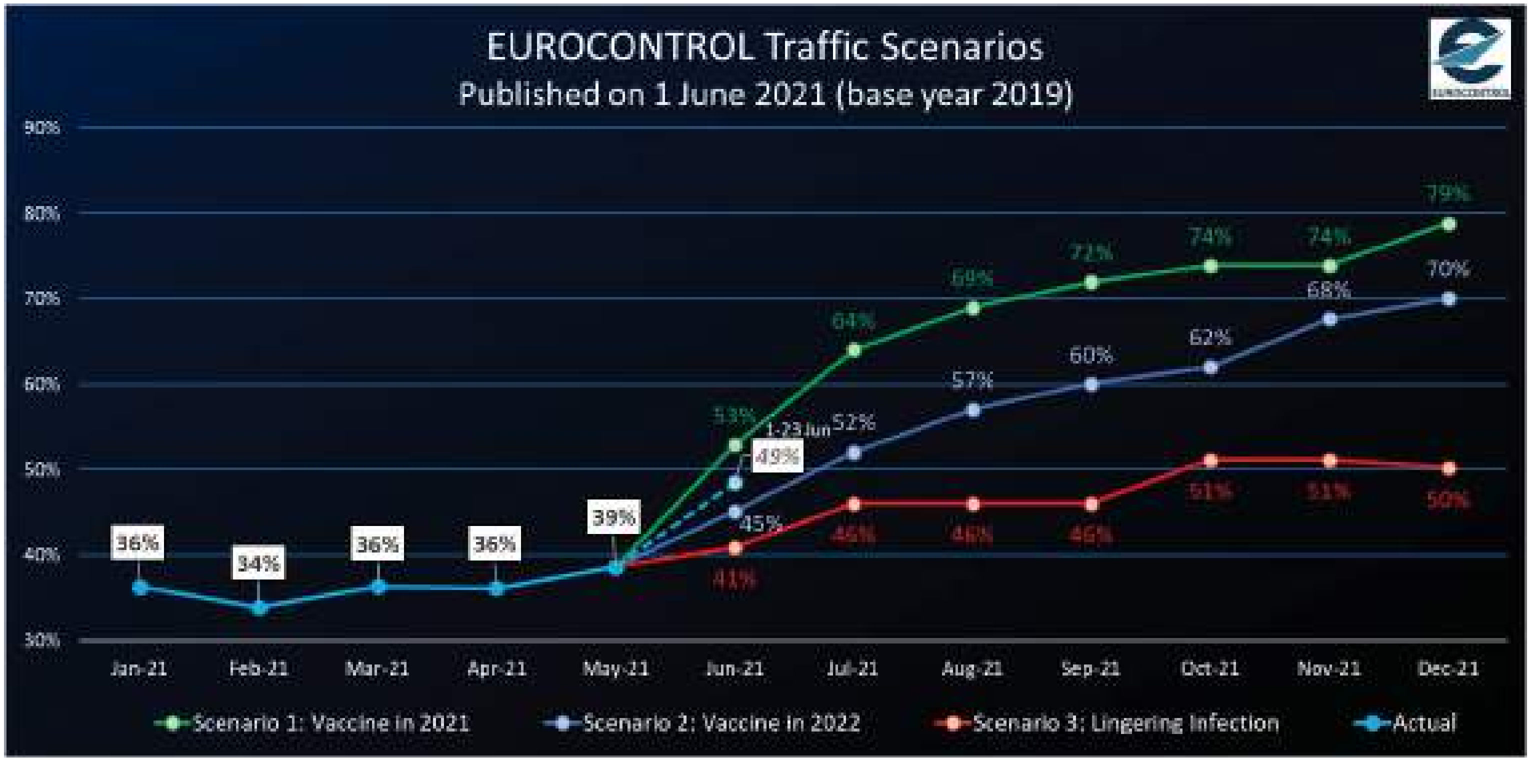
Current traffic evolution



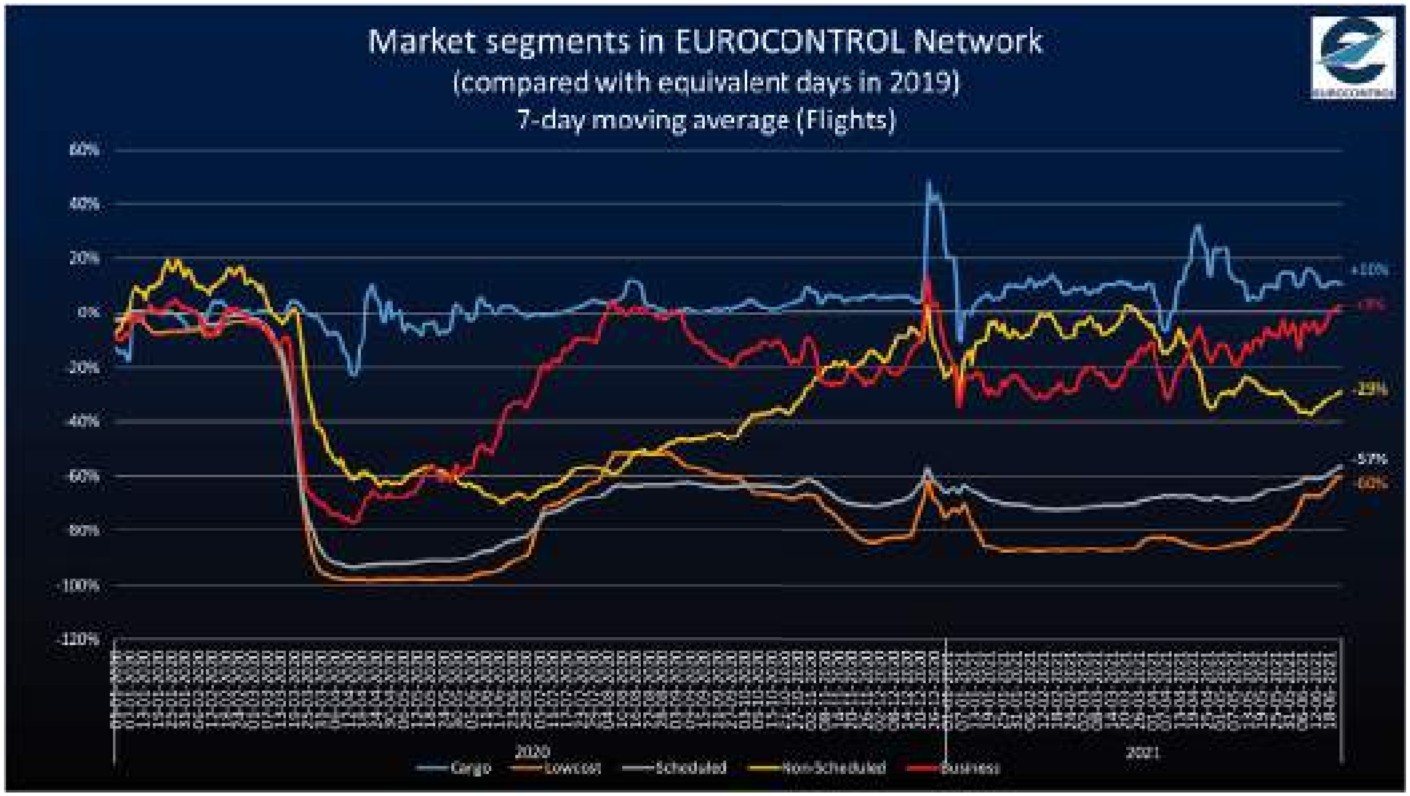
- The traffic has clearly been increasing over the last 7 weeks with a significant acceleration on 1st June with 2 digit increases.
- After having been stable since January at around -64% compared to 2019, the traffic has now reached -48% over the last week.

Current situation compared to the latest EUROCONTROL traffic scenarios

- **Traffic at 49%** on 1-23 June 2021 compared to 1-23 June 2019.
- This is in line with the latest EUROCONTROL traffic scenarios published on 1 June 2021.



Market Segments



On 23 June 2021, compared to 2019:

- **All-cargo** and **Business Aviation** are the only segment above 2019 levels with **+10%** and **+3%** respectively. Strong growth in business jet flights in Russia, Greece, across the Balkans and much of Eastern Europe.
- **Charter** decreased to **-29%** and decreasing since mid March.
- **Traditional** increased slightly to reach **-57%**.
- **Low-Cost** remains the most affected segment but has shown a significant rebound since 1st June reaching **-60%** vs 2019.

https://www.trucking.org/news-insights/ata-truck-tonnage-index-decreased-07-may

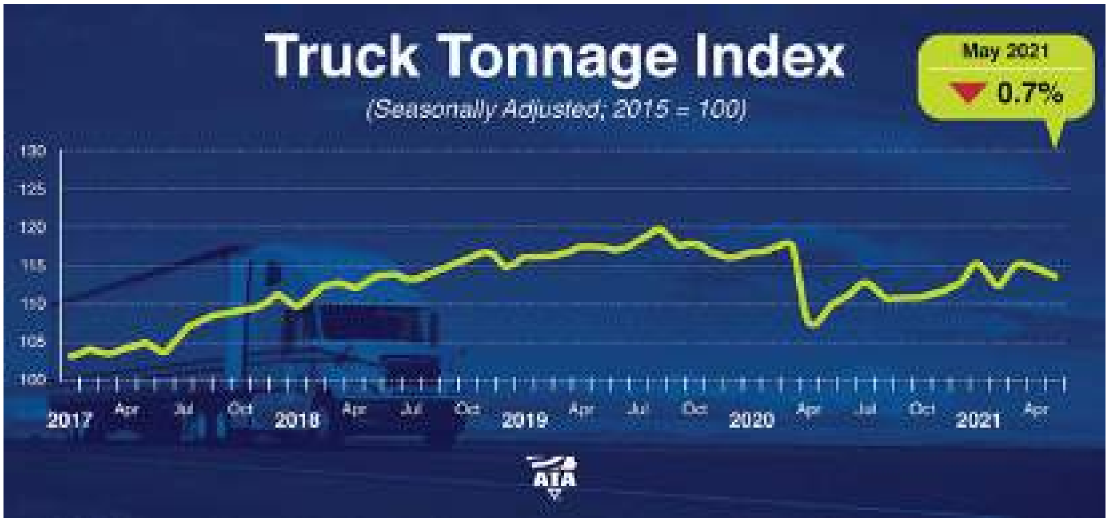
ATA Truck Tonnage Index Decreased 0.7% in May

June 22, 2021

Media contact: Sean McNally

Index 3.7% Above May 2020

Arlington, Virginia -- American Trucking Associations' advanced seasonally adjusted (SA) For-Hire Truck Tonnage Index decreased 0.7% in May after falling 0.6% in April. In May, the index equaled 113.7 (2015=100) compared with 114.5 in April.



"Tonnage, despite falling slightly over the last two months, remains well above the lows of last year," said **ATA Chief Economist Bob Costello**. "This is no small deal considering that truck tonnage fell significantly less than many other indicators during the depths of the pandemic in the spring of 2020.

"One freight segment that is helping tonnage is gasoline as demand for travel, both commuting and vacation related, picks up," he said. "I'm also expecting retail freight to remain robust as inventories are at historic lows. As retail stocks are rebuilt, it will boost freight. As has been the case for some time, trucking's biggest challenges are not on the demand side, but on the supply side, including difficulty finding qualified drivers."

April's reading was revised down slightly to -0.6% from our May 18 press release.

Compared with May 2020, the SA index rose 3.7%, which was preceded by a 6.7% year-over-year jump in April. Year-to-date, compared with the same five months in 2020, tonnage is up 0.4%.

The not seasonally adjusted index, which represents the change in tonnage actually hauled by the fleets before any seasonal adjustment, equaled 113.8 in May, 0.2% below the April level (114). In calculating the index, 100 represents 2015. ATA's For-Hire Truck Tonnage Index is dominated by contract freight as opposed to spot market freight.

Trucking serves as a barometer of the U.S. economy, representing 72.5% of tonnage carried by all modes of domestic freight transportation, including manufactured and retail goods. Trucks hauled 11.84 billion tons of freight in 2019. Motor carriers collected $791.7 billion, or 80.4% of total revenue earned by all transport modes.

ATA calculates the tonnage index based on surveys from its membership and has been doing so since the 1970s. This is a preliminary figure and subject to change in the final report issued around the 5th day of each month. The report includes month-to-month and year-over-year results, relevant economic comparisons, and key financial indicators.

Dallas Fed Energy Survey

Second Quarter | June 23, 2021

Oil and Gas Activity Continues Expanding; Outlook Improves Further

What's New This Quarter

Special questions this quarter ask about expectations for a global crude oil supply gap, current and expected investments in renewables by oil and gas firms, firm-level cybersecurity, and the relative effectiveness of a carbon tax versus tax credits in reducing emissions.

Activity in the oil and gas sector continued growing strongly in second quarter 2021, according to oil and gas executives responding to the Dallas Fed Energy Survey. The business activity index—the survey's broadest measure of conditions facing Eleventh District energy firms—remained elevated at 53.0, essentially unchanged from its first-quarter reading.

Oil and gas production increased, according to executives at exploration and production (E&P) firms. The oil production index rose from 16.3 in the first quarter to 35.0 in the second quarter—its second-highest reading since the survey's inception in 2016. Similarly, the natural gas production index increased 19 points to 35.0.

The index for capital expenditures increased from 31.0 to 42.4, indicating an acceleration in capital spending among E&P firms. Additionally, the index for the expected level of capital expenditures next year came in at 53.0, up from 49.5 in the first quarter.

Costs are rising. Among oilfield services firms, the index for input costs rose notably, from 36.0 to 56.0—a record high and suggestive of significant cost pressures. No oilfield services firms reported a decrease in input costs this quarter. Among E&P firms, the index for finding and development costs jumped from 3.9 in the first quarter to 28.3 in the second. Additionally, the index for lease operating expenses also increased, from -5.9 to 23.4.

Oilfield services firms reported improvement across all indicators. The equipment utilization index remained positive, though slipping from 63.2 in the first quarter to 42.0 in the second. Operating margins improved further, with the index increasing from 14.0 to 22.5. The index of prices received for services rose from 20.0 to 30.0.

The aggregate employment index posted a second consecutive positive reading, edging up from 8.4 to 9.9. Employment growth continues to be driven primarily by oilfield services firms. The employment index was 25.5 for services firms versus 2.0 for E&P firms. The aggregate employee hours index edged up from 22.8 to 24.0. The aggregate wages and benefits index also increased, from 14.8 to 20.6.

Six-month outlooks improved notably, with the index moving up from 70.6 last quarter to 71.9—the highest reading in the survey's five-year history. While uncertainty continued to decline, the aggregate index increased three points to -19.6.

On average, respondents expect a West Texas Intermediate (WTI) oil price of $70 per barrel by year-end 2021; responses ranged from $49 to $85 per barrel. Survey participants expect Henry Hub natural gas prices of $3.10 per million British thermal units (MMBtu) at year-end. For reference, WTI spot prices averaged $71 per barrel during the survey collection period, and Henry Hub spot prices averaged $3.24 per MMBtu.

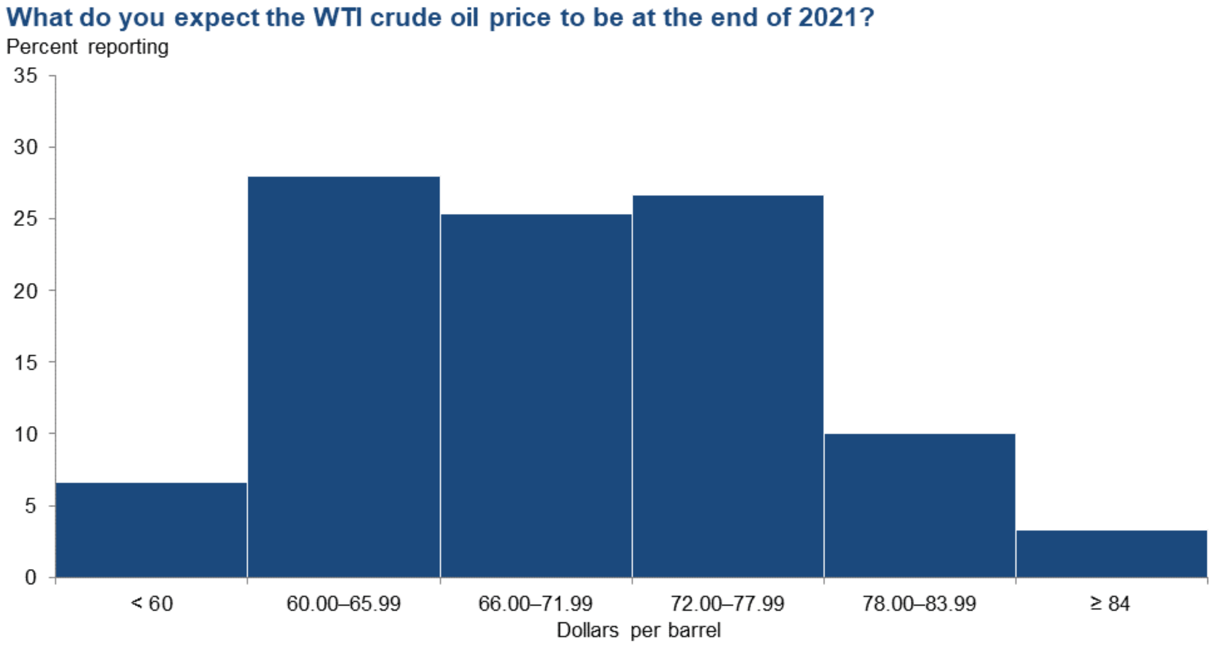
Next release: September 29, 2021

Data were collected June 9–17, and 152 energy firms responded. Of the respondents, 101 were exploration and production firms and 51 were oilfield services firms.

The Dallas Fed conducts the Dallas Fed Energy Survey quarterly to obtain a timely assessment of energy activity among oil and gas firms located or headquartered in the Eleventh District. Firms are asked whether business activity, employment, capital expenditures and other indicators increased, decreased or remained unchanged compared with the prior quarter and with the same quarter a year ago. Survey responses are used to calculate an index for each indicator. Each index is calculated by subtracting the percentage of respondents reporting a decrease from the percentage reporting an increase. When the share of firms reporting an increase exceeds the share reporting a decrease, the index will be greater than zero, suggesting the indicator has increased over the previous quarter. If the share of firms reporting a decrease exceeds the share reporting an increase, the index will be below zero, suggesting the indicator has decreased over the previous quarter.

Price Forecasts

West Texas Intermediate Crude



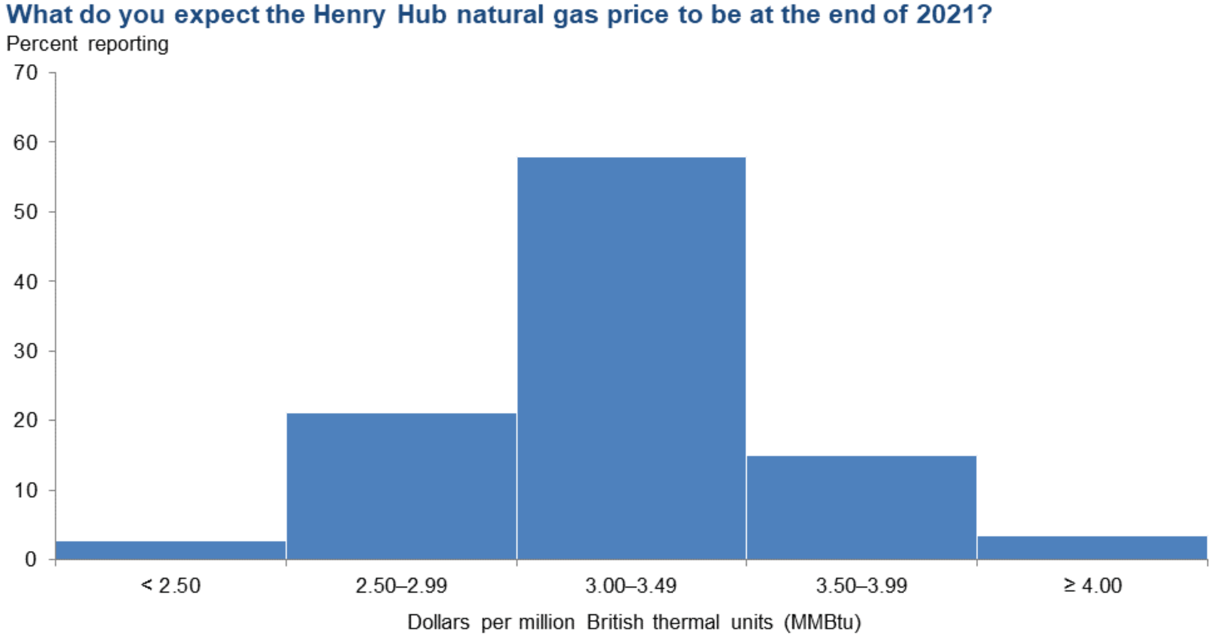
NOTES: Executives from 150 oil and gas firms answered this question during the survey collection period, June 9–17, 2021. For reference, WTI (West Texas Intermediate) spot prices averaged $71.05 per barrel during the period.
SOURCES: Federal Reserve Bank of Dallas; Energy Information Administration (reference price).

West Texas Intermediate crude oil price (dollars per barrel), year-end 2021

Indicator	Survey Average	Low Forecast	High Forecast	Price During Survey
Current quarter	$69.71	$49.00	$85.00	$71.05
Prior quarter	$61.13	$45.00	$85.00	$64.39

NOTE: Price during survey is an average of daily spot prices during the survey collection period.
SOURCES: Energy Information Administration; Federal Reserve Bank of Dallas.

Henry Hub Natural Gas



NOTES: Executives from 147 oil and gas firms answered this question during the survey collection period, June 9–17, 2021. For reference, Henry Hub spot prices averaged $3.24 per MMBtu during the period.
SOURCES: Federal Reserve Bank of Dallas; *Wall Street Journal* (reference price).

Henry Hub natural gas price (dollars per MMBtu), year-end 2021

Indicator	Survey Average	Low Forecast	High Forecast	Price During Survey
Current quarter	$3.10	$2.20	$5.00	$3.24
Prior quarter	$2.80	$2.00	$4.00	$2.59

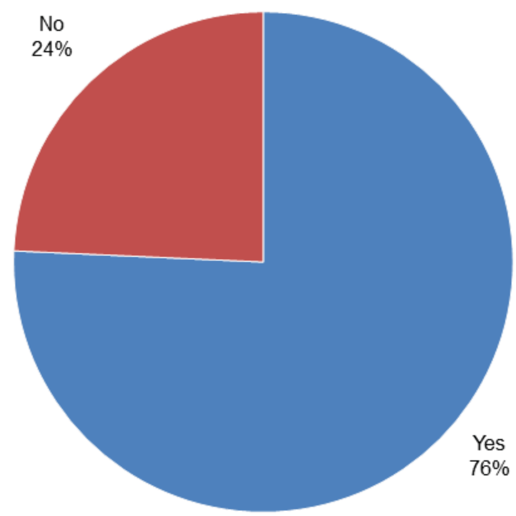
NOTE: Price during survey is an average of daily spot prices during the survey collection period.
SOURCES: Federal Reserve Bank of Dallas; *Wall Street Journal*.

Special Questions

Data were collected on June 9–17; 152 oil and gas firms responded to the special questions survey.

Do you believe there will be a global crude oil supply gap in the next two to four years?

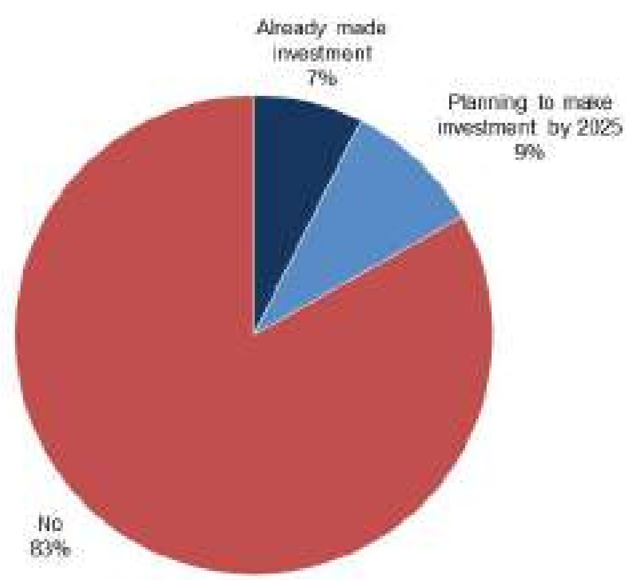
Seventy-six percent of executives said they believe there will be a global crude oil supply gap in the next two to four years.



NOTE: Executives from 140 oil and gas firms answered this question during the survey collection period, June 9–17, 2021.
SOURCE: Federal Reserve Bank of Dallas.

Has your firm already made, or is it planning to make, investments in wind and/or solar?

The majority of the executives—83 percent—said they don't have investments in wind and/or solar. Seven percent note they already have an investment, and 9 percent are planning to make an investment by 2025. (Percentages don't sum to 100 due to rounding.)



NOTES: No executives are planning to invest in wind and/or solar after 2025. Executives from 149 oil and gas firms answered this question during the survey collection period, June 9–17, 2021.
SOURCE: Federal Reserve Bank of Dallas.

Special Questions Comments

Exploration and Production (E&P) Firms

- I'm extremely curious about the western world's reaction if carbon capture and sequestration (CCS) become viable at scale. I believe there is a (negative) visceral reaction to the oil and gas industry at large in the western world. If CCS works at scale, does the negative sentiment around the traditional energy sector abate? I'm skeptical.
- We will likely be investing in natural gas co-generation facilities to sell electricity and for carbon capture for reinjection to enhance recovery. Solar and wind are not competitive with our other options. Tax credits and a carbon tax are both effective tools, but the current political tenor, which is effectively bashing oil and gas entities in all aspects while showering grants, tax benefits and other subsidies on perceived "green" energies, is not a good step. The very entities that can have an immediate and permanent effect on capturing, reinjection and sequestration are the ones being bashed daily. A cooperative approach, bringing incentives to all industries to "green up" a bit, is an approach that most would approve. All modeling shows natural gas and oil play an important part in any future energy supply for the country and for the world. Our industry should be partners in the "greening" process and be encouraged rather than bashed at all opportunities.
- Labor and capital will be the critical limitations on U.S. producers' ability to grow oil production.
- Investors want to say they are contrarian, but they follow the herd. The amount of money being thrown at renewables will crater the price of another commodity (electricity). Intermittency makes these electrons lower value than dispatchable electrons. Areas of high wind and solar resources are large distances from population centers, with no transmission. Think of the economic rent extracted by pipelines in the Marcellus or trains in North Dakota to get the product to market. Wholesale electric prices are already negative sometimes in the wind corridor of West Texas and Oklahoma. How, you might ask? Production tax credits incentivize producers to pay someone to take the electricity, so they get the tax credit. Economics!
- Carbon taxes, tax credits and the like are just taxes. It's politics and does nothing except to give the politicians more power.
- Why do specific members of the government continue to fly their private jets but at the same time promote the Green New Deal [climate change proposals]. When they demonstrate to the public that they are not using jet fuel and gasoline completely, then they can promote wind and solar. Isn't it kind of hard to fly an airplane on wind or solar? Oil has more energy than wind and solar. I am not against wind and solar but do realize that the public is not willing to give up the consumption they use in oil. Can they live without their cellphones, clothes and cars which rely heavily on oil and gas? No, the public cannot give that up easily. Natural gas is a clean fuel, and if you get rid of oil, then you need gas to fuel the electric grid.
- I haven't seen a good plan on a rollout of a "carbon tax"—i.e., how it would be applied, what industries, what levels, who collects it, who administers it, who actually pays for it and where, and what will become of the tremendous funds collected. Logic says the most ineffective player (U.S. government) will be the collector, with the leakage spilling out to fund political action groups that have absolutely no connection to energy in the first place. Otherwise, the smallest carbon tax pricing I've seen in the press has been only $25.00 per ton of CO_2 emissions equivalent. Further readings indicate this converts to approximately $10.75 per barrel, considering a range of U.S.-produced crude oils. I have seen some politicians proposing a $60.00 or more per-ton initial carbon tax, with annual escalations. That's $25.80 per barrel if assessed at the wellhead for U.S. production. What a great way to absolutely cripple the U.S. oil and gas industry. Question: How many of our economic competitor nations around the world will willingly shoot themselves in the foot with a carbon tax like this and yet, simultaneously, try to compete against China, India and Russia? Are they going to do this to themselves? You know the answer is no.
- Global warming is a tool for control and taxation. The earth is not running on a thermostat. It's dynamic. If carbon increases in the air, then plants will benefit and increase the oxygen in the air.
- Once the consumer is confronted with the cost of carbon emission in daily life, there will be real progress in making the energy transition to lower-carbon fuels. Simply trying to choke off supply by regulation and fiat will not provide a sustainable solution.

Oil and Gas Support Services Firms

- I have worked in the upstream segment of the E&P industry for 35 years and have worked on several CO_2 tertiary floods during that period. Most of us in the technical side of the business recognize carbon capture exists somewhere between difficult-to-implement and a complete charade.
- The climate targets set by the U.S. government are completely unrealistic. There will be more internal combustion engine vehicles on the road in 2030 than there are now. There is no way we can hit the 2030 target. The U.S. public will reject the Green New Deal as soon as they understand the personal impact to them in transportation, home utilities, cost inflation, etc.

Historical data are available from first quarter 2016 to the most current release quarter.

Business Indicators: Quarter/Quarter

Business Indicators: All Firms
Current Quarter (versus previous quarter)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	53.0	53.6	58.3	36.4	5.3
Capital Expenditures	36.6	30.0	47.3	42.0	10.7
Supplier Delivery Time	7.3	7.8	21.3	64.7	14.0
Employment	9.9	8.4	20.5	68.9	10.6
Employee Hours	24.0	22.8	28.0	68.0	4.0
Wages and Benefits	20.6	14.8	25.2	70.2	4.6

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	71.9	70.6	78.2	15.5	6.3

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Uncertainty	−19.6	−22.2	23.6	33.1	43.2

Business Indicators: E&P Firms
Current Quarter (versus previous quarter)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	50.0	47.1	55.0	40.0	5.0
Oil Production	35.0	16.3	44.0	47.0	9.0
Natural Gas Wellhead Production	35.0	15.9	43.0	49.0	8.0
Capital Expenditures	42.4	31.0	51.5	39.4	9.1
Expected Level of Capital Expenditures Next Year	53.0	49.5	59.0	35.0	6.0
Supplier Delivery Time	4.0	4.8	18.0	68.0	14.0
Employment	2.0	1.0	13.0	76.0	11.0
Employee Hours	12.0	11.6	17.0	78.0	5.0
Wages and Benefits	17.0	7.7	20.0	77.0	3.0
Finding and Development Costs	28.3	3.9	32.3	63.6	4.0
Lease Operating Expenses	23.4	−5.9	31.6	60.2	8.2

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	71.3	69.6	77.7	16.0	6.4

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Uncertainty	−22.7	−21.4	23.7	29.9	46.4

Business Indicators: O&G Support Services Firms
Current Quarter (versus previous quarter)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	58.8	66.7	64.7	29.4	5.9
Utilization of Equipment	42.0	63.2	52.0	38.0	10.0
Capital Expenditures	25.5	28.0	39.2	47.1	13.7
Supplier Delivery Time	14.0	14.3	28.0	58.0	14.0
Lag Time in Delivery of Firm's Services	10.2	18.8	18.4	73.5	8.2
Employment	25.5	23.5	35.3	54.9	9.8
Employment Hours	48.0	45.1	50.0	48.0	2.0
Wages and Benefits	27.5	29.4	35.3	56.9	7.8
Input Costs	56.0	36.0	56.0	44.0	0.0
Prices Received for Services	30.0	20.0	30.0	70.0	0.0
Operating Margin	22.5	14.0	34.7	53.1	12.2

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	72.9	72.6	79.2	14.6	6.3

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Uncertainty	–13.8	–24.0	23.5	39.2	37.3

Business Indicators: Year/Year

Business Indicators: All Firms

Current Quarter (versus same quarter a year ago)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	68.1	17.3	78.0	12.1	9.9
Capital Expenditures	46.5	8.7	60.6	25.4	14.1
Supplier Delivery Time	20.7	9.0	36.4	47.9	15.7
Employment	6.4	−16.7	29.6	47.2	23.2
Employee Hours	29.0	2.1	42.0	44.9	13.0
Wages and Benefits	29.8	−2.0	41.1	47.5	11.3

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	84.4	53.6	89.1	6.3	4.7

Business Indicators: E&P Firms

Current Quarter (versus same quarter a year ago)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	66.7	25.0	76.7	13.3	10.0
Oil Production	37.3	−3.9	57.1	23.1	19.8
Natural Gas Wellhead Production	38.9	3.0	55.6	27.8	16.7
Capital Expenditures	51.6	13.0	65.9	19.8	14.3
Expected Level of Capital Expenditures Next Year	64.8	35.0	73.6	17.6	8.8
Supplier Delivery Time	18.9	7.2	33.3	52.2	14.4
Employment	−3.3	−13.2	19.8	57.1	23.1
Employee Hours	19.5	11.2	33.3	52.9	13.8
Wages and Benefits	23.4	−4.0	35.6	52.2	12.2
Finding and Development Costs	30.3	−12.0	40.4	49.4	10.1
Lease Operating Expenses	28.9	−20.2	41.1	46.7	12.2

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	84.0	59.1	88.9	6.2	4.9

Business Indicators: O&G Support Services Firms
Current Quarter (versus same quarter a year ago)

Indicator	Current Index	Previous Index	% Reporting Increase	% Reporting No Change	% Reporting Decrease
Level of Business Activity	70.6	2.0	80.4	9.8	9.8
Utilization of Equipment	58.0	4.3	70.0	18.0	12.0
Capital Expenditures	37.3	0.0	51.0	35.3	13.7
Supplier Delivery Time	24.0	12.8	42.0	40.0	18.0
Lag Time in Delivery of Firm's Services	22.5	6.3	32.7	57.1	10.2
Employment	23.6	–24.0	47.1	29.4	23.5
Employment Hours	45.1	–16.0	56.9	31.4	11.8
Wages and Benefits	41.2	2.1	51.0	39.2	9.8
Input Costs	65.3	20.4	67.3	30.6	2.0
Prices Received for Services	26.6	–24.5	38.8	49.0	12.2
Operating Margin	24.0	–28.0	44.0	36.0	20.0

Indicator	Current Index	Previous Index	% Reporting Improved	% Reporting No Change	% Reporting Worsened
Company Outlook	85.1	42.5	89.4	6.4	4.3

https://www.reuters.com/article/us-usa-interior-leasing/haaland-says-no-plan-right-now-to-ban-new-oil-gas-leasing-idUSKCN2DZ24A

ENERGY & ENVIRONMENT

JUNE 23, 202110:17 AMUPDATED 3 HOURS AGO

Interior sec'y says no plan 'right now' to ban new oil, gas leasing

By Valerie Volcovici
3 MIN READ

WASHINGTON (Reuters) -U.S. Interior Secretary Deb Haaland on Wednesday told a congressional hearing that there is no plan to permanently ban new oil and gas drilling on federal land but her agency will soon release a report that will assess the future of the federal oil and gas leasing program.

FILE PHOTO: U.S. Rep. Deb Haaland speaks during a Senate Committee on Energy and Natural Resources hearing on her nomination to be Interior Secretary on Capitol Hill in Washington, DC, U.S. February 23, 2021. Graeme Jennings/Pool via REUTERS

The Biden administration paused the government's oil and gas leasing auctions on federal acres in January pending a review that is expected to be completed in the coming weeks. The move was part of a sweeping plan to rein in fossil-fuel extraction and combat the effects of climate change.

Republican and some Democratic lawmakers in oil-reliant states have raised concerns that the pause would lead to a permanent ban, depriving those states of revenue.

"I don't think there is a plan right now for a permanent ban but ... the review will come out early summer and we will assess the fossil fuel programs at that time," Haaland told a House natural resources subcommittee.

She said oil and gas production "will continue well into the future" but said the administration wants "to make sure American taxpayers are getting a good return on their investment."

Last week, a federal judge in Louisiana granted a preliminary injunction to Louisiana and 12 other states that sued Democratic President Joe Biden and the

Interior Department over the freeze on new drilling auctions. Louisiana is a major hub for offshore oil and gas production.

Republican Congressman Garret Graves of Louisiana asked Haaland at the hearing whether the Interior Department has taken any steps to resume new leasing activity in light of that court decision, including publishing a new lease sale in the Federal Register.

Haaland said the Interior Department has not published details of a new lease sale in the Federal Register and said her agency and the Justice Department were reviewing the decision.

Separately, Republican Congressman Pete Stauber of Minnesota asked Haaland why the Biden administration plans to rely on ally countries for the bulk of the metals needed to build electric vehicles. Reuters first reported the strategy last month.

Stauber's district includes Antofagasta Plc's proposed Twin Metals copper mine, which is under regulatory review by the Interior and Agriculture departments. The Interior Department has also taken steps that impede U.S. critical minerals projects from Rio Tinto Ltd, ioneer Ltd and others.

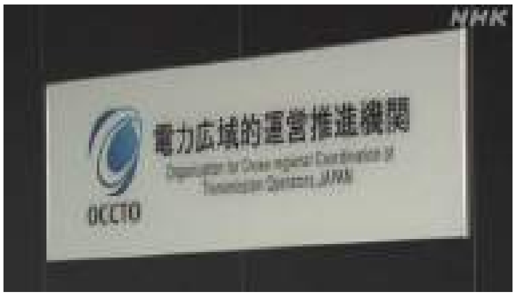
Haaland did not answer Stauber's question directly, but said that Biden supports U.S. energy independence.

"We agree that ensuring the availability of critical minerals and the future of our energy needs is very important to Americans," she said.

Reporting by Valerie Volcovici; additional reporting by Ernest Scheyder; editing by Jonathan Oatis

Summer electricity supply and demand Expected to improve with restart of nuclear power plant and restoration of thermal power plant

June 19, 2021 5:33



Electricity supply and demand this summer was expected to be the tightest in many regions in recent years, but is expected to improve with the restart of nuclear power plants and the restoration of shut down thermal power plants.

The OCCTO, which regulates the supply and demand of electricity nationwide, has so far indicated the reserve rate of electricity supply and demand in Honshu, Shikoku, and Kyushu, assuming a heat wave of about once every 10 years. Was expected to increase from 3.7% to 3.8%.

Although it exceeds the minimum required of 3% for stable supply, it was considered to be the toughest in recent years.

However, in addition to Kansai Electric Power, Mihamagenpatsu Unit 3 located in Fukui Prefecture was supposed to be re-activated during this month, supply from such that the prospect of recovery was standing on was stopped at the trouble Shikoku and Tohoku of thermal power plants The power is expected to increase.

As a result, the reserve margin for this summer, which reflects the latest situation, is expected to improve from the 5% level to the 6% level in Honshu, Shikoku, and Kyushu in July.

In August, TEPCO's jurisdiction and Tohoku Electric Power's jurisdiction will improve slightly to 3.9%, but other regions of Honshu and Shikoku are expected to rise to the 6% level, and Kyushu to the 8% level.

Although the supply and demand of electric power is expected to improve this summer, electric power companies will continue to make every effort to secure a stable supply.

Excerpt

SENATE APPROPRIATIONS COMMITTEE, ENERGY AND WATER DEVELOPMENT SUBCOMMITTEE HEARING REVIEW OF THE FY2022 BUDGET SUBMISSION FOR THE DEPARTMENT OF ENERGY

JUNE 23, 2021

SEN. JOHN KENNEDY, R-LA., RANKING MEMBER

WITNESSES:
JENNIFER GRANHOLM, SECRETARY OF ENERGY

KENNEDY: Thank you, Madam Chair. You can probably guess from my opening comments, Madam Secretary, I see the climate as a discrete scientific issue. I think it's a mistake to approach it with too much emotion. Passion is good, but not when it interferes with your judgment.

I've got a couple of - of 30,000 foot question, feet questions. How much money in public and private dollars does the department think it would make - it would take to make the world carbon neutral?

GRANHOLM: I don't have a number for that, but probably a lot.

KENNEDY: Hundreds of trillions of dollars, do you think?

GRANHOLM: It would be a lot, for sure.

KENNEDY: Okay. How much money, in public and private doctors - dollars, does the department think it would take to make the United States carbon neutral?

GRANHOLM: Again, it would be a lot.

KENNEDY: Hundreds of trillions?

GRANHOLM: I don't know about hundreds of trillions, but it would be a lot of money.

KENNEDY: It'd be in the trillions.

GRANHOLM: Yes.

KENNEDY: Mid trillions.

GRANHOLM: I don't know.

KENNEDY: I understand. Here's my question, to make the United States carbon neutral based on the administration's plans, I think it would be fair to say it's going to cause displacement, major displacement. Now I don't use that in a - in a - in a pejorative sense, I think that's just an accurate description. It's going to change our economy dramatically.

Many people are going to gain - many people are going to lose, and that's what I mean by displacement. If we, today, spent these, to be fair, tens of trillions of dollars that I think many members of the administration would like to spend and make the United States of American carbon neutral and nobody else has our - our aggressive - ups our aggressive approach, and they only make modest gains in CO2 emissions, how much is it going to lower the world temperature and how much is - of it - how much - how much are we going to reduce carbon emissions?

GRANHOLM: I want to say that the administration has a really firm commitment to communities to be able to take advantage of the economic opportunity (inaudible)...

KENNEDY: I know, Madam Secretary. Forgive me for interrupting, but we both know now, I'm - I'm - I'm really - want to try to probe your mind here. We both know this is going to cause major displacement. Let's don't kid each other. You're not going to turn coal miners into coders overnight, and you're not going to turn fossil fuel workers into solar experts overnight, and there not as many solar jobs as there are oil and gas, so I don't want to get off into that.

And I'm not trying to be critical of the administration, but I - these are important questions. If we - if we become carbon neutral and we don't get cooperation from China and India, what have we - what have we accomplished?

GRANHOLM: The goal is to get cooperation from China and India.

KENNEDY: I know, but what if they don't?

GRANHOLM: Well...

KENNEDY: What if we go spend these tens of trillions of dollars in President Xi Jinpiang, the people of China are wonderful people, by the way. President Xi (inaudible), we know that. The Communist Party, they're gangsters. What - what if they - what - I mean, they probably built a coal power - a coal powered power plant while we - you and I have been talking. What have we achieved?

GRANHOLM: The administration has a strategy to make sure that all of our - all of the people who have signed onto this Paris agreement meet the goals that they have articulated, and that means working with allies, and that means...

KENNEDY: I - I get it, I get it.

GRANHOLM: ... (inaudible) strategy...

KENNEDY: And that's fair, but I'm asking a very practical question. My son, who I love dearly, has a strategy to have his dad by him a 9/11 Targa Porsche, it's not going to happen. And I'm raising a very legitimate question, I think. If we spend these trillions of dollars and we go through all this displacement and we don't get cooperation from China and India, what - what -what - is the pain worth the gain, and how do we know?

GRANHOLM: I would say we have a strategy to get those countries on board. And if we don't pursue this strategy, what then? Then you have climate disasters that are upon us. California is now - could be on fire again this summer. And if we don't take action, then where are - where is - where are we with respect to the other disasters. So we have to approach our allies --

(CROSSTALK)

KENNEDY: Let me ask you one last question. I get it. I get it. If I -- if you can indulge me, Madam Chair, if we spent all the money that the Biden administration wants to spend, let's take in its current infrastructure bill to reduce CO2 admissions. What percentage of the increase in carbon admissions worldwide, not the United States, is going to be reduced?

GRANHOLM: The -- all of these countries have signed on. All of them have.

KENNEDY: No, I'm talking about -- I know and you're trusting them.

GRANHOLM: Well, no, verified.

KENNEDY: But I believe -- I believe in metrics.

GRANHOLM: Yes.

https://gazettengr.com/nigeria-accidentally-struck-206-trillion-cubic-feet-of-gas-reserve-minister-sylva/

Nigeria accidentally struck 206 trillion cubic feet of gas reserve: Minister Sylva

The country's transition from gas to renewable fuel will be gradual when it has fully utilised the benefits associated with gas, the minister said.

NEWS AGENCY OF NIGERIA • JUNE 27, 2021

Minister of State for Petroleum, Timipre Sylva

Minister of State for Petroleum, Timipre Sylva, has said that the country accidentally discovered 206 trillion cubic feet of gas reserves while in search of crude oil.

Mr Sylva, disclosed this in Abuja at a News Agency of Nigeria (NAN) forum. He said that the country could discover an additional 600 trillion cubic feet reserve to enable it achieve the desired development required of a gas nation.

"We have a lot of gas in this country. We have 206 trillion cubic feet of gas reserves.

"This number is already discovered in gas reserves and this 206 trillion cubic feet reserve was found while looking for oil, so it was accidentally discovered.

"We were actually going to look for crude oil and we found gas, and in that process of accidentally finding gas, we have found up to 206 tcf.

"So, the belief is that if we really aim to look for gas dedicatedly, we will find up to 600 trillion cubic meters of gas," he said.

The country's transition from gas to renewable fuel will be gradual when it has fully utilised the benefits associated with gas, the minister said.

"We are also transiting and that is why we are talking about gas. We are seeing gas as a bridge to renewable fuels.

"We came from coal which is solid, to crude oil; now we are moving to gaseous gas and then to renewables.

"The belief in the industry is that if we have this kind of vast resource and we have not tapped it, why should we abandon it and move to renewables.

"We have not used gas to drive our cars and few people use it to cook; we have not used gas to generate electricity or used it to fire our fertiliser blending plants, then why should we abandon it and move to renewables.

"What we are saying is that the western countries are in a position to move to renewables after using coal and crude oil to stabilise the electricity in their areas and everybody there enjoys it.

"But we have a situation in Nigeria where a lot of people do not have access to electricity yet.

"So, what we are saying is that we agree to transit but let us use our gas first to develop our country and get the benefits of development, that point where everybody has electricity, then we can transit to renewable fuel," he added.

Mr Sylva explained that so far gas was being used as a transition fuel, as Nigeria and Africa as a continent does not contribute more than one per cent of global warming as carbon emission.

SAF

Dan Tsubouchi @Energy_Tidbits · 2h

Here is #COP26 problem for US, EU, CAN & all developed countries pushing the ROW to commit to #NetZero. Nigeria won't be alone. Look at list of Top 20 countries by population. Who will give the $ trillions needed to get them to sign on, even a partial sign on? #EnergyTransition

Top 20 Most Populous Countries

Rank	Country	Populaton 2020	World Share
1	China	1,439,323,776	18.47%
2	India	1,380,004,385	17.70%
3	United States	331,002,651	4.25%
4	Indonesia	273,523,615	3.51%
5	Pakistan	220,892,340	2.83%
6	Brazil	212,559,417	2.73%
7	Nigeria	206,139,589	2.64%
8	Bangladesh	164,689,383	2.11%
9	Russia	145,934,462	1.87%
10	Mexico	128,932,753	1.65%
11	Japan	126,476,461	1.62%

Dan Tsubouchi @Energy_Tidbits · 3h

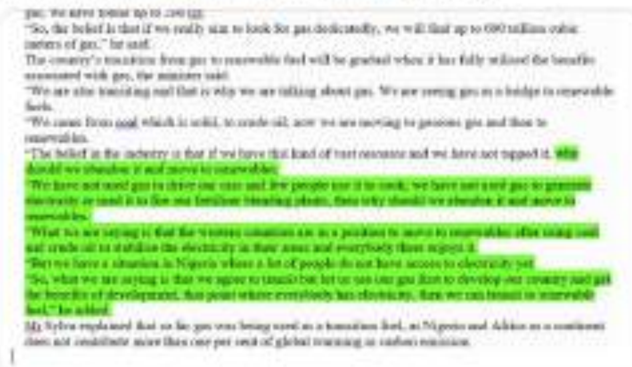
Reinforce why #COP26 can't/won't get developing countries to sign up onto #NetZero & #EnergyTransition. Nigeria says okay for western countries who are in position to use renewables, but are moving first to #NatGas before can transit to ...

3 2

SAF

Dan Tsubouchi @Energy_Tidbits · 3h

Reinforce why #COP26 can't/won't get developing countries to sign up onto #NetZero & #EnergyTransition. Nigeria says okay for western countries who are in position to use renewables, but are moving first to #NatGas before can transit to #RenewableEnergy. Thx @chigrl for flagging



Tracy (Chi) @chigrl · 5h

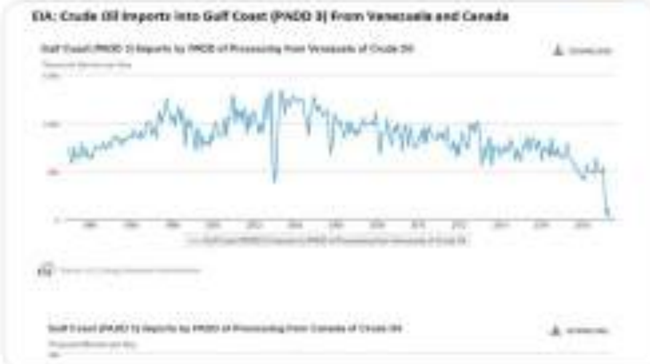
#Nigeria accidentally struck 206 trillion cubic feet of #gas reserve: Minister Sylva

gazettengr.com/nigeria-accide...

1 3

Dan Tsubouchi @Energy_Tidbits · Jun 26

2/2. Doubt Cdn #OilSands #Oil sector finds this ironic. but Cdn heavy/medium oil filled void in #PADD3 from less VEN oil. Removal of sanctions should see mid term VEN oil fill void that #KeystoneXL would have delivered to PADD 3. Negative to mid term Cdn heavy medium oil. #OOTT



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Dan Tsubouchi @Energy_Tidbits · Jun 26

1/2. Negative to mid term Cdn #Oil exports to Gulf Coast. US lowers bar for VEN #Maduro sanctions removal ie. no longer insist Maduro goes. US creates EU/CAN peer group when wasn't one, provides cover & higher probability to sanctions removal by US. #OOTT

U.S.-EU-Canada: Joint Statement on Venezuela - United States Depart...

The following statement was released by Secretary of State Antony J. Blinken, the EU High Representative for Foreign Affairs and Security ...

state.gov

3 5 5

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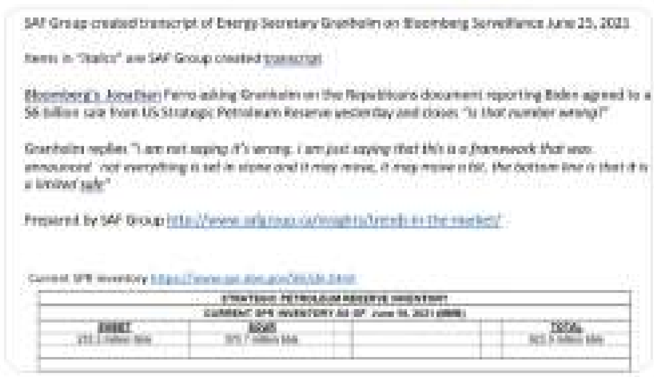
Dan Tsubouchi @Energy_Tidbits · Jun 25

Support for summer #LNG prices. @JMA_bousai updated Japan July-Sept ave temp forecast still calls for warmer than normal summer. #TokyoOlympics starts July 23, even without foreign spectators, should add some more than usual power demand. #NatGas
jma.go.jp/bosai/map.html...

1

Dan Tsubouchi @Energy_Tidbits · Jun 25

Strategic Petroleum Reserve sale likely closer to $7b than $6b? @FerroTV asks @SecGranholm if Republicans $6b is right? Granholm didn't say its wrong, not set in stone and may move a bit. Political speak for yes to $6b, but now we have to change it because they leaked it. #OOTT



SAF Group created transcript of Energy Secretary Granholm on Bloomberg Surveillance June 25, 2021

Items in "italics" are SAF Group created transcript

Bloomberg's Jonathan Ferro asking Granholm on the Republicans document reporting Biden agreed to a $6 billion sale from US Strategic Petroleum Reserve yesterday and closes *"is that number wrong?"*

Granholm replies *"I am not saying it's wrong. I am just saying that this is a framework that was announced. not everything is set in stone and it may move, it may move a bit. the bottom line is that it is a limited sale"*

Prepared by SAF Group https://www.safgroup.ca/insights/trends-in-the-market/

Current SPR inventory [illegible]

STRATEGIC PETROLEUM RESERVE INVENTORY			
CURRENT SPR INVENTORY AS OF [illegible] 2021 (MMB)			
SWEET	SOUR		TOTAL
[illegible] million bbls	[illegible] million bbls		[illegible] million bbls

1 4

Dan Tsubouchi @Energy_Tidbits · Jun 25

old news but good news. apparently he has said this before today. and it's to buy a round and obviously for over 21. but still who doesn't want to get a free round from @AnheuserBusch?

> **Dan Tsubouchi** @Energy_Tidbits · Jun 25
> Free #Beer.. did you just hear @AnheuserBusch CEO tell @BeckyQuick on @SquawkCNBC that they will give a free beer to everyone if US hits @POTUS July 4 vaccination rate?

SAF

Dan Tsubouchi @Energy_Tidbits · Jun 25

Free #Beer. did you just hear @AnheuserBusch CEO tell @BeckyQuick on @SquawkCNBC that they will give a free beer to everyone if US hits @POTUS July 4 vaccination rate?

1 2

SAF

Dan Tsubouchi @Energy_Tidbits · Jun 24

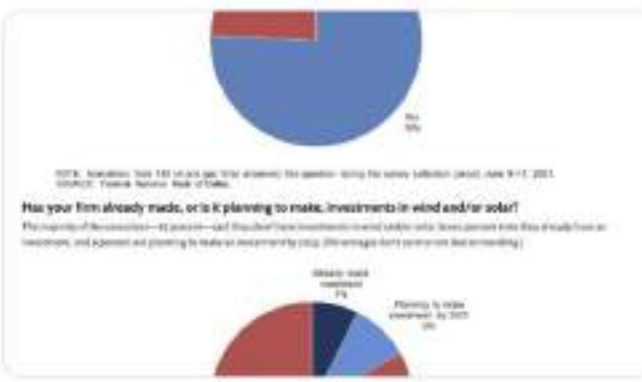
#Gasoline prices. just filled up in #Calgary Husky station. don't recall the lower grades last week but the 91 octane jumped up to $155.9 a litre a week ago.

2 1

SAF

Dan Tsubouchi @Energy_Tidbits · Jun 24

#OilSupplyGap, 76% of 101 E&P + 51 OFS respondents to @DallasFed survey see oil supply gap in next 2-4 yrs. No wonder, 83% don't plan #Wind #Solar investments. No surprise, >$70 #Oil & >$3 #NatGas prices drive highest 6-mth outlook reading in survey 5-yr history. #OOTT



Dallas Fed @DallasFed · Jun 23

Energy Survey: Oil and Gas Activity Continues Expanding; Outlook Improves Further

The business activity index remained elevated at 53.0, essentially unchanged from its first-quarter reading.

dallasfed.org/research/surve...

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1 3

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Dan Tsubouchi @Energy_Tidbits · Jun 24

Is this a reality check forecast by #CNPC for #NatGas to reach 12% of CN energy mix by 2030 vs CN 15% target? or set up for US/EU #COP26 negotiators to get a "win" by getting CN to stay firm to existing 15%? Surely CNPC didn't step out on limb here. Hmmm! #LNG #EnergyTransition

Reuters Business @ReutersBiz · Jun 24

China to use more natural gas in energy mix to 2035 - CNPC reut.rs/3wTpiUR

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Dan Tsubouchi @Energy_Tidbits · Jun 23

US can't control what CN IN actually spend to be #CarbonNeutral, but politics aside, shouldn't #Biden admin have a rough estimate of how many $trillions to get US to carbon neutral? How can anyone say #EnergyTransition won't cost more? #NatGas #OOTT

Kennedy Presses Granholm: What If We Don't Get ...
During today's Senate Appropriations Committee hearing, Sen. John Kennedy (R-LA) pressed Energy ...
youtube.com

2

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Dan Tsubouchi @Energy_Tidbits · Jun 23

For those not near their laptop. @EIAgov weekly #Oil #Gasoline #Distillates inventory data for week ended June 18 just out. Note gasoline had a draw vs expectations of build. Prior to release, WTI was $73.77 #OOTT
ir.eia.gov/wpsr/overview...

Oil/Products Inventory June 18: EIA, Bloomberg Survey Expectations, API

(million barrels)	EIA	Expectations	API
Oil	-7.61	-3.50	-7.20
Gasoline	-2.93	1.05	0.96
Distillates	1.75	1.00	0.99
	-8.79	-1.45	-5.25

Note:In addition, SPR draw of 1.7 mmb for June 18 week
Note: Cushing had a draw of 1.83 mmb for June 18 week
Source EIA, Bloomberg
Prepared by SAF Group

Dan Tsubouchi @Energy_Tidbits · Jun 23

Thx Greg. #OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Jun 23
>
> Note, my partner warns "Producers do not buy WTI contracts to hedge they're short delta on the calls they sold; they simply sell their production at the higher prices and take the hedging loss. If anything, the dealers who are long the calls are selling delta into higher prices" twitter.com/Energy_Tidbits...

4

Dan Tsubouchi @Energy_Tidbits · Jun 23

Note, my partner warns "Producers do not buy WTI contracts to hedge they're short delta on the calls they sold; they simply sell their production at the higher prices and take the hedging loss. If anything, the dealers who are long the calls are selling delta into higher prices"

> **Dan Tsubouchi** @Energy_Tidbits · Jun 23
>
> US #Shale oil produces need to monetize physical barrels to cover mark-to-market hedge losses. Always good to hear #Oil trader/shipper perspective. Thx #Euronav Rustin Edwards for reminder and @gulf_intel for usual good Daily Silk Road "Live". #OOTT twitter.com/Energy_Tidbits...
>
> SAF Group created transcript of Gulf Intelligence Daily Silk Road "Live" Podcast June 23, 2021, Excerpt comments
> Rustin Edwards, Head, Fuel Oil Procurement, Euronav NV [illegible]
>
> Items in "italics" are SAF Group created transcript
>
> At 16:20 min mark, Edwards "*well, I actually think we'll start seeing increases in US production this week again. US production had a moderate increase in production of 11.2, my call is that we'd see 11.3, maybe 11.4. I think 11.5 [illegible] week. A lot of that can be looked at what happened on options expiry in the United States. You know a lot of shale producers, they hedge with zero cost collars. So they're basically buying the put and selling the call option. As the [illegible] option goes into expiry, they have to cover their delta, so they have to buy the future to cover that short call positio[illegible] we saw at the expiry of WTI, there were massive inflows to the buy side of the TI contracts going into expiry. We s[illegible] price rallies on New York state open, sorry New York market open, which was indicating of that [illegible] coverage that going on. so the only way that shale producer can offset that loss on the future is to actually produce the oil, they [illegible] monetize that physical barrel against that mark to market loss in their call options. So that's why I think we'll start seeing more impetus on the shale producers to get barrels out of the ground into the market place because they w[illegible] cover that loss.*"
>
> Prepared by SAF Group [illegible]

2 8

Dan Tsubouchi @Energy_Tidbits · Jun 23

3/3. #LNGSupplyGap is delay driven. $TOT Mozambique Phase 1 delay has chain effect, backs up 5 bcf/d. See SAF Group Apr 28 blog Multiple Brownfield LNG FIDs Now Needed To Fill New #LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2? #NatGas safgroup.ca/insights/trend...


SAF

Blog Summary

Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

3

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Dan Tsubouchi @Energy_Tidbits · Jun 23

2/3. Adding 4.3 bcf/d is big, but dwarfed by items like India. #Petronet gave 1st specific forecast for what it means if #NatGas is to be 15% of energy mix by 2030 - India will need to increase #LNG imports by ~13 bcf/d. See SAF Group June 20 Energy Tidbits memo.

1 1

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Dan Tsubouchi @Energy_Tidbits · Jun 23

1/3. #LNGSupplyGap coming. big support for @qatarpetroleum expansion to add 4.3 bcf/d LNG. but also say "there is a lack of investments that could cause a significant shortage in gas between 2025-2030" #NatGas #LNG

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Dan Tsubouchi @Energy_Tidbits · Jun 23

US #Shale oil produces need to monetize physical barrels to cover mark-to-market hedge losses. Always good to hear #Oil trader/shipper perspective. Thx #Euronav Rustin Edwards for reminder and @gulf_intel for usual good Daily Silk Road "Live". #OOTT

Dan Tsubouchi @Energy_Tidbits · Jun 18

Why more #Oil growth in 22. Hedge losses in 2021/hedges roll off for 2022. Another 3-6 mths of strong oil & stock prices & protected dividends, E&P will be still be cashed up & investors won't object to moving off Covid survival plans & more capital ...

1 5 18

Dan Tsubouchi @Energy_Tidbits · Jun 23

#JCPOA. Is only been an hour but Brent hasn't moved, still $75.60. Thx @NBCNews @aliarouzi #OOTT

Ali Arouzi @aliarouzi · Jun 23

Rouhani's Chief of staff just said that 'lifting of economic sanctions on Iran has been agreed in Vienna.
More than 1,040 sanctions imposed on Iran during Trump era will be lifted including sanctions on people within Supreme leader's compound & other individuals & institutions'.

2

Dan Tsubouchi @Energy_Tidbits · Jun 22

was watching the is local #Calgary deer feast on our backyard flowers and she moved to the front to keep eating. she ended up crossing the street but cars stopped to let cross.

4 2

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Dan Tsubouchi @Energy_Tidbits · Jun 22

3/3 going to be in a situation where demand has not only recovered, but that is stronger than where it was. and you don't have that capacity anymore that you are really going to need other than maybe as a little bit of a buffer." Note @ManusCranny set up question below. #OOTT

5 11

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Dan Tsubouchi @Energy_Tidbits · Jun 22

2/3. "that you have been seeing now, since 2014' So this has now been going for a better part of a decade. And to me, this is something where the market is slowly realizing that even with all the spare capacity that OPEC currently has off the market, that eventually you ... #OOTT

1 2 6

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Dan Tsubouchi @Energy_Tidbits · Jun 22

1/3. Why #Oil to $100 by #Trafigura @saadrahim. Concerns absorbed by market ie. OPEC spare capacity, inflation, floating oil storage down, etc. Demand moved from China & manufacturing led to US/EU led, services led. "really been a question of structural underinvestment ... #OOTT

1 9 21

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Dan Tsubouchi @Energy_Tidbits · Jun 21

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hard to believe 8 yrs ago the #Calgary Elbow River was prob 15 ft higher. other side is lower so had 4 ft of main floor flooding. we only had 10 ft of flooding so only lost basement.

1 · 1 · 8

Dan Tsubouchi @Energy_Tidbits · Jun 21

SAF

Good Monday morning #Oil data point to note. @Vortexa crude oil floating storage. 88.11 mmb at 06/18, -9.40 mmb WoW and -121.34 mmb YoY. Still up vs pre Covid, but a demand recovery of 1 mmb/d wipes that out very quickly. Positive for #Oil. Thx @Vortexa @TheTerminal #OOTT

Crude Oil Floating Storage & Brent Price

Date	Vortexa Crude Oil Floating Storage (million barrels)	Brent $/b
06/18/2021	88.1	$73.51
06/19/2020	209.5	$42.19
06/12/2019	50.0	$56.84
06/29/2018	49.5	$75.44
06/30/2017	64.9	$46.91

Source: Bloomberg, Vortexa

Prepared by SAF Group

Global Crude Oil Floating Storage – Vortexa Ltd

3 · 12

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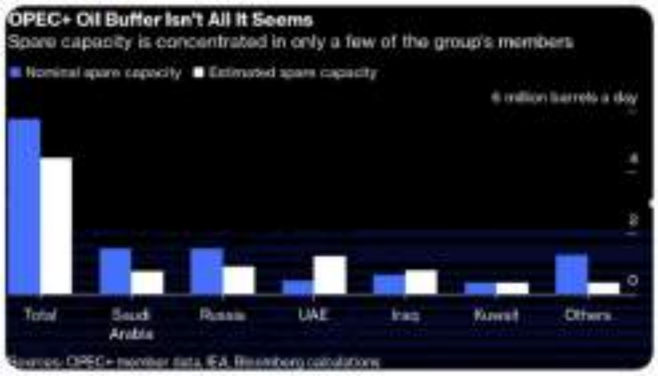
Dan Tsubouchi @Energy_Tidbits · Jun 20

Overlooked bullish #Oil factor. A must read is @JLeeEnergy weekly @bopinion piece, he estimates #OPEC+ true spare capacity is probably closer to 4.5 mmb/d, rather then 5.8 mmb/d suggested in Declaration of Cooperation. #OOTT



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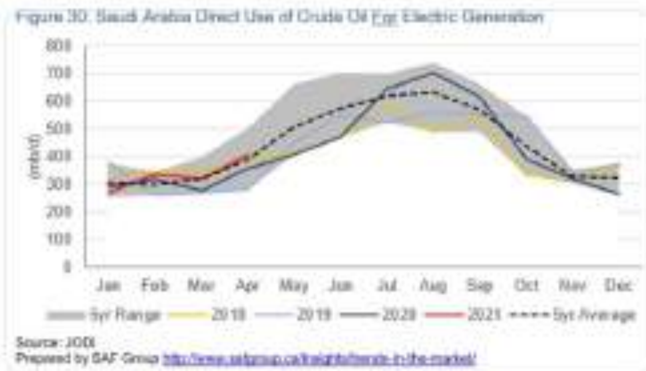
SAF

Dan Tsubouchi @Energy_Tidbits · Jun 20

Reminder, just moving into peak seasonal period for Saudi using #Oil for electricity every summer. Can use an additional ~300,000 b/d from April to summer peak. Below is graph incl @JODI_Data from SAF Group June 20, 2021 Energy Tidbits memo. safgroup.ca/insights/trend… #OOTT



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Dan Tsubouchi @Energy_Tidbits · Jun 20

Positive for #LNG. #Petronet's fcast for India #NatGas consumption & #LNG imports in 2030 is the 1st specific India forecast to what it means if #NatGas is 15% of India's energy mix. Here is the write up from SAF Group June 20, 2021 Energy Tidbits memo posted earlier today.

Dan Tsubouchi @Energy_Tidbits · Jun 18

1/3. #LNGSupplyGap is coming in 2020s. #Petronet reminds India target #NatGas to be 15% of energy mix by 2030. Means consumption 5.5 to 22.6 bcf/d, #LNG imports <3 to 15.8 bcf/d in 2030. Assumes India can reverse declining production and can grow <3 to 6.8 ...

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Dan Tsubouchi @Energy_Tidbits · Jun 20

Bit of a rocky start, but @MacHughesGolf just birdied 7 to get back to -3. How can this not be an amazing experience to have in his back pocket going forward. Look at the leaderboard, he is fighting hard, right in the mix among a pretty impressive leaderboard.

Leaderboard — Live

Pos.	Player	R4	Thru	Total
1	B. DeChambeau	-2	8	-5
T2	C. Morikawa	-3	11	-4
T2	R. McIlroy	-1	8	-4
T2	L. Oosthuizen	+1	7	-4
T5	M. Hughes	+2	8	-3
T5	B. Koepka	-3	11	-3
T5	J. Rahm	-1	8	-3

1 · 6

Dan Tsubouchi @Energy_Tidbits · Jun 20

Our weekly SAF June 20, 2021 Energy Tidbits memo was just posted to our SAF Group website. This 47-pg energy research piece expands upon and covers many more items than tweeted this week. See the research section of the SAF website. #Oil #OOTT #OPEC #LNG safgroup.ca/insights/trend…

SAF

Energy Tidbits

June 20, 2021

Produced by: Dan Tsubouchi

Will Biden Push For His Moon Shot JCPOA Deal Before Wildcard Raisi Takes Over As Iran President in August?

Welcome to new Energy Tidbits memo readers. We are continuing to add new readers to our Energy Tidbits memo, energy blogs and tweets. The focus and concept for the memo was set in 1999 with input from PMs, who were looking for research (both positive and negative items) that helped them shape their investment thesis to the energy space, and not just focusing on daily trading. Our priority was and still is to not just report on events, but also try to interpret and point out implications therefrom. The best example is our review of investor days, conferences and earnings calls focusing on sector developments that are relevant to the sector and not just a specific company results.

2 2