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Inside This Issue…

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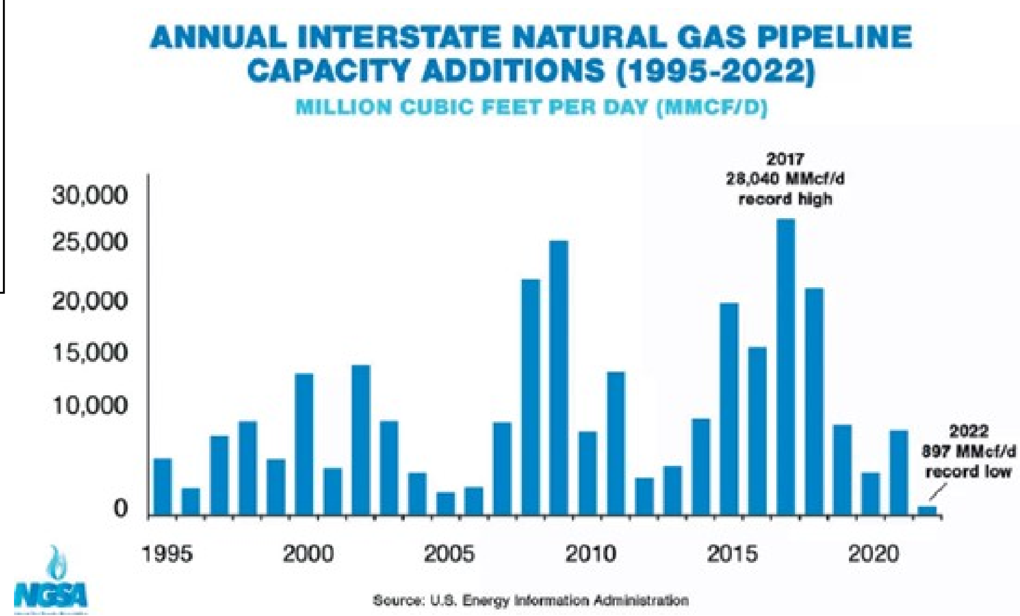
Is this the Tipping Point for Energy Infrastructure

By: Natural Gas Supply Association

Natural gas, wind, solar, storage and electric transmission projects are all needed to keep up with demand, but all are at risk. Years of delays have hindered projects already struggling with a permitting process that leaves stakeholders without any ability to predict how or when the process may eventually end. In the case of natural gas, both consumption and production reached all-time highs in the U.S. last year. Yet we added the lowest amount of natural gas pipeline capacity on record.



Sure, it's tough on the energy industry, but the biggest hostages to the process are really:

- Consumers - end up paying more for their energy
- Grid reliability - risk during extreme weather when it's most critical
- Low-carbon future - reliant on cooperation and integration of many energy sources requiring more infrastructure.

Consumers paid more this winter in states where natural gas infrastructure was constrained. The most egregious example is in the Northeast, where natural gas pipelines are most needed, but numerous projects have been stalled by the permitting process. The result: Higher natural gas prices for consumers in the Northeast relative to other parts of the country.

Consumers, grid reliability and lower emissions depend on more infrastructure.

More than half of all U.S. electricity is affected by the availability of natural gas pipeline infrastructure, stressing reliability and jeopardizing our emission reduction goals.

- Natural gas directly generates 40% of U.S. electricity, displacing fuels with higher emissions
- It also facilitates the adoption of the 14% of U.S. electricity generated by solar and wind energy by seamlessly partnering with them as they ebb and flow during the day.

Lack of sufficient infrastructure limits the ability of grid operators to secure the energy that households and businesses need during extreme weather events, when it's most critical. In ISO-NE's own words: "Without adequate gas, the region may not be able to meet the demand for home heating and electricity - and when reliability suffers, the clean energy transition suffers."

The cost of inaction.

Natural gas is essential to achieving a low-carbon future as we rely more on low emissions fuels. In fact, by 2050, natural gas and renewable energy together are projected to generate 76% of U.S. electricity. (EIA)

Right now, every 1% increase in natural gas-fired electricity enables an additional 0.88% of renewable energy to come online. That's because natural gas power plants naturally partner with solar and wind energy to rapidly balance the electric grid when weather conditions temporarily disrupt solar or wind power production. This partnership reduces emissions and makes the grid more reliable and resilient.

By 2050, pipelines will be needed for carbon capture technologies, renewable natural gas, certified natural gas and to produce and store hydrogen. These breakthroughs in technology and markets are essential to the net-zero energy future and energy infrastructure will play a key part of these exciting innovations.If this is the tipping point, we can act now by modernizing permitting reform to tip things the right way with infrastructure to secure a low-emissions future.

How Gas Pipeline Rates Are Really Set and Why You Should Care

Published by: Rick Smead, RBN Energy LLC

The rates regulators set for transporting natural gas on interstate pipelines are all-important. They determine how much it costs to get gas from A to B, whether new capacity can be funded, and serve as the bedrock of regional gas price relationships around the nation's pipeline grid. But the process for establishing those rates can seem opaque and is often misunderstood - it's one of those things you need to be directly involved in to fully grasp. Well, RBN's Advisory Practice lives and breathes gas pipeline rate cases month in, month out, and we thought it would be interesting - and kind of fun - to take you behind the curtain and explain how rate cases at the Federal Energy Regulatory Commission (FERC) really play out.

Don't worry, this won't be a deep dive on how to become a rate analyst. Instead, it will be a straightforward explanation of how all the parties in a gas pipeline rate case - the pipeline owner, consumer representatives, FERC staff, the commission itself and others - find their way to a quick and fair resolution of the issues at hand. Maybe we've been doing this too long, but we can argue there's a certain beauty to it.

From the outside, you might think that a FERC rate-setting procedure is as cut-and-dried as a three-day-old Christmas turkey, a process in which the pipeline owner files reams of financial data, a plethora of FERC accountants audit the filing and crunch the numbers, and the commissioners vote to approve rates based on that auditing and number-crunching.

But au contraire. Sure, filings are made, numbers are crunched, and FERC does ultimately approve or reject the rates. However, the process leading up to that decision usually involves a very complicated and dynamic negotiated interaction among all the parties. As we'll discuss next, it starts with the formal stuff, but evolves into an informal and confidential resolution, the so-called "settlement process."

First, we'll quickly describe the formal process you see in public, then we'll explain how the informal, behind-the-scenes settlement process works and the many reasons it's a heck of a lot better than a bevy of lawyers, accountants and experts duking it out in front of a judge. As we said up front, we know a lot about how this process works from the work we do in FERC Continued on page 3.

Gauging The Impact Of The DOE's Pause In LNG Export Licenses

Published by: David Braziel, RBN Energy LLC

There's no doubt about it: The Biden administration's decision to pause approval of LNG export licenses poses a new threat to a number of projects thought to be nearing a final investment decision (FID). The questions brought on by the move are profound: how big of a problem is this for U.S. developers, how does the timeout affect the projects now in limbo, and - over the longer term - what does the added uncertainty regarding incremental LNG exports mean for U.S. crude oil and natural gas production and what does it mean for the global energy landscape?

The U.S.'s mammoth reserves of natural gas, combined with strong global demand for LNG, have spurred a sharp rise in LNG export volumes over the past few years. As recently as December, an average of about 14 Bcf/d of LNG - or around 14% of the dry gas produced in the U.S. each day - is being liquefied and shipped overseas, almost all of it from export terminals along the Gulf Coast. And, with several new LNG export projects under construction, we expect those volumes to nearly double over the next four years.

The extraordinary growth in U.S. LNG export capacity has been facilitated by a mostly predictable federal permitting process. It may sometimes have been slower than developers would have liked, but LNG export projects that entered the federal permitting process with both the Federal Energy Regulatory Commission (FERC) and the Department of Energy (DOE) were generally granted their project authorizations and export licenses. And once they had them, they had been able to hold onto them via extensions - until lately, that is.

Before we delve into the Biden administration's latest move, which may set back or even derail a number of multibillion-dollar LNG export projects on the drawing boards, we should provide a little background on the permitting and development process. Every project that plans to export U.S. natural gas as LNG - meaning not only projects in the U.S. but any project in Mexico or Canada that plans to source feedgas from the U.S. - requires an export license from the DOE. The export licenses come in two flavors, one for Free Trade Agreement (FTA) countries and one for non-Free Trade Agreement (non-FTA) countries, and typically allow for exports to continue through 2050. Projects need both licenses to export competitively - they are usually granted in that order (FTA first, then non-FTA) - and both typically come after a project has already received its FERC authorization. (Figure 1 shows the FTA and Non-FTA countries that imported U.S. LNG in 2023 - light-blue- and gold-shaded countries, respectively.)

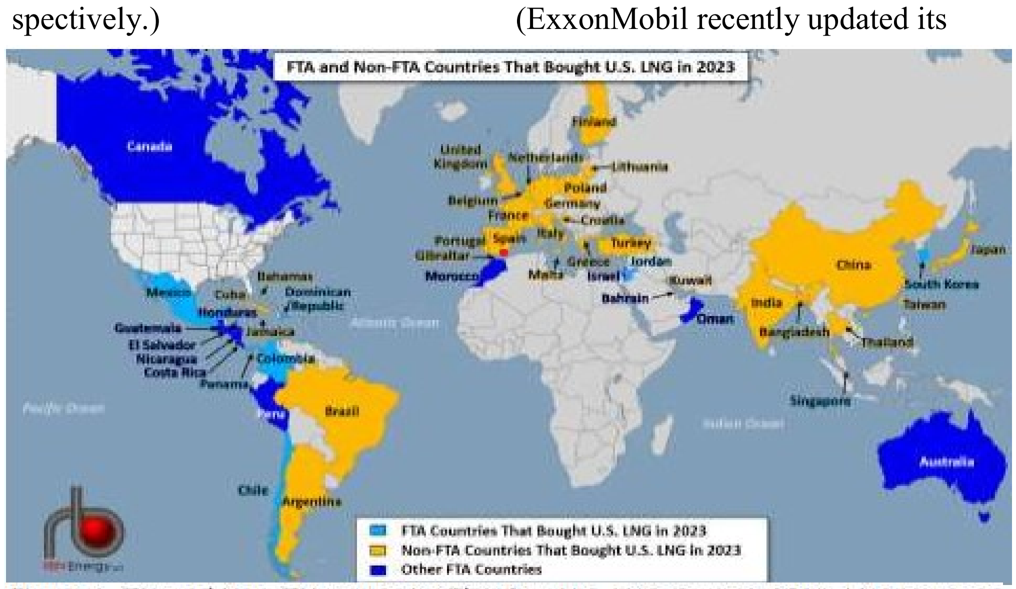


Figure 1. FTA and Non-FTA Countries That Buy U.S. LNG. Source: RBN's LNG Voyager

For more than a dozen years now, it's been the DOE's standard practice to give an LNG export project seven years from the department's export-license approval to get the facility up and running - that is, to send out its first LNG shipment, even if the project hasn't formally begun commercial operation. That approach worked well, at least initially: Every U.S. LNG export facility that is now operational, including Venture Global's still-commissioning Calcasieu Pass LNG, has started up within that seven-year timeframe. By the early 2020s, however, the pace of development for many export projects had slowed - largely because of the market-shifting effects of the COVID pandemic, but also due to the sheer number of projects trying to advance - and several developers asked the DOE to extend the "commencement deadlines" in their export licenses by a year or more to give them more time to line up long-term sales agreements and state and local approvals.

The DOE generally went along. For example, in March 2020 the department granted Qatar Energy and ExxonMobil - the developers of Golden Pass LNG - a 17-month extension on the project's non-FTA export license, to September 2025. (ExxonMobil recently updated its guidance that the project will begin producing LNG in the first half of next year.) However, on April 21, 2023, the DOE announced that it will no longer consider license extensions unless the project in question is (1) already under construction and (2) can prove extenuating circumstances outside its control. The same day, the department granted a 25-month extension to Sempra Infrastructure's Port Arthur LNG (already under construction at the time), giving that project until June 2028 to finish up, but denied a second extension request to Energy Transfer's Lake Charles LNG, which has a number of offtake agreements in hand but was - and still is - in the pre-FID stage. The denial of Lake Charles LNG's extension caused consternation at the time but, since a second extension would have been unprecedented, at least the DOE's decision could be rationalized. (Lake Charles filed for a new export license in August and later sought an expedited ruling in its favor.) But there were other warning signs in the Lake Charles decision - namely, language that referenced the roughly 26 Bcf/d of approved non-FTA export licenses that, if realized, would bring total approved non-FTA licensed exports to about 50 Bcf/d. As we'll get to next, that "overhang" of prospective LNG export capacity was part of the justification of what was to come next.

That was the Biden administration's announcement on January 26, when it said the DOE would be taking "a temporary pause on pending decisions on exports of (LNG) to non-FTA countries <u>until the (department) can update the underlying analyses for authorizations</u>." That phrase we underlined is key, in that Section 3(a) of the Natural Gas Act (NGA) states that requests to export (or import) gas should generally be approved unless it's determined that they "will not be consistent with the public interest." In essence, the administration is raising the question of whether allowing the export of more LNG (i.e. gas) than the volumes already permitted by existing, under-construction and soon-to-be-under-construction LNG export facilities would, in its view, be contrary to the public interest by either (1) raising domestic natural gas prices to economically harmful levels, or (2) undermining U.S. efforts to reduce greenhouse gas (GHG) emissions.

The implication is that the DOE may decide there is a determinable maximum-LNG-export number out there - 45 Bcf/d? 35 Bcf/d? 25 Bcf/d? Who knows! — at which point incremental LNG exports would flip from being consistent with the public interest to being, well, inconsistent. Energy Secretary Jennifer Granholm said the DOE's internal review is expected to take "several months"; after that, its findings will be open to public comment. Here's the bottom line: No further decisions on license-extension requests or applications for new export licenses are likely until sometime next year, and the degree to which extension requests are considered in 2025 and beyond will likely depend on November's election results.

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How Gas Pipeline Rates…

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rulemakings, rate case filings, litigation and settlement negotiation, along with the fundamental market analysis needed to support regulatory pleadings and civil litigation in both federal and state courts.

Rates Based on Costs

It's true that pipeline rates are based on accounting costs, which is how FERC has always interpreted the Natural Gas Act (NGA) mandate that pipeline tariff rates be "just and reasonable." But in determining those costs, there typically is an enormous amount of disagreement about which customer groups ought to be paying what, and how much risk the pipeline ought to be responsible for in its recovery of those costs. For example, some costs, like depreciation and the cost of capital, are matters of expert opinion, and there are a whole lot of experts out there willing to offer their opinions for a fee.

When a pipeline owner wants to change - almost always increase - its tariff rates, it files a rate case with the FERC. The pipeline is generally allowed to place its proposed new rates into effect six months after they're filed, with a condition that any part of the increase that's not ultimately approved by FERC will be refunded to customers with interest based on the prime rate. So if it takes two or three years to finish a formal case, customers can end up paying elevated rates for all that time, holding out hope for future refunds but in the meantime paying rates they typically believe to be too high. It can be frustrating all around.

THE SETTLEMENT PROCESS

Rates Based on Reasonable Agreement

Ultimately, the whole aim of FERC's rate-setting process is to establish transportation tariff rates for services provided. The NGA rules say they'll be based on costs and that the way they're turned into rates will be blessed by the FERC. Fair enough. Well, you have everyone in the room - the pipeline, the interested consumers, and FERC staff - so why on earth wouldn't everyone just want to gather enough facts to tell how much upside or downside they might have in the gigantic formal process, and then negotiate an agreement they can all live with?

Today when a rate case is filed, FERC starts trying to encourage settlement: At the same time they appoint an administrative law judge (ALJ) to run the formal process they also appoint a "settlement judge" who attempts to herd the cats through the settlement process. Then FERC staff, which pulls the laboring oar in auditing and analyzing the pipeline's rate case, at least initially, puts together an informal version of its proposed settlement level of cost of service, called the "Top Sheets." These are typically issued four or five months after the case is filed - in other words, before the rates take effect on an interim, refundable basis. Then, although the rest of the gang could have been vaguely talking settlement up until then, the Top Sheets kick off the settlement process in earnest. It's not unusual for the pipeline and its customers to be trading offers and counteroffers within a week of the Top Sheets coming out.

That's not to say that everything is then rainbows and unicorns. From the time the Top Sheets come out and the first offers are traded, everyone's typically mad at each other - there's usually a huge gap between the staff and customer positions vs. the pipeline's proposal. But over time - after phrases like "That's non-negotiable" and "That's a non-starter" are uttered a few dozen times - the walls gradually break down and the parties move begrudgingly toward an "I-guess-we-can-live-with-this" middle ground. All along, everyone is looking at their own bottom line and considering the risk that something bad could happen to them in the formal case. So, before too long they all tend to drift toward a consensus.

In most instances, a settlement can be reached and put up to FERC for approval within six months of the Top Sheets - much less than a year after the case was filed and only a few months after the refundable rates took effect. If settlements are uncontested, the formal-case ALJ and FERC can act pretty fast to get them approved, and there will often be a deal for the pipeline to place the lower settled rates in effect long before FERC's approval of the settlement. So a two-year-minimum, very risky process gets replaced by a negotiated process that everyone can live with and takes much less than a year.

It's an old adage that no negotiated deal is fair unless everyone goes away a little disappointed. That rule is very true in rate-case settlements. But the combination of realism and the value of rate certainty almost always carries the day.

Umpires, Referees, and Shuttle Diplomats

We should point out that the FERC staff plays a dual role as an antagonist to the pipeline. Staff professionals will shuttle between the parties, gain a deep understanding of their positions, recommend alternatives, and give real-world perspectives as to how those positions might play out in a full formal resolution of the case. In other words, the same folks who will make the pipeline really mad with the Top Sheets then help find the ultimate balance between the parties. That role of the middleman deal-maker is also often played by customers, customer groups, or even the pipeline itself, when there are major inter-customer disputes.

And similarly, the cat-herding settlement judge participates in all the settlement conferences, which are completely confidential and confined to

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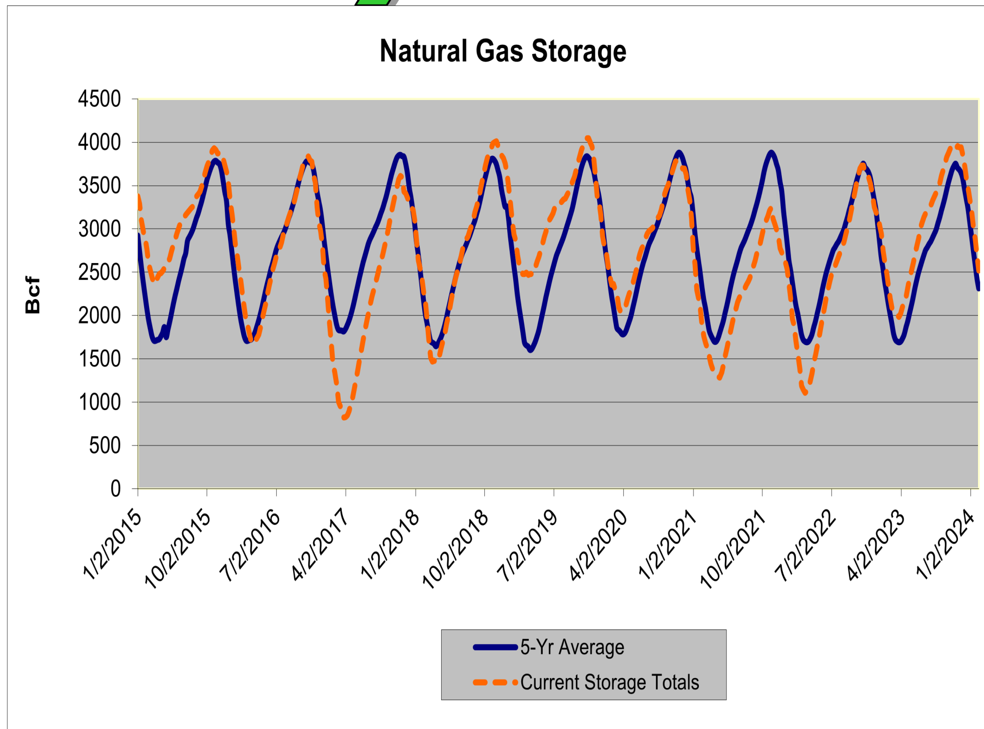
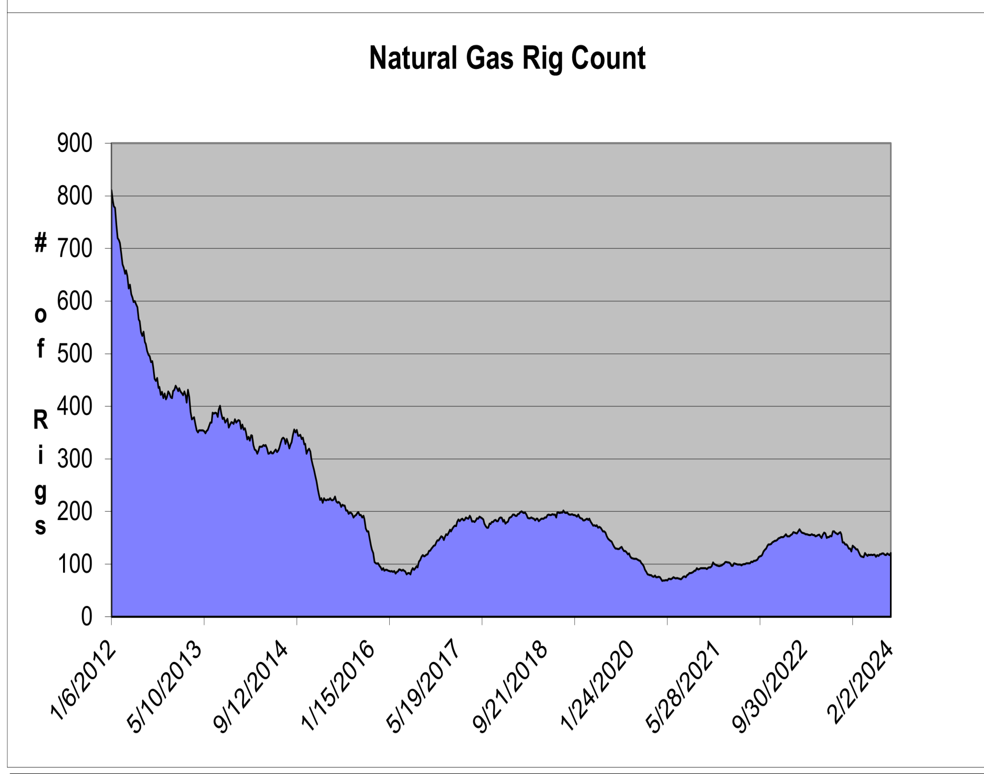
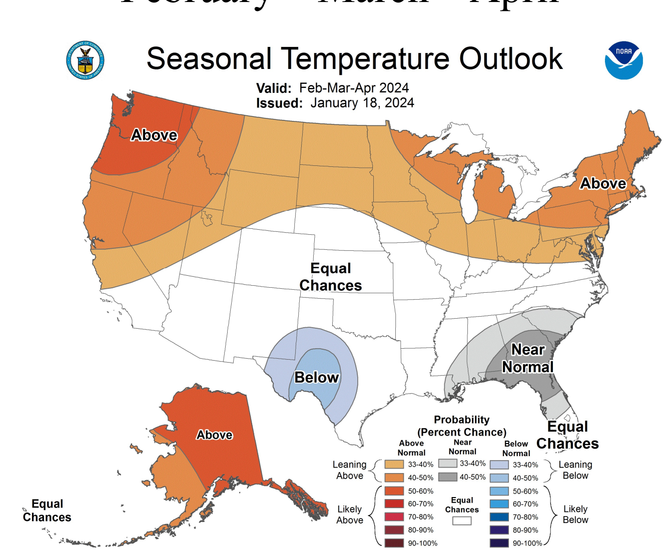
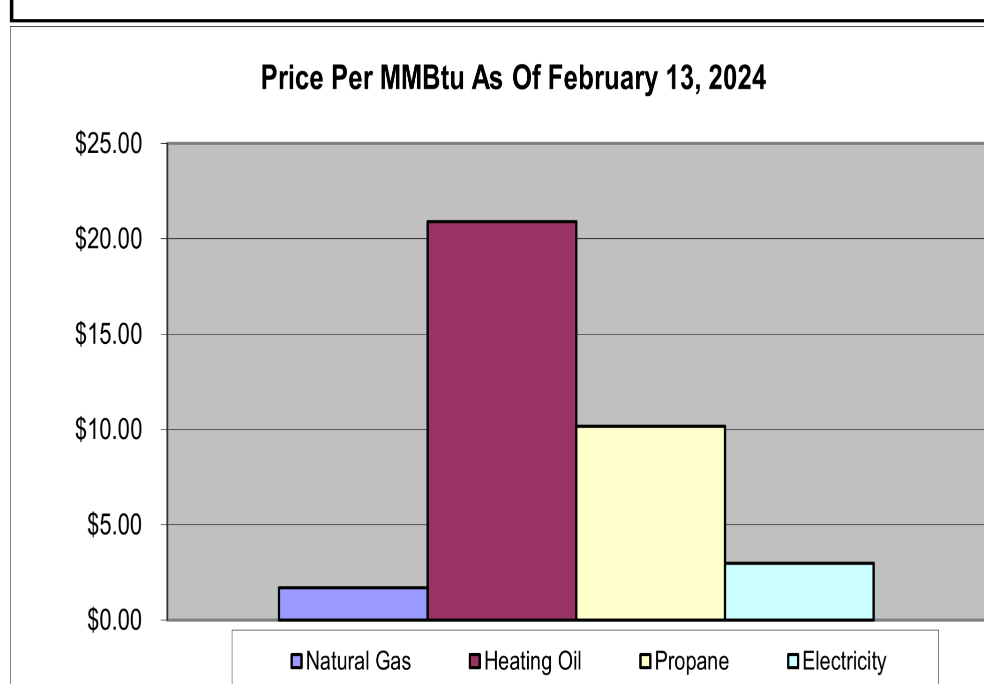
Snapshots





Seasonal Temperature Outlook
February – March – April





Gauging The Impact...

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As we said earlier, none of this should have a measurable impact on the volumes of natural gas flowing to existing LNG export facilities or the projects that are under construction.

The real effects - in project timing at the very least and maybe on some projects' ability to proceed - will be on the terminals that have commissioning deadlines they cannot meet and that depend on DOE license extensions, as well as projects that have applied for new export licenses - applications that have now been put on ice. Lake Charles LNG falls into that latter category, having filed (as we said) for a new license last August. Also in that camp is the Altamira LNG project in Mexico, which was expected to begin commissioning at the end of last year but is still awaiting its non-FTA export license. Without the license, Altamira will only be able to export LNG to the short list of FTA countries.

Venture Global's Calcasieu Pass and Plaquemines LNG projects both have outstanding requests to the DOE for small increases in how much LNG they can export to non-FTA countries - again, those asks are now on hold, but the projects can operate within their original export licenses in the meantime. A number of pre-FID projects also have licenses pending, including Venture Global's CP2 (Calcasieu Pass 2) and Cheniere En ergy's Corpus Christi midscale expansion. Both projects have enough commercial commitments to take FID - on Phase 1 in CP2's case - but are awaiting regulatory approvals, including their non-FTA export licenses.

The Biden administration's decision to pause further action on LNG export licenses was well- received by environmental groups, many of which were disappointed by the administration's March 2023 approval of ConocoPhillips's $8 billion Willow oil project on Alaska's North Slope. (These groups also have been highly critical of - and often in fervent opposition to - all LNG export projects.) The decision also aligns with the view of the Industrial Energy Consumers of America (IECA), a group representing petrochemical producers, manufacturers and other large energy consumers that has fought LNG exports since the beginning, intending that exporting an increasing share of U.S. natural gas supply stresses the domestic pipeline grid, reduces gas supply reliability and raises gas prices for U.S. industries. The IECA also asserted that then-record LNG exports during the winter of 2021-22 contributed to massive increases in natural gas and electricity prices.

Advocates of expanded LNG exports blasted the DOE's timeout, with the American Petroleum Institute calling it "a win for Russia and a loss for American allies, U.S. jobs and global climate progress." Senator John Kennedy of Louisiana - a state that, with Texas, has more at stake in the matter than any other - said in an op-ed in The Wall Street Journal that he will put a hold on all DOE and State Department nominees until the administration ends the pause. On both sides of the aisle, this is one more piece of energy policy that appears to be suffering from the nation's polarized politics.

There are convincing economic, political and strategic cases to be made that the continued expansion of U.S. LNG exports is a net positive. For example, a May 2023 EIU study found that LNG exports are unlikely to have a significant impact on domestic natural gas prices: While exports will pull natural gas prices higher, the study concluded, the projected increase is only modest at best, particularly as compared with the impact of weather. As for domestic politics, the majority of U.S. lawmakers support LNG exports due to the jobs created and the positive impact on U.S. balance of payments. A restriction on U.S. LNG exports would limit outlets on domestic gas production growth, not just in gas-focused basins like the Haynesville but also in crude-focused basins like the Permian and Eagle Ford where associated gas disposition is critical to crude production growth. A slowdown in crude production could have the impact of raising domestic gasoline and diesel prices, which as we've already seen poses political risks of its own.

And we've got to acknowledge the chilling economic effect the perception in the investment community that politics are driving domestic energy policy and creating substantial long-term investment uncertainty. The LNG export projects impacted by the announcement represent tens of billions of dollars and investors are undoubtedly watching these developments with bated breath. If political motivations are enough to freeze LNG export permitting, could the same be done to crude oil exports? After all, the administration has shown a willingness to use the tools at its disposal - namely, draining 180 MMbbl of crude oil from the Strategic Petroleum Reserve (SPR) in 2022 - when political pressure mounts. At that time, the motivation was high gasoline prices and, as you may remember, some were also calling for crude oil export curtailments.

Then, there's the strategic angle. After Russia's invasion of Ukraine in February 2022, President Biden made commitments to supply more LNG to Europe and to increase supplies through 2030. A number of European utilities and gas marketers that sell LNG to members of the European Union (EU) have contracted for LNG from several of the LNG export projects now in limbo. If those projects languish or fade away, these buyers presumably would need to turn to other sources. What kind of message would that send to U.S. allies? In that same vein, if the U.S. were to put a cap on LNG exports at, say, 30 Bcf/d or 35 Bcf/d, wouldn't the gap in global LNG supply be filled by others, including (ironically) Russia (notorious for high-methane-emission production of natural gas)? It wouldn't be the first time we misfired on that front. The price cap on Russian crude has not exactly gone as planned. Similarly, a limit on U.S. LNG exports would seem to play right into the hands of Russia and other foreign energy powers.

Perhaps the most frustrating aspect of the pause is its counterproductive impact on the strategic aims surrounding climate change. It would be reasonable to presume that, if LNG supply is artificially limited, growing global energy needs may be met with cheaper, more carbon-intensive fuels - especially coal. It's been well-documented that U.S. GHG emissions have declined over the last decade largely as a result of coal-to-gas switching in the power generation sector. But decarbonization goals are global in scope. And lower emissions from the U.S. and other Western countries have been more than offset by huge increases elsewhere - primarily in China and India - as developing economies strive to provide cheap power to their populations. Presumably, a much more climate-friendly approach would be to support U.S. LNG exports and provide whatever assistance they would need to displace coal through economic competition in those nations.

When we step back and look at the potential fallout from this decision, in the short-term, the impacts are relatively limited. We should not forget that after the approval of the first major export project, Cheniere's Sabine Pass LNG facility, there was a very extended period before the next licenses were issued, as the DOE analyzed and studied whether the exports were consistent with the public interest. The industry still ultimately thrived, once the logjam was broken. The primary short-term effect can be, as it was then, loss of competitive opportunities to other exporting nations. The next wave of export capacity coming online over the next few years is far enough along to be largely unaffected. But longer-term, the move could prove much more costly economically, environmentally and strategically. That's an awfully big wager on what pretty much everyone sees as a political gambit.

How Gas Pipeline Rates...

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the parties in the case - as opposed to the formal process, which is completely public. So the settlement judge will listen, observe, and from time to time offer his or her polite opinion as to who's been "smoking something." The settlement judge has no authority to make any of the decisions, but since all the settlement judges are also ALJs in the formal process in other cases, their observations carry a lot of weight.

All in all, the settlement process in gas pipeline rate cases has been a massive improvement in the onerous, messy world of regulation. Probably the only downside to settlement being so pervasive is that, with almost all cases getting settled confidentially, with nothing but rates showing up in public, in a negotiation no one really knows how FERC would decide an issue that it hasn't decided in a long time. This creates some uncertainty for everyone. But maybe that's not bad - uncertainty can lead to fear, and fear can lead to agreement. Meanwhile, the value of rate-certainty, at levels that everyone can accept, is enormous. FERC and the industry have done good.

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