Energy Tidbits

February 19, 2023

Produced by: Dan Tsubouchi

Shell Working Hard Right Now/Progressing LNG Canada Phase 2 FID Hard Right Now, But Don't Think Will Come This Year

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. Our target is to write on 48 to 50 weekends per year and to post by noon MT on Sunday. The Sunday noon timing was because PMs said they didn't have research to read on Sundays and Sundays are a day when they start to think about the investing week ahead.

This week's memo highlights:

1. Shell says it's working hard right now and progressing LNG Canada 1.8 bcf/d Phase 2 FID, but don't think will come this year (Click Here)

2. Shell's LNG Outlook 2023, mgmt. says "a clear [LNG] supply-demand gap is opening up, which has actually started earlier than the presentation we showed this time last year." (Click Here)

3. Russia pipeline exports to EU down 7.9 bcf/d YoY in 2022, down~15 bcf/d in Nov/Dec vs 2019, Gazprom must expect a lot of this to be long lasting as they are looking to build major new export pipelines to Asia (Click Here)

4. Antero Resources "*With this being the first downward price cycle in which the Haynesville is the marginal supplier. This would suggest a more rapid supply response following and expected decline and rigs.*" (Click Here)

5. No peak oil demand in sight, IEA Oil Market Report "*Global oil demand is set to rise by 1.9 mb/d in 2023, to a record 101.7 mb/d*" (Click Here)

6. Pease follow us on Twitter at [LINK] for breaking news that ultimately ends up in the weekly Energy Tidbits memo that doesn't get posted until Sunday noon MT.

7. For new readers to our Energy Tidbits and our blogs, you will need to sign up at our blog sign up to receive future Energy Tidbits memos. The sign up is available at [LINK].

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Natural Gas – 100 bcf draw in US gas storage; now 328 bcf YoY surplus

YoY storage at 328 bcf YoY surplus

Last week we noted that it was a colder than normal the last week of Jan running into the start of Feb resulting in a draw of -217 bcf for the week of Feb 3. This week it was warmer which led to a widened YoY surplus vs last week. So for the week of Feb 10, the EIA reported a -100 bcf draw (vs expectations of -108 bcf), a -47% decrease from the -190 bcf draw reported for the week of Feb 10 last year. This compares to last weeks draw of -217 bcf, and the 5-year average draw of -166 bcf. Total storage is now 2.266 tcf, representing a surplus of +328 bcf YoY compared to a deficit of -370 bcf last year and is +183 bcf above the 5-year average vs +117 bcf above last week. Below is the EIA's storage table from its Weekly Natural Gas Storage Report [LINK].

Figure 1: US Natural Gas Storage

	Stocks billion cubic feet (Bcf)				Year ago (02/03/22)		5-year average (2018-22)	
Region	02/03/23	01/27/23	net change	implied flow	Bcf	% change	Bcf	% change
East	529	578	-49	-49	493	7.3	513	3.1
Midwest	641	708	-67	-67	561	14.3	600	6.8
Mountain	120	132	-12	-12	123	-2.4	128	-6.3
Pacific	124	140	-16	-16	183	-32.2	206	-39.8
South Central	951	1,025	-74	-74	774	22.9	803	18.4
Salt	271	297	-26	-26	210	29.0	236	14.8
Nonsalt	680	728	-48	-48	563	20.8	567	19.9
Total	2,366	2,583	-217	-217	2,133	10.9	2,249	5.2

Source: EIA

Natural Gas – AGA heating degree days, warm start to Feb

Week ending Feb 11 was 19.5% warmer than normal

HH gas prices fell below $3 on Jan 25 and continue to languish. Last week's (Feb 12, 2023) Energy Tidbits memo highlighted NOAA's ranking January 2023 was the 6th warmest in the last 129 years. Every Monday, the AGA issues the weekly heating degrees data for the week ended the prior Saturday. In this case, it was the HDD data for the week ended Feb 11, which was 19.5% warmer than normal and 12.9% warmer YoY. January was warm every week except for the last week (AGA's weeks that end on Saturday) Jan 29-Feb 4 which was 10.6% below normal and 3.9% below last year. But that was only colder than normal week in Jan and Feb to date. Last week's (Feb 12, 2023) Energy Tidbits noted the AGA data showing January was 18.1% warmer than normal and 19.1% warmer than Jan 2022. Our Supplemental Documents package includes the full AGA HDD recap. [LINK]

Natural Gas – Feb is almost as significant as Jan for winter natural gas demand

Feb is a big month for natural gas demand

Warm weather in February is never good. On Tuesday, we tweeted [LINK] "*Never good for #NatGas when it's this warm in Feb, which is the 2nd most important winter month for temperature driven #NatGas consumption. See 👇excerpt Jan 8/23 Energy Tidbits memo. Feb res/com10-yr ave 43.4 bcf/d or 22% of winter season. Jan is 46.7 bcf/d, & 23%. #OOTT".* Just like January, warm weather in February is never good. On Jan 7, we tweeted [LINK] on the below data on why temperature is key for winter natural gas demand and prices. It's why warm weather in the winter, especially in Jan, is never a positive for natural gas prices, but also the same for Feb. There can be huge swings in residential/commercial natural gas demand depending if it's hot, normal, or cold. The different between a hot and cold month can be almost 500 bcf in a month. Below is a table we have previously posted

that shows these swings. It shows AGA heating degree days vs US total natural gas consumption and US residential/commercial natural gas consumption. (i) Residential/commercial demand is normally >40% of total US natural gas consumption in DJF. (ii) For the last 10 year average, Jan was 46.7 bcf/d, Feb 43.4 bcf/d, and Dec 38.0 bcf/d. (iii) The high to low swings for Dec can be up to 12.6 bcf/d, Jan can be up to 9.8 bcf/d, and Feb can be up to 17.2 bcf/d. (iv) The biggest months over the past 10 winters were Jan 2014 at 51.9 bcf/d, Feb 2015 at 50.9 bcf/d, and then Dec 2017 at 49.5 bcf/d.

Figure 2: US Winter Natural Gas Consumption vs Heating Degree Days

US Winter Natural Gas Consumption vs Heating Degree Days

Heating Degree Days By Month

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	10 Year Average	
	HDDs	HDDs	HDDs	HDDs	HDDs	HDDs	HDDs	HDDs	HDDs	HDDs	HDDs	HDDs	%
Oct	308	303	265	257	200	218	306	307	308	205	332	280	7%
Nov	572	623	658	484	459	542	650	636	469	539	597	569	14%
Dec	763	920	763	649	856	873	789	778	804	696	876	807	20%
Jan	918	1,019	967	935	843	963	941	808	899	1005		921	23%
Feb	795	903	955	718	597	699	810	760	896	790		793	20%
Mar	827	831	738	511	618	660	804	555	572	638		680	17%
Oct 1 - Mar 31	4,183	4,599	4,346	3,554	3,573	3,955	4,300	3,844	3,948	3,873	1,805	4,050	100%

Note: Oct includes Sept if applicable. March includes Apr if applicable.

Source: AGA, SAF

Total US Consumption

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	10 Year Average	
	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	%
Oct	61.3	60.2	61.7	64.3	62.1	65.5	73.7	75.1	74.9	73.0	76.4	67.2	13%
Nov	72.3	77.2	78.6	75.2	72.1	78.6	90.5	92.6	81.3	89.8		80.8	15%
Dec	80.8	94.0	86.4	83.6	92.5	99.5	96.8	101.6	101.9	97.0		93.4	18%
Jan	92.8	103.4	100.5	100.0	93.3	107.8	110.0	106.3	106.0	115.9		103.6	20%
Feb	91.6	97.9	104.5	91.8	82.9	96.8	107.5	108.3	108.5	109.3		99.9	19%
Mar	81.3	82.5	83.6	76.3	81.1	90.2	93.8	87.4	84.1	89.8		85.0	16%
Average	**80.0**	**85.9**	**85.9**	**81.9**	**80.7**	**89.7**	**95.4**	**95.2**	**92.8**	**95.8**	**76.4**	**88.3**	100%

Source: EIA, SAF

US Residential & Commercial Demand

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	10 Year Average	
	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	bcf/d	%
Oct	14.6	13.9	13.4	12.8	12.2	13.1	15.9	14.4	14.4	12.6	15.1	13.7	7%
Nov	26.3	28.8	30.2	23.0	22.0	26.3	32.8	32.6	24.4	27.3		27.4	14%
Dec	34.2	43.0	36.9	30.4	40.5	42.2	39.5	39.0	40.1	34.5		38.0	19%
Jan	47.0	51.9	47.4	45.0	42.4	49.5	48.6	42.2	44.1	48.8		46.7	23%
Feb	42.3	48.0	50.9	38.4	33.7	39.8	45.7	42.0	48.2	45.1		43.4	22%
Mar	34.3	36.2	33.1	24.4	30.8	34.8	35.9	27.8	29.7	31.5		31.8	16%
Average	**33.1**	**37.0**	**35.3**	**29.0**	**30.3**	**34.3**	**36.4**	**33.0**	**33.5**	**33.3**	**15.1**	**33.5**	100%

Source: EIA, SAF

Data source EIA Natural Gas Monthly

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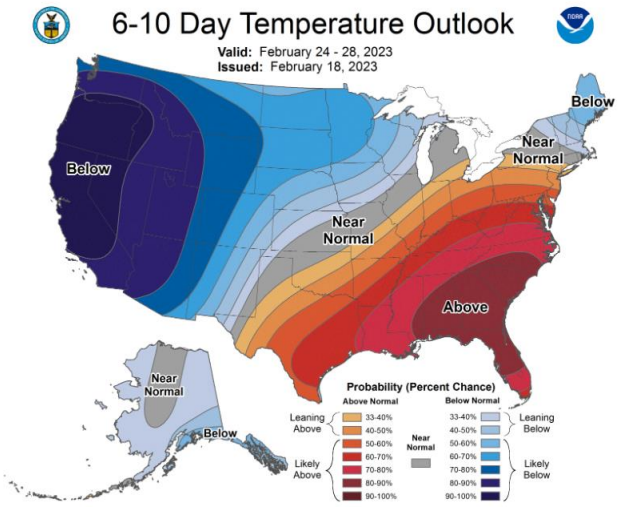
Source: EIA, AGA, SAF

Natural Gas – NOAA still doesn't see cold in most of the populous eastern US

NOAA 6-10 & 8-14 day temp outlook

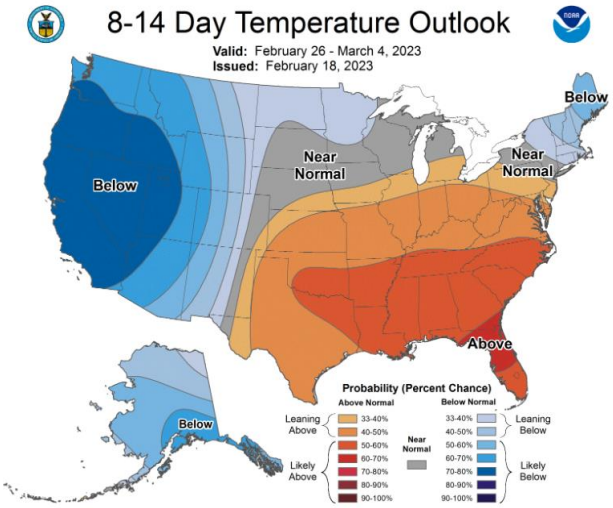
Yesterday, we tweeted [LINK] *"unfortunately for #NatGas, updated @NOAA 6-10, 8-14 day temperature probability forecasts thru March 4 still don't show colder than normal temps across all the US. #OOTT."* The problem for natural gas is that the forecasts for colder than normal tempeatures still miss most of the populous east. Our tweet yesterday included NOAA's below Feb 18 updated 6-10 day and 8-14 day outlook that run up thru March 4.

Figure 3: NOAA 6-10 day temperature outlook as of Feb 18



Source: NOAA

Figure 4: NOAA 8-14 day temperature outlook as of Feb 18



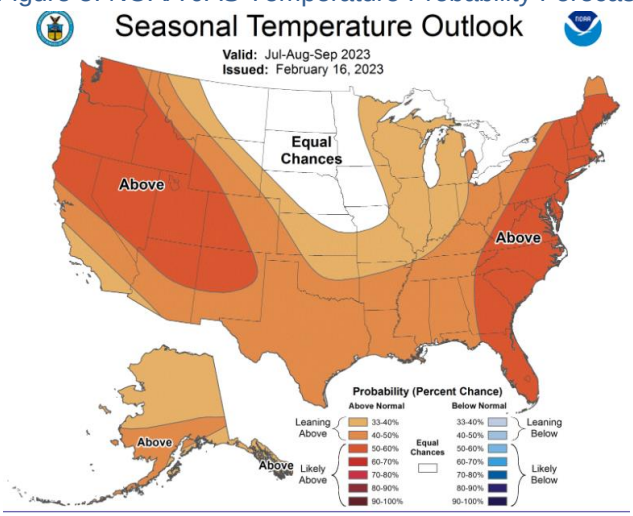
Source: NOAA

Natural Gas – NOAA's early look is warmer than normal summer in the US

We recognize that weather forecasts, even near term, are far from 100%, but, on Thursday, NOAA released its monthly update to its seasonal temperature forecasts. It is still early but the outlook for the summer JAS [LINK] calls for warmer than normal temperatures across almost all of the US. This would be supportive of natural gas prices. Below is NOAA's Feb 16 temperature probability map for JAS.

NOAA forecasts hot summer

Figure 5: NOAA JAS Temperature Probability Forecast

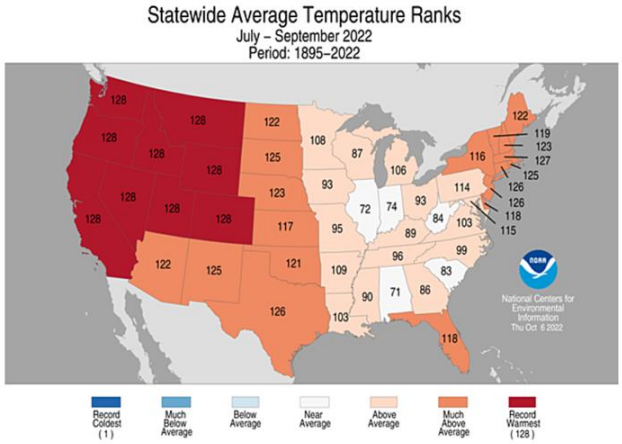


Source: NOAA

But JAF 2023 will be comped vs JAF 2022 hottest summer on record in the US

A warm summer 2023 will be supportive of natural gas but the weather driven element of natural gas demand will be less YoY vs summer 2022 because summer 2022 was the hottest summer on record. Here is what we wrote in our Oct 16, 2022 Energy Tidbits memo. "*It was an excellent summer for weather related natural gas demand in the US. It couldn't' be better. On Thursday, NOAA issued its recap of US climate for September. September was the 5th hottest in the 128-years of recording [LINK],. And July-September was the hottest summer on record. [LINK]. Below are graphics depicting the state average temperature ranks for September and for July-September."*

Figure 6: US Statewide Average Temperature Ranks July – September 2022



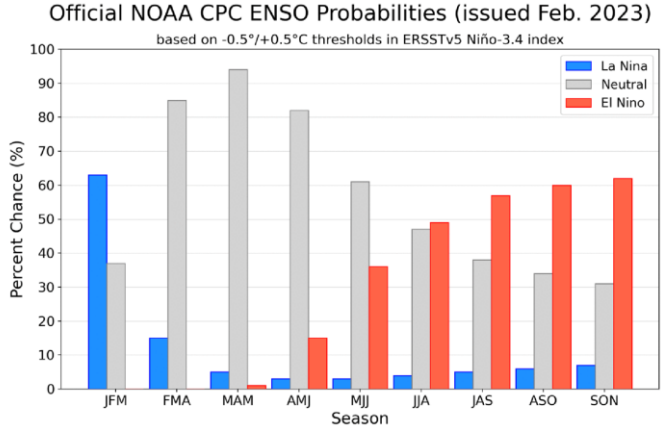
Source: NOAA

Natural Gas – NOAA sees 60% probability for El Nino conditions during Aug/Sept/Oct

La Nina/El Nino focus to turn to summer

Last Thursday, NOAA posted the updated monthly El Nino/La Nina outlook, which is issued on the 2nd Thurs of every month [LINK]. The major part of winter is over so the El Nino/La Nina focus shifts to the summer and to hurricane season. The probability forecast is 60% chance for El Nino conditions in the peak hurricane months of Aug/Sept/Oct. However, the qualifier is said by NOAA that forecasting El Nino/La Nina conditions for the summer is difficult ahead of the spring. NOAA writes "*There are increasing chances of El Niño at longer forecast horizons, though uncertainty remains high because of the spring prediction barrier, which typically is associated with lower forecast accuracy*." Again, weather is never 100% the same, but El Nino summers are normally associated with low Atlantic hurricane seasons, whereas neutral/La Nina conditions are more likely normal hurricane seasons. Below is the NOAA CPC ENSO Feb update.

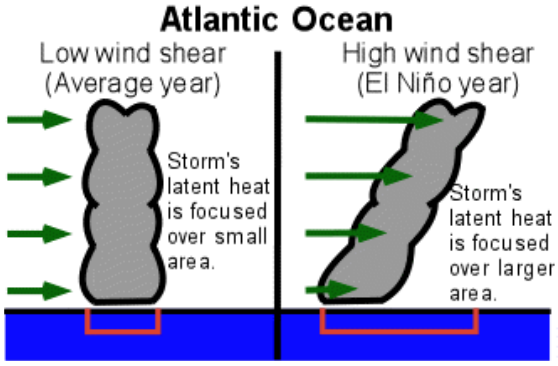
Figure 7: Early Feb NOAA CPC ENSO El Nino/La Nina Outlook



Source: CPC/IRI

El Nino years tend to be low Atlantic hurricane years. Our prior Energy Tidbits over the years/decades noted that "*The hurricane forecasters note that warm El Nino years tend to have less hurricane activity in the Atlantic and Gulf of Mexico, but typically more hurricane activity in the Pacific. The primary explanation for the decline in hurricane frequency during El Niño years is due to the increased wind shear in the environment. It is commonly explained that "In El Niño years, the wind patterns are aligned in such a way that the vertical wind shear is increased over the Caribbean and Atlantic. The increased wind shear helps to prevent tropical disturbances from developing into hurricanes. In the eastern Pacific, the wind patterns are altered in such a way to reduce the wind shear in the atmosphere, contributing to more storms*". This is the common explanation, and we referenced the University of Illinois's description because they also had a good simple graphic (see below). We double checked the link this week, and it is still active after more than a decade, the University of Illinois explanation is found at: [LINK]

Figure 8: Early-March NOAA El Nino/La Nina Outlook



Source: University of Illinois

Natural Gas – EIA, US shale/tight natural gas forecast +5.0% or +4.859 bcf/d YoY in Mar

Shale/tight gas production

Warm start to winter aside, the biggest negative to HH prices continues to be the very strong growth in US natural gas production driven by the major shale/tight plays. Remember that the top US shale/tight oil plays are oil wells that produce associated NGLs and natural gas. EIA's Drilling Productivity Report Feb 2023 was released on Tuesday, and the key takeaway is that Mar 2023 would be the 11th consecutive month of growth for US shale/tight natural gas, albeit the last few have been more modest MoM growth but growth, nonetheless. The DPR [LINK] is the EIA's forecast for oil and natural gas production from the major shale/tight oil and gas basins for the current month (in this case Feb) and the next month (in this case Mar). (i) Shale/tight natural gas is forecasted to have 11 months of consecutive growth and has been breaking out since April, as increasing US LNG export capacity out of the Gulf Coast is driving natural gas growth in Louisiana and Texas. US shale/tight natural gas was 90.105 bcf/d in April and Feb is forecasted to be 96.165 bcf/d (96.656 bcf/d previously) with Mar production forecasted to be 96.591 bcf/d. (ii) MoM. The largest increases came from Eagle Ford (+0.190 bcf/d MoM), Haynesville (+0.131 bcf/d MoM), Permian (+0.097 bcf/d MoM) and

Appalachia (+0.080 bcf/d MoM). (iii) Total US shale/tight natural gas production is expected +4.859 bcf/d YoY for Mar. All shale/tight plays are up YoY, with the most notable YoY increases being Haynesville +2.177 bcf/d YoY, Permian +2.049 bcf/d YoY, and Eagle Ford +1.134 bcf/d YoY; with Haynesville and Permian acting as key shale/tight plays feeding growth US LNG exports. (iv) Remember US shale/tight gas is ~90% of total US natural gas production. So, whatever the trends are for shale/tight gas are the trends for US natural gas in total. Below is our running table showing the EIA DPR data for the shale/tight gas plays, and the MoM changes in major shale/tight natural gas production. Our Supplemental Documents package includes the EIA DPR.

Figure 9: MoM Change – Major Shale/Tight Natural Gas Production

mmcf/d	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Mar YoY	Mar YoY %	Mar less Feb
Anadarko	6,286	6,118	6,134	6,275	6,554	6,658	6,715	6,708	6,832	6,997	6,981	6,876	6,908	622	10%	32
Appalachia	36,298	35,443	35,476	35,155	35,121	35,332	35,486	35,577	35,434	35,417	35,279	35,018	35,098	-1,200	-3%	80
Bakken	3,079	2,932	3,076	3,088	3,086	2,915	3,191	3,156	3,246	3,323	3,308	3,160	3,191	112	4%	31
Eagle Ford	6,288	6,298	6,394	6,538	6,671	6,985	7,101	7,220	7,311	7,390	7,365	7,232	7,422	1,134	18%	190
Haynesville	14,425	14,527	14,863	15,023	15,261	15,643	15,835	15,878	16,083	16,257	16,440	16,471	16,602	2,177	15%	131
Niobrara	5,196	5,254	5,187	5,195	5,205	5,212	5,223	5,062	5,074	5,124	5,211	5,156	5,161	-35	-1%	5
Permian	20,160	19,533	19,870	20,227	20,373	20,417	20,584	20,930	21,143	21,268	21,615	22,112	22,209	2,049	10%	97
Total	91,732	90,105	91,000	91,501	92,271	93,162	94,135	94,531	95,123	95,776	96,190	96,165	96,591	4,859	5%	426

Source: EIA, SAF

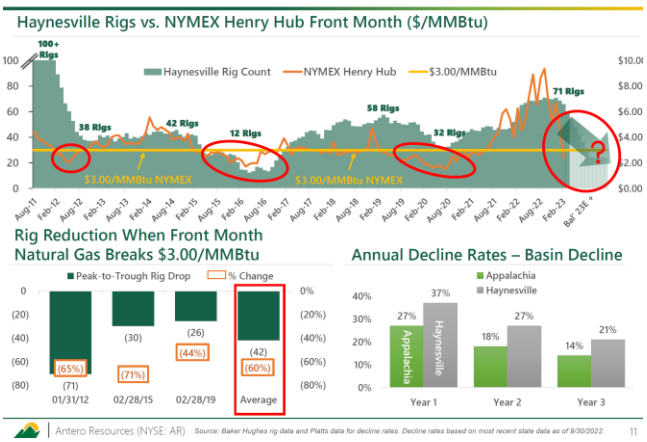
Natural Gas – Antero expects rapid supply response as price drive Haynesville rig cuts

Antero on Haynesville

We have been highlighted how we expect US natural gas rigs to decrease with HH below $3, which should lead to a natural gas supply response in 3 to 6 months thereafter. We hadn't considered the Haynesville as a marginal gas producer that would see a quick rig and supply response until we heard Antero Resources, an Appalachian natural gas producer, who held its Q4 call on Thursday. Yesterday, we tweeted [LINK] "*US #NatGas supply response. Note @business transcript & @AnteroResources slide. "With this being the first downward price cycle in which the Haynesville is the marginal supplier. This would suggest a more rapid supply response following and expected decline and rigs." #OOTT."* Antero is not a Haynesville player but, highlighted its view that the Haynesville is a marginal gas play and that it expects to see a rapid Haynesville supply response given below $3 HH prices will be driving a near term cut in rigs and therefore production. (i) To date, Haynesville gas rigs, per Baker Hughes weekly rig count, haven't yet dropped. Haynesville gas rigs hit 70 rigs on Sept 2, 2022, ranged from 68 to 72 since then with the last two weeks at 70 gas rigs. (ii) We agree with Antero that the major risk to US natural gas supply with low HH prices is always the marginal gas plays. Whereas the least impacted are the natural gas that is being produced as associated natural gas in oil wells ie. Permian, where the production is driven by the oil economics. It's hard not see any impact on Haynesville drilling & natural gas production, but we have to wonder if the response won't be something less than historical due to the Haynesville being a big supplier of US LNG exports. (iii) Here is what Antero said on the Haynesville. "*As illustrated on this page, as a result of higher maintenance capital costs, limited liquids revenue uplift, and widening basis differentials on natural gas, we estimate that most Haynesville companies that are not able to generate free cash flow in today's pricing environment. Why is this important? With Appalachian pipelines near maximum capacity and Permian associated gas being dictated by oil prices. The Haynesville is now the marginal natural gas producing region." "Further dive into the macro story on gas, let's turn to Slide number 11 titled Expected Decline in Activity from the Haynesville. The chart on the top of the slide illustrates the relationship between natural gas prices and the Basin's drilling activity. Since 2011, every time NYMEX Henry Hub prices fell below $3. Rig counts and activity in the*

Haynesville noticeably declined. While we have kept the line at $3 on this chart, this fair to say in today's inflationary environment, the old $3 level is likely now closer to $3.50 to $4. The chart on the bottom left highlights the change in recount each time natural gas drop below $3. On average, rigs decline 60% or 42 rigs through the last three cycles. But the hand some [ph] now as the marginal supplier of natural gas and activity expected to fall significantly in the months ahead is important to review the decline profile of the Haynesville. As displayed on the chart on the lower right hand side of this page. The estimated annual base decline rates of the Haynesville are materially higher than that of Appalachia. With this being the first downward price cycle in which the Haynesville is the marginal supplier. This would suggest a more rapid supply response following and expected decline and rigs." Below is their slide 11.

Figure 10: Expected decline in activity from Haynesville



Source: Antero Resources

Patterson-UTI sees gas rigs declining in basins like the Haynesville

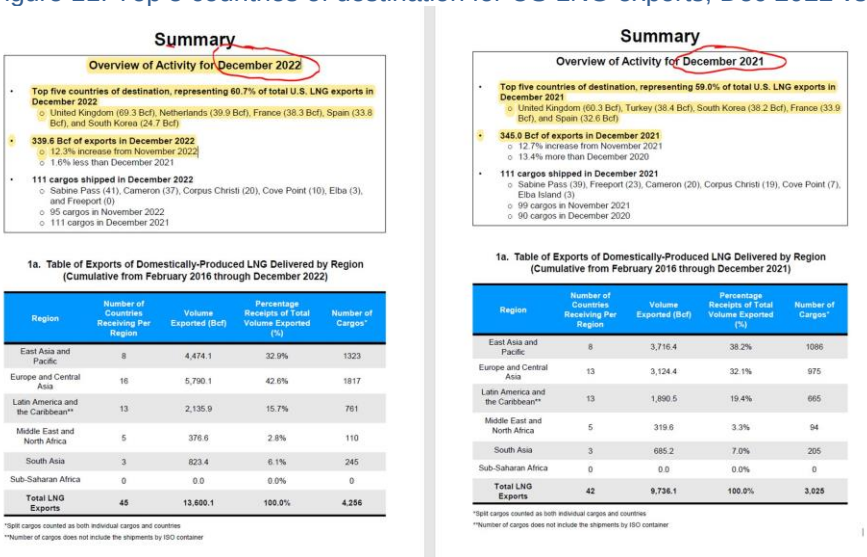
Patterson-UTI held its Q4 call on Feb 9. In the Q&A of the Q4 call, mgmt. was asked about the downside risk to natural gas activity and replied where it saw the potential for declining US gas rigs. Mgmt replied "*Yeah. And we certainly recognize there's potential for a downside case, but I think it affects different companies differently. And back to the discussion of Northeast versus the other gas basins, the way that our customers have been behaving and we -- in discussions with our customers, we believe that market remains relatively steady for us in both drilling and completions. Our customers are well hedged up there. The rigs are working under long-term contracts. So if there is a downside case materializing, it's likely happening outside of the Northeast, whether it's East Texas, North Louisiana, Haynesville, maybe areas of South Texas, Oklahoma, where you still have a lot of gas production. But with the number of rigs we have working in the Haynesville, that's only 10% of our rig count. So I think we're kind of limited in a downside case in those basins*."

Natural Gas – US LNG Exports 11.0 bcf/d in Dec, -1.6% YoY

Dec 2022 US LNG Exports

As a reminder the US Dept of Energy posts monthly US LNG export data two weeks before the EIA (part of the US Dept of Energy) posts US LNG export data in its monthly Natural Gas Monthly report (next report is Feb 28). Normally, any differences in data points are due to rounding. The DOE report is better as it provides detailed information on LNG imports and exports including LNG volumes to the top US export countries. The US Department of Energy reported the December LNG export actuals on Tuesday [LINK] and we continue to see the impact of the Freeport LNG shut in in June (2.2 bcf/d). On Wednesday, we tweeted [LINK] "*US #LNG exports Dec/22 were 11.0 bcfd, -1.6% YoY, +12.3% MoM. Still impact #FreeportLNG 2.2 bcfd 06/08/22 shut. Dec/22 top 5 export markets: UK, Dutch, France, Spain, Korea. Dec/21 top 5 export markets: UK, Turkey, Korea, France, Spain. @ENERGY data 2 wks before @EIAgov. #OOTT".* December saw 339.6 bcf (11.0 bcf/d) of LNG exports, up +12.3% MoM. The top 5 countries with export deliveries from the US were the UK (69.3 bcf), Netherlands (39.9 bcf), France (38.3 bcf), Spain (33.8 bcf), and South Korea (24.7 bcf), representing 60.7% of total US LNG exports. There has been a shift in the over the last year in top 5 exports with the energy crisis in Europe and the geo-political impacts from the Russian invasion of Ukraine when we look at the top export destinations from a year ago. There was 345.4 bcf of exports in December 2021; the top five export countries in December 2021 were UK (60.3 bcf), Turkey (38.4 bcf), South Korea (38.2 bcf), France (33.9 bcf), and Spain (32.6 bcf), representing 59.0% of total US LNG exports through the month. Below is part of the graphic from our tweet showing the top 5 export countries in Dec 2022 vs Dec 2021. Our Supplemental Documents package includes excerpts from the DOE LNG Monthly.

Figure 11: Top 5 countries of destination for US LNG exports, Dec 2022 vs Dec 2021



Summary

Overview of Activity for December 2022

- **Top five countries of destination, representing 60.7% of total U.S. LNG exports in December 2022**
  - United Kingdom (69.3 Bcf), Netherlands (39.9 Bcf), France (38.3 Bcf), Spain (33.8 Bcf), and South Korea (24.7 Bcf)
- **339.6 Bcf of exports in December 2022**
  - 12.3% increase from November 2022
  - 1.6% less than December 2021
- **111 cargos shipped in December 2022**
  - Sabine Pass (41), Cameron (37), Corpus Christi (20), Cove Point (10), Elba (3), and Freeport (0)
  - 95 cargos in November 2022
  - 111 cargos in December 2021

1a. Table of Exports of Domestically-Produced LNG Delivered by Region (Cumulative from February 2016 through December 2022)

Region	Number of Countries Receiving Per Region	Volume Exported (Bcf)	Percentage Receipts of Total Volume Exported (%)	Number of Cargos*
East Asia and Pacific	8	4,474.1	32.9%	1323
Europe and Central Asia	16	5,790.1	42.6%	1817
Latin America and the Caribbean**	13	2,135.9	15.7%	761
Middle East and North Africa	5	376.6	2.8%	110
South Asia	3	823.4	6.1%	245
Sub-Saharan Africa	0	0.0	0.0%	0
Total LNG Exports	**45**	**13,600.1**	**100.0%**	**4,256**

*Split cargos counted as both individual cargos and countries
**Number of cargos does not include the shipments by ISO container

Summary

Overview of Activity for December 2021

- **Top five countries of destination, representing 59.0% of total U.S. LNG exports in December 2021**
  - United Kingdom (60.3 Bcf), Turkey (38.4 Bcf), South Korea (38.2 Bcf), France (33.9 Bcf), and Spain (32.6 Bcf)
- **345.0 Bcf of exports in December 2021**
  - 12.7% increase from November 2021
  - 13.4% more than December 2020
- **111 cargos shipped in December 2021**
  - Sabine Pass (39), Freeport (23), Cameron (20), Corpus Christi (19), Cove Point (7), Elba Island (3)
  - 99 cargos in November 2021
  - 90 cargos in December 2020

1a. Table of Exports of Domestically-Produced LNG Delivered by Region (Cumulative from February 2016 through December 2021)

Region	Number of Countries Receiving Per Region	Volume Exported (Bcf)	Percentage Receipts of Total Volume Exported (%)	Number of Cargos*
East Asia and Pacific	8	3,716.4	38.2%	1086
Europe and Central Asia	13	3,124.4	32.1%	975
Latin America and the Caribbean**	13	1,890.5	19.4%	665
Middle East and North Africa	5	319.6	3.3%	94
South Asia	3	685.2	7.0%	205
Sub-Saharan Africa	0	0.0	0.0%	0
Total LNG Exports	**42**	**9,736.1**	**100.0%**	**3,025**

*Split cargos counted as both individual cargos and countries
**Number of cargos does not include the shipments by ISO container

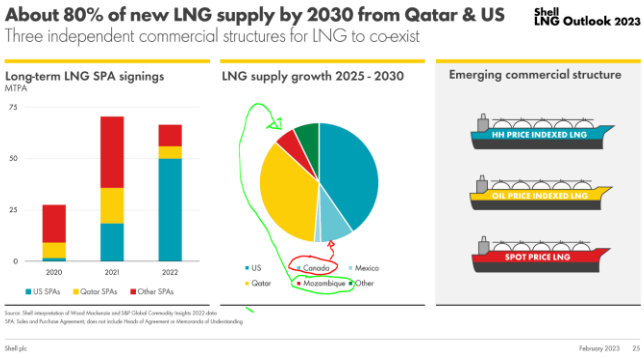
Source: DOE

Natural Gas – Shell working hard on LNG Canada Phase 2 FID, but not likely in 2023

LNG Canada

It looks like we will have to wait until 2024 for Shell to FID LNG Canada's 1.8 bcf/d Phase 2 based on mgmt. comments at the Shell LNG Outlook 2023 on Thursday. (i) We say "wait" and not "if" for a couple reasons for two reasons. Shell's forecast for global supply additions 2025-2030 has to include it for the Canada wedge. And when asked about its FIDs for this year and next to add LNG supply coming onstream five years out, Shell led with LNG Canada Phase 2. But they also said they FID for LNG Canada Phase 2 is not likely this year. (ii) Upon seeing the slide deck and ahead of the webcast, we tweeted [LINK] "*Does Shell 2025-30 LNG adds assume FID #LNGCanada 1.8 bcfd Phase 2? What else could make CAN LNG adds 25-30 that much larger than MZ that must incl at least @TotalEnergies 1.7 bcfd Phase 1? Reminder #LNGCanada Phase 1 is 1.8 bcfd is already material to Cdn #NatGas. #OOTT."* When we saw the slide (see below), we thought Shell is building in LNG Canada Phase 2 In their 2025-2030 forecast as there is no other explanation for the forecast growth in Canada LNG. (ii). In the Q&A, mgmt. was asked "*Just had a question on the LNG supply outlook. I just wanted to kind of get your views on what do you expect to be FID in terms of new LNG supply over the course of this year and next year because there does seem to be a lot of gas out there globally to be developed. You talked about the US and the growth from (inaudible). Also, you've got Canada, you've got other places that I think are riskier but have a lot of gas like Tanzania, Senegal, and Mauritania. So just if you could talk through a little bit about your expectations on FIDs and I suppose where you see that kind of range in terms of new supply kind of coming on stream four, five years out."* Mgmt led off with LNG Canada replying "*Yeah. So let me start with Canada, perhaps, we are working with the joint venture on progressing the second stage of that and showing [ph] an additional third and fourth train. I think the critical thing is getting it to the right level of competitiveness in terms of also the capital returns that we'll then achieve from that project as well as finding the right balance in terms of its carbon footprint also with the local stakeholders and the government of BC and their requirements. It's something that we're working on hard right now, but I don't think, Anish, that we will be seeing that come to an FID this year. So we're continuing to progress that."* (iii) So the takeaway is that Shell has LNG Canada Phase 2 FID in their forecast for 2025-2030 LNG supply, is working hard on the Phase 2 FID "*right now", but but I don't think, Anish, that we will be seeing that come to an FID this year. So we're continuing to progress that".* This is why we say we will have to wait until 2024 for Shell to FID LNG Canada Phase 2 and not "if" it will.

Figure 12: Shell forecast global LNG supply additions 2025-2030



Source: Shell

TC Energy says Shell asked them evaluate Coastal GasLink expansion

It's not just Shell that is working hard right now on the potential LNG Canada 1.8 bcf/d Phase 2 FID, it's also TC Energy at the request of Shell. TC Energy held its Q4 call on Tuesday morning and as the Q&A was going, we tweeted [LINK] "*Breaking! See 👇transcript. @TCEnergy just said #LNGCanada "they've asked us to begin the evaluation of Phase 2". Phase 2 adds another 1.8 bcf/d, would take total LNG Canada to 3.6 bcf/d. Positive for Cdn #natgas #OOTT."* Here is the transcript we made of the mgmt's reply in the Q&A. At 7:14am MT, mgmt. replied "*Coastal GasLink is basically Canada's LNG corridor and we're working with our customer, LNG Canada, who is developing not only their first trains, but they've asked us to begin the evaluation of Phase 2. So as you say, we're very excited to be contemplating the expansion of our system. This would not be a linear development. It's the addition of six compressor stations sites, which we've demonstrated at Wilde Lake that we just brought to mechanically complete that we can deliver those on schedule and on time. The project economics, those are obviously confidential, but we're encouraged by the possibility of advancing to a FID stag that as you say would bring the total investment in that LNG corridor to returns that are more commensurate with what our expectations would be."*

LNG Canada Phase 1 sets up Cdn supply squeeze like in the US today

We remind that the under construction LNG Canada 1.8 bcf/d Phase 1 is a material natural gas event for Alberta/BC natural gas. And that LNG Canada 1.8 bcf/d Phase 2 is another material natural gas supply event. Here is what we wrote in our June 12, 2022 Energy Tidbits memo. "*Yesterday, we also tweeted [LINK] a reminder that the under construction LNG Canada Phase 1 of 1.8 bcf/d sets up a similar natural gas supply squeeze as being seen today in the US. And this is just from the under construction LNG Canada Phase 1. We tweeted "#LNGCanada Phase 1 is 1.8 bcfd already sets up Cdn #NatGas supply squeeze like in US. >10% of BC/AB #NatGas supply 16 bcfd ie. like US #LNG exports now ~12 bcfd vs ~100 bcfd total supply. LNG Canada Phase 2 adds another 1.8 bcfd. Cdn nat gas looks very good thru 2030. #OOTT". The US currently exports ~12 bcf/d vs total US natural gas supply of ~100 bcf/d. LNG Canada Phase 1 is 1.8 bcf/d vs BC/Alberta natural gas supply of ~16*

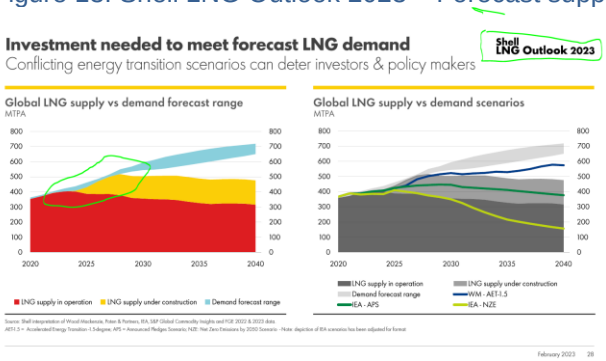
bcf/d. The math is very similar. LNG Canada and Shell have never been specific on the exact timeline but have noted that they expect first LNG by the middle of this decade ie. inferring late 2024. And our tweet reminded that LNG Canada Phase 2 is another 1.8 bcf/d for a total of the two phases being 3.6 bcf/d.

Shell's bullish LNG outlook

Natural Gas – Shell sees LNG supply gap opening up earlier than last year

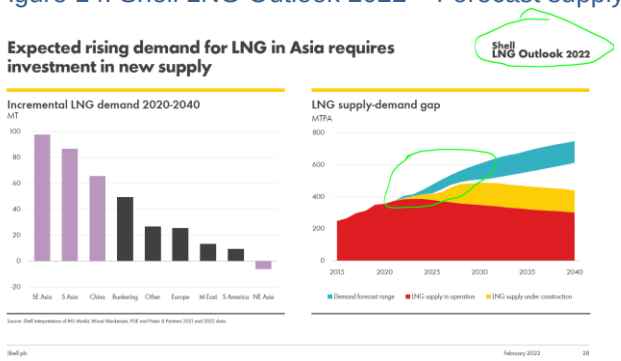
There was a good example of how it isn't easy to interpret data when comparing graphs that don't give specific data points. (i) When we saw the Shell LNG Outlook 2023 slides before the webcast, we tweeted [LINK] "*Shell's still bullish 2023 outlook for #LNG supply gap isn't as superbullish as 2022 that was done a few days before RUS invaded Ukraine and subsequent EU demand destruction, adding back coal, etc. Still "more investment in supply will be needed to meet future demand". #*OOTT". That was based on eyeballing this graph vs last year's graph for LNG supply/demand. We had assumed that Shell's slides with many demand destruction items and their slides not giving any specific time for the LNG supply gap meant that it was still bullish, but less bullish than last year's outlook for LNG. (ii) Here is what Shell said in its LNG Outlook 2023 "*in the near-term, the global LNG market is expected to remain tight and exposed to supply and demand shocks, with limited new supply coming online. More investment will be needed to meet future LNG demand."* Compare that to LNG Outlook 2022 "*The global LNG market is expected to remain tight in the near term, with a supply demand gap forecast to emerge in the middle of the current decade."* (iii) But Shell sees an earlier supply gap. In its prepared remarks, mgmt. said "its prepared remarks "*We have supply that touches the bottom end of the range of demand expectations, but not the top. And then ultimately, a clear supply-demand gap is opening up, which has actually started earlier than the presentation we showed this time last year, driven by the consequences of the events in Russia. So, the world will continue to need more LNG and more projects coming on stream later this decade. And the right-hand side of the chart shows the left-hand side forward-looking forecasts compared to some of the backward-looking demand scenarios by the IEA and others that are trying to get to a defined outcome. And what you see there is more uncertainty over the demand but a continued need for LNG for the coming period regardless."* Below are Shell's LNG supply/demand forecasts from the LNG Outlook 2023 and LNG Outlook 2022. We recommend downloading the Shell LNG Outlook 2023 as it has many excellent slides. Our Supplemental Documents package includes excerpts from Shell LNG Outlook 2023.

Figure 13: Shell LNG Outlook 2023 – Forecast supply gap



Source: Shell

Figure 14: Shell LNG Outlook 2022 – Forecast supply gap



Source: Shell

Natural Gas – Woodside has "2023 planned major maintenance" on its LNG

Big year for LNG maintenance

We remind that 2023 is expected to be a year of heavy maintenance/turnarounds on LNG export facilities following the push on all global LNG facilities to produce as much LNG as possible so Europe could replace Russian natural gas. On Tuesday, we tweeted [LINK] "*Big #LNG maintenance/turnaround year! "Woodside Plans Major [#LNG] Asset Maintenance" reports @ByMichaelSin. See 👇Fits @Shell CEO Wael Sawan reminder #LNG plants ran hard in 2022 to offset EU cutting out RUS #NatGas. #OOTT."* On Tuesday, Woodside Energy posted its "*Line-Item Guidance and Other Items*" [LINK], which included its "*2023 planned major maintenance. Major turnaround activity in 2023 is planned for the following assets: • Pluto LNG major turnaround in Q2 2023, duration approximately 4 weeks • North West Shelf LNG Train 1 major turnaround in Q3 2023, duration approximately 4 weeks • Ngujima-Yin FPSO dry dock in H1 2023, duration approximately 4 months."*

Shell reminded 2023 should be a big year of global LNG maintenance

Our Woodside tweet referenced Shell's comments that 2023 would be year of heavy LNG maintenance. Here is what we wrote in our Feb 5, 2023 Energy Tidbits. "*One of the reasons we like earnings calls is that we often get sector insights from the Q&A, where mgmt has to respond outside of their planned script. Shell held its Q4 call on Thursday. It wasn't a detailed answer but, in the Q&A, Shell CEO Sawan warned that 2023 should be a big year for industry LNG plant maintenance, which makes sense how LNG export facilities were being pushed to deliver as much as possible with Europe needed to replace Russian pipeline gas. We aren't aware of any global LNG plant turnaround schedule. In the Q&A, Sawan replied "Let's take the first one. There isn't a huge amount of LNG coming into the market over the next two years, it's around 20 million tons is what we see, but that's about it. And that one shouldn't also forget that many of these machines have been running hard now for a good year and you're beginning to see some of the challenges in just the reliability of the machines around the world. So that's, that's an issue."*

Natural Gas – Pakistan dropping LNG to quadruple domestic coal-fired power

Pakistan dropping LNG for coal

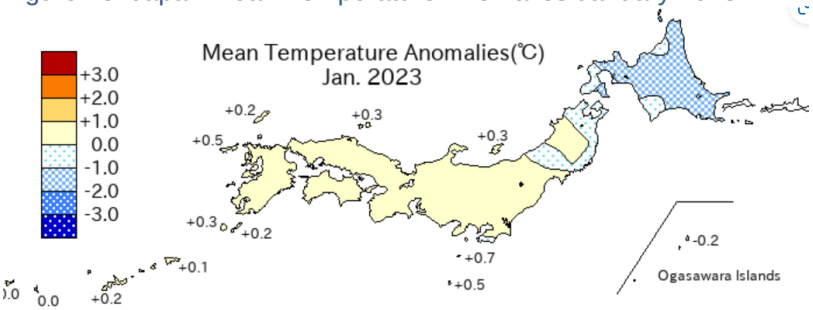
No one should have been surprised to see the Reuters report that Pakistan saying LNG is no longer part of their longer term energy plan and that it plans to quadruple domestic coal-fired power. Pakistan has been unable to attract LNG cargoes and, last year, had a number of LNG cargos not delivered per their existing long term contracts as the LNG supplier chose instead to pay the penalty so it could deliver the LNG cargoes to higher priced Europe markets. On Monday, Bloomberg reported "*Pakistan plans to quadruple its domestic coal-fired capacity to reduce power generation costs and will not build new gas-fired plants in the coming years, its energy minister told Reuters on Monday, as it seeks to ease a crippling foreign-exchange crisis. A shortage of natural gas, which accounts for over a third of the country's power output, plunged large areas into hours of darkness last year. A surge in global prices of liquefied natural gas (LNG) after Russia's invasion of Ukraine and an onerous economic crisis had made LNG unaffordable for Pakistan. "LNG is no longer part of the long-term plan," Pakistan Energy Minister Khurram Dastgir Khan told Reuters, adding that the country plans to increase domestic coal-fired power capacity to 10 gigawatts (GW) in the medium-term, from 2.31 GW currently."* Our Supplemental Documents package includes the Reuters report.

Natural Gas – No significant demand for natural gas in January in Japan

Japan temperature recap for Jan

Mean temperatures were more or less normal throughout most of Japan in January with slightly below normal temperatures in the northeastern region and slightly above normal temperatures in the more populous central/southern region. On Thursday, the Japan Meteorological Agency posted its recap of January weather [LINK] and their mean temperature anomalies map (below) shows the mean temperature breakdown for the month. Their recap noted, "*Temperature fluctuations were significant over Japan, because winter monsoon was weak in mid-January and strong in late January."* And "*In late January, strong cold air inflow resulted in heavy snowfalls in some regions mainly on the Sea of Japan side and also on the Pacific side*."

Figure 15: Japan Mean Temperature Anomalies January 2023



Source: Japan Meteorological Agency

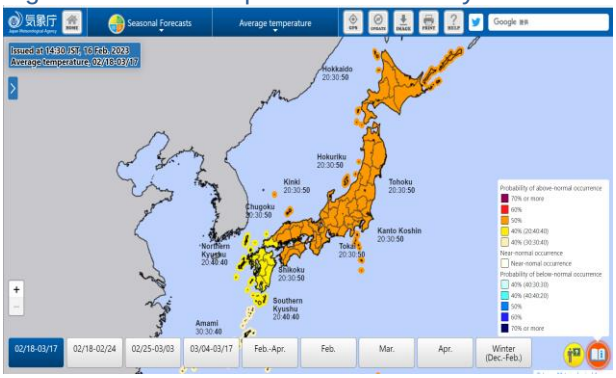
Natural Gas – Japan weather forecast now pointing to warmer than normal Feb/Mar

Japan expects a warmer than normal end to winter

Japan near-term weather forecasts continue to bounce around week to week. Last week's (Feb 12, 2023) Energy Tidbits memo noted the Japan Meteorological Agency's near term forecast for a colder than normal Feb. There was a big change in their new weekly forecast. On Thursday, the Japan Meteorological Agency updated its 30-day outlook [LINK] and is

forecasting warmer than normal weather for the most of the country, which represents another forecast reversal. However, the end of Feb and beginning of Mar is near the end of winter so a warmer than normal forecast signals the end of weather driven demand for natural gas.

Figure 16: JMA Temperature Probability Feb 18 – Mar 17



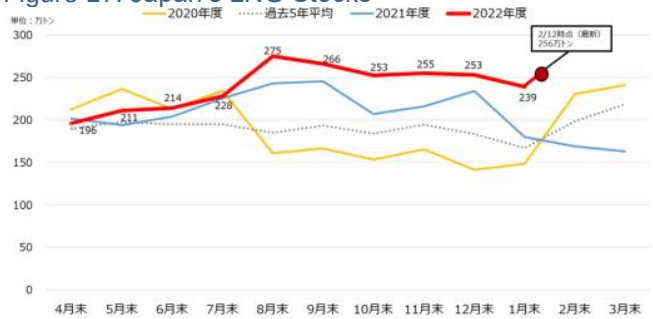
Source: Japan Meteorology Agency

Natural Gas – Japan's LNG stocks up +5.8% WoW to 123 bcf

Japan LNG stocks +5.8% WoW

It looks like the recent warmer weather in Japan led to some additions to their LNG stocks. But generally, it has been milder winter, so Japan's LNG stocks are at high levels. It means that Japan is in pretty good shape to avoid LNG shortages in the winter. Especially since Europe is still warm. We always warn that Japan's LNG stockpiles are not huge relative to LNG imports that have ranged from 7 to 14 bcf/d since Jan 1, 2021. LNG stockpiles held by Japanese power producers continue to exceed both last year's level and the seasonal average. Japan's METI weekly LNG stocks data was released on Wednesday [LINK]. LNG stocks at Feb 13 were ~123 bcf +5.8% WoW from Feb 5 of ~116 bcf and well above the 5-year average of 95 bcf. Below is the LNG stocks graph from the METI weekly report.

Figure 17: Japan's LNG Stocks



Source: METI

Natural Gas – Japan LNG Imports in Jan +0.5% YoY to 10.56 bcf/d

Japan Jan LNG imports +0.5% YoY

On Thursday, Japan's Ministry of Finance posted its import data for Jan [LINK]. As noted above, Jan was warmer than normal in the more populous southern and central Japan. The MOF reported Japan's Jan LNG imports were 10.56 bcf/d, which was +0.5% YoY. But it is important to remember that year ago Jan 2022 LNG imports of 10.51 bcf/d were the lowest imports in any January in a decade. So January 2023 LNG imports were only marginally higher than decades low January LNG imports. Below is our table that tracks Japan LNG import data.

Figure 18: Japan Monthly LNG Imports

bcf/d	2015	2016	2017	2018	2019	2020	2021	2022	22/21	2022	22/21
Jan	13.06	11.22	12.85	12.79	11.69	11.63	12.48	10.51	-15.8%	10.56	0.5%
Feb	13.26	12.30	13.36	14.23	12.61	10.99	13.84	12.19	-11.9%		
Mar	12.60	12.62	12.61	12.28	11.30	11.16	11.04	10.07	-8.7%		
Apr	10.56	10.21	10.52	8.97	9.00	8.31	7.96	8.92	12.0%		
May	8.91	8.55	9.66	9.92	8.62	7.09	7.67	8.92	16.3%		
June	10.61	10.02	9.90	8.88	8.32	8.42	9.13	9.29	1.7%		
July	10.77	10.19	10.19	10.55	10.56	9.35	9.58	9.54	-0.4%		
Aug	10.93	11.96	11.24	11.73	9.45	9.04	9.75	9.71	-0.4%		
Sept	11.06	10.67	9.31	10.04	10.30	10.41	8.66	8.52	-1.6%		
Oct	9.38	9.73	9.50	10.12	9.75	9.20	7.17	7.88	9.9%		
Nov	10.71	12.07	10.26	10.15	10.03	9.63	9.38	8.88	-5.4%		
Dec	12.51	11.69	12.31	11.23	10.54	11.96	10.89	9.39	-13.8%		

Source: Japan Ministry of Finance

Natural Gas – Gazprom being forced to look for new long export pipelines to Asia

Gazprom looking at new export pipelines

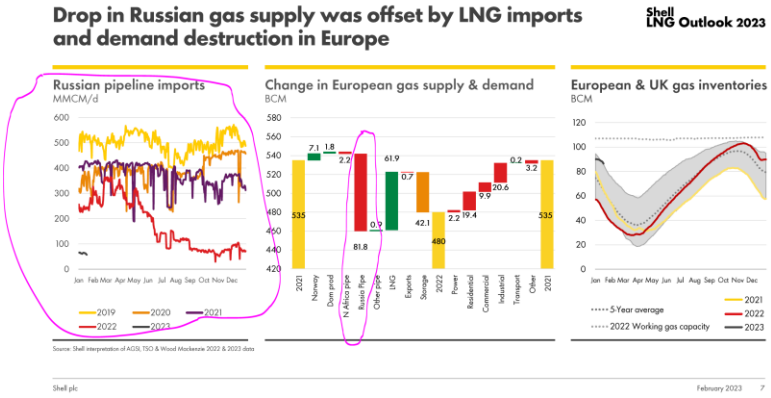
Earlier this morning, we tweeted [LINK] *"Positive for #NatGas #LNG for 2020s. "Gazprom eyes new markets" "diversifying markets is always beneficial". TASS forgot "being forced to" because Gazprom will have some level of permanent hit to volumes from loss of EU market until can build new major export pipelines. #OOTT."* You have to give Europe credit for hanging in on their determination to cut off Russian natural gas. No question the perfect storm got them thru this winter without a natural gas crisis, but adding LNG terminals is causing Gazprom to realize that there will be some level of long lasting market loss of Europe as the major natural gas export market. And that their export volumes will be hit to some degree unless they can build major new export pipelines to Asia. And these take years to build. Our tweet said TASS forgot to add "being forced to" with this morning's TASS report [LINK] " G*azprom eyes new markets, plans to launch new projects" "Gazprom is currently researching new markets and intends to begin additional gas pipelines projects in the near future, Gazprom CEO Alexey Miller said in an interview with on Rossiya 1 TV channel. "Diversifying routes is always beneficial because you can't put all of your eggs in one basket. Of course, we're thinking about new markets, we have a lot of resources for many years to come. It is evident that we will begin executing new big projects for the construction of major gas pipelines in the very near future," he said".* Our Supplemental Documents package includes the TASS report.

Gazprom pipeline exports to Europe were down 7.9 bcf/d in 2022 on average

The impact of Gazprom's loss of natural gas pipeline exports to Europe was huge in 2022 and it was far from a full year impact. In Shell's LNG Outlook 2023 this week, they estimated Europe's natural gas pipeline imports from Russia were down 81.8 bcm YoY in 2022, which is 7.9 bcf/d if averaged out over all of 2022. The impact was

far less than a full year. Shell also provided an impact on a monthly basis, which shows that the reduction of Russia natural gas pipeline imports was ~15 bcf/d in Nov and Dec vs 2019 levels.

Figure 19: Drop in Russian natural gas pipeline supply to Europe



Source: Shell

Natural Gas – Shell reminds why Europe is not out of the woods for natural gas

Europe not out of the woods

We have been highlighting how Europe was able to avoid a natural gas crisis because all the cards fell in its favor – mild temperatures in Europe and in Asia, China diversified 50% of its LNG to Europe, demand destruction, increasing coal-fired power, etc. In its LNG Outlook 2023, Shell reminded how Europe is not out of the woods in 2023, rather it is a "*multi-year issue*". In the Q&A, mgmt. replied why they see this as a multi-year issue. Mgmt said "*my answer was the same that we are not out of the energy crisis in Europe, far from I think. And I would agree with your point that there seems to be some who feel that it's all back to normal. This is I think a multi-year energy crisis and we all have to collectively figure out how we address that. Why do I say that? I think just looking at some of the fact. So, last year what happened with Russia was roughly 2.5% of global gas demand was taken out because of the reduction in gas supplies from Russia into Europe. That caused havoc in the markets, as you know well. What supported or what bridged the gap? Of course, LNG played an important role, mild weather played an important role and critically demand destruction also played an important role. Let's take the first one. There isn't a huge amount of LNG coming into the market over the next two years, it's around 20 million tons is what we see, but that's about it. And that one shouldn't also forget that many of these machines have been running hard now for a good year and you're beginning to see some of the challenges in just the reliability of the machines around the world. So that's, that's an issue. The second issue of course is that China was the one that diversed roughly 50% of its LNG to come here to Europe or 50% of Europe's needs was met with diverted LNG cargoes from China. That might change or is likely to change, given where things are going with the recovery, the economic recovery in China. So you look at that. You don't want to be in a position to be depending on the weather as your savior or the fact that you're going to destroy more demand. And so I do think this is a multi-year issue. We've been very vocal with governments here in Europe that we're going to have to need to move faster. What does Shell do as a result of this? Of course, our*

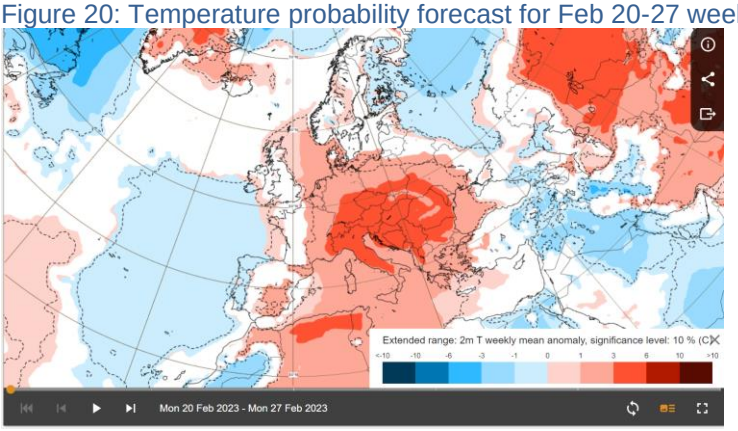
portfolio has typically been positioned for Northern Hemisphere winters, that's why we typically have our longs. We, of course, work on significant support in storage. This year or last year, sorry, we invested in storage in Germany and in Austria, which was part of where we used our working capital, for example. We're investing in projects right now. We have peers depressurization that's coming onstream and penguins in the UK. So we have a lot of opportunities to be able to supply the market and of course, create value through the tremendous portfolio that we have in LNG".

Natural Gas – A much warmer than normal last week of Feb for Europe

Warm end to Feb

Last week's (Feb 12, 2023) Energy Tidbits noted the then latest ECMWF Feb near term forecasts for Europe with the commentary winter looks more or less done in Europe as the ECMWF were forecasting warming than normal temperatures to end Feb. This week's latest ECMWF forecast (Feb 16) has the same forecast – it is expected to be well above normal temperatures to end Feb. On Friday, we tweeted [LINK] "*Forecasts for warm temps to end Feb and the main part of winter in Europe. Red on a winter temperature map is never good for #NatGas. #OOTT."* Every Monday and Thursday, the European Centre for Medium-Range Weather Forecasts updates its near-term forecasts. The forecasts normally are released in early afternoon MT. Our tweet included the ECMWF Feb 16 update for warmer than normal temperatures across all of Europe for Feb 20-27 week. [LINK] As we put in our tweet, red is never good for natural gas in a temperature forecast for winter.

Figure 20: Temperature probability forecast for Feb 20-27 week



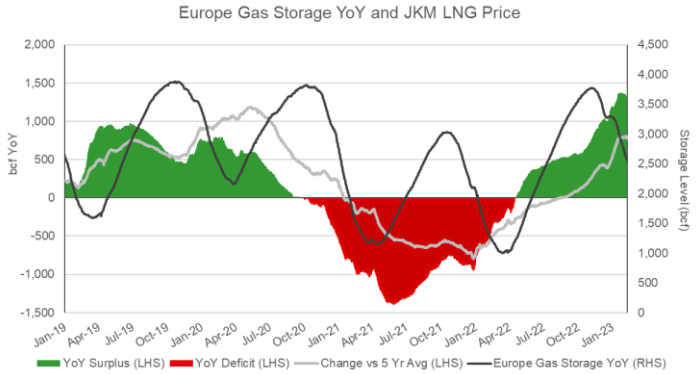
Source: ECMWF

Natural Gas – Europe storage is now +32.5% YoY ie. 64.47% full vs 31.97%

It's been a great winter so far for Europe in that, other than for a short period, it has been well above normal for most of continental Europe. There has been negligible weather driven demand for natural gas, which along with the continued industrial demand destruction, means storage levels are at very high levels. This winter (Nov 1/22) began with gas storage at 94.94% capacity, up 17.86% YoY and is now a YoY surplus of 32.5%. However, temperatures remained a bit cooler this past week resulting in storage falling slightly by -0.34% WoW to 64.47% on Feb 16. Storage is now +32.5% greater than last year levels of

31.97% and is +20.21% above the 5-year average of 44.26%. Below is our graph of Europe Gas Storage Level.

Figure 21: Europe Gas Storage Level



Source: Bloomberg

Oil – US oil rigs down -2 rigs to 607 oil rigs on Feb 17

US oil rigs down -2 WoW

Baker Hughes released its weekly North American drilling activity data on Friday. This week total US oil rigs were down -2 rigs to 607 rigs as of Feb 17, notably with +2 rigs being added at Cana Woodford which was more than offset by a -3 rig decline at other basins. The total US oil rig count is now at 607 rigs, up +87 YoY, +126 from the 2022 low of 481 rigs in January and +435 since the 2020 low of 172 rigs on Aug 14. US gas rigs were up +1 WoW to a total of 151 rigs, an increase of +27 rigs YoY. Below is our graph of total US rigs.

Figure 22: Baker Hughes Total US Oil Rigs

Source: Baker Hughes

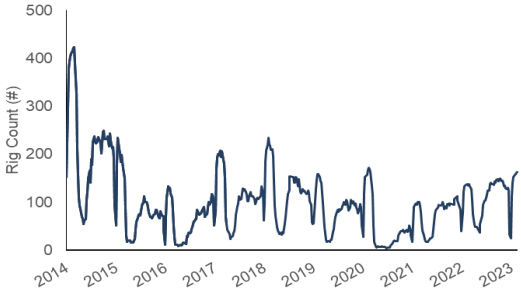
Oil – Total Cdn rigs down -2 WoW to 248 total rigs, +28 rigs YoY

Cdn rigs -2 WoW

There was the traditional big ramp up in Cdn rigs in Jan post Xmas/New Years holiday, but that ramp up is over, but we are seeing the peak of winter drilling program in Feb so any increases for the remainder of winter are likely to be modest at most. One key reason for potential modest increases is that NE BC drillers are trying to catch up now that the BC/Blueberry River First Nations deal was reached. BC rigs were flat this week at 19, up 6

from 13 rigs in middle January. Total Cdn rigs were -2 WoW to 248 rigs as of Feb 17. As noted in last weeks memo, the modest increase in rig count is no surprise as the holiday season officially wrapped up. However, we do not expect the Cdn rig count to increase much further as the end of winter drilling is now only a few weeks away. Notably, the week of Feb 17 saw a +1 rig increase in SK, while AB saw a decline of -3 rigs. There is now a total of 248 rigs, +76 vs the comparable Covid period of 172 rigs on Feb 19, 2021. Cdn oil drilling rigs have increased to 163, up +28 YoY from 135 rigs a year ago and Cdn gas rigs were down -4 rig WoW to 85 rigs. Below is our graph of total Cdn oil rigs.

Figure 23: Baker Hughes Total Canadian Oil Rigs



Source: Baker Hughes

Oil – US weekly oil production flat at 12.3 mmb/d WoW

US oil production flat WoW

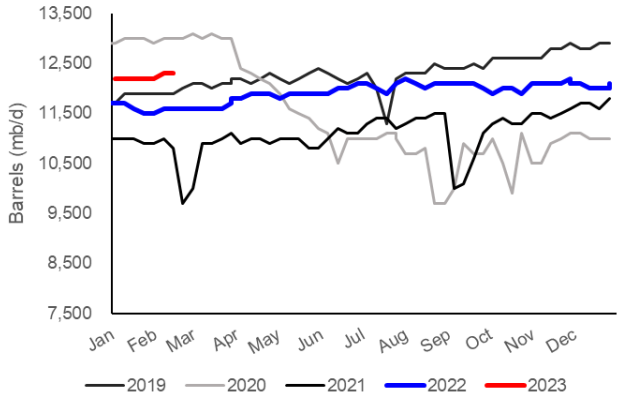
The EIA estimates US oil production was flat WoW at 12.3 mmb/d for the week ended Feb 10 with lower 48 production and Alaska production both also flat WoW. US oil production, based on the weekly estimates, has been mostly range bound between 11.9 to 12.1 mmb/d since the 2nd week of May. But broke above 12.1 mmb/d to 12.2 mmb/d for the week ended Jan 6 as well as five weeks ago, the first time since it touched 12.2 mmb/d in the 1st week of August. Lower 48 production was flat WoW at 11.8 mmb/d this week and Alaska was flat at 0.456 mmb/d WoW. US oil production is up +0.700 mmb/d YoY at 12.3 mmb/d but is still down significantly at -0.900 mmb/d since the 2020 peak of 13.1 mmb/d on March 13.

Figure 24: EIA's Estimated Weekly US Oil Production

	Week 1		Week 2		Week 3		Week 4		Week 5	
Year-Month	End Date	Value	End Date	Value	End Date	Value	End Date	Value	End Date	Value
2021-Jan	01/01	11,000	01/08	11,000	01/15	11,000	01/22	10,900	01/29	10,900
2021-Feb	02/05	11,000	02/12	10,800	02/19	9,700	02/26	10,000		
2021-Mar	03/05	10,900	03/12	10,900	03/19	11,000	03/26	11,100		
2021-Apr	04/02	10,900	04/09	11,000	04/16	11,000	04/23	10,900	04/30	10,900
2021-May	05/07	11,000	05/14	11,000	05/21	11,000	05/28	10,800		
2021-Jun	06/04	11,000	06/11	11,200	06/18	11,100	06/25	11,100		
2021-Jul	07/02	11,300	07/09	11,400	07/16	11,400	07/23	11,200	07/30	11,200
2021-Aug	08/06	11,300	08/13	11,400	08/20	11,400	08/27	11,500		
2021-Sep	09/03	10,000	09/10	10,100	09/17	10,600	09/24	11,100		
2021-Oct	10/01	11,300	10/08	11,400	10/15	11,300	10/22	11,300	10/29	11,500
2021-Nov	11/05	11,500	11/12	11,400	11/19	11,500	11/26	11,600		
2021-Dec	12/03	11,700	12/10	11,700	12/17	11,600	12/24	11,800	12/31	11,800
2022-Jan	01/07	11,700	01/14	11,700	01/21	11,600	01/28	11,500		
2022-Feb	02/04	11,600	02/11	11,600	02/18	11,600	02/25	11,600		
2022-Mar	03/04	11,600	03/11	11,600	03/18	11,600	03/25	11,700		
2022-Apr	04/01	11,800	04/08	11,800	04/15	11,900	04/22	11,900	04/29	11,900
2022-May	05/06	11,800	05/13	11,900	05/20	11,900	05/27	11,900		
2022-Jun	06/03	11,900	06/10	12,000	06/17	12,000	06/24	12,100		
2022-Jul	07/01	12,100	07/08	12,000	07/15	11,900	07/22	12,100	07/29	12,100
2022-Aug	08/05	12,200	08/12	12,100	08/19	12,000	08/26	12,100		
2022-Sep	09/02	12,100	09/09	12,100	09/16	12,100	09/23	12,000	09/30	12,000
2022-Oct	10/07	11,900	10/14	12,000	10/21	12,000	10/28	11,900		
2022-Nov	11/04	12,100	11/11	12,100	11/18	12,100	11/25	12,100		
2022-Dec	12/02	12,200	12/09	12,100	12/16	12,100	12/23	12,000	12/30	12,100
2023-Jan	01/06	12,200	01/13	12,200	01/20	12,200	01/27	12,200		
2023-Feb	02/03	12,300	02/10	12,300						

Source: EIA

Figure 25: US Weekly Oil Production



Source: EIA, SAF

Oil – North Dakota Dec oil production down -12.9% MoM

North Dakota oil production

No one should be surprised to see the North Dakota Industrial Commission's report this week that North Dakota production was below 1 mmb/d. Our Dec 18, 2022 Energy Tidbits highlighted the blizzard that hit North Dakota and how that had cut oil output by 200,000 to 250,000 b/d. On Thursday afternoon, the North Dakota Industrial Commission posted its Director's Cut, which includes December oil and natural gas production data [LINK]. Consistent with the blizzard impact, North Dakota Dec production was down -12.9% MoM to 0.956 mmb/d which is -16.5% below production of 1.145 mmb/d in Dec 2021. Prior to the blizzard, NDIC noted it had been a strong completions month. As a result, estimated well

completions were 104 in December, a large increase of +46 from 58 in November. Our Supplemental Documents package includes excerpts from the Director's Cut.

Figure 26: North Dakota Oil Production By Month

(b/d)	2017	2018	2019	2020	2021	2021/2020	2022	2022/2021
Jan	981,380	1,179,564	1,403,808	1,430,511	1,147,377	-19.8%	1,088,613	-5.1%
Feb	1,034,248	1,175,316	1,335,591	1,451,681	1,083,554	-25.4%	1,089,091	0.5%
Mar	1,025,690	1,162,134	1,391,760	1,430,107	1,108,906	-22.5%	1,122,640	1.2%
Apr	1,050,476	1,225,391	1,392,485	1,221,019	1,123,166	-8.0%	900,597	-19.8%
May	1,040,995	1,246,355	1,394,648	859,362	1,128,042	31.3%	1,059,060	-6.1%
June	1,032,873	1,227,320	1,425,230	893,591	1,133,498	26.8%	1,096,783	-3.2%
July	1,048,099	1,269,290	1,445,934	1,042,081	1,076,594	3.3%	1,072,632	-0.4%
Aug	1,089,318	1,292,505	1,480,475	1,165,371	1,107,359	-5.0%	1,075,307	-2.9%
Sept	1,107,345	1,359,282	1,443,980	1,223,107	1,114,020	-8.9%	1,121,063	0.6%
Oct	1,183,810	1,392,369	1,517,936	1,231,048	1,111,910	-9.7%	1,121,754	0.9%
Nov	1,194,920	1,375,803	1,519,037	1,227,138	1,158,622	-5.6%	1,098,389	-5.2%
Dec	1,182,836	1,402,741	1,476,777	1,191,429	1,144,999	-3.9%	956,288	-16.5%

Source NDIC, NDPA

Oil – North Dakota crude by rail down MoM to 79,124 b/d in Dec

North Dakota CBR down MoM in December

The other impact of the Dec blizzard and extreme cold in Dec was a hit to crude by rail. The North Dakota Pipeline Authority posted its monthly update "*February 2023 Production & Transportation"* [LINK]. Please note that we always go to the backup excel sheets from the North Dakota Pipeline Authority for more detailed numbers of crude by rail out of North Dakota. The NDPA Monthly Update (graph below) report only provides rounded numbers, and these rounded numbers are not accurate enough to match the graphs. In the backup excel, the NDPA estimates crude by rail in Dec was a low of 64,124 b/d and a high of 94,124 b/d for an average of 79,124 b/d. This is below the Nov average of 84,251 b/d and Dec 2021 average of 125,047 b/d. Below is a chart from the NDPA monthly update showing the crude by rail volumes since 2014. Our Supplemental Documents package includes excerpts from the NDPA monthly update.

Figure 27: Estimated North Dakota Rail Export Volumes

Source: North Dakota Pipeline Authority

Oil – EIA shale/tight oil forecast +9.0%, +0.766 mmb/d YoY in Mar

US shale/tight oil production

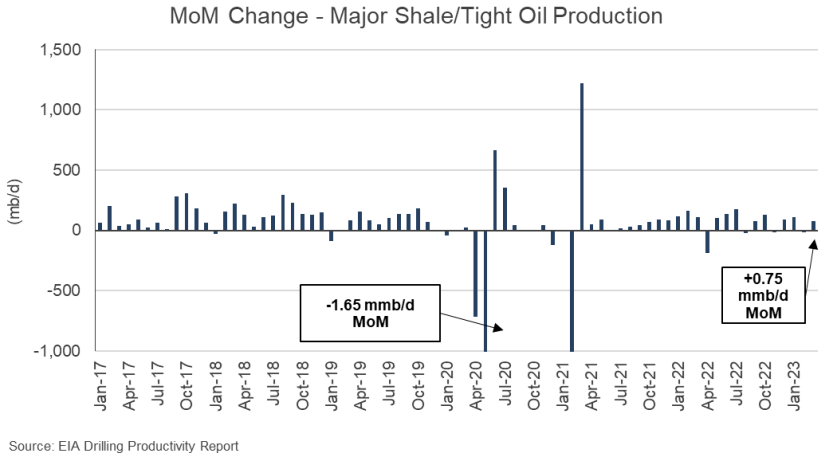
The EIA Drilling Productivity Report Jan 2023 [LINK] forecast for US shale/tight oil shows a continued modest MoM increase in Feb and Mar after being fairly stuck for July-Oct. The DPR is the EIA's forecast for production for the major shale/tight oil and gas basins for the current month (in this case Feb) and the next month (in this case Mar). (i) Shale/tight oil was flat from July thru Oct but there is some modest growth forecast for both Jan, Feb, and now Mar. The EIA now forecasts total US shale/tight oil in Feb at 9.282 mmb/d and Mar at 9.357 mmb/d. (ii) The growth is somewhat distributed across all basins except Haynesville and Appalachia basically flat MoM. The Permian and Bakken have the most significant increases of +30,000 b/d and +21,000 b/d, respectively. The Permian Mar is 5.682 mmb/d, vs 5.652 mmb/d in Feb. Eagle Ford is also forecasted up +4,000 b/d MoM in Mar following two consecutive increases in Jan and Feb, benefitting from its higher natural gas ratio and the pull for natural gas for US LNG exports. (iii) Note that shale/tight oil is approx. ~75% of total US production, so whatever the trends are for shale/tight oil are normally the trends for US oil in total. Below is our table of running DPR estimates of shale/tight oil production and our graph of MoM changes in major shale/tight oil production.

Figure 28: MoM Change – Major Shale/Tight Oil Production

Thousand b/d	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Mar YoY	Mar YoY %	Mar less Feb
Anadarko	399	398	391	406	413	425	424	425	423	427	431	433	445	46	12%	12
Appalachia	113	111	114	124	130	128	120	120	122	126	136	137	140	27	24%	3
Bakken	1,172	1,169	1,172	1,178	1,173	1,136	1,183	1,168	1,182	1,200	1,206	1,178	1,199	27	2%	21
Eagle Ford	1,123	1,140	1,149	1,152	1,180	1,204	1,224	1,208	1,223	1,231	1,209	1,176	1,180	57	5%	4
Haynesville	33	34	35	36	37	37	37	37	37	37	37	37	37	4	12%	0
Niobrara	613	610	627	630	632	649	648	640	653	662	675	669	674	61	10%	5
Permian	5,138	5,055	5,131	5,232	5,367	5,329	5,347	5,403	5,460	5,542	5,605	5,652	5,682	544	11%	30
Total	8,591	8,517	8,619	8,758	8,932	8,908	8,983	9,002	9,100	9,224	9,299	9,282	9,357	766	9%	75

Source: EIA Drilling Productivity Report

Figure 29: MoM Change – Major Shale/Tight Oil Production



Source: EIA Drilling Productivity Report

Oil – EIA DUC's marginal increases in January

DUCs up slightly in Jan

We have been warning that we see a key risk to how much US oil production can sustainably grow in 2023 and beyond is the need to increase rig counts (not have less frac spreads) to

replenish the inventory of Drilled UnCompleted wells at higher levels and the challenge for oilfield services to add capacity to increase frac spreads and completions. In our Dec 18, 2022 Energy Tidbits memo, we noted how DUCs in the Permian are really about the same level as five years ago when Permian production was about half current levels. One wildcard is our previously noted caveat that DUCs do not account for potential refracs. The biggest problem in the past with the EIA's Drilling Productivity Report [LINK] estimate of Drilled UnCompleted wells was that the data had been constantly revised and sometimes significantly. (i) However, the DUC estimates provide a clear picture of the trend that DUCs haven't really increased since Feb. It's why there is the need for drilling rigs to pick up to replenish the DUC inventory if the US is to have strong oil growth in 2023. We highlight a slight increase in the Jan data. (i) It is also important to remember that a portion of the DUCs will never be completed as there are drilled wells that don't look like they can justify the higher cost of completion. (ii) Drilled Uncompleted Wells are up 42 MoM (143 YoY) in January to 4,671 DUCs, which compares to 4,387 DUCs in Feb. Note that Dec's data was revised up +52 to 4,629 from 4,577. (iii) But at 4,671 DUCs, it means that a total 4,203 DUCs were worked down since the Jun/20 peak of 8,874. The largest work downs are coming from the Permian (-399 YoY) and Eagle Ford (-205 YoY). With DUCs being worked down so significantly we will need to see rig counts go up to replenish DUCs in the near future. (iii) Note that shale/tight oil is approx. ~70% of total US production, so whatever the trends are for shale/tight oil are normally the trends for US oil in total. Below is our table of running DPR estimates of shale/tight oil production and our graph of MoM changes in major shale/tight oil production. Our Supplemental Documents package includes the EIA DPR.

Figure 30: EIA - Estimated Drilled UnCompleted Wells

Drilled UnCompleted	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan	Jan YoY %	Jan YoY
Anadarko	773	758	753	740	724	727	723	716	722	723	710	712	722	726	-4%	-32
Appalachia	565	457	473	471	497	526	524	529	562	576	597	620	631	633	39%	176
Bakken	464	436	426	426	429	425	427	426	474	494	501	528	552	553	27%	117
Eagle Ford	685	683	653	642	612	598	611	620	593	582	561	517	482	478	-30%	-205
Haynesville	372	369	371	395	419	441	466	483	513	535	558	595	624	637	73%	268
Niobrara	354	343	331	317	320	310	328	345	362	393	443	497	539	561	64%	218
Permian	1,444	1,482	1,380	1,302	1,294	1,244	1,218	1,180	1,117	1,097	1,051	1,068	1,079	1,083	-27%	-399
Total	4,657	4,528	4,387	4,293	4,295	4,271	4,297	4,299	4,343	4,400	4,421	4,537	4,629	4,671	3%	143

Source: EIA, SAF

Oil – Devon says increase breakeven level from $30 to $40 driven by inflation

Devon's increasing breakeven cost

When a large US oil producer says their breakeven level has increased $10/boe in the last year, it's worth looking at what they said. It is certainly good food for thought as this is a way larger impact than everyone would think from a company like Devon. There was good food for thought from the Q&A of Devon's Q4 call on Wednesday. Unfortunately, it's not 100% clear but there was a clear indication from Devon that inflation is having a larger impact on breakeven costs for companies to Devon's size. Devon also notes the impact of cash taxes but we have to believe there is more. The assumption has always been that large producers have the scale and buying power to minimize the impact of inflationary costs on their oil and gas operations. We should say that we think there has to be more than inflation leading to this $10/b YoY increase. Devon also mentioned cash taxes. We don't see how an inflation impact of 10% or even 20% should impact costs per boe by anywhere near a $10/boe impact. And we think it's because Devon only address inflation in their answer. But mgmt was asked "*year-ago on this call, you talked about on ultra-low breakeven around 30 bucks. and in your press release yesterday, you talked about presentation other. You talked about a*

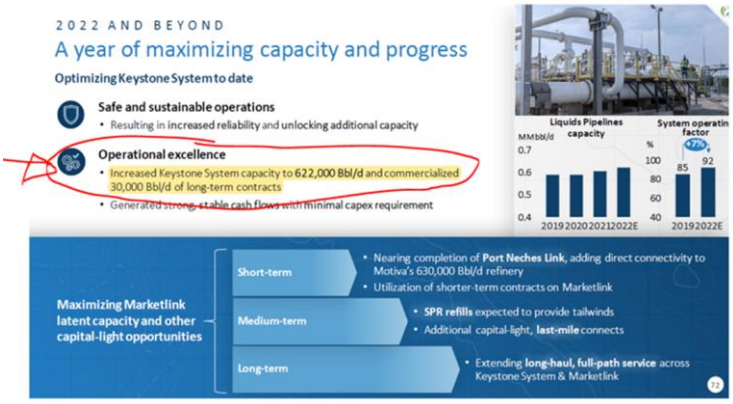
$40 breakeven, it seems that with the moderate inflation. I guess, expectations. Those two numbers don't really seem to align. Can you walk-through what's changed, they felt $40 a $10 increase in breakeven is what you're trying to communicate." Mgmt replied "*Yeah, no, you bet, Doug, so no question, the cost structure as we've been talking about is moved higher on a Year-over-Year basis, we had the benefit for the better part of 2022, given the supply chain work that we did and the great work the teams did to kind of lock in kind of firm contracts with term, you're starting to see some of that unwind now is Clay referenced earlier. And so that contract refresh has resulted in higher-cost structure that you're seeing in this year. And so that's really what's driven that break-even higher now, there are some other impacts as you're well aware, our cash taxes. We expect to be higher this year as we've utilize the NOLs in 2022 that's been an impact that's driving that cost higher, but far and away I know everybody is tired of talking about it, I certainly am as well, but it's the inflationary impact that we've seen across the frankly, every cost category and you used the word Moderate I would actually choose a different adjective, when you think about most of these cost categories, we've seen anywhere between 30% and 50% kind of inflation, depending on which cost category you're talking about, that's what we're walking into in 2023."*

Oil – Sounds like Keystone oil pipeline is moving ~~585,000 b/d

Keystone movig ~585,000 b/d

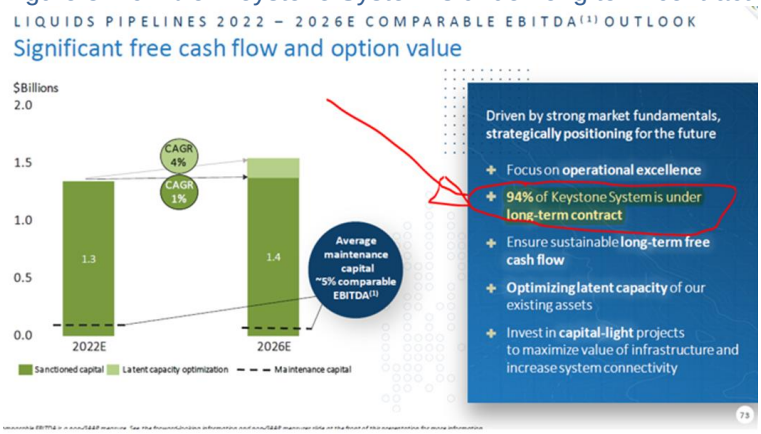
On Tuesday, we tweeted [LINK] "*Sounds like #Keystone #Oil pipeline moving ~585 kbd. @TCEnergy did not give volume, but said "we're limited in our ability at this time to move uncommitted or spot volumes", represent 6% of capacity. 11/29/22 investor day, capacity increased to 622 kbd. 94% of 622 = 585. #OOTT."* TC Energy held its Q4 call on Tuesday. On the call, TC Energy didn't confirm exactly how much oil is flowing thru the Keystone oil pipeline, but it sounds to us it is flowing ~585,000 b/d vs capacity of 622,000 b/d. In the call, TC Energy confirmed Keystone is running at lower volumes but would not give a b/d number. Rather they said they said Keystone is 94% contracted and 6% is left for uncommitted or spot capacity by the regulator, and right now "that's 6% of the volume at this time, we're not able to move". Ie. moving at 94% of capacity. Here is the full excerpt of their prepared comments. "*Commercially, we're able to deliver all of our contracted volume requirements, but we're limited in our ability at this time to move uncommitted or spot volumes. And just to give you some perspective on that, Keystone is 94% contracted. We're required to leave 6% of our space for uncommitted or spot capacity by the regulator, and it's -- that's 6% of the volume at this time, we're not able to move. So we're working through these remedial actions. It is going to take some time for the root cause investigation to play out and for us to determine not just what caused the failure, but why those circumstances were in place at the time. And once we work through that, at that time, we'll be getting with PHMSA on a path towards how we return the system back to baseline operations. And at this point in time, I don't have a time frame that I can communicate on that. But we'll continue to be transparent as we've been up to date*". Our tweet included the below slides from the TC Energy Nov 29, 2022 Investor Day, which said the increased Keystone capacity to 622,000 b/d and that 94% o the Keystone system is under long term contract. Ie. the implication is that today they are moving at ~585,000 b/d.

Figure 31: Keystone capacity increased to 622,000 b/d



Source: TC Energy Nov 29, 2022 Investor Day

Figure 32: 94% of Keystone System is under long term contract

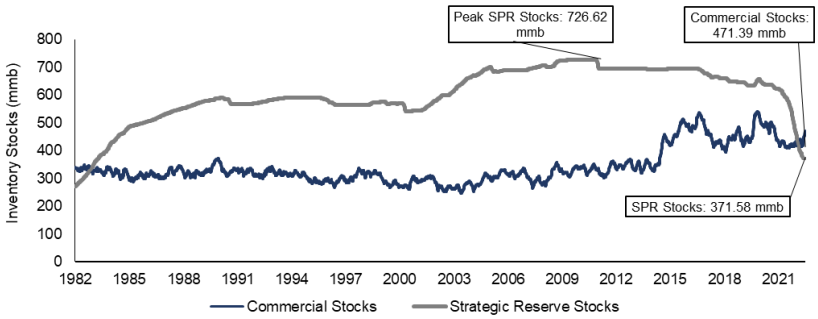


Source: TC Energy Nov 29, 2022 Investor Day

Oil – US SPR reserves now -99.8 mmb lower than commercial crude oil reserves

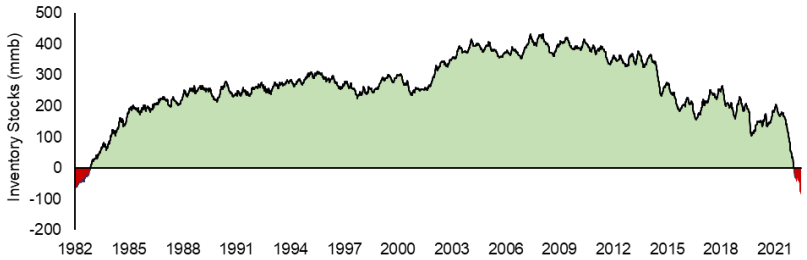
Oil in US Strategic Petroleum Reserves (SPR) moved below total US commercial crude oil reserves in the Sept 16 week for the first time since 1983, with the deficit widening again this week due to the big build in commercial oil stocks that was primarily driven by another drop in US oil exports during the cold weather in the Gulf Coast. The EIA's new weekly oil data for Feb 10 has SPR reserves at 371.6 mmb vs commercial crude oil reserves at 471.4 mmb. The last time the SPR was down at this level was on Dec 1983 at 371.,291 mmb. The below graphs highlight the difference between commercial and SPR stockpiles.

Figure 33: US Oil Inventories: Commercial & SPR



Source: EIA

Figure 34: US Oil Inventories: SPR less commercial



Source: EIA

Oil – US SPR going 26 mmb lower with the new plan to sell 26 mmb from SPR

On Monday, Bloomberg reported "*The Biden administration plans to sell more crude oil from the Strategic Petroleum Reserve, fulfilling budget directives mandated years ago that it had sought to stop as oil prices have stabilized. The congressionally mandated sale will amount to 26 million barrels of crude, according to people familiar with the matter. The sale is in accordance with a budget mandate enacted in 2015 for the current fiscal year, said a spokesperson for the Department of Energy. The Energy Department has sought to stop some of the sales required by 2015 legislation so that it can refill the emergency reserve, which currently has about 371 million barrels. After this latest release, the reserve will dip to about 345 million."* The last time the SPR was 345 mmb was in Aug 1983 at 345.7 mmb.

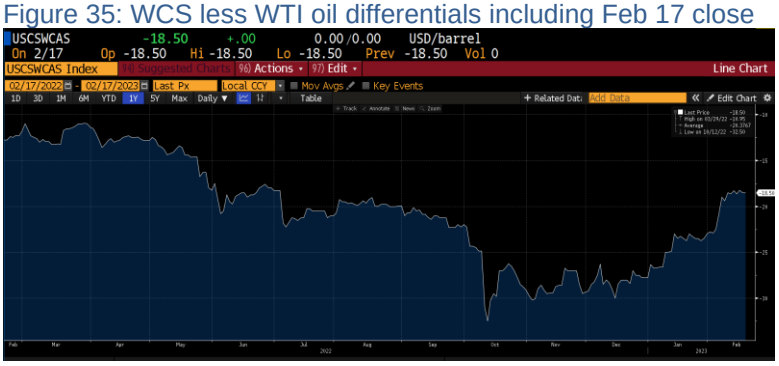
Oil – Cdn oil differentials basically flat at $18.50 at close on Feb 17

WCS less WTI differentials

Note that we would expect to see a narrowing of Cdn oil differentials as normally happens every spring. Six weeks ago, the WCS-WTI differential was $26.60 on Jan 6, but narrowed to $23.00 on Jan 13, bounced up and down to close at $23.75 on Jan 27, down the next week to close at $22.50 on Feb 3, then down last week to close at $18.65 on Feb 10, and basically flat to close at $18.50 on Feb 17. For perspective, a year ago, the WCS-WTI differential was

$12.75 on Feb 17, 2022. Below is Bloomberg's current WCS–WTI differential as of Feb 17, 2023 close.

Figure 35: WCS less WTI oil differentials including Feb 17 close



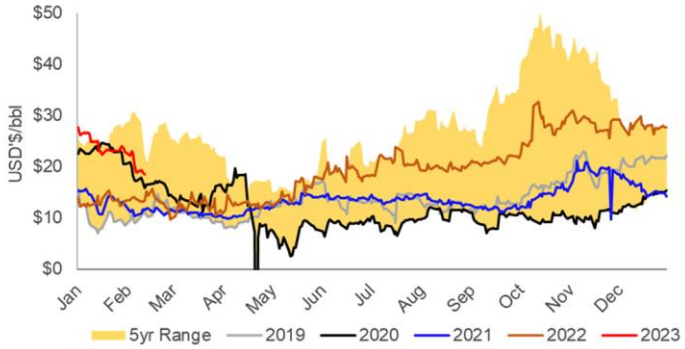
Source: Bloomberg

Oil – Moving into normal season narrowing of Cdn heavy oil differentials

WCS differentials normally narrow in spring

Unfortunately, there are often items like Keystone pipeline outage that impact Cdn heavy oil differentials. And the huge item, the release of mostly medium oil out of the SPR. It's not just unplanned events, but there are many items that impact Cdn heavy oil differentials, but we remind that we are just moving into the time of the year that normally sees Cdn heavy oil differentials narrow. This is the time of year, when refineries tend to maximize production of asphalt ahead of the annual summer paving season. As is said in Canada, there are two seasons in Canada – winter and paving season. Below is graph showing WCS-WTI differentials that shows this normal seasonal trend of narrowing WCS-WTI differentials from Feb thru May.

Figure 36: WCS less WTI oil differentials



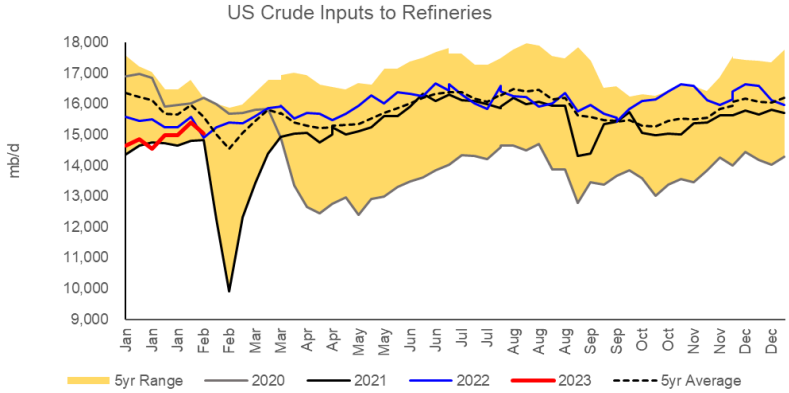
Source: Bloomberg

Oil – Refinery inputs down -0.383 mmb/d WoW to 15.027 mmb/d as weather warms

Refinery crude oil inputs declined this week, back down to similar levels seen two weeks ago after a partial recovery last week from the cold weather in the Gulf Coast in Jan that led to

some temporary refinery impacts. On Wednesday, the EIA released its estimated crude oil input to refinery data for the week ended Feb 10. The EIA reported crude oil inputs to refineries were down -0.383 mmb/d this week to 15.027 mmb/d and are +0.125 mmb/d YoY from 14.902 mmb/d for the week ended Feb 11, 2022. Note that Feb/early March is when we normally see refineries move into turnaround/maintenance ie. crude oil inputs seasonally decline, as they switch to produce more summer fuels. This week's refinery utilization was up to 86.5%, which is -1.4% WoW and +1.2% YoY. Total products supplied (i.e., demand) decreased WoW, down -1.234 mmb/d to 19.302 mmb/d, and Motor gasoline was down -0.154 mmb/d to 8.274 mmb/d from 8.428 mmb/d last week. The 4-week average for Motor Gasoline was down -0.273 mmb/d YoY to 8.334 mmb/d. The 4-week average of Total demand was down -2.264 mmb/d YoY to 19.848 mmb/d.

Figure 37: US Refinery Crude Oil Inputs (thousands b/d)



Source: EIA

Oil – US "net" oil imports down -1.027 mmb/d WoW to 3.086 mmb/d

US "net" oil imports down WoW

US "NET" imports down -1.072 mmb/d to 3.086 mmb/d for the Feb 10 week. US imports were down -0.826 mmb/d to 6.232 mmb/d. US exports were up +0.246 mmb/d to 3.146 mmb/d. The WoW decrease in US oil imports was driven mostly by Top 10 with a decrease of -0.704 mmb/d. Some items to note on the by country data. (i) Canada was down this week -0.300 mmb/d to 3.556 mmb/d. (ii) Saudi Arabia was down -0.122 mmb/d to 0.262 mmb/d. (iii) Colombia was up +0.073 mmb/d to 0.143 mmb/d. (iv) Ecuador was down -0.051 mmb/d to 0.156 mmb/d. (v) Iraq was up +0.092 mmb/d to 0.322 mmb/d. (vi) Mexico was down -0.224 mmb/d to 0.690 mmb/d.

Figure 38: US Weekly Preliminary Oil Imports by Major Countries

US Weekly Preliminary Crude Imports By Top 10 Countries (thousand b/d)															
(thousand b/d)	Nov 11/22	Nov 18/22	Nov 25/22	Dec 2/22	Dec 9/22	Dec 16/22	Dec 23/22	Dec 30/22	Jan 6/23	Jan 13/23	Jan 20/23	Jan 27/23	Feb 3/23	Feb 10/23	WoW
Canada	3,076	3,844	3,354	3,423	3,795	3,066	3,504	2,949	3,737	3,707	3,419	3,587	3,856	3,556	-300
Saudi Arabia	211	685	338	274	317	513	473	479	464	453	433	640	384	262	-122
Venezuela	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mexico	528	495	300	585	602	632	581	428	668	909	511	758	913	690	-223
Colombia	143	170	290	292	248	71	353	357	246	245	244	216	70	143	73
Iraq	141	385	363	252	282	227	289	354	150	201	195	469	230	322	92
Ecuador	101	42	242	159	157	70	274	87	137	0	69	243	207	156	-51
Nigeria	181	43	50	159	171	136	66	141	143	211	114	317	248	75	-173
Kuwait	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Angola	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Top 10	4,381	5,664	4,937	5,144	5,572	4,715	5,540	4,795	5,545	5,726	4,985	6,230	5,908	5,204	-704
Others	1,178	1,399	1,100	868	1,295	1,104	712	917	805	1,135	920	1,053	1,150	1,028	-122
Total US	5,559	7,063	6,037	6,012	6,867	5,819	6,252	5,712	6,350	6,861	5,905	7,283	7,058	6,232	-826
Source: EIA															

Source: EIA

Oil – Chevron set ship >100,000 b/d Venezuela crude to Gulf coast in Feb

Chevron ramping up Venezuela oil to US

We recognize that most have been in the camp that don't expect Chevron to quickly ramp up Venezuela oil to the Gulf Coast refineries. Chevron only got their 6-month license in Dec but it looks like they will be able to ship >100,000 b/d in Feb. On Thursday, Bloomberg reported "*Chevron is set to ship over 100,000 bpd of Venezuelan crude to the US in February under a license from the US Treasury Department, Reuters reports, citing shipping documents and data viewed by the outlet. * Chevron also exported around 75,000 bpd of Venezuelan crude to its Pascagoula, Mississippi refinery in January * Firm also sold cargoes to Phillips 66 and Valero Energy * Chevron has received and exported three cargoes of Venezuelan oil to the same destinations and is set to load five additional cargoes by the end of February."*

Oil – Libya sees low-risk development to go from 1.2 to 1.5 mmb/d in 2023

Libya low risk oil growth in 2023

We have been reporting on how Libya has surprisingly been able to keep oil production steady ~1.2 mmb/d. At the same time, we have always highlighted the big near term upside potential to its oil production if east vs west armed fighting can stay on the sidelines as that will see the return of foreign capital for both natural gas and oil. But even before foreign capital, the Libya National Oil Corporation has many low risk development opportunities to increase oil production. On Tuesday, the Libya Herald reported [LINK] on comments from one of Libya NOC's operating companies, Arabian Gulf Oil Company (AGOCO) Chairman Salah Gatrani. The Libya Herald wrote "*The continuation of the Arabian Gulf Oil Company's (AGOCO) development operations at this pace will inevitably lead to Libya reaching a production rate of more than 1.5 million barrels of oil per day in 2023, AGOCO chairman Salah Gatrani said in an exclusive statement to Libya Herald. He said this was because of the stability witnessed by the country in general, and by the oil sector in particular. Therefore, he continued, the Gulf Company has developed its own plan within the efforts of the National Oil Corporation (NOC). Libya has been unable to maintain production beyond 1.2 million bpd. Gatrani was commenting to Libya Herald following Sunday's AGOCO's meeting on developing reserves and increasing oil production in the sector companies, attended by relevant AGOCO and NOC management. The AGOCO chairman said that his company has already begun to implement the plan prepared by the NOC to raise production and increase reserves."* Our Supplemental Documents package includes the Libya Herald report.

Oil – Two years ago, Russia said only half of its reserves were profitable at $50

Russia on its oil reserves

There have been a number of different views on why Russia said they were voluntarily reducing production by 500,000 b/d in March. We have had a much simpler view because we have been following and highlighting Russia's own comments that half of their reserves aren't profitable at $50. So our approach has been that their voluntary cut is because they have production that isn't worth producing given the hit to their revenue per barrel from how sanctions have forced Russia to discount their oil prices, increased shipping and insurance costs, etc. After seeing a range of views on why Russia is doing the voluntary cuts, we retweeted our Feb 10, 2023 tweet that started off "Voluntary = non-profitable?". On Wed, we tweeted [LINK] "*see 👇thread how two years ago russia acknowledged, at least in russian media, half of their oil reserves weren't profitable at $50. no one should be surprised they are shutting in 500,000 bpd given price discounts etc #OOTT*." Our Feb 10 tweet was "[LINK] "*Voluntary = non-profitable? Russia's "voluntary" reduction of 500,000 b/d. Makes sense, See 👇09/02/21 & 01/27/21 tweets, admitted had a lot of marginal #Oil. Then add forced price discount & higher shipping, insurance costs from sanctions. #OOTT".* Russia's 2021 comments makes believe their voluntary cut is really just an acknowledgement that some of its oil production wasn't profitable given the impact of forced price discount, added shipping and insurance costs from sanctions. Long before sanctions, Russia openly acknowledged, at least in Russia press, that half of its reserve weren't profitable at $50. Now that was referring to reserves and not necessarily production, but given how Russian oil exports are being hit by price discounts, higher shipping and insurance costs, we have to wonder if the 500,000 b/d is really just shutting in production that isn't profitable.

Sept 2, 2021, Russia said only half of its oil reserves were profitable at $50

Our Friday tweet linked to a Sept 2, 2021 tweet [LINK] "*Only half of Russia's #Oil reserves are profitable at $50 says Deputy Energy Minister Sorokin. Fits Jan 27 linked tweet. Bullish for mid/long term oil prices. Detailed comment in SAF Group Jan 27, 2021 Energy Tidbits memo https://safgroup.ca/news-insights/ #OOTT*." Our Sept 5, 2021 Energy Tidbits memo was titled "*Only Half of Russia's Oil Reserves are Profitable at $50 says Deputy Energy Minister Sorokin*." We then wrote ""*We will ask the same rhetorical question as we did in our Jan 31, 2021 Energy Tidbits – imaging what markets would say if Exxon were to come out in their year end reporting and say only 50% of its existing oil reserves are profitable at $50? On Thursday, we tweeted [LINK] "Only half of Russia's #Oil reserves are profitable at $50 says Deputy Energy Minister Sorokin. Fits Jan 27 linked tweet. Bullish for mid/long term oil prices. Detailed comment in SAF Group Jan 27, 2021 Energy Tidbits memo". There was a typo in the tweet as we should have said the Jan 31, 2021 Energy Tidbits memo that was titled "Russia Says Increasing Water Cut, Deteriorating Development, Etc Mean Only 36% of Its Oil Reserves are Profitable." This week, Russia's Deputy Energy Minister Sorokin came out with almost identical comment as he did on Jan 27, 2021 saying "even in our current structure of reserves, a significant part of it is unprofitable at a price of $50 – about half there. There is a very large layer of opportunities for working with the current resource base: with small fields, with depleted, with tailing assets, with deeper and more difficult layers. What you need to concentrate on". Sorokin's Jan 27 comments were basically overlooked as they were only in the TASS Russian news version. But we thought then and still think know that this is a significant admission from Russia as to the mid/long oil supply and we believe a*

bullish comment for oil in the 2020s. One difference is that Sorokin gave much more insight into the uneconomic oil reserves in his Jan 27 comment in Russia. Below is what we wrote in our Jan 31, 2021 Energy Tidbits on his comments. Our Supplemental Documents package includes the TASS Sept 2 report on Sorokin's comments."

Jan 27, 2021, Sorokin said 64% of oil reserves not profitable

Our Friday tweet also linked to a Jan 27, 2021 tweet. Here is what we wrot in or Jan 31, 2021 Energy Tidbits memo on that tweet. "*Imagine what markets would say if Exxon were to come out in their year end reporting and say that 64% of its existing oil reserves are not profitable at >$50 oil. The stock would be creamed as markets would think Exxon wouldn't have oil growth potential and its oil production had likely peaked. This is what Russia said this week for their oil reserves. We were surprised by a TASS Russian news story on Wed morning and would have thought it was a fake if it wasn't on TASS as we would never have thought Russia's #2 oil official (after Novak) would be saying what he did. We tweeted [LINK] "1/2. must read, bullish for oil @tass_agency story "only 36% of oil reserves in Russia are profitable". multiple indicators of maturing oil supply ie. deeper, smaller pools, etc. Effectively says RUS has more or less reached peak oil supply unless #Oil prices are higher #OOTT .." and [LINK] "2/2. surprising RUS lays this out, but fits to Novak's Dec comments and why they would want higher oil prices for 2020s sooner. see SAF Group blog Russia Says its a Price Taker at $45 in 2021, May Be the New Strategy Needed for OPEC+ to Fix Post Covid Oil Prices For 2020s. #OOTT". TASS wrote "Only 36% of 30 billion tons of oil reserves in Russia are profitable, which is associated with the deterioration of development conditions and a drop in the quality of reserves, writes the Deputy Minister of Energy of the Russian Federation Pavel Sorokin in an article for the Energy Policy magazine. "According to the data of the inventory of the economics of field development, carried out on behalf of the Russian government, out of 30 billion tons of recoverable oil reserves in Russia, only 36% is profitable in the current macroeconomic conditions. This is due to the deterioration of development opportunities: an increase in water cut, the need to permeability and compartmentalization of reservoirs, withdrawal into marginal zones and strata with small thicknesses, and so on, "Sorokin explained." This is significant, Sorokin is basically saying Russia has more or less reached peak oil supply, or at least peak oil supply unless prices are going higher. Maybe there is some growth but Russia has to first arrest declines. This is very different than what we see in the Middle East. Russia is saying its maturing oil production/reserves base needs higher oil prices as its oil base is maturing and they are going after smaller pools (higher cost per barrel), deeper zones (higher costs per barrel) and need new technology (we wonder if this means shale, although Putin has been negative). And also very different than Saudi Arabia. Their costs are going up to, but they aren't saying their oil production/reserves needs higher oil prices to be economic. Rather they and others like we saw with Kuwait this week need higher oil prices to balance their govt budget. They don't say they need higher oil prices to develop its oil reserves. One reminder, producing oil reserves isn't like drinking a glass of water, where you turn the cup down and the water flows out at the same rate until the glass is empty. As oil reserves produce more from a reservoir that is economic today, the oil recovery rate*

declines over time and the future barrels become more expensive to produce. This is more than food for thought. If peak oil demand isn't here until 2030, then its bullish for oil post Covid. Even if oil demand only recovers to pre Covid, its bullish or at least supportive of higher prices. Our Supplemental Documents package includes the Google Translate version of the TASS Russian story."

Oil – Timeline leading up to Russia's invasion of Ukraine

Timeline pre Russia's invasion

Feb 24 marks one year from the start of Russia's invasion of Ukraine. We can't imagine how long it has felt for Ukrainians given all they have had to suffer. And no one could have predicted they would still be in the fight of their lives one year later with no clear idea what will happen over the coming days and weeks. When you think about the situation, you wonder how did it all come to here? There is a good recap of the events leading up to the invasion by Reuters "*Timeline: The events leading up to Russia's invasion of Ukraine*". [LINK] Our Supplemental Documents package includes the Reuters timeline.

Oil – OPEC MOMR: Relatively neutral with slight increase to forecasts

OPEC Monthly Oil Market Report

On Tuesday, OPEC released its Monthly Oil Market Report at ~6:15 am MT. (i) We thought the overall takeaway from the OPEC MOMR for Feb was neutral. There was a small YoY increase in 2023 demand and call on OPEC but a small narrowing of the oil & products stocks vs the 2015-2019 average. (ii) 2022 average demand was unchanged at 99.55 mmb/d, which was -0.72 mmb/d vs pre-Covid of 100.27. (iii) 2023 average demand was increased to 101.87 mmb/d (was 101.77). OPEC's 2023 demand changes by quarter: Q1/23 now 101.26 mmb/d (was 101.04), Q2/23 now 100.70 mmb/d (was 100.65), Q3/23 now 101.99 mmb/d (was 101.90), Q4/23 demand now 103.51 mmb/d (was 103.47). This means 2022 YoY growth remains at +2.54 mmb/d while 2023 was revised up to +2.32 mmb/d from +2.22 mmb/d. (iv) China demand. The MOMR increased expectations for China oil demand as it moves away from Covid restrictions with slight upward revisions in OPEC's 2023 forecasts. China's demand forecast now reflects a full year average 15.40 mmb/d, up from 15.27 mmb/d. Q1/23 now 15.10 mmb/d (was 14.90), Q2/23 now 15.22 mmb/d (was 15.20), Q3/23 now is 15.25 mmb/d (was 15.32), and Q4/23 now 16.03 mmb/d (was 15.89). In Feb's MOMR, they wrote *"The world oil demand growth forecast for 2022 remains unchanged from last month's assessment at 2.5 mb/d. The OECD demand in 4Q22 was adjusted downward to reflect the latest data but non-OECD demand in 4Q22 was revised higher due to improvements in economic activity in some countries and a slight recovery in oil demand in China after the lifting of its zero-COVID-19 policy. For 2023, world oil demand growth is adjusted slightly upwards by 0.1 mb/d to stand at 2.3 mb/d. The OECD is projected to grow by around 0.4 mb/d and non-OECD at about 2.0 mb/d."* (v) non-OPEC supply. Immaterial decreases to YoY growth for 2022 of +1.89 mmb/d to 65.57 mmb/d (was +1.93 mmb/d to 65.61 mmb/d), and for 2023 of +1.44 mmb/d (was +1.55) to 67.01 mmb/d (was 67.16 mmb/d) partially due to lower starting point. Note that 2023 growth is inclusive of NGLs. (vi) OPEC Secondary Sources for Jan -49,000 b/d MoM to 28.876 mmb/d. For OPEC10 (the countries in the quota), Jan production was 24.485 mmb/d, which is only -37,000 b/d MoM vs 24.522 mmb/d in Dec. (vii) Direct Communications (what the OPEC countries report). There were a few items to note vs what countries reported directly vs Secondary Sources estimates: Libya did not provide direct communications estimate for Dec; Venezuela says it produced 732,000 b/d in Jan vs 686,000 b/d from Secondary Sources; Iraq says it produced less at 4.331

mmb/d vs Secondary Sources of 4.424 mmb/d. Our Supplemental Documents package includes excerpts from the OPEC MOMR Feb.

Oil – No sign yet of peak oil demand, IEA OMR forecasts record oil demand in 2023

IEA Oil Market Report

The key reminder from the IEA this week is that there is still no sign of peak oil demand. On Wednesday, the IEA released its monthly Oil Market Report for Jan at 2am MT. They only release very limited public info, but Bloomberg provided detailed tables and added color from the report. So big thanks, as usual, to the Bloomberg team. (i) The IEA forecasts another new record oil demand in 2023 and with huge YoY oil demand momentum to exit 2023. (ii) The IEA is known as an oil demand bear who seems to reluctantly increase its oil demand forecasts. *It did so again this month. We tweeted [LINK] "'Total [#Oil] demand will hit a RECORD 101.9 mb/d [2023], 1.4 mb/d more than the 2019 average" @IEA OMR Feb. Vs OMR Jan "Global oil demand is set to rise by 1.9 mb/d in 2023, to a record 101.7 mb/d". See 👇02/05 tweet, @fbirol signaled a demand increase. #OOTT."* Oil demand YoY growth for 2023 revised up and is now +2.0 mmb/d YoY to another new record 101.9 mmb/d. (iii) The IEA sees oil markets moving from a surplus in H1 to a deficit in H2. The IEA wrote, "*Crude oil supply is set to fall below refinery demand in the second half of the year."* This makes sense as the normal seasonal pattern for oil demand is Q1 of every year (peak of winter) is normally down QoQ vs Q4 of the prior year. Then oil demand normally increases a little big QoQ in Q2, before the bigger increases in Q3 (peak of summer consumption) and another increase in Q4. The IEA forecasts Q4/22 oil demand at 100.8 mmb/d, but then forecasts 2023 oil demand by quarter of 100.1 mmb/d in Q1/23, 101.1 mmb/d in Q2/23, 102.9 mmb/d in Q3/23 and 103.5 in Q4/23. (iv) No signs of oil demand growth slowing down to leave 2023. IEA's Q4/23 demand forecast of 103.5 mmb/d is +0.6 mmb/d QoQ and +2.7 mmb/d YoY. (v) On Russia, IEA highlights that oil production and exports are holding up well. The IEA writes "*Russian oil production and exports have held up relatively well despite sanctions. The country has managed to reroute shipments of crude to Asia and the G7 price cap on crude appears to be helping to keep the barrels flowing. In January, output was down only 160 kb/d from pre-war levels, with a lofty 8.2 mb/d of oil shipped to markets."* (vi) On the negative, the IEA estimated the deficit of OECD industry stocks narrowed at Dec 31 vs Nov 30. The Feb OMR estimates Dec 31 OECD stocks at 95.7 mmb below the 5-yr average, vs Jan OMR that had Nov 30 OECD stocks at 125.9 mmb below the 5-yr average. (vii) Feb OMR 2023 non-OPEC YoY growth is increased to +0.9 mmb/d YoY to 66.6 mmb/d (was +0.7 mmb/d to 66.4), but note the big increase MoM was to FSU (Russia and other countries that were former Soviet Union) that was increased to 13.0 mmb/d (was 12.7 mmb/d) in 2023. Our Supplemental documents package includes the IEA release and the Bloomberg reports.

Figure 39: IEA Global Demand Forecast by OMR Report Month

mmb/d	2020	2021	21-20	Q1/22	Q2/22	Q3/22	Q4/22	2022	22-21	Q1/23	Q2/23	Q3/23	Q4/23	2023	23-22
Feb 23	91.0	97.7	6.7	99.5	98.7	100.7	100.8	100	2.3	100.1	101.1	102.9	103.5	101.9	1.9
Jan 23	91.0	97.7	6.7	99.5	98.7	100.7	100.5	99.9	2.2	99.6	100.8	102.9	103.5	101.7	1.8
Dec 22	91.0	97.7	6.7	99.5	98.7	100.7	100.8	99.9	2.2	99.7	100.6	102.7	103.4	101.6	1.7
Nov 22	91.0	97.7	6.7	99.4	98.7	100.3	100.7	99.8	2.1	99.6	100.5	102.3	103.0	101.4	1.6
Oct 22	91.0	97.7	6.7	99.4	98.5	100.0	100.6	99.6	1.9	99.5	100.4	102.1	102.9	101.3	1.7
Sep 22	91.0	97.7	6.7	99.5	98.4	99.9	100.9	99.7	2.0	100.2	101.0	102.6	103.3	101.8	2.1
Aug-22	91.0	97.6	6.6	99.4	98.5	100.0	100.8	99.7	2.1	100.3	101.1	102.5	103.3	101.8	2.1
July 22	91.0	97.5	6.5	99.3	97.8	99.4	100.2	99.2	1.7	99.8	100.8	102.0	102.7	101.3	2.1
June 22	91.0	97.5	6.5	99.3	98.2	99.8	100.4	99.4	1.9	100.5	101.1	101.9	102.7	101.6	2.2
May 22	91.0	97.5	6.5	98.8	98.2	100.0	100.4	99.4	1.9						
Apr 22	91.0	97.5	6.5	98.5	98.3	100.1	100.5	99.4	1.9						
Mar 22	91.0	97.5	6.5	99.0	98.8	100.2	100.6	99.6	2.1						
Feb 22	91.0	97.4	6.4	98.9	100.1	101.7	101.6	100.6	3.2						
Jan 22	91.0	96.4	5.4	97.8	99.3	100.9	100.8	99.7	3.3						
Dec 21	91.0	96.2	5.2	97.9	99.1	100.8	100.3	99.5	3.3						

Source: IEA, SAF

Looks like Birol was signaling an IEA increase to its 2023 oil demand forecast

We look at IEA's Executive Director as similar to politicians in that they all like to give hints on what is to come. Kind of like, you should have listened to what I said. Last week's (Feb 12, 2023) Energy Tidbits highlighted what we thought was a signaling by IEA Executive Director that the IEA would be increasing its oil demand forecast for 2023. Here is what we wrote "*The IEA posts its monthly Oil Market Report on Wed Feb 15. Last Sunday afternoon, we tweeted [LINK] "Hmmm! Maybe an increase to @IEA 2023 #Oil demand in Feb OMR? @fbirol "i look at the #JetFuel demand in China, it is growing very, very strongly. if the rebound continues at this pace, we may see definitely upward pressure on the demand side". Thx @menakadoshi. #OOTT." IEA Executive Director Fatih Birol was interviewed on Bloomberg last Sunday afternoon. And he seemed to signal that the IEA will be increasing its oil demand growth forecast for 2023, at least for China. He was asked about the biggest uncertainty for the near term for oil said it was China, both for oil and natural gas. He referenced the IEA current forecast assumes China is half of the global oil demand increase in 2023 and that was assuming a moderate recovery. And a stronger recovery would put upward pressure on demand and prices. He specifically noted jet fuel demand was growing "very very strongly" and if that continues, hen may see definite upward pressure. Our tweet included the transcript of his response. Here is what he said 'Birol "there are many uncertainties as we have been discussing since a year. Oil markets are always seeing a lot of uncertainties, but in the year 2023. If you ask me to choose the most important uncertainty, it is for me, China. Both for oil and gas markets. Because last year, 2022, Chinese oil and gas consumption, domestic consumption, declined for the first time since 40 years. We have never seen Chinese oil and gas demand decline since 40 years. And if we consider that China is the #1 oil importer of the world, top LNG importer of the world. If Chinese economy rebounds, rebounds strongly, this will have important implications for the oil and LNG markets. Because even current situation if we see a moderate rebound of Chinese economy, we expect this year about half of the growth in global oil demand will come from China only. But this is moderate and maybe as some international financial institutions claim, Chinese economic rebound may be much stronger than expected. This will put some higher upward pressure on the demand side and*

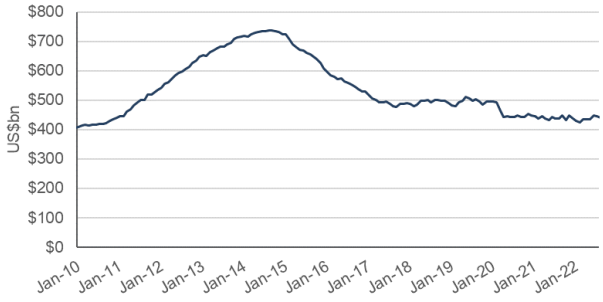
therefore on the prices unless OPEC+ countries take steps to comfort the market. But the same applies to LNG markets as well. " Bloomberg's Doshi "I am going to ask you to answer the OPEC question in just a bit. But before that Mr. Birol, why haven't we seen any feed in yet of the China recovery process into prices yet. Do you think because it's just too nascent?" Birol "It is just starting, For example before coming here, I look at the jet fuel demand in China, it is growing very, very strongly. If the rebound continues at this pace, we may see definitely upward pressure on the demand side."

Oil – Saudi nest egg, decrease in net foreign assets in December

Saudi net foreign assets

We continue to believe the #1 financial theme for Saudi Arabia in the 2020s will be their continued, and likely increasing, use of Other People's Money as they try to transition their country to MBS's Vision 2030. We believe this has been obvious with how Saudi Arabia's net foreign assets dropped by about $300 billion over seven years. We are surprised that markets and oil watchers didn't seem to pay attention to the Saudi net foreign assets data i.e., what we call their nest egg to help them thru the Energy Transition. Saudi net foreign assets have dropped by $297.5b in the last 8 years, from is peak of $737.0b on Aug 31, 2014, to $439.5b on Dec 31, 2022. That is an average of $3.1b per month for the last 8 years. Oil prices continued to fall throughout December with Brent crude averaging ~$82 for the month, compared to ~$91 in November. Saudi Arabia's net foreign assets on December 31 were down -$12.3b MoM to $439.5b vs $451.8b in November and $444.5b in October. Saudi Arabia is far from going broke but there has been a huge decline in the last 8 years, but it is still a very big nest egg. This net foreign asset depletion is why we have been highlighting that the primary financial theme for Saudi Arabia in the 2020s is getting Other People's Money (OPM) to fund as much of their Vision 2030 as possible. And no question, accessing OPM has helped to slow down and temporarily pause the decline in net foreign assets. Saudi Arabia's central bank (SAMA) doesn't provide explanations for the monthly swings. Saudi net foreign assets on December 31 of $439.5b are down -$9.4b YoY from $448.9b on December 31, 2021. We believe the $297.5b drop in net foreign assets is why there has been such a big push in the last few years to get OPM so Saudi doesn't keep depleting its nest egg. And why we call this the #1 financial theme for Saudi Arabia in the 2020s – the increasing use of Other People's Money. And not just in Saudi Aramco, although we do expect to see more equity and bond sales from Aramco. Below is our graph of Saudi Arabia net foreign assets updated for the December 31 data.

Figure 40: Saudi Arabia Net Foreign Assets



Source: Bloomberg

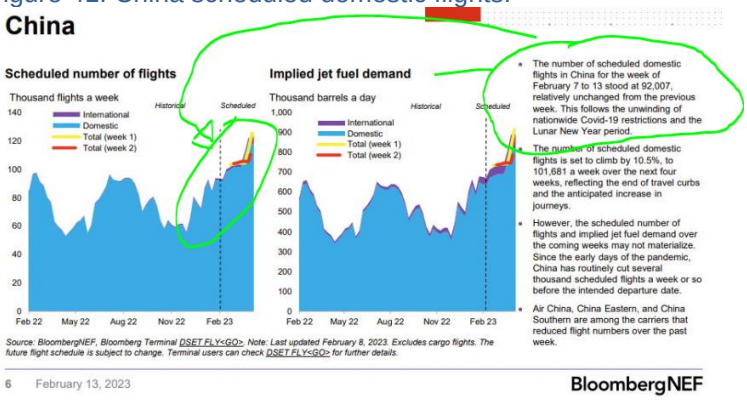
Source: Bloomberg

Oil – China domestic flights -0.7% WoW, but international flights continue to ramp up

China domestic flights

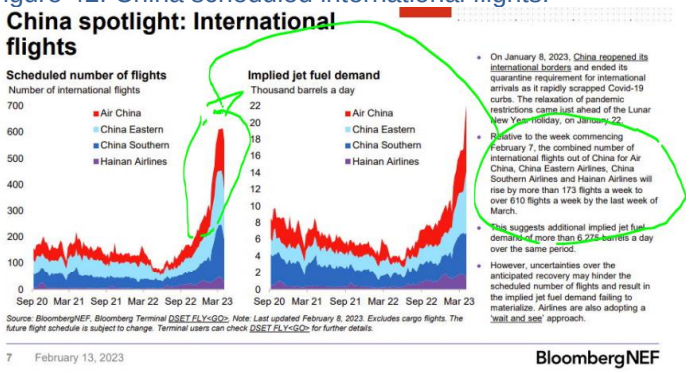
China's scheduled domestic flights were flat this week, but scheduled international flights continue to ramp up. On Monday, we tweeted [LINK] "*China domestic flights post Covid restrictions lift & Lunar New Year period. Feb 7-13: -0.7% WoW. Jan 31-Feb 6: +10.9% WoW. Jan 24-30: -9% WoW. Jan 17-23: +7% WoW. Jan 10-16: +20% WOW. China international flights continue to ramp up. Thx @BloombergNEF Claudio Lubis. #OOTT."* For International flights, BNEF wrote "*Relative to the week commencing February 7, the combined number of international flights out of China for Air China, China Eastern Airlines, China Southern Airlines and Hainan Airlines will rise by more than 173 flights a week to over 610 flights a week by the last week of March."* Below are the BNEF China scheduled domestic and international flights.

Figure 41: China scheduled domestic flights.



Source: BloombergNEF

Figure 42: China scheduled international flights.



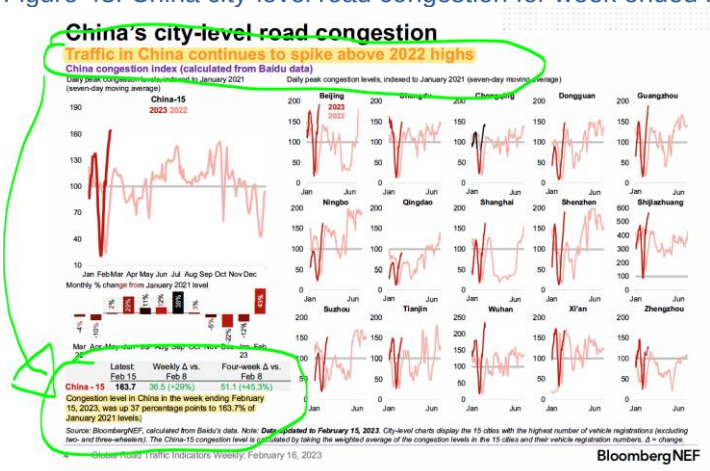
Source: BloombergNEF

Oil – "Traffic in China continues to spike above 2022 highs"

China's city road congestion up strong

There doesn't seem to be much doubt that the removal of Covid restrictions has led to people to get in their cars and back to work or just get out and about. On Thursday, we tweeted [LINK] *"Traffic in China continues to spike above 2022 highs". China city-level road congestion (Baidu data). +37% for wk ending Feb 15 to 163.7% of Jan 2021 levels. China reopening! Thx @BloombergNEF. #OOTT".* BloombergNEF's Global Road Traffic Indicators Feb 16, 2023 described China's city-level road congestion as "*Traffic in China continues to spike above 2022 highs"* based on Baidu data for the week end Feb 15 that estimated China congestion level for week ending Feb 15, 2023 was up 37% to 163.7% of Jan 2021 levels. This follows two prior strong weeks. On Feb 9, we tweeted [LINK] "*China reopening. China city-level road congestions (Baidu data) up big post Lunar New Year holiday. +52% for wk ending Feb 8 to 127.2% of Jan 21 levels. +50% for wk ending Feb 1 (New Year was Jan 22) to 75.2% of Jan 2021 levels. Thx @BloombergNEF. #OOTT."* Our tweet included the below BloombergNEF graphic that shows Baidu data for road congestion in China's major cities.

Figure 43: China city-level road congestion for week ended Feb 15



Source: BloombergNEF

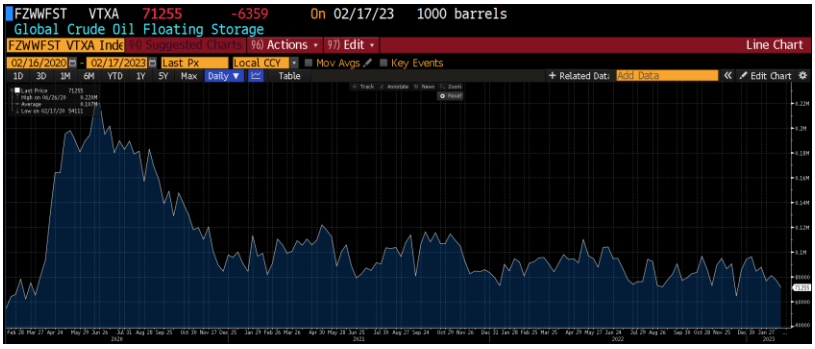
Oil – Vortexa crude oil floating storage 71.26 mmb. -6.35 mmb WoW

Vortexa crude oil floating storage

We are referencing the Vortexa global crude oil floating storage data posted on the Bloomberg terminal as of 10am MT yesterday. Note that these estimates get revised over the course of the week and the revisions can go back months. We do not check daily for the revisions, so our comments on the new estimates are compared to the prior week's Vortexa estimates posted on Bloomberg on Feb 11 at 10am MT. (i) As of 10am MT yesterday, Bloomberg posted Vortexa crude oil floating storage estimate for Feb 17 of 71.26 mmb, which is -6.35 mmb WoW vs revised up big Feb 10 of 77.61 mmb. Note Feb 10 was revised +14.58 mmb vs 63.03 mmb originally posted on Bloomberg as of 10am MT on Feb 11. (ii) What still isn't clear is now the increasing number of dark tankers moving Russian oil is impacting the Vortexa estimates. (iii) All of the last seven weeks revisions were upward revisions but the +14.58 mmb revision to Feb 10 was the only one mor than the +3.41 mmb revision for Feb 3. (iv) The revisions from the estimates posted yesterday at 10am MT vs the

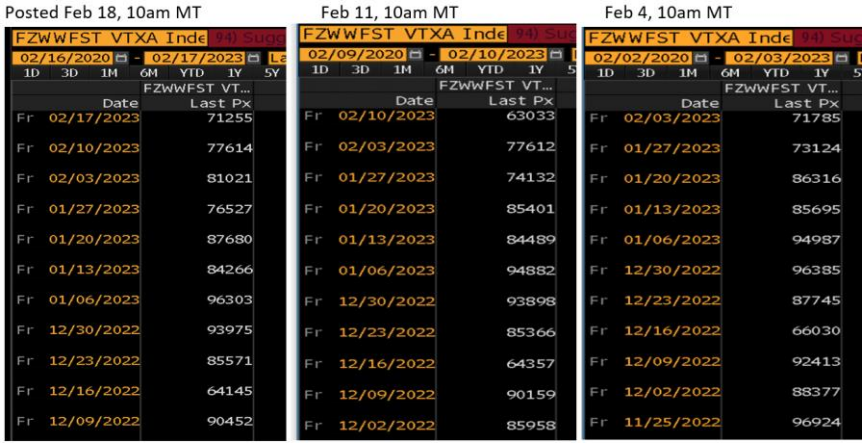
estimates posted on Bloomberg as of 10am MT on Feb 11 are as follows: Feb 10 revised +14.58 mmb. Feb 3 revised +3.41 mmb. Jan 27 revised +2.40 mmb. Jan 20 revised +2.28 mmb. Jan 13 revised -0.22 mmb. Jan 6 revised +1.42 mmb. Dec 30 revised +0.08 mmb. (v) There is still a wide range of floating storage for the past several weeks, but a simple average for the past seven weeks is 82.10 mmb, which is up vs last week's 81.92 mmb. (vi) Also remember Vortexa revises these weekly storage estimates on a regular basis and we do not track the revisions through the week. (vii) Feb 17 estimate of 71.26 mmb is -149.05 mmb vs the post-Covid peak on June 26, 2020 of 220.31 mmb. (viii) The below graph goes back 3 years and not just 2 years as floating oil storage was in the big ramp up period in Q2/20 as Covid started to have a huge impact. Feb 17 estimate of 71.26 mmb is +17.15 mmb vs Pre-Covid of 54.11 mmb on Feb 17, 2020. Feb 17 estimate of 71.26 mmb is -9.26 mmb YoY vs Feb 18, 2022 of 80.52 mmb. (ix) Below are the last several weeks of estimates posted on Bloomberg as of 10am MT on Feb 18, 10am MT on Feb 11, and 10 am MT on Feb 4.

Figure 44: Vortexa Floating Storage posted on Bloomberg Feb 18 at 10am MT



Source: Bloomberg, Vortexa

Figure 45: Vortexa Estimates Posted Feb 18 10 am MT, Feb 11 10am MT, Feb 4 10am MT



Source: Bloomberg, Vortexa

Oil – US TomTom mobility indicator shows YoY strength for US/Europe

US oil indicators weekly

In the BloombergNEF US Oil Indicators Weekly report we continue to see the same signals from the indicators for US gasoline consumption from BloombergNEF US Oil Indicators Weekly. On Friday we tweeted, [LINK] "*US TomTom congestion index for week ended Feb 10 is closer than a year ago, but still below 2019 levels. Probably not surprising given continued uncertainty on economy & rates. But still trending the right way! Thx @BloombergNEF Danny Adkins. #OOTT.*" Mobility indicators like TomTom data point to stable levels in North American driving YoY, although cumulative road congestion has yet to recover to 2019 levels. Following the WoW decline for the week of Feb 5, North American road congestion was flat WoW for the week of Feb 10. Although the data is stronger than the comparable period in 2021/22, it remains below relative levels in 2020 prior to the start of the pandemic. The TomTom mobility data seems logical as MoM North American road traffic was flat resulting in a lowered differential to 2022's levels, but overall congestion remains below the 2019 average. It its worth noting that TomTom data on congestion levels now reflects daily average congestion compared to peak congestion previously. The change in methodology took effect from January 19.

Figure 46 Mobility Indicators

Source: BloombergNEF

Oil & Natural Gas – sector/play/market insights from Q4 calls

Sector insights from Q4 calls

Once again, we ran out of time this weekend to write up all the Q4 calls that we reviewed. It was a big week for Q4 calls. This is our favorite time each time of each quarter as it is quarterly reporting and this is when we get the best insights into a range of oil and gas themes/trends, sectors and plays. As a reminder, our Energy Tidbits memo does not get into the quarterly results, forecasts, or valuation. Rather the purpose of highlighting a company is to note themes/trends and plays that will help shape a reader's investment thesis to the energy sector. In the conference calls, we also tend to find the best insights from the Q&A portion as opposed to the prepared remarks. Plus, we tend to get the best E&P sector insights from services, pipelines, refineries, and utilities

Comstock – Low natural gas prices leads to releasing 2 of 9 natural gas rigs

Comstock Resources held its Q4 call on Tuesday. Comstock is a large independent focused on natural gas in the Haynesville and east Texas. But is probably best known because Dallas Cowboys owner Jerry Jones is the big shareholder. As expected, the January crash in natural gas prices is leading to industry cutting back on natural gas drilling. In the Q4, Comstock wrote "In response to the current lower natural gas prices, Comstock is releasing two of its nine operated drilling rigs and currently plans to spend approximately $950 million to $1.15 billion in 2023 on drilling and completion activities primarily focused on the continued development of its Haynesville/Bossier shale properties and delineation of its Western Haynesville play. Comstock also expects to spend $75 million to $125 million on infrastructure, including upgrades to its Western Haynesville pipeline and processing facilities, and for other development costs. Under its current operating plan, Comstock expects to drill 67 (50.5 net) and complete 69 (49.2 net) operated horizontal wells in 2023, including eight (8.0 net) wells in the Western Haynesville area."

EQT – Non-Marcellus natural gas basins are maturing

Earlier in the memo, we noted Patterson-UTI's view of where they expect to see declining US natural gas rigs with low HH gas prices – it's basically everywhere but

the Marcellus. EQT, the leasing US independent natural gas producer held its Q4 call on Thursday. EQT's natural ga sis in the Appalachia – Marcellus and Utica. In the Q&A, mgmt. gave their view of maturing basins and the increasing marginal break-even price of natural gas. Mgmt replied "*Yes, I think there's a couple things that are happening from an activity level, as these mature basins -- these shell placed in your mature -- the amount of activity levels will lower over time. That should have an impact on lowering service costs. But also the other thing that's taken place is the break-evens in the United States is rising as operators are moving to Tier 2 geology and both in geography and also in the zones that they're completing. That will have the impact of increasing the marginal break-even price of gas. That will help solidify price."*

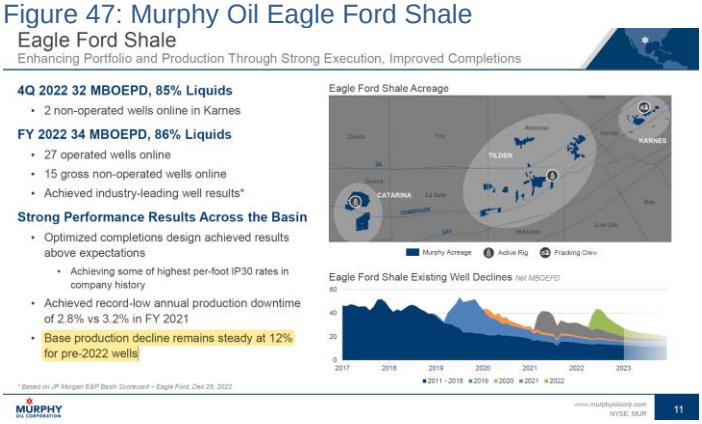
Galp – No idea when they expect TotalEnergies Mozambique LNG to restart

Galp Energia is a partner in the TotalEnergies Mozambique LNG project and held its Q4 call on Monday. Galp did not give any indication when they think the partners would make a restart decision. Galp's Q4 release, Q4 call mgmt. prepared comments and Q4 call slide deck made no mention of this project. Note Galp is in the Eni operated Coral FLNG offshore Mozambique that started up in Q4/22. Int the Q&A, mgmt. was asked "*And at the same time, I see that you haven't included much upside from Mozambique. And I was wondering whether you believe Mozambique is not coming on stream before 2030 or you just taking a more prudent approach there*". Mgmt replied "*Number two, as you correctly are alluding to, for sure, there is upside in Mozambique. It is promising and interesting to see that our colleagues in Total has just recently been to Mozambique. The reports from the ground is pointing to that the security situation is improving. And that is -- it's very positive sign with respect to also the further development of Mozambique. And by the way, let me, also say that we are extremely happy so far with how Coral South is ramping up. It's an astounding achievement by the teams that has been involved that -- that an FLNG project is*

Murphy Oil – Base Eagle Ford declines are 12%

One of the many Q4 calls that we read but never wrote up was the Murphy Oil Q4 call on Jan 26. In their prepared remarks, management said "*Additionally, our base production management efforts continue with base declines averaging 12% for wells online prior to 2022."* No question a base decline of pre-2022 wells being 12% is a low number, but this includes a lot of wells that are more than a few years old and Murphy, as seen in the below graph, hasn't been looking for growth from the Eagle Ford.

Figure 47: Murphy Oil Eagle Ford Shale



Source: Murphy Oil

Patterson-UTI – Still no spare super spec rigs

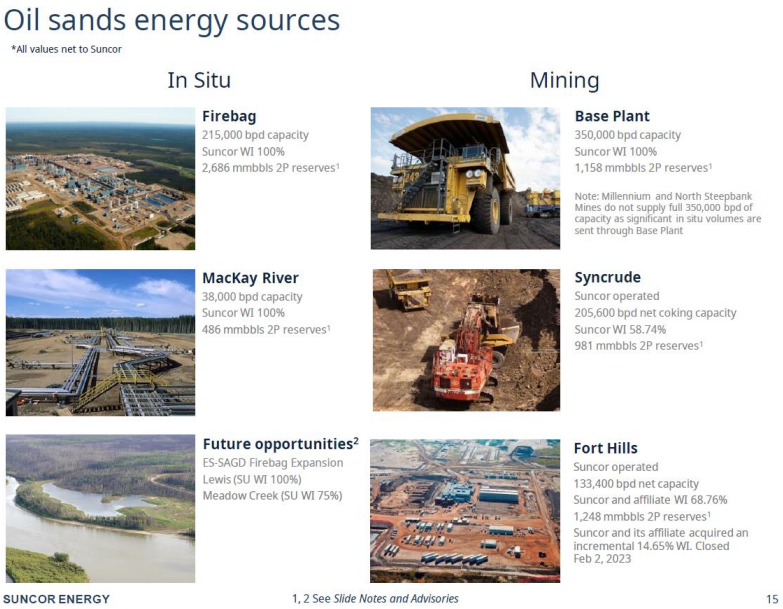
Patterson-UTI held its Q4 call on Feb 9. (i) Earlier in the memo, we highlighted their views on which basins should see declining natural gas rigs. (ii) Still no spare super spec/high end rigs. This is the same theme as other service companies. Mgmt said "*As we look ahead, we remain optimistic that we are in a multi-year upcycle. Tier 1 super spec rigs and premium pressure pumping equipment are effectively sold out due to the strong growth in activity over the past two and half years.*" (iii) Gas rigs will decline but oil rigs should more than pickup the slack. In their prepared comments.. Mgmt said "*In the near term, we expect some rigs and gas basins outside of the Northeast will be let go, while other rigs were reactivated to go to work in the oil basins. This may have a short-term effect of moderating growth in the rig count, but we expect utilization of Tier 1 super spec rigs to remain very high positively supporting pricing turning*." And "*Throughout the year, I expect the overall US rig count for the industry will continue to increase, especially for super-spec rigs driven by increases in the oil basins, and acknowledging that there may be near-term softness in gas basins outside of the Northeast."* (iv) But the super spec/high end rigs drilling for natural gas are moving over to oil plays like Permian. In the Q&A, mgmt. said they expect any reduction in high end rigs drilling for natural gas in Haynesville or East Texas will be absorbed by oil basins. (v) Pressure pumping to remain robust. In their prepared comments mgmt. said "*We anticipate the demand for pressure pumping services will remain robust while the supply of equipment will continue to be constrained. The lead times for new equipment, particularly for advanced Tier 4 dual fuel engines are still longer than usual, which makes it difficult to quickly add to existing capacity. Additionally, as customers' demands for higher flow rates grow, the amount of horsepower per spread is also increasing, which will further limit the availability of pressure-pumping spreads.*" (vi) Some temporary rig declines in Colombia as companies deal with the govt changes on the oil market. In the Q&A, mgmt. replied *"Yeah. So there has been some changes in the Colombia market. We were working as six, seven rigs and now our rig counts coming down. It's -- a lot of it's due to changes in the fiscal setup for the operators down there. The operators are trying to work through that and see how that's going to affect. And we do expect our*

rig count to move up again in Colombia, so we also see potential for some possibilities in Ecuador as well and we continue to work on that."

Suncor – Recap of its assets is a good one for others to follow

Suncor reported Q4 on Tuesday. We couldn't help highlight what we thought was something we would like to see in all company year-end slide decks. On Tuesday, we tweeted [LINK] "*Kudos to @Suncor for good reference data of all key assets in today's slide deck. ie. oil sands 942 kbd net to $SU: Base plant 350 kbd, Firebag 215 kbd, Syncrude 205.6 kbd Fort Hills 133.4 kbd, Mackay River 38 kbd. Wish all companies did this! #OOTT."* Suncor's year-end presentation had a great recap of all its key assets. The descriptions were short and sweet but provide a great reference guide for all of Suncor's assets and not just for the oil sands assets. Below are the oil sands recaps. Our Supplemental Documents package includes the Suncor asset recaps including oil sands, offshore and refining.

Figure 48: Suncor's Oil sands assets



Source: Suncor

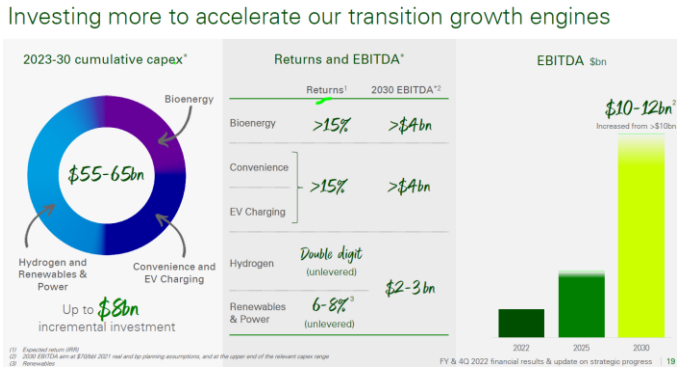
Energy Transition – BP adds more convenience stations for EV charging potential

Convenience & EV charging

No one should have been surprised to see that Travel Centers of America ended up being sold to BP after "*competitive rounds of bidding from potential buyers."* On Thursday mornng, Travel Centers of America announced it had agreed to be sold to BP for $86/share with an equity value of $1.3b. The $86/share prices was an 84% premium to the 30-day average trading price of $46.68. Upon seeing the news, we tweeted [LINK] "*Here's why @bp_plc is buying Travel Centers of America. See 👇 its updated strategy focus transition growth on its two high return >15% transition growth areas: (i) bioenergy. (ii) convenience & EV charging*

that expects >15% return. vs renewables & power 6-8% unlevered. #OOTT". We say no one should be surprised because we linked to our Feb 7 tweet [LINK] on BP's updated strategy that saw it shift its energy transition priority to its higher return transition growth areas: bioenergy and convenience & EV charging. These two areas are expected to generate >15% returns compared to lower returns Renewables of 6-8% unlevered. So BP buying more convenience stations with EV charging potential makes sense. Put more of their transition growth capex into the higher return areas. Below is the BP returns chart attached to our Feb 7 tweet. Our Supplemental Documents package includes the TCA release.

Figure 49: BP's expected returns by energy transition areas



Source: BP

Energy Transition – Ford temporarily halts F150 Lightning production re battery issue

Ford F150 lightning halts production

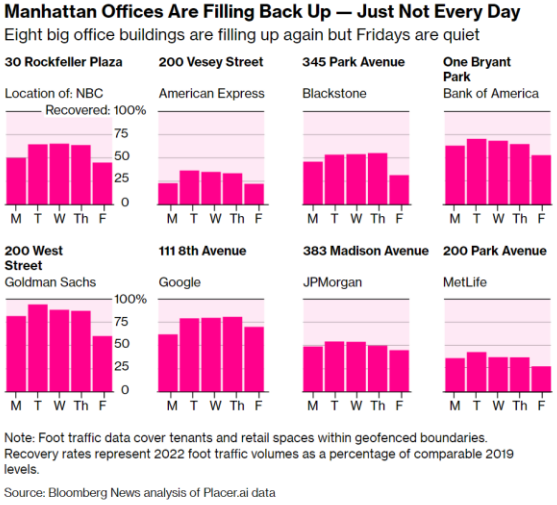
It was a good last month for the Ford F150 Lightning up until last week. In late Jan, the Ford F150 Lightning was named Edmunds Top Rated Electric Truck for 2023 and, it also won the big one, being named Edmunds Top Rated Best of the Best winner for 2023. But it was a bad last week. On Tuesday, we tweeted [LINK] "*Ford down $1.57 today. "has temporarily halted production & stopped shipments of its hot-selling F-150 Lightning electric pickup truck over an unidentified problem with its battery" reports @KeithNaughton. #EV markets waiting on what caused the problem. #EnergyTransition #OOTT."* Bloomberg reported "*the automaker confirmed Tuesday it stopped building the plug-in pickup at its factory in Dearborn, Michigan, while engineers seek a solution to a "potential quality issue" discovered on a truck at the plant. Ford said in an emailed statement that it's not delivering trucks that are in transit to dealers."* On Wednesday, Car and Driver wrote [LINK] "*UPDATE 2/15/23: Ford issued a fresh statement on Wednesday afternoon stating that it has figured out what the problem is with the F-150 Lightning's battery. The automaker is now saying production at the Rouge Electric Vehicle Center will be suspended "through at least the end of next week," which will be February 24 or later. "During a standard Lightning pre-delivery quality inspection, one vehicle displayed a battery issue. We believe we have identified the root cause of this issue. By the end of next week, we expect to conclude our investigation and apply what we learn to the truck's battery production process; this could take a few weeks. We will continue holding already-produced vehicles while we work through engineering and process updates."* Our Supplemental Documents package includes the Car and Driver report.

Capital Markets – Remote working hurts downtown economies, $12b/yr Manhattan

Remote working hits downtown economies

There is no question downtown office working has had a strong recovery from the Covid bottoms, but there is also no question that remote working continues to be a significant part of what seems to be a new hybrid work model. The question is to what percentage will it ultimately settle at. But for now, it is still significant and it is having a significant economic cost on downtown economies. Of course the flipside is that a hurt to cost to the downtown economies means that when a worker no longer spends their money commuting, parking, eating, drinking, shopping downtown by their office, they are saving some of it but also spending some of these savings in their local economies elsewhere. But last Sunday, Bloomberg reported [LINK] "*Remote Work Is Costing Manhattan More Than $12 Billion a Year*." And "*But new data on in-person work analyzed by Bloomberg News show that in a number of cities across the US, Fridays at the office are dead. Mondays are a crapshoot. And returning to pre-pandemic work schedules looks like a lost cause. Nowhere is the economic cost of remote work more pronounced when it comes to spending than in the world's leading financial center: New York. Manhattan workers are spending at least $12.4 billion less a year due to about 30% fewer days in the office, according to a Bloomberg News analysis using exclusive data from Stanford University economist Nicholas Bloom's WFH Research group. That figure was calculated by multiplying the annual inflation-adjusted loss in spending per worker by the US Census Bureau's estimated nearly 2.7 million commuters and residents who worked in Manhattan in 2019. That means the average worker is spending $4,661 less per year on meals, shopping and entertainment near their offices in New York. That compares to $3,040 in San Francisco and $2,387 in Chicago. These behaviors are most entrenched in cities with longer commutes, a higher proportion of white-collar workforces and longer-lasting pandemic restrictions."* Our Supplemental Documents package includes the Bloomberg report.

Figure 50: Manhattan offices are filling back up – just not every day



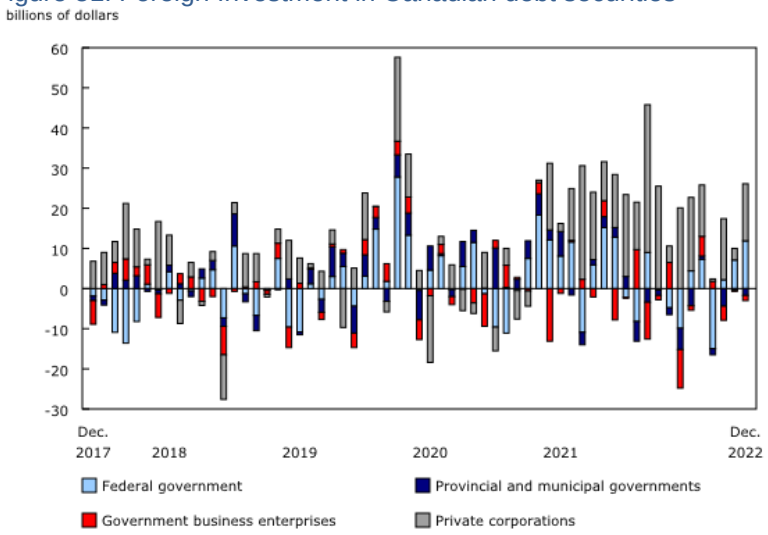
Source: Bloomberg

Capital Markets – Canadian investors divest by $2.3bn in foreign securities

International transactions in Cdn securities

Statistics Canada released Canada's international transactions in securities for December 2022 on Feb 17 [LINK]. Foreign investors acquired $21.2 bn of Canadian securities in December with the largest target purchases being in debt securities. This marks the highest investment since November 2021; the overall foreign investment activity was moderated by a divestment in Canadian equity securities. Non-residents invested $13.6 bn into money market securities in December and an additional $9.7bn into Canadian bonds (primarily US$ denominated corporate bonds). Non-resident investors divested $3.0 bn of Canadian equity securities from their portfolios, mainly made up of federal and provincial government debt instruments. Long term interest rates continued their upward trend and increased by 33bps in December. Canadian investors reduced their investment by $2.3bn of foreign securities in December with $1.5bn in foreign debt divestitures; this followed 5 straight months of investment. Investment activity was led by sales of non–US foreign bonds and a divestment in non-US foreign shares. The report stated, *"Foreign investors reduced their exposure to government debt securities by $23.7 billion in 2022, while they had acquired $203.3 billion worth of these instruments in the previous two years in the context of increased borrowing needs to support Canadian enterprises and households impacted by the COVID-19 pandemic. Meanwhile, foreign investment in corporate debt securities increased substantially in 2022 to reach an unprecedented $179.3 billion, up from $79.9 billion in 2021. New corporate bonds denominated in foreign currencies in the first half of 2022 led the investment activity."* And "*In 2022, Canadian investors reduced their exposure to foreign securities by $7.5 billion, a first divestment since 2008 during the global financial crisis. Overall, investors sold $62.4 billion of foreign shares in 2022 following acquisitions totalling $112.6 billion in 2021. The divestment activity was largely in US shares as share prices, as measured by the Standard and Poor's 500 composite index, were down by 19.4% in 2022.*" Below is a graph illustrating foreign investment in Canadian debt securities.

Figure 51: Foreign Investment in Canadian debt securities



Source: Statistics Canada

Demographics – 1 in 4 Canadians are unable to cover a $500 unexpected expense

1 in 4 Cdns can't cover $500 unexpected expense

One of the stories that got some general Canadian news coverage was the Statistics Canada Monday report "*One in four Canadians are unable to cover an unexpected expense of $500*". [LINK]. Statistics Canada wrote "*One in four Canadians are unable to cover an unexpected expense of $500 In fall 2022, over one-third (35%) of Canadians reported that it was difficult for their household to meet its financial needs in the previous 12 months. When asked whether their household had the resources to cover an unexpected expense of $500, 26% said that they would be unable to do so, with a slightly larger percentage of women (29%) reporting this difficulty than men (24%).*" And "*Young adults were among those most concerned over finances. Almost half (46%) of people aged 35 to 44 years found it difficult to meet their financial needs in the previous 12 months, the highest proportion of any other age group. Those aged 45 to 54 years (41%) had the next highest proportion, and people aged 65 years and older (25%) were the least likely to report difficulty. Similarly, when asked whether their household could cover an unexpected expense of $500 today, more than one-third (35%) of people aged 35 to 44 years said that they would be unable to do so, followed by those aged 45 to 54 years (30%). People aged 65 years and older (19%) were the least likely to expect difficulty covering such an unexpected expense.*"

Twitter – Look for our first comments on energy items on Twitter every day

@Energy_Tidbits on Twitter

For new followers to our Twitter, we are trying to tweet on breaking news or early views on energy items, most of which are followed up in detail in the Energy Tidbits memo or in separate blogs. Our Twitter handle is @Energy_Tidbits and can be followed at [LINK]. We wanted to use Energy Tidbits in our name since I have been writing Energy Tidbits memos for over 20 consecutive years. Please take a look thru our tweets and you can see we aren't just retweeting other tweets. Rather we are trying to use Twitter for early views on energy items. Our Supplemental Documents package includes our tweets this week.

LinkedIn – Look for quick energy items from me on LinkedIn

Look for energy items on LinkedIn

I can also be reached on Linkedin and plan to use it as another forum to pass on energy items in addition to our weekly Energy Tidbits memo and our blogs that are posted on the SAF Energy website [LINK].

Misc Facts and Figures

During our weekly review of items for Energy Tidbits, we come across a number of miscellaneous facts and figures that are more general in nature and often comment on sports and Calgary items.

National Margarita Day is Feb 22

One the best food & drink holidays of the year is Wednesday. And for those who need an excuse to have a margarita, Wednesday Feb 22 is National Margarita Day. [LINK] This isn't like the Caesar drink that is undisputed to have been created in Calgary. Rather there are a number of different origins of the Margarita. But as to the mix, Foodimentary reports "*Authentic' Margaritas are made with bitter Mexican limes (key limes). These are smaller thin-skinned limes, much more tart than regular limes.*

The IBA's (International Bartenders Association) official standard for the margarita is 7:4:3, that is 50% Tequila, 29% Cointreau, 21% fresh lime or lemon juice." And for those fortunate enough to be in Mexico this week, have a really good Margarita.

Smuggling cocaine in Parmesan cheese from Netherlands into Italy?

We recognize the Netherlands is a top cheese producing nation, but it is best known for its Edam and Gouda cheeses. So we have to wonder about why the criminals didn't think it would raise some attention by importing big wheels of Parmesan cheese from the Netherlands into Italy. Yesterday Sunday World reported [LINK] "*Italian drug gang caught smuggling high-quality cocaine concealed in Parmesan cheese Ten arrests were made and more than 100 kilos of cocaine was seized, which was hidden in massive wheels of cheese. Italian police have arrested two members of a criminal gang who have been smuggling vast quantities of cocaine concealed in Parmesan cheese imported from the Netherlands. The Guardia di Finanza in Turin dismantled the crime gang suspect of large-scale cocaine trafficking across Lombardy, Veneto, Tuscany, Sicily and Sardinia. Ten arrests were made and more than 100 kilos of cocaine was seized, which was hidden in massive wheels of Parmesan cheese."*

Figure 52: Cocaine smuggling in Parmesan cheese wheels

Source: Sunday World