The Energy and Environmental Markets Advisory Committee

Physical Energy Infrastructure Subcommittee Report

EEMAC

Introduction

The backbone of the U.S. energy system – and, indeed, the global energy system – is petroleum, natural gas, and electricity. These energy sources are distinct yet interconnected. Many systems depend exclusively on a single source: for example, transportation is overwhelmingly dependent on petroleum.[1] Some ability to substitute is more prevalent in other settings. Petroleum and natural gas can be burned to generate electricity and can be substituted for one another in some settings such as industrial boilers. The number of end uses that can substitute between energy sources is limited, and the long life of energy infrastructure imposes tradeoffs that last for years or decades. A future energy system is expected to rely more heavily on electricity, with most of that electricity generated from emission-free sources.

From a physical perspective, energy is conserved but may be transformed. This is relevant in markets as well, where sources of energy are substitutable, especially in the long run. However, substitution is imperfect in certain applications and over certain timeframes. For example, while light vehicle transport might eventually replace petroleum fuels with electric power, that substitution is much more difficult for air transport. The varying degree of substitutability affects choices about energy demand, the resulting market signals that arise, and ultimately infrastructure.

While physical markets are important to ensure delivery through wholesale markets and ultimately to retail customers, the financial transactions underpinning the system are equally important. Swings in energy production, consumption, and prices compel providers and consumers to manage risk, including through CFTC-regulated markets. Financial and physical markets are naturally connected, though in different ways and to differing degrees across products.

As these examples make clear, and is reiterated in the following pages, infrastructure is part of a complex tapestry of debate about the future and current use of energy. Commercial, financial, technological, regulatory, and environmental factors collide in a charged political and policy setting. Comprehending energy markets now and in the future requires a detailed understanding of the current infrastructure and the contemporary choices about investment in new infrastructure.

[1] More than 90 percent, not counting biofuels that are blended with petroleum products for fuel performance. EIA Total Energy Flow

Five recurring themes arise in the report providing mental throughlines for understanding the relationship between physical energy infrastructure and market outcomes. While each theme has some application to each source of energy, some are more applicable than others. The five themes pervading this report are:

- Technological change and regulatory reform have reshaped markets in recent decades
- Infrastructure constraints contribute to price volatility in physical markets
- Extreme weather events affect demand and strain physical infrastructure
- The energy transition magnifies demand and policy uncertainty
- Permitting and policy uncertainty distort market signals for infrastructure investment

Available technology shapes markets. When technology shifts, markets reorient. The oil and gas sector in North America has been the epicenter of a massive technological change with the shift from extracting conventional to unconventional deposits. This change has been enabled by a suite of technologies including hydraulic fracturing, directional drilling and geosteering, and advanced seismography. Collectively, these technologies allow extraction of resources once considered subeconomic or too poor to exploit. In the face of depletion of some conventional resources, the shift has made unconventional petroleum and natural gas resources inframarginal with substantial price and volatility impacts for both petroleum and natural gas. By opening new regions for production, infrastructure has been required on a massive scale. The domestic glut of petroleum and natural gas has reversed historic patterns of the United States as a net importer; today U.S. exports to the world are important across a variety of global markets, and U.S. markets are connected in new and important ways to distant market forces.

Something similar has happened in electricity markets, where renewable technologies have become very cost-competitive with existing fuel-based generators. Coupled with market restructuring efforts since the late 1990s, today's electricity markets have both a greater amount of low marginal cost generation and more scope for market forces. The former has attracted substantial generation investment and demand for additional transmission infrastructure.

When infrastructure constrains the balance of supply and demand, physical markets react by pricing scarcity. More frequent constraints give rise to more frequent price volatility. Volatility in the physical markets is potentially transmitted to derivatives markets. This is true for all forms of energy. While different sources have slightly different market dynamics, the relationship between derivative and physical markets is common. Derivatives are an important tool for risk management. Differences in storage are relevant; both petroleum and natural gas have important storage

systems similar to other types of commodities. Electricity has historically not had wholesale storage, though technological improvements in battery storage are emerging and could potentially reshape electricity markets in years to come.

In recent years a number of high-profile extreme weather events have strained physical energy infrastructure by causing abnormal swings in demand. While extreme weather events have always been a concern for the energy system, changing production, increasing demand, and less spare capacity make these events a growing concern. Increasing incidence of events once considered extreme raises the probability of low-frequency but high-impact events, with commensurate effects in physical markets and implications for infrastructure.

Increasing evidence of anthropogenic climate change has led to increasingly strident calls for global policy intervention in an attempt to avoid the worst potential consequences. A centerpiece of this policy response is an effort to transition the global energy system from one reliant on fossil fuels and attendant emissions to one embracing non-emitting sources of energy. Policy to coordinate such a transition has been uneven globally and even within countries over time. The resulting policy uncertainty[2] creates risk premiums that can be substantial and impedes infrastructure investment.[3] Policy choices to use mandates rather than prices provides a less clear and consistent signal to market participants.

In addition to the policy uncertainty, the prospect of changing demand for energy services makes forecasting more fraught, and projecting future demand is an important part of any fixed investment. Investors are wary of stranding assets, and the compound demand and policy uncertainty increase the risk premium for many kinds of physical energy infrastructure assets. The U.S. system has proven to be fairly adept at incremental investments. Nonmarginal changes and major projects that transform the existing system are a greater challenge.

Large specific investments typically require approval through permitting processes at federal, state, and local levels. Some of these permitting authorities overlap, leading to contradictory determinations. Permitting has become a flashpoint, in part because it becomes a proxy for policy decisions. Long permitting delays for what once would have been uncontroversial infrastructure

[2] See Baker, Bloom, and Davis (2016), Dang et al. (2023), Palikhe et al. (2024).
[3] Blyth et al. (2007)

investments are now normal. The delays are long enough that some projects die while waiting in line for permits. This is true for all types of infrastructure projects.

TABLE 1: ENERGY PRODUCTS AND MARKETS

	Product	Infrastructure	Physical Market	CFTC-Regulated Market
Crude Oil	Varies by grade; easily storable	Various transport, costs decreasing in asset specificity; regulated pipeline tariffs; exports by pipeline and water	Global price with regional and quality adjustments; bilateral and competitive spot markets	Multiple benchmarks with deep participation; deliverable; trading interest much larger than physical
Refined Products	Various products with observable differences; easily storable	Various transport, costs decreasing in asset specificity; regulated pipeline tariffs; exportable	Regional adjustments; bilateral and competitive spot markets	Single benchmark by category with deep participation; deliverable
Natural Gas	Homogeneous after processing; storage possible but limited (geologic and regulatory)	Pipeline/LNG transport; regulated transmission tariffs; exports by pipeline and LNG	Retail markets mostly regulated monopolies, some competitive market; regional pricing differences; bilateral and spot wholesale markets	Single benchmark with deep participation; mostly deliverable
Electricity	Homogeneous within time; designed network; storage emerging	Wired network only, with separate regional interconnections; regulated transmission tariffs	Wholesale markets mix of bilateral and centralized, some centralized markets have regulated retail; regional pricing differences	Multiple futures linked to physically separate markets; mostly financial

Derivatives and swaps markets are important tools in risk management and can help facilitate project finance in certain circumstances. Derivatives arise when the market demands standardized risk management tools, with the depth and breadth of those markets determined by the size of and connections across the energy system. Electricity and natural gas markets have moved away from regulated vertical integration and towards greater market coordination. Greater reliance on market mechanisms is congruent with increasing numbers of parties interested in managing price risks. Table 1 provides a comparison of the

characteristics of different energy products, the types of relevant infrastructure, and characteristics of the physical and financial markets.

The following report has two chapters. The first provides an overview of the current state of infrastructure and investment for petroleum and refined products. The second chapter addresses cross-cutting finance and permitting issues.

There are many energy and energy-adjacent issues that are not addressed. Natural gas and electricity markets are important but not addressed in this final report. Coal remains an important energy source, even if its prominence has fallen in recent decades. The relatively lack of coal derivatives and reliance on long-term contracting makes it less relevant to CFTC oversight. A large number of emergent energy-related markets are potentially interesting – hydrogen and ammonia, CO_2, and carbon credits are all developing and could potentially gain relevance in coming years. While interesting, those markets are beyond the scope of this report.

References

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Blyth, W., Yang, M. and Bradley, R., 2007. *Climate policy uncertainty and investment risk*. OECD Publishing.

Dang, T.H.N., Nguyen, C.P., Lee, G.S., Nguyen, B.Q. and Le, T.T., 2023. Measuring the energy-related uncertainty index. *Energy Economics*, *124*, p.106817.

Palikhe, H., Schaur, G. and Sims, C., 2024. Environmental Policy Uncertainty. *Journal of the Association of Environmental and Resource Economists*. September 2024 Volume 11, Number 5 pp. 1135 – 1163

Petroleum and Petroleum Products

Oil is a global commodity with about 70 percent of global oil traded internationally.[4] Petroleum is the leading commodity traded in futures markets, both by traders invested in the physical market and hedgers who find oil to be a valuable proxy for other economic activity. Although derivatives trading in oil developed later than for many agricultural products,[5] this is attributable to the unusual price stability that was sustained for decades by the organization of the global industry.[6] As that historical structure decayed in the 1970s, risk management for the world's most-traded commodity became imperative.

The United States is and has been the largest consumer of oil for many decades. Though China is closing the gap in recent years as a greater share of global oil consumption moves to East Asia,[7] U.S. consumption has been broadly stable over the past two decades.[8]

Because deposits are depleted as oil is produced, the industry requires a steady stream of investment in new wells to maintain production levels. This also means that high-value deposits are discovered and extracted relatively early, leading to increasing costs over time. A series of technological advances have allowed the United States to profitably exploit historically unprofitable deposits characterized as unconventional, including shales and other related geological formations. U.S. petroleum production ended decades of decline in the late 2000s as unconventional oil production began to increase. Production has expanded both because of an increasing number of wells drilled, but also due to a steep reduction in unprofitable investments and increasing production per well.[9] Expanding production required building new wells and field facilities to extract petroleum and deliver it into the supply chain. At the end of 2022, the United States had just over 400,000 producing oil wells, and about 120,000 more natural gas wells that produce measurable oil.[10]

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[4] Statistical Review of World Energy, comparing 2022 trade movements for oil to 2022 oil consumption: 68815 MMbpd/97309 MMbpd = 0.707 or 70.7 percent.
[5] Lambert, E., 2010. *The Futures: the Rise of the Speculator and the Origins of the World's Biggest Markets*. Basic Books.
[6] McNally, R., 2017. *Crude volatility: the history and the future of boom-bust oil prices*. Columbia University Press.
[7] Statistical Review of World Energy, comparing 2000, when 27.6 percent of consumption was in the Asia Pacific region and 63.5 percent was in OECD members. By 2022, when global consumption was 27 percent higher, the Asia Pacific share had grown to 36.3 percent and OECD share had fallen to 46.4 percent.
[8] EIA, U.S. Weekly Product Supplied.
[9] EIA, Drilling Productivity Report
[10] For a complete summary, see Appendices B and C of EIA, U.S. Summary of Oil and Gas Wells by Production Rate, released December 27, 2023.

Unlike many other producing nations, in the United States a majority of producing minerals are privately owned, allowing for decentralized decision-making about where and when to drill, and a sharing of rents from successful investments with private owners through royalties and other contractual arrangements.[11] As a result, the low barriers to entry make oil production in the United States a highly competitive enterprise with many relatively small producers; even the largest producers are small relative to other oil-producing firms around the world, many of which are state-supported.[12]

Upstream petroleum attracts substantial capital investment, but the investment is variable as oil prices fluctuate. High prices attract capital investment that leads to increased production that can lead to lower prices that deter capital investment. In 2023 the projected capital expenditure for oil and gas in North America was $200 billion. Of that amount, about 70 percent was spent on drilling and well services, which represents an increase from around 55 percent ten years earlier.[13] One way to interpret that change is that upstream investment is now occurring in mature plays with existing infrastructure. Another interpretation is that firms are underinvesting in complementary infrastructure to support newly producing wells. A second and related change over time has been the pivot to unconventional deposits. Now 95 percent of drilling expenditures is for unconventional resources, representing an increase from a decade earlier but a sea change from two decades before.

As more and more production came from shale, U.S. production creeped upwards until in 2018 it surpassed the previous monthly record set in 1970. The United States surpassed Saudi Arabia and Russia and is the leading producer of oil and associated liquids. U.S. oil production hit all-time recorded high levels in 2023, reaching 13.3 million barrels per day, exceeding the previous high mark of 13 MMbpd set in late 2019. The longtime previous peak of 10 MMbpd set in 1970 was exceeded in 2018, underscoring the rapid rise in domestic production. The oil industry has recently experienced a wave of consolidation through mergers and acquisitions as producers have sought to secure long-term supplies. The U.S. industry remains competitive with many relatively small producers, differentiating it from other countries that are often dominated by a single producer.

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[11] Brown, J.P., Fitzgerald, T. and Weber, J.G., 2016. Capturing rents from natural resource abundance: Private royalties from US onshore oil & gas production. *Resource and Energy Economics*, *46,* pp.23-38. Fitzgerald, T. and Rucker, R.R., 2016. US private oil and natural gas royalties: estimates and policy relevance. *OPEC Energy Review*, *40*(1), pp.3-25.

[12] Medlock K. Fed Energy Conference presentation, Nov 7, 2023

[13] S&P Global Commodity Insights

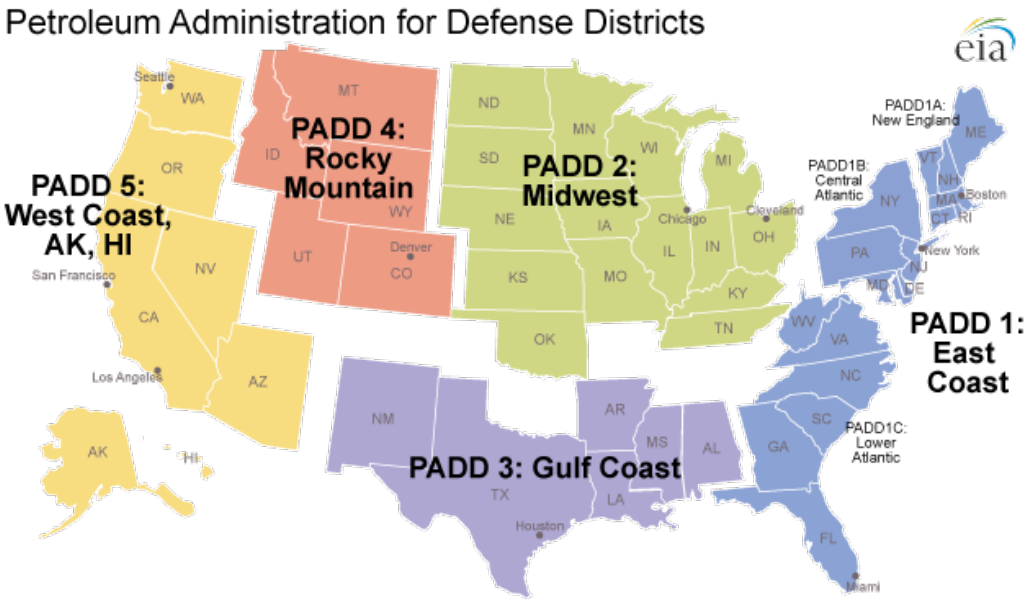
At the end of 2015, a four-decade ban on exporting crude oil was lifted, so the United States now exports both refined products and crude oil. This helped swing the United States from a net importer to a net exporter of petroleum in 2019. While the trade surplus is small relative to consumption,[14] the impact of the switch is significant for markets and the infrastructure that supports them.

Like other commodities, crude oil is an intermediate good. An intricate supply chain has developed over time to transform crude oil and transport to ultimate consumers the final products that they demand. Unlike many other countries, petroleum demand in the United States is predominantly in the form of gasoline. On a volumetric basis, gasoline consumption is between 40-45 percent of the total, with distillate/diesel/heating oil making up around 20 percent and jet fuel/kerosene about 8 percent. The balance is a variety of products including residual oil, natural gas liquids including propane and propylene, lubricants, aviation gasoline, asphalt, and other products.[15] This contrasts with European markets, which consume a slate of products dominated by diesel.[16] Differences in consumption and refinery configurations between the United States and Europe create opportunities for trade in both gasoline and diesel. Infrastructure for product exports has proved to be flexible and allowed U.S. exports to expand dramatically.

In addition to the changes in international trade, there are substantial movements of both crude oil and refined products within the United States, with many market participants and substantial price variation both across space and over time. Much of the investment in petroleum infrastructure over time has been to bring domestic production that is largely in the middle of the continent to the consumers who are predominantly on the coasts. This includes important pipeline links with Canada. As population grows and moves and demand for petroleum changes, the transportation network must adjust. Figure 1 shows the regions used by the federal government to track petroleum movements.

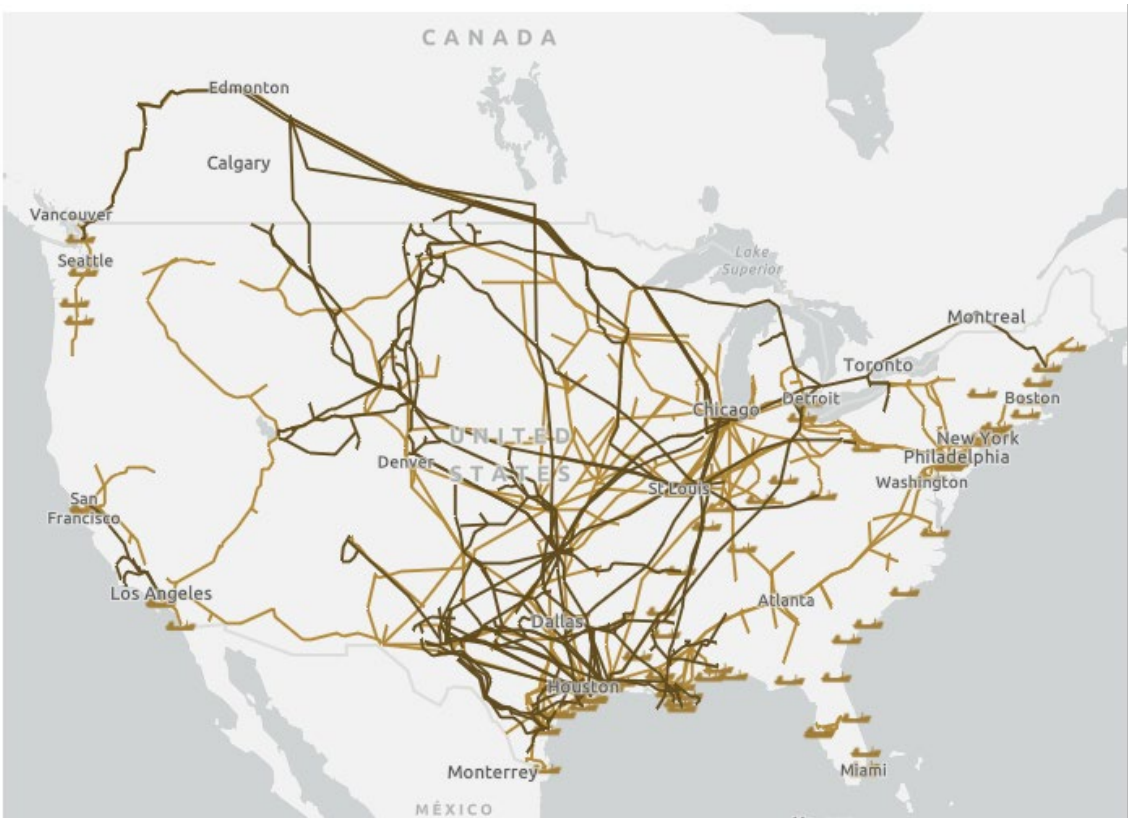
[14] In 2022, the surplus was 1191 MMbpd/20010 MMbpd = 0.06 or 6 percent of consumption. In contrast, in 2005, import reliance was 12549/20802 = 0.60 or 60 percent of consumption. EIA net imports of crude oil and petroleum products and total product supplied of crude oil and petroleum products.
[15] All information in this paragraph comes from EIA U.S. Weekly Product Supplied.
[16] Eurostat

FIGURE 1: PETROLEUM ADMINISTRATION FOR DEFENSE DISTRICTS (PADDS)



Source: EIA

FIGURE 2: U.S. CRUDE OIL AND PRODUCT PIPELINES



Source: EIA Energy Mapping

There were 84,500 miles of crude oil pipelines in the United States in 2022; about two-thirds of the mileage is in interstate pipelines and the balance in intrastate.[17] Refined petroleum products flow through a separate system of 64,000 miles, of which over 80 percent is interstate. Over the previous five years ending in 2022, additions to the pipeline network were substantial but mostly intensive. Extensive additions to these networks were modest; crude pipelines added about 4 percent to the total mileage and refined products about 2 percent, but 20 million barrels per day of liquid pipeline capacity was added.[18] This volume is significant, approximately equivalent to U.S. domestic liquids demand, but reflects easing of constraints at different points of the supply chain.

These systems are privately owned and operated, with several hundred entities operating the systems. Unlike interstate natural gas pipelines that require federal (FERC) approval, intrastate liquids pipelines generally require permitting from states in which they operate.[19] These networks are shown in Figure 2 along with marine terminals for petroleum transport.

The centerpiece of the petroleum supply chain is the oil refinery, where crude oil is manufactured into consumable fuels like gasoline, diesel, and jet fuel. U.S. refineries are among the most sophisticated in the world, and as a whole the U.S. refining complex has grown more capable of processing relatively low-value crude grades into higher-value products.[20] Despite a decrease from over 250 refineries in 1982 to less than half that number 40 years later, total throughput capacity has increased. Closing relatively small refineries and expanding relatively large ones may provide economies of scale, but also makes the system more fragile because a single outage can be more impactful.

The rapid expansion of U.S. petroleum strained and even overwhelmed the infrastructure. The absence of available alternatives led to substantial shares of production moving by rail rather than the less expensive pipeline option. Rail infrastructure is valuable insofar as it is flexible, but it does come at an opportunity cost[21] and poses some risks.[22] Rail is not used uniformly but moves

[17] PHMSA Hazardous Liquids Pipeline Miles

[18] EIA Liquid Pipeline Data Note that this figure includes crude, products, and hydrocarbon gas liquids, both before (y-grade) and after fractionation.

[19] Klass, A.B. and Meinhardt, D., 2014. Transporting oil and gas: US infrastructure challenges. *Iowa L. Rev., 100,* 95. The exception to this is interstate pipelines that also cross an international border. Keystone XL is a high-profile example of a project that needed federal approval (from Department of State) for a border crossing.

[20] E.g., note the increase in catalytic cracking and catalytic hydrocracking capacity, Number and Capacity of Petroleum Refineries, EIA

[21] One example of this is precedence that oil shipments received in the Northern Plains in preference to agricultural products that rely on rail as a primary means of transport. Bushnell et al, NBER Working Paper 23924

[22] Mason NBER Working Paper 24299

oil from PADD 2 to PADD 1 and PADD 5, and from PADD 4 to PADD 3.[23] These are areas that have brought in new resources and lack pipeline capacity or face other physical limitations. Rail fills the gap and provides a viable alternative when pipeline capacity is not available. This is important because preventing pipelines from being built may not be completely effective in preventing production—it simply shifts transport to rail and increases the environmental cost.[24]

In addition to traditional refined products like gasoline and diesel, an important part of the unconventional revolution in American oil and gas has been the greater prominence of other liquids. Traditionally byproducts of refining, these liquids are also increasingly found with natural gas deposits. These hydrocarbon gas liquids are sometimes called natural gas liquids or NGLs. This category includes ethane, butane, isobutane, propane, propylene, and pentanes plus. These products are used both by final consumers (propane, butane, and natural gasoline) and as intermediate goods (ethane and propylene), particularly in the petrochemical sector. These products primarily move as y-grade, a blended stream of NGLs, via pipeline to fractionation facilities which separate them into finished or intermediate products close to demand centers. Since 2015, propane production increased by about two-thirds and exports have tripled.[25]

A. Petroleum and Liquids Financial Market

Petroleum markets have been financialized only relatively recently. In part, this is due to the history of price formation for oil. For long periods of the 20th century, prices did not vary due to the control exerted by a succession of different agents: Standard Oil, the Texas Railroad Commission, the Organization of Petroleum Exporting Countries.[26] In between and more recently, the global oil market has been punctuated by periods of extreme volatility, and tools to manage that risk are at a premium.

While various over-the-counter contracts have been used for many years, the first petroleum contracts were heating and fuel oil contracts that began trading in 1978.[27] This was just in time for the oil price shock precipitated by the Iranian Revolution, and gasoline contracts

[23] EIA, Movements of Crude Oil and Selected Product by Rail
[24] Covert & Kellogg, NBER Working Paper 23855, Clay et al., NBER Working Paper 23852
[25] EIA, Weekly U.S. Exports of Propane and Propylene
[26] McNally, R., 2017. *Crude Volatility: the history and the future of boom-bust oil prices*. Columbia University Press.
[27] Lambert, E., 2010. *The Futures: the Rise of the Speculator and the Origins of the World's Biggest Markets*. Basic Books. Pp 157-8

followed in 1981. This set the stage for the launch of U.S. crude oil contracts in 1983. The global oil market followed with the popular Brent crude contract beginning to trade in 1988.[28]

Although the quality differences between WTI and Brent are relatively small, the two benchmarks are priced reflecting different supply chains.[29] In the past, divergence between the two prices has been taken as evidence of infrastructure constraints, particularly in the inland United States, even as marginal (coastal) barrels in the physical market have remained near parity.[30] The availability and liquidity of the oil futures markets led to dramatic financialization of crude oil markets.[31] Derivatives markets spawned and allowed for a far larger set of participants than the physical market alone.

B. Speculation in Petroleum and Liquids Financial Markets

The crude oil market is the single largest commodity market in the world, reflecting the ubiquity of petroleum as an energy source. The correlation between crude futures and broader measures of macroeconomic performance, in addition to cash settlement opportunities, make crude futures an attractive instrument for hedging broader, non-commercial risks. The trading of crude oil derivatives in this way has led to concerns about speculation in the market and price signals that are disconnected from physical fundamentals.[32]

At least six different motivations have been posited for the phenomenon of speculation driving crude oil prices after 2003: 1) increased participation by financial investors in oil futures led to increased co-movement with other commodities and asset classes 2) index fund traders pushed oil futures prices higher 3) oil futures prices preceded higher spot prices 4) historical relationships

[28] For details about launching the initial Brent contract, see chapters 3-4 in Imsirovic, A., ed. 2023. Brent Crude Oil: Genesis and Development of the World's Most Important Oil Benchmark. Palgrave.
[29] Since June 2023, the current Brent basket includes WTI Midland as one possible deliverable grade, in part due to depletion of Brent proper and other North Sea crudes that were long considered interchangeable (Forties, Oseberg, Ecofisk, Troll). See ICE for more information on changing Brent definitions over time.
[30] Borenstein, S. and Kellogg, R., 2014. The incidence of an oil glut: who benefits from cheap crude oil in the Midwest?. *The Energy Journal*, *35*(1), pp.15-34. This is particularly relevant as the Brent benchmark has been redefined over time to the point that it no longer includes production from the Brent field but does contain a fraction of U.S. production since 2023.
[31] For further documentation, see Alquist, R. and Kilian, L., 2010. What do we learn from the price of crude oil futures?. *Journal of Applied Econometrics*, *25*(4), pp.539-573. and Büyükşahin, B. and Harris, J.H., 2011. Do speculators drive crude oil futures prices?. *The Energy Journal*, *32*(2), pp.167-202.
[32] Bouchouev (2023) is a recent contribution that rejects the traditional view of physical markets determining pricing and transmitting signals to the financial market. The alternative paradigm is price discovery in the financial market, largely driven by the dynamics of hedging strategies, that is then transmitted to the (smaller) physical market. This paradigm differs substantially from the views about speculation that are discussed above and have been tested empirically.

between oil prices and inventories deteriorated 5) structural relationships between spot and futures prices changed 6) time-varying risk premia in oil futures explained by price changes. Careful analysis of data undermines these alternative hypotheses and supports a broad commodity surge after 2003 that carried recently-financialized oil along with it.[33]

1. Petroleum and Liquids Infrastructure Limitations

With this basic understanding of the current infrastructure, four current limitations are outlined. These include limited capacity on crucial refined product pipelines, changes in refinery capacity on the West Coast, distortions created by the Renewable Fuels Standard (RFS), and issues affecting crude oil markets.

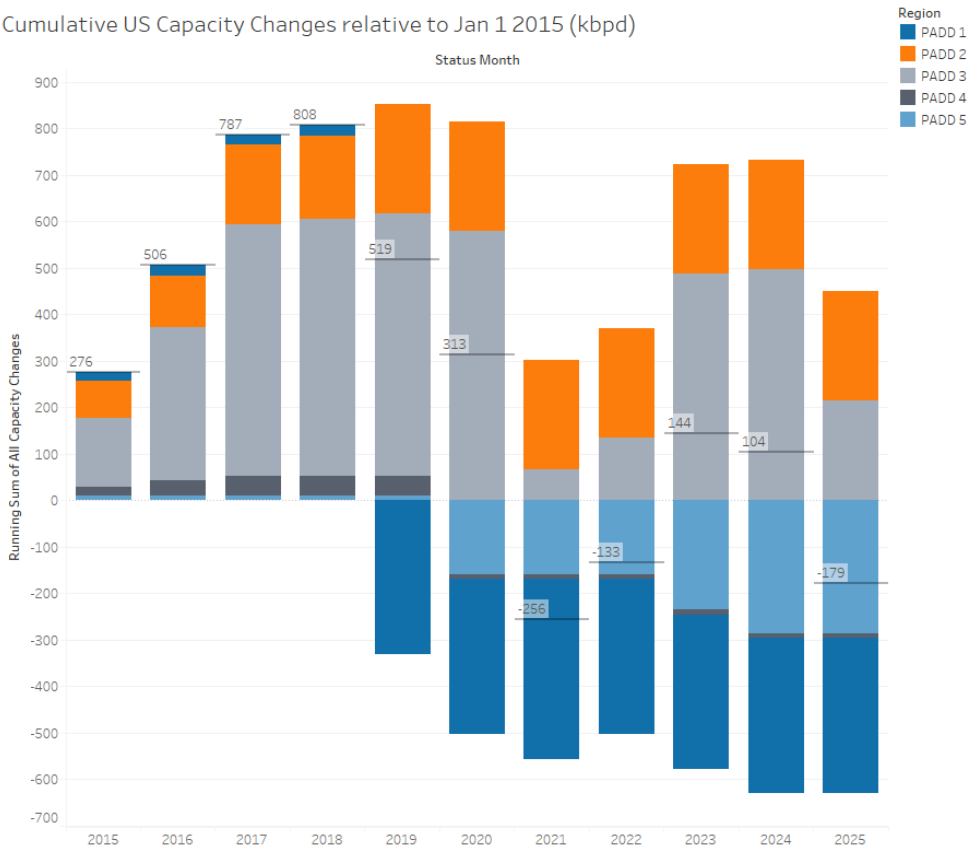
A. Petroleum Product Market Infrastructure Limitations: Product Pipelines

Product pipelines are crucial for moving product surpluses from refining centers to demand centers. Over half of U.S. refining capacity (9.9 mbd) is concentrated in the Gulf Coast region (PADD 3).[34] The Gulf Coast region has about 17.5 percent of gasoline and 21 percent of distillate (diesel) demand.[35] The surplus is transported to the coasts, particularly PADD 1, which is severely deficient in refinery capacity relative to demand. PADD 1 refinery production of gasoline, jet fuel, and diesel have fallen to less than 700 kbd, while demand remains almost 5 MMbpd (as shown in Figure 4).

Over recent years, this imbalance between PADDs has been exacerbated by refinery closures in the Northeast while the Gulf Coast has increased capacity, which is depicted in Figure 3. In 2019, the explosion of Philadelphia Energy Solutions (PES) removed 355 kbd of refining capacity from the Northeast. To make matters worse, PES was configured to yield gasoline, which the region needs the most. The loss of this capacity has been masked over recent years by the legacy impacts of coronavirus, but demand is slowly coming back post pandemic and is starting to cause increasing tightness in NYH product markets. Figure 4 shows the long-term trend.

[33] Fattouh, B., Kilian, L. and Mahadeva, L., 2013. The role of speculation in oil markets: What have we learned so far?. *The Energy Journal*, *34*(3).
[34] EIA Refinery Capacity and Utilization
[35] EIA, SEDS Table F3 and Table F5

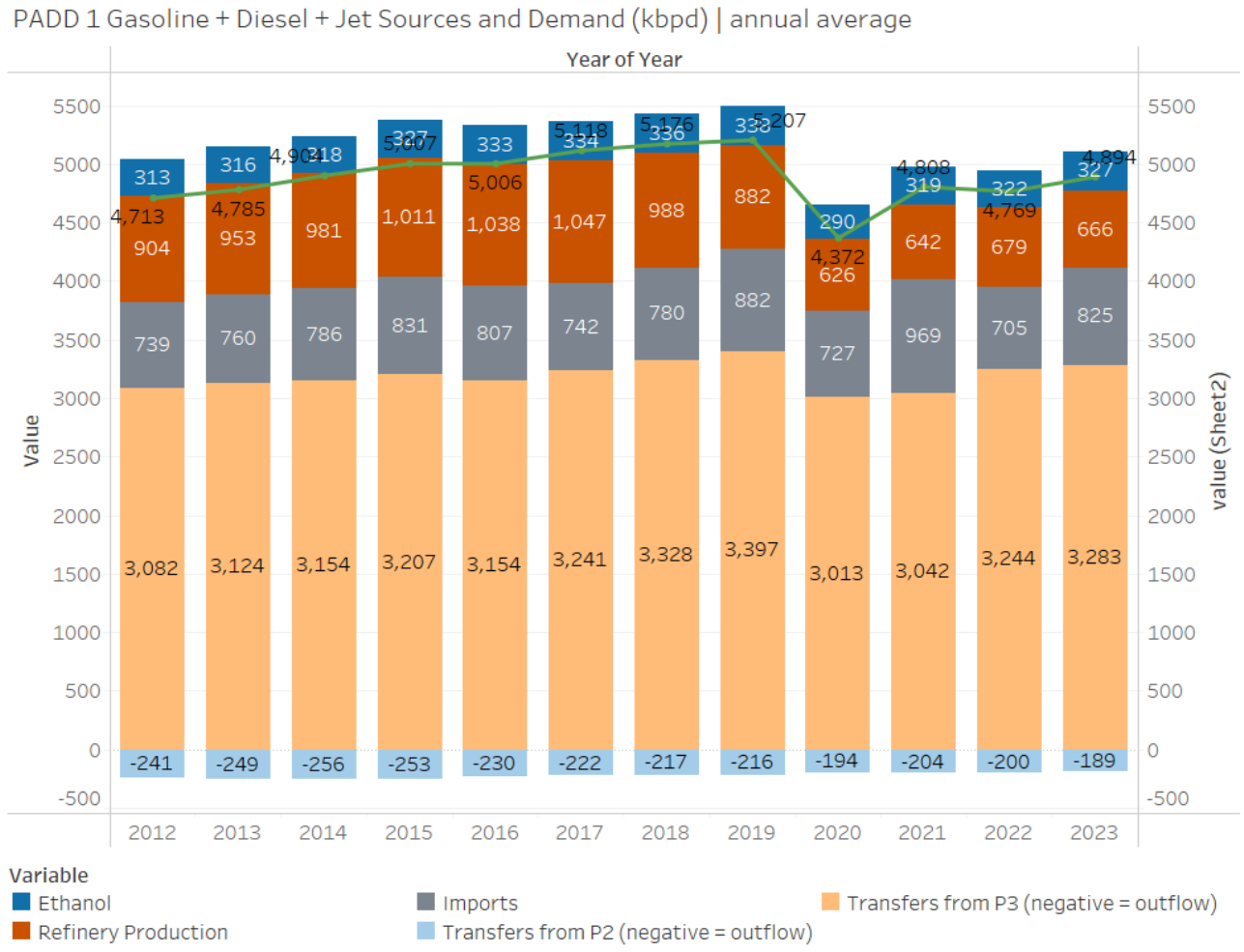
FIGURE 3: U.S. REFINING CAPACITY CHANGES, 2015 - 2025



Source: Vitol Data

Historically, petroleum products markets have endeavored to solve the imbalance of product production and demand via pipeline capacity. Colonial Pipeline runs from Pasadena, TX to Linden, NJ (New York Harbor). Colonial Pipeline has Line 1 carrying gasoline from Pasadena to Greensboro, NC, Line 2 carrying diesel and jet fuel from Pasadena to Greensboro, and Line 3, which carries all products from Greensboro to Linden. Along the way, the pipeline has many injection points from refineries where the pipeline picks up product, as well as "stub lines," which are smaller offshoots to deliver product to cities in the Southeast. Colonial Pipeline connects with Products Pipeline Southeast (PPL) in Collins, MS where product can move between pipelines either through interconnections or through private tank farms. PPL is a pipeline that takes gasoline, diesel, and jet fuel from Baton Rouge, LA to Ronald Reagan International Airport near Washington DC. These two pipelines do much of the work rebalancing the U.S. product markets, moving nearly 2.4 mbd of products from PADD 3 to PADD 1. Figure 4 illustrates the relative importance of these imports to PADD 1 supply.

FIGURE 4: PADD 1 REFINED PRODUCTS SUPPLY, 2012-2023



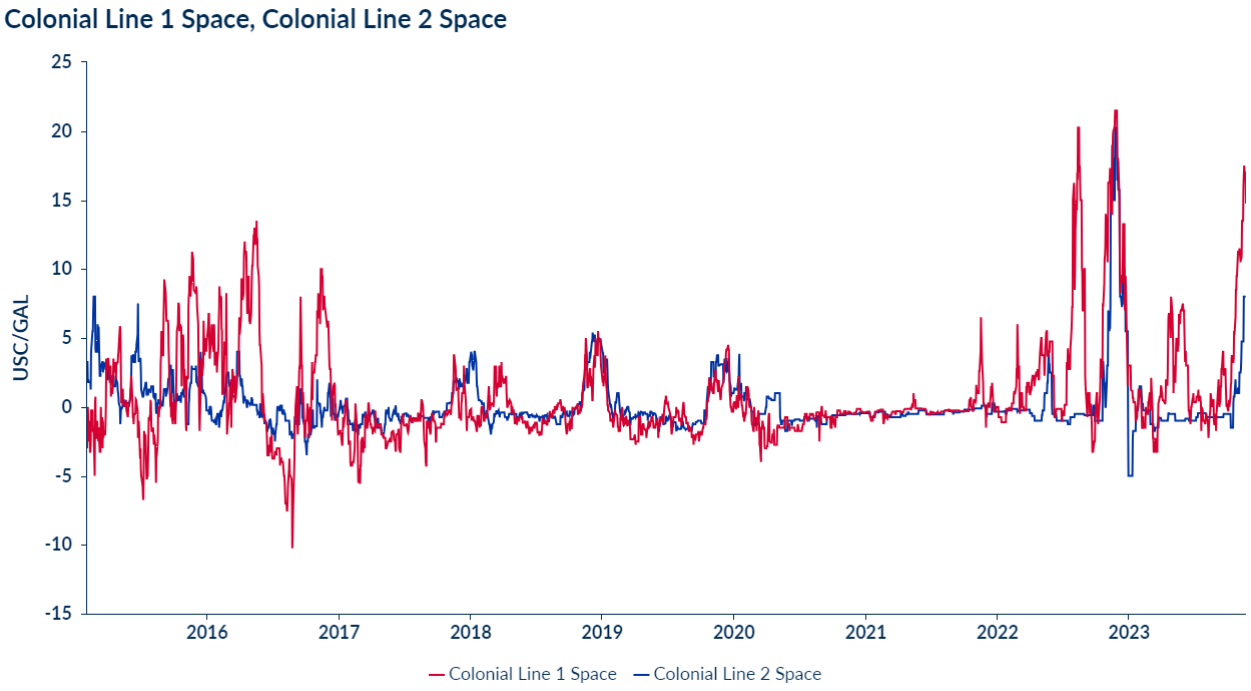
Source: Vitol Data

Because the Northeast has continued to lose refining capacity and PADD 3 has continued to increase refining capacity, the increasing volumes needing to be rebalanced mean these crucial product pipelines have become constrained. Colonial Pipeline has started to go on allocation (no free capacity) more often, and the price spreads between origin and destination have started to become very severe. Figure 5 shows how the value of space in Colonial Line 1 and Line 2 has become both more expensive and more volatile. The more frequent and severe dislocations mean that end users are having to pay a substantial premium to what refiners are being paid for producing gasoline and diesel, and the cost of transportation is making up the difference. Pipelines are the most efficient and cheapest form of transportation for oil. The market tends to use the cheapest form of transportation first, and then as that mode becomes saturated, prices force the market to find the next cheapest mode of transportation. The cost of moving gasoline

from Houston to New York Harbor (NYH) on Colonial Pipeline costs less than 8 cpg. The cost of moving gasoline by railcar from Houston to NYH is very roughly 35 cpg. The cost of moving gasoline from Houston to NYH by ship is roughly 20 cpg. We have seen recently linespace move to 20 cpg in an effort to bring into service vessels to move products.

Even these economics mask some of the major limitations of moving products via water. Section 27 of the Merchant Marine Act of 1920, better known as the Jones Act, restricts all shipments of goods between one U.S. points to be done on vessels built and flagged in the United States, with U.S. owners and crews. The current universe of Jones-capable clean product MR tankers (medium-size between 10,000 and 55,000 dwt) is 20 vessels. By comparison, the global universe of all clean product MR tankers is over 1500 vessels. The relatively small number of Jones -capable vessels is a constraint on moving product from the Gulf Coast to NYH. In the end, the U.S. gasoline market is forced to balance via exports and imports. In times of stress, PADD 3 is often forced to export gasoline to West Africa, which is a gasoline-short region. Europe, which is long on gasoline and often supplies West Africa, then has more product to send to PADD 1. To have ships laden with the same cargo passing each other in the Atlantic is inherently inefficient but reflects the power of arbitrage to satisfy demands.

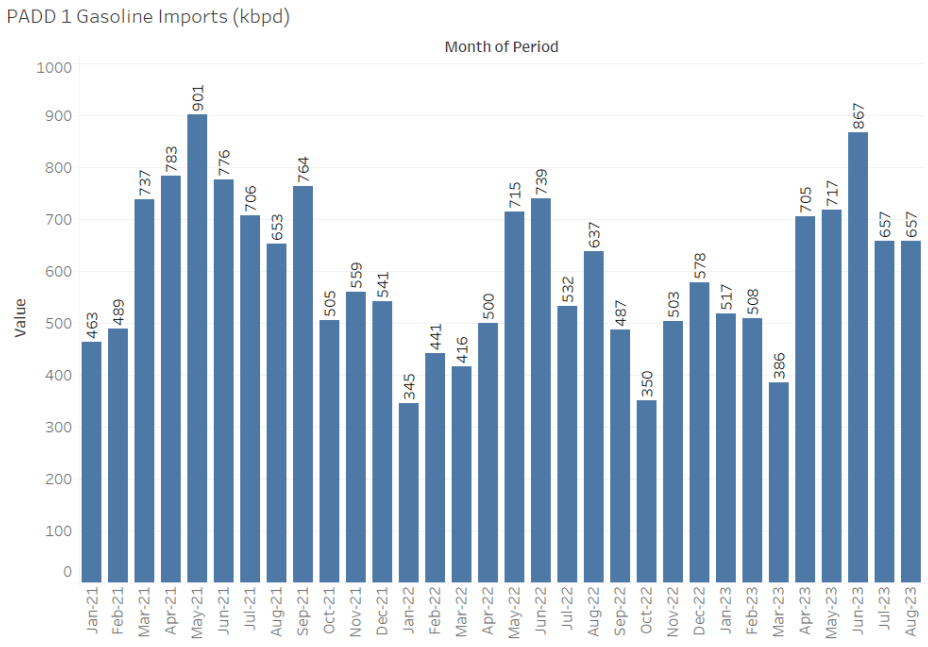
FIGURE 5: LINESPACE CHARGES FOR COLONIAL PIPELINE, 2015-2023



Source: Platts Pricing Data

The most obvious infrastructural constraint within US product markets is in transportation of product between PADD 3 and PADD 1. The reduction of refining capacity in PADD 1, and the increase in refining in PADD 3 has pushed past the available pipeline capacity. This has become increasingly severe in recent years. All improvements to both Colonial and PPL pipelines have been completed, aside from building an additional pipeline. In 2013, Colonial proposed to shippers an additional mainline which would have added substantial capacity to its operations, but shippers did not want to commit financially to an asset that would surely have resulted in pipeline overcapacity, resulting in no margin. Without additional pipeline capacity, Jones Act restrictions on maritime movements have further limited the market's ability to mitigate imbalances.[36] Further exacerbating the problem over recent years is increasing freight rates making other options like rail less attractive. It is likely that these issues will continue for the next few years at a minimum.

FIGURE 6: PADD 1 GASOLINE IMPORTS

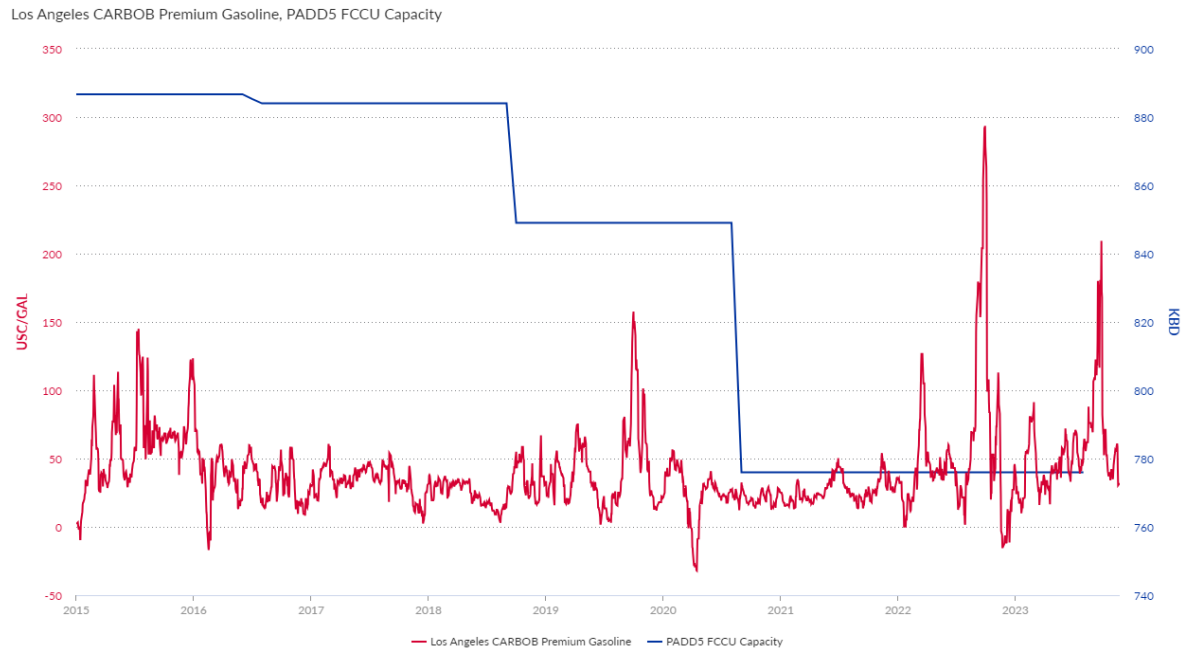


[36] A recent study estimated short-run counterfactual prices for gasoline, jet fuel, and diesel if the Jones Act were not enforced and found a range of price effects: $0.63-0.2/bbl reductions in PADD 1 and gasoline price increases of $0.30/bbl in PADD 3. Kellogg, R. and Sweeney, R.L., 2023. *Impacts of the Jones Act on US Petroleum Markets*. National Bureau of Economic Research Working Paper No. 31938.

B. Petroleum Product Market Infrastructure Limitations: PADD 5 Refineries

California has received considerable attention recently because of its Low Carbon Fuel Standard (LCFS), which is impacting physical infrastructure all over the country, but most acutely within the state. The LCFS program was passed by the California Air Resources Board (CARB) in 2009, with implementation starting in 2011. The purpose of the LCFS program is to reduce GHG emissions and improve air quality within the state. Part of the program is a credit system providing producers of renewable diesel a financial incentive beyond normal market economics. Because of this, refiners have been incentivized to convert their refineries to renewable diesel plants. The program has been a success and renewable diesel is now over half of diesel consumed within the state of California. However, it has come with a reduction in fluid catalytic converter (FCC) capacity, the main gasoline producing unit in a refinery. It has been noted that prices of gasoline in California have become more volatile and more expensive as a premium to RBOB gasoline futures, as shown in Figure 7.

FIGURE 7: CARBOB – NYH RBOB AND PADD 5 REFINING CAPACITY

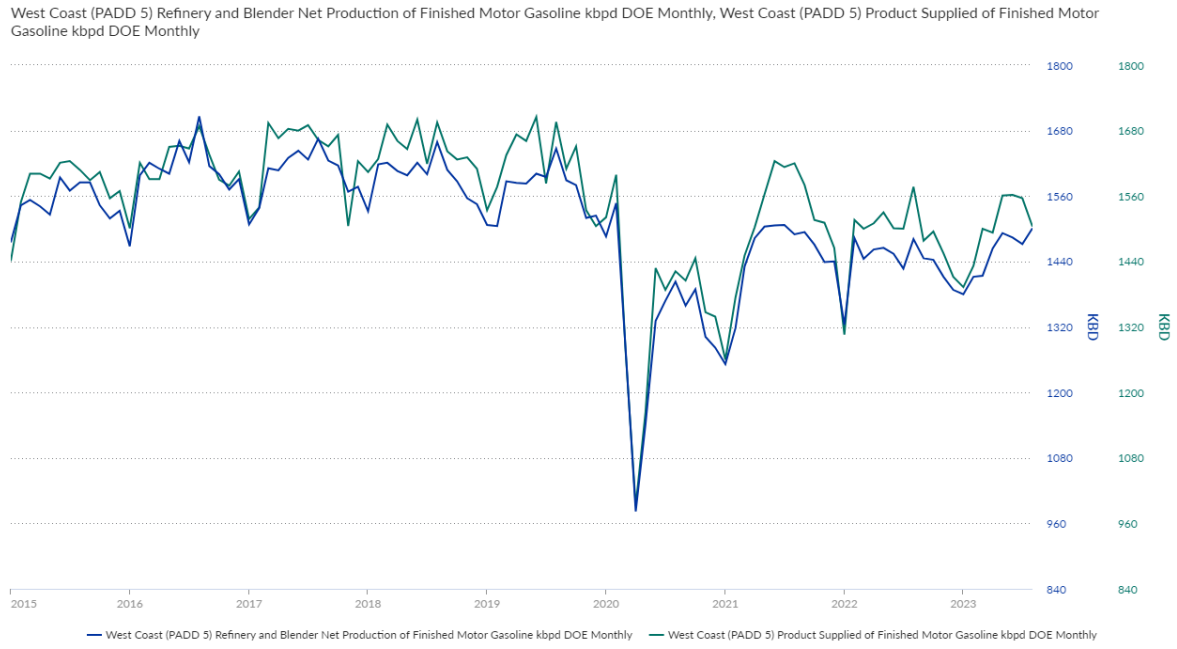


Source: Vitol Data

While it might be reasonable to expect that less production would leave a market imbalanced, that appears to not necessarily be the case. The reduction in FCC capacity has resulted in less gasoline production as shown in Figure 7, but it has also coincided with a nearly

matching reduction in gasoline consumption within the state of California thanks to electric vehicle penetration and the legacy effects of the pandemic. It therefore appears that PADD 5 does not have as large of a structural shortage of gasoline as one might think. Nonetheless, the reduction in both capacity and demand has resulted in a smaller and less flexible market. A market that has fewer participants to respond to price will be inherently less flexible and also more susceptible to price spikes. In a market with many participants, there are more options to increase production or reduce demand on the margin, allowing the market to dampen its own shocks. It seems as if the PADD 5 gasoline market is experiencing shrinking pains, but that comes at the cost of price volatility. Figure 8 shows the close balance between production and consumption in PADD 5, reflecting the relatively weak links it has with other regions.

FIGURE 8: PADD 5 PRODUCTION AND PRODUCT SUPPLIED, 2015-2023



Source: Vitol visualization of DOE PSM data

C. Regulation and Infrastructure Problems Relating to RFS Mandates

Congress passed the Energy Policy Act of 2005 in an effort to improve energy security through increased biofuel blending in the United States. The Environmental Protection Agency (EPA) was to implement the Renewable Fuels Standard (RFS) in accordance with this law. In 2007, Congress expanded the RFS with the Energy Independence and Security Act of 2007. At its core, the RFS obligates parties to blend a specific volume of renewable fuel each year and implements a

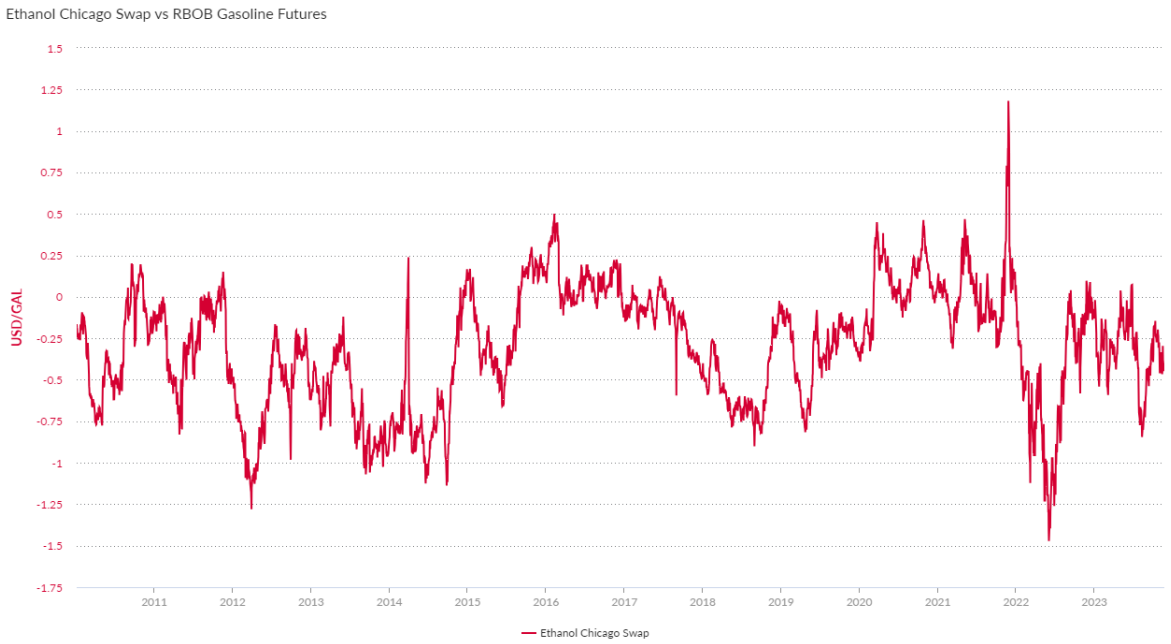
credit system for trading obligations between parties who cannot or choose not to blend their obligated volumes with those that do blend and ensure that the mandated volumes are included in transportation fuels. Renewable Identification Numbers (RINs) were the tool created to track and trade compliance. A RIN is created when a gallon of biofuel (e.g., ethanol) is blended into a transportation fuel (e.g., gasoline).[37] The manufacturer or importer of the unblended fuel is required to obtain and surrender RINs to assure that the biofuel is ultimately blended, even if the blending is done by another party.

Traditionally, ethanol has made up the preponderance of biofuel volume as it was economically more viable than other biofuels. Ethanol itself creates a set of infrastructure issues because it cannot be transported by pipeline and instead relies on a system of rail, barge, and truck transport. The dominant transport mode is rail. The vast preponderance of ethanol production is in PADD 2, and the greatest volumes move from PADD 2 to the other PADDs with lesser volumes moving from PADD 3 to PADDs 1 and 5.[38]

Ethanol more often than not trades below the value of RBOB gasoline. Figure 9 shows the basis differential. Ethanol helps boost octane, which is an important feature of gasoline. Gasoline blendstocks for oxygenate blending "BOBs" are the petroleum-based gasolines made to be blended with ethanol before being sold at the pump. RBOB gasoline is reformulated gasoline for oxygenate blending and CBOB is conventional gasoline for oxygenate blending. The price of BOBs trade at a discount to base gasoline that could be used without the inclusion of ethanol. Therefore, even if ethanol were to trade at a 10c premium to gasoline, if CBOB is trading even just a 2c discount to its non-ethanol ready equivalent, ethanol remains economical because it only makes up 10 percent of the blend (called "E10" to distinguish from other possible blends).

[37] There are multiple classes of RINs, including for biodiesel and niche fuels with little production.
[38] A relatively small amount moves from PADD 4 to PADD 5. See Movements between PAD Districts. Plant production capacity for ethanol shows nearly 95 percent of production capacity in PADD 2.

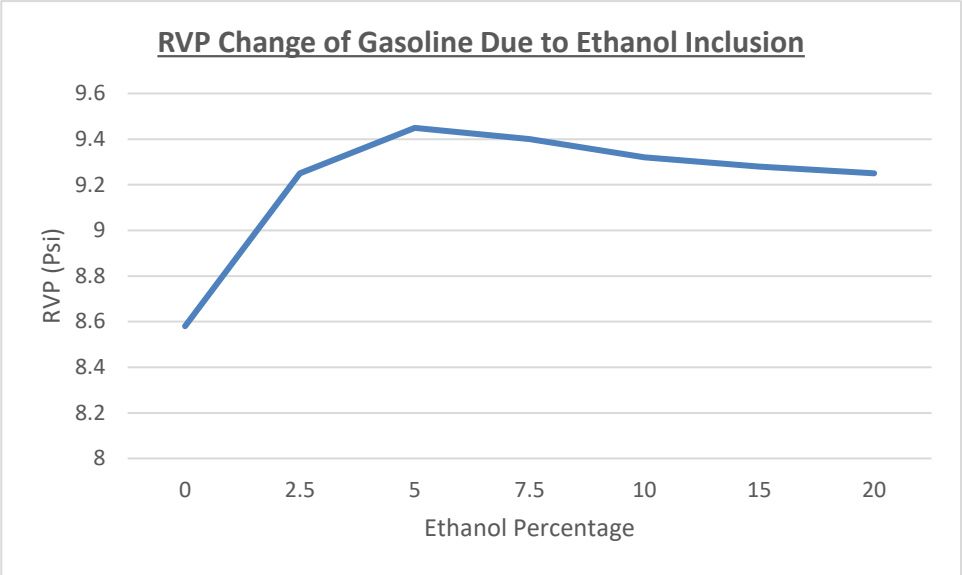
FIGURE 9: CHICAGO ETHANOL – NYH RBOB



Source: Vitol visualization of exchange prices

Around 2013 RIN values started to have and maintain meaningful value. The market realized that it had hit the "blend wall" of around 10 percent by volume. The blend wall reflects the difficulty of the markets to absorb higher blends. Part of this is due to hesitancy by consumers to purchase fuel with lower energy density that may also pose issues for certain (especially older) engines. There are technical and regulatory issues are well. When ethanol is blended with gasoline, the Reid vapor pressure (RVP) of the finished blend tends to have increased by about 1 Psi, meaning that the blended fuel is slightly more volatile than unblended gasoline. Figure 10 shows how RVP of gasoline changes as a function of ethanol blending. Because the EPA tightly controls RVP specifications for gasoline, this would have been a major obstacle. To solve this problem, Congress passed a 1.0 Psi waiver for gasoline blends containing between 9-10 percent ethanol. While solving the immediate problem, this narrowly defined exception laid the groundwork for the market's next hurdle, pushing past the blend wall to blends with more than 10 percent ethanol (greater than E10).

FIGURE 10: RVP OF GASOLINE ACROSS ETHANOL BLENDS



Source: Amirkabir Journal of Science & Research

If gasoline blenders wanted to blend more than E10, they would cease to receive a 1 Psi waiver. This would require that those choosing to blend more ethanol would have to lower the RVP of the petroleum-based gasoline by approximately 1 Psi. This is both a costly exercise, but also a logistically impractical one too. Most gasoline is blended with ethanol at the rack. To accommodate higher ethanol blends, racks would have to carry an additional gasoline grade. This requires more tankage and access to supply. Gasoline pipelines don't carry these grades and refiners do not make these grades so it is very unlikely that rack blenders would be able to access supply of sufficiently low RVP gasoline.

Were Congress and the EPA to extend the 1 Psi waiver to ethanol blends above 10 percent, there would be a path for the market to develop the necessary infrastructure to higher blends. There are additional hurdles for the market. For example, in reformulated gasoline markets (typically urban) where there is no 1 Psi waiver E10, one might expect blends to have gone toward 15 percent. The problem there is likely at the retail level. Most retailers only have one tank of regular (generally 87 octane) gasoline. If a retailer wanted to offer E15 (15 percent ethanol), they could no longer offer E10. Because of its rarity, there is still some consumer skepticism of E15, as there was for E10 20 years ago. Similarly, cars before 2001 are not approved to use E15, causing more potential legal and financial problems. The regulatory environment is limiting to infrastructure that would allow ethanol blends higher than E10. Midwestern governors have petitioned to eliminate RVP waivers, hopefully paving the way to greater use of ethanol important in

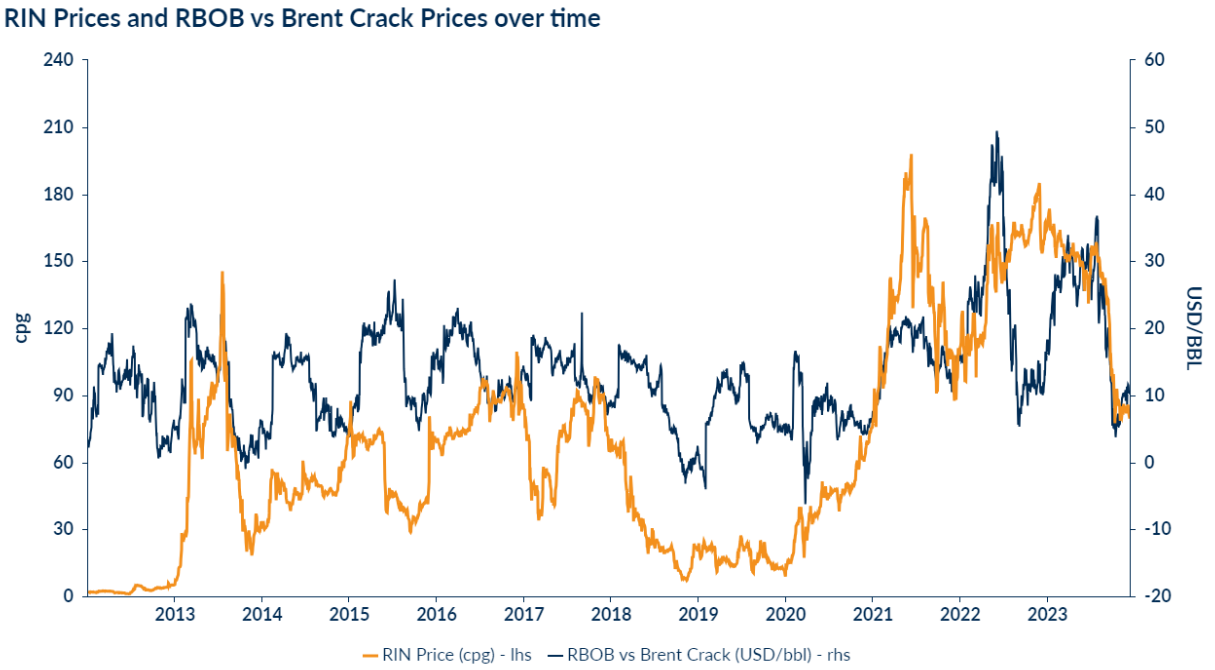
their states.[39] EPA has taken temporary steps in the same direction by issuing summer RVP waivers to allow more E15 into the market.[40]

The ethanol blend wall has been an issue for a while but may become an increasing issue over time. Biofuel targets under the RFS are volumetric rather than a share of all gasoline sold, with EPA providing advance notice of the required volumetric obligation. The original mandates did not take into account gasoline and diesel demand declines, so now EPA periodically resets the targets. This introduces some uncertainty about the targets, and the blend wall and RIN compliance will gain salience if the volumes are set higher than the market is prepared to absorb. If this persists as an issue, RIN prices will increase in value as will price volatility. RIN price volatility may seem innocuous, but RINs are an input cost to every gallon of gasoline and diesel in the country. When RIN prices go up, it impacts the price of gasoline cracks and diesel cracks. Figure 11 shows how these series have evolved over time. Additional volatility in RINs can be transmitted to petroleum product markets.

[39] https://www.federalregister.gov/documents/2023/03/06/2023-04375/request-from-states-for-removal-of-gasoline-volatility-waiver#:~:text=The%petition%specifically%requested%the%removal%of%the%1-psi%waiver%as%a%permanent%solution%to%provide%year-round%E15%in%those%states%beginning%in%the%summer%of%2023

[40] https://www.epa.gov/newsreleases/epa-issues-emergency-fuel-waiver-e15-sales-0 These waivers have been extended.

FIGURE 11: RIN PRICE AND NET REFINER MARGIN, 2012-2023



Source: Vitol

D. Infrastructure Limitations in Crude Oil Markets

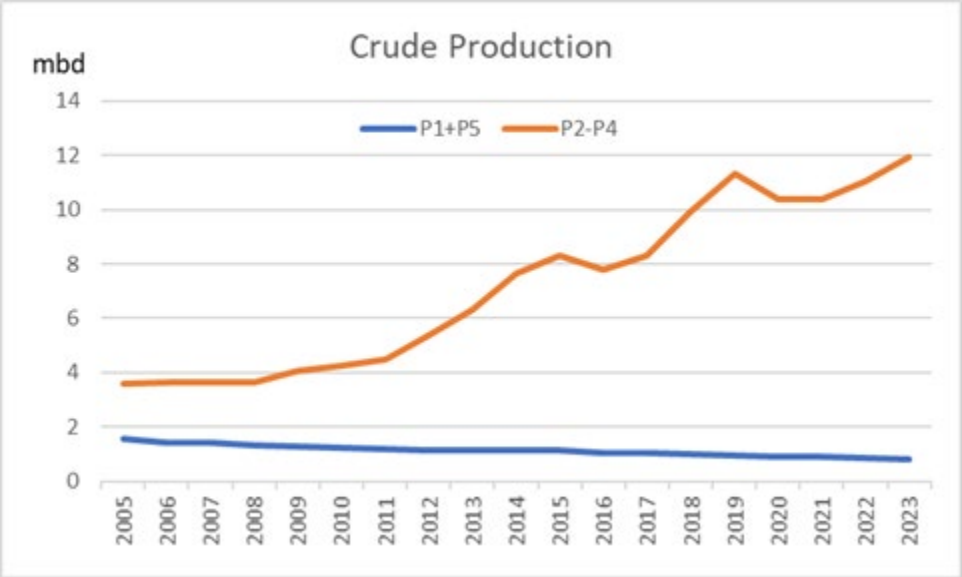
Expanding U.S. crude oil production has presented numerous infrastructure-related issues in oil markets. The ability to modulate crude prices on the back of production has been a keen global interest for many years, including recently in the aftermath of Russia's invasion of Ukraine and war in the Middle East. The ability to quickly react to oil price swings depends on spare capacity. Spare capacity is expensive, because it requires substantial investment both in finding and developing producible deposits, and in the attendant midstream capacity to deliver that oil to market in a timely fashion. Despite the increase in U.S. production and the impact it has had on global markets, there is not sufficient spare capacity in the United States to affect global pricing.[41] Furthermore, the competitive structure of the upstream sector in the United States is not conducive to withholding substantial amounts of productive capacity from the market. The role of spare capacity in creating a "swing producer" will remain in the select hands of foreign producers who can control national oil companies and coordinate decisions.

[41] Multiple studies draw the same inference. See McNally, R., 2017. *Crude volatility: the history and the future of boom-bust oil prices*. Columbia University Press. or Newell, Richard G., and Brian C. Prest. "The unconventional oil supply boom: Aggregate price response from microdata." *The Energy Journal* 40, no. 3 (2019): 1-30.

A second issue is how pricing reflects infrastructure constraints in the market. Two major reference grades of crude oil are West Texas Intermediate (WTI) and Brent. Historically, Brent traded at a small discount to WTI, which has physical properties preferred by refiners. That pattern broke in 2010 as U.S. oil production began to noticeably increase.[42] It was not possible to move the extra production through established channels. WTI traded at a substantial discount to Brent in part to cover higher transport costs. Substantial investment in new pipeline capacity and export terminals have contributed to a closure in the WTI-Brent spreads. Changing historical relationships between the two grades does not appear to raise any immediate regulatory issues and traders can adapt to the changing relationships.

Infrastructure investment does reflect distinct differences in the crude supply and demand dynamics between the coasts (PADDs 1 and 5) and central core of the country (PADDs 2, 3 and 4). Figure 12 illustrates the divergent trends. All production growth has been in PADD 2-4 while PADD5 crude production continues to decline and PADD 1 production remains negligible. PADD 5 relies heavily on declining production in Alaska, which has been subject to intense political debate around making additional federal acreage available for exploration.

FIGURE 12: CRUDE OIL PRODUCTION BY PADD, 2005-2023

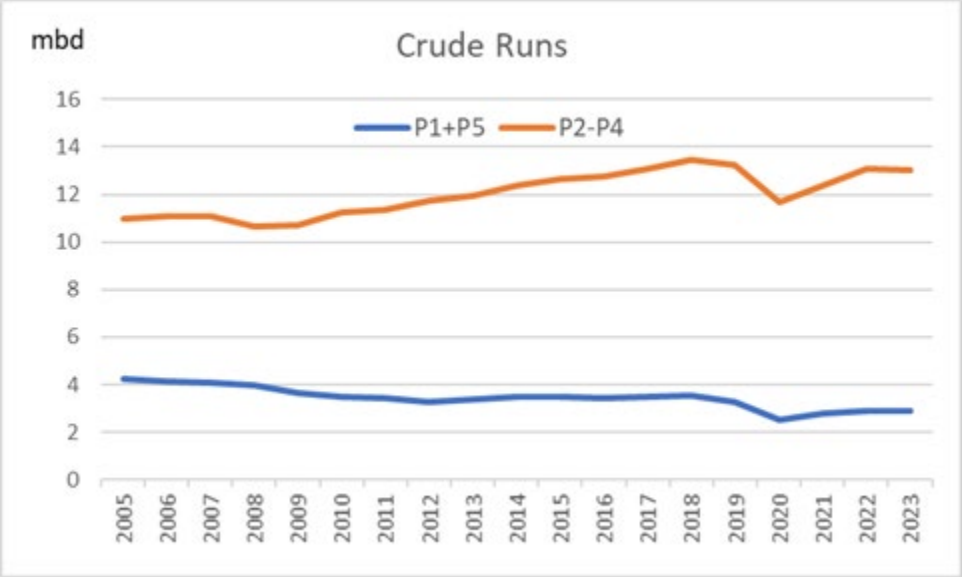


Source: EIA

[42] Several studies have documented this with varying dates of structural breaks. An accessible example is Buyukşahin, B., Lee, T.K., Moser, J.T. and Robe, M.A., 2013. Physical markets, paper markets and the WTI-Brent spread. *The Energy Journal*, *34*(3), pp.129-152.

By a similar token, Figure 13 shows how refinery runs in PADDs 2, 3, and 4 have grown, taking advantage of ample supply of both domestic production and Canadian imports. Without easy access to growing supply, runs in PADDs 1 and 5 have declined. This leads to substitution of transporting products rather than crude.

FIGURE 13: REFINERY CRUDE RUNS BY PADD, 2005-2023



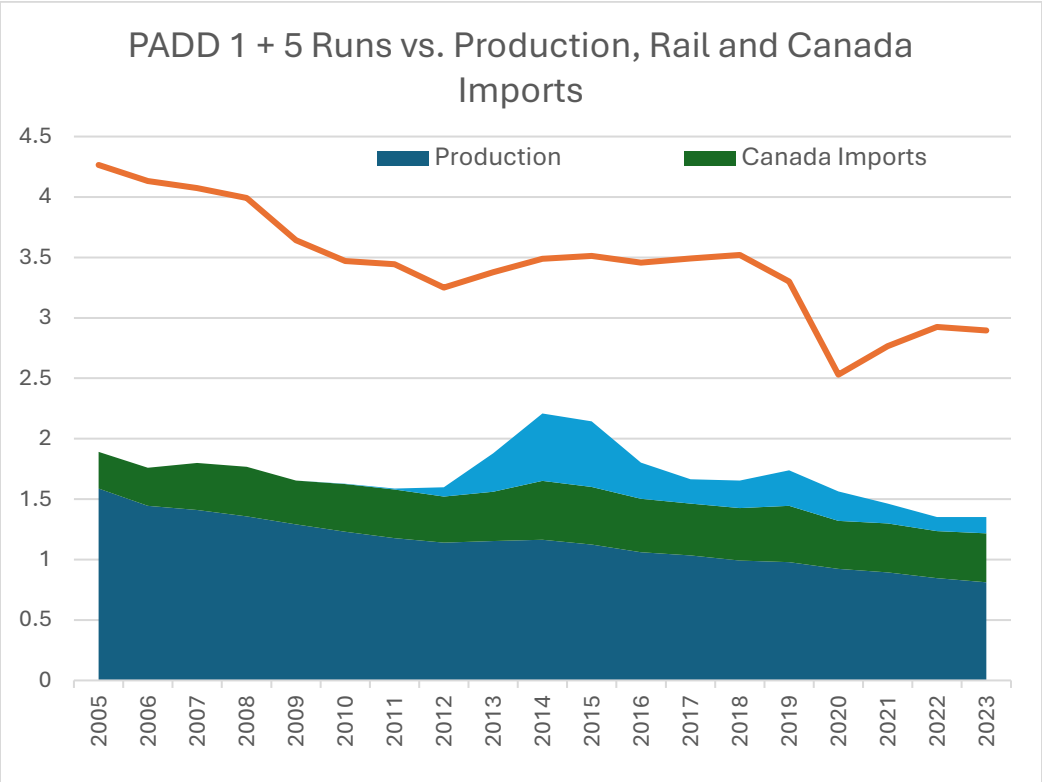
Source: EIA

With this geographic discrepancy, for a time period in the 2010s rail provided a bridge to supply some of this production growth to the coast – primarily Bakken crude from North Dakota. However, with the completion of the Dakota Access pipeline to the Gulf Coast and the dip in Bakken production during Covid, rail has fallen back to minimal levels. Canadian crude infrastructure is tightly integrated with the United States with thousands of miles of pipelines tying the two countries together. Like U.S. production, the growth in imports from Canada is focused in PADDs 2, 3, and 4 while Canadian imports to the east and west coasts have remained constant.[43]

Figures 14 and 15 illustrate these trends.

[43] Canada has simultaneously made its own major pipeline investments, notably the Trans Mountain Express that will deliver Alberta crude to the coast of British Columbia for export.

FIGURE 14: PADD 1 AND PADD 5 REFINERY RUNS AND SUPPLY DISPOSITION



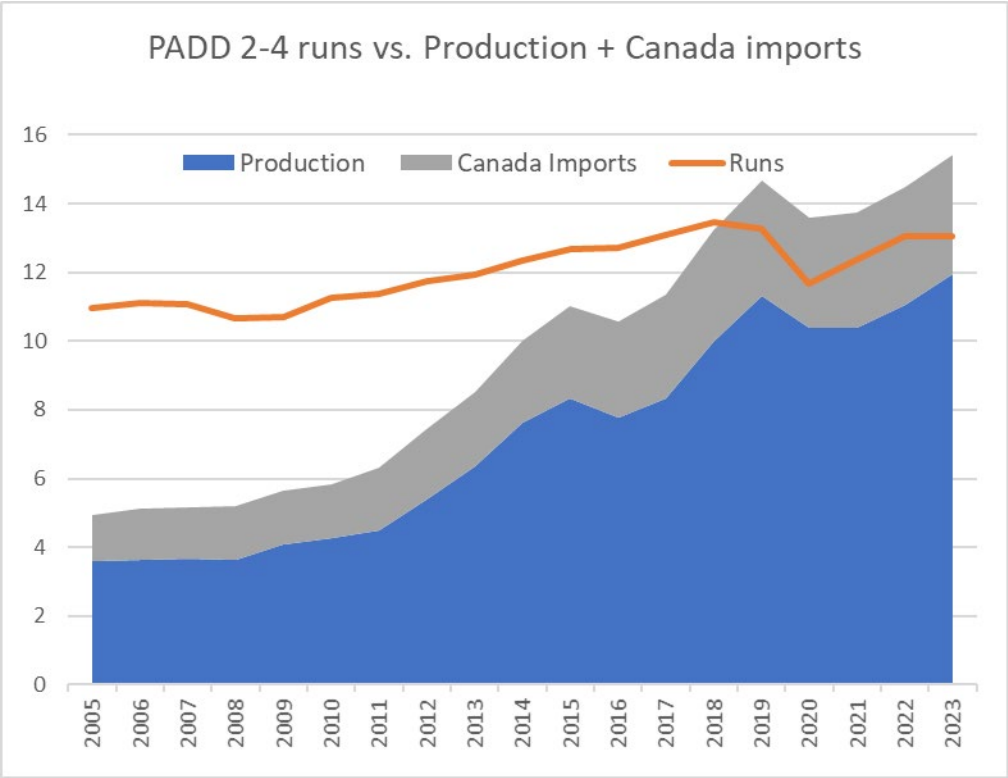
Source: EIA

Combining crude supply and demand together, PADDs 1 and 5 remain short while PADDs 2, 3, and 4 continue to develop a still greater surplus. In previous years the ban on crude exports and the U.S. position as a net importer led to wider inland crude price differentials compared to waterborne crudes.[44] These conditions have been relaxed and the previous basis differentials have largely disappeared. Growth in North American supply and stagnant refinery demand has resulted in the need for crude oil exports from the U.S. Gulf Coast to maintain growing production. Meanwhile, East and West coast refiners remain importers to satisfy their demand for crude.

Figure 16 shows this difference. Infrastructure linking the middle of the country with demand centers on the coast would help U.S. consumers take better advantage of increased production.

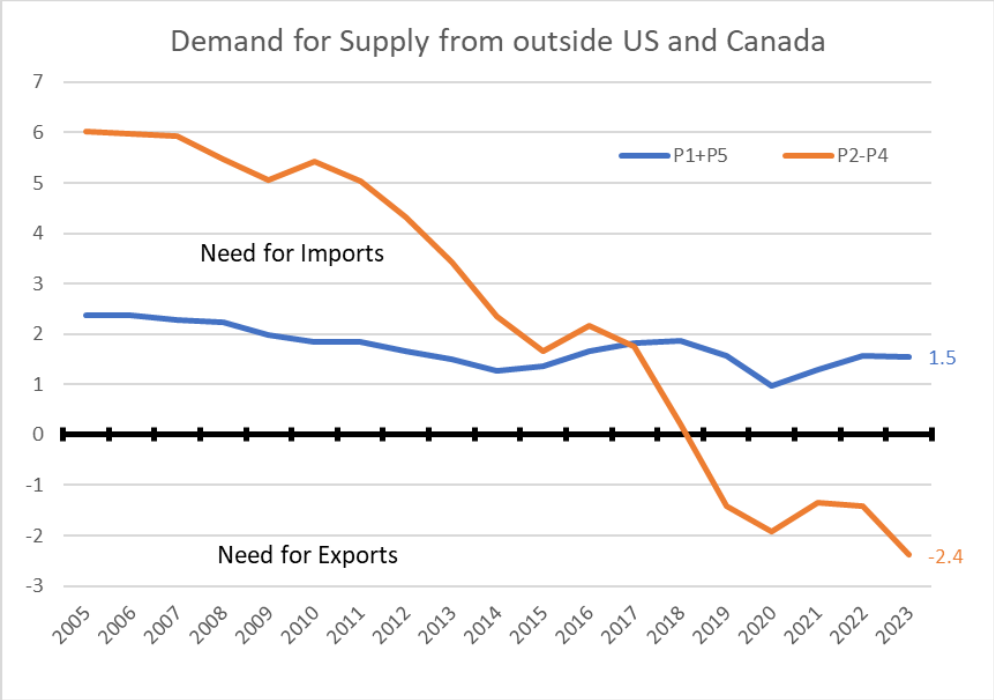
[44] Borenstein, S. and Kellogg, R., 2014. The incidence of an oil glut: who benefits from cheap crude oil in the Midwest?. *The Energy Journal*, *35*(1), pp.15-34.

FIGURE 15: PADD 2, 3 AND 4 REFINERY RUNS AND SUPPLY DISPOSITION



Source: EIA

FIGURE 16: NET IMPORTS EXCLUDING CANADA, BY PADD, 2005-2023



Source: EIA

Geographic separation of markets is exacerbated by regulation in product markets. Different specifications of gasoline are required in different parts of the country. Complying with federal air quality regulations forces some areas to use reformulated gasoline, and consumers pay higher prices in those local markets. These regulatory provisions interact with infrastructure constraints, leading to price effects more than twice the average in locations that must use higher-priced product and also face limited transport options.[45]

Crude oil markets react to geopolitical events, whether because supply is interrupted or due to the costs of rechanneling flows using existing global infrastructure. Geopolitical shocks can result in supernormal backwardation in the crude oil futures markets for a month or more,[46] in part because physical logistics constrain the ability of the market to recalibrate quickly. This effect is most pronounced during periods of low interest rates when price volatility may be more muted. That predictable reaction to heightened geopolitical risk attracts speculators. One policy suggestion to limit such behavior is to increase margin requirements to discourage speculative activity by non-physical participants.

List of Abbreviations

bbl: barrel (42 gallons)

CARB: California Air Resources Board

CBOB: Conventional blendstock for oxygenate blending

cpg: cents per gallon

dwt: deadweight tons

EIA: Energy Information Administration

E10: finished gasoline blend with 10 percent ethanol

E15: finished gasoline blend with 15 percent ethanol

FCC: Fluid catalytic cracker

FERC: Federal Energy Regulatory Commission

kbd: thousand barrels per day

LCFS: Low-Carbon Fuels Standard

[45] Brown, J., Hastings, J., Mansur, E.T. and Villas-Boas, S.B., 2008. Reformulating competition? Gasoline content regulation and wholesale gasoline prices. *Journal of Environmental Economics and Management*, *55*(1), pp.1-19.

[46] El-Gamal, M.A., Jaffe, A.M. and Medlock III, K.B., 2023. Cheap Money, Geopolitics and Supernormal Backwardation of the WTI Forward Curve. *Economics of Energy & Environmental Policy*, *12*(1).

MMbpd: million barrels per day

MR: medium-sized tankers 10,000 - 55,000 dwt

NYH: New York Harbor

OECD: Organization of Economic Cooperation and Development

PADDs: Petroleum Administration for Defense Districts

PES: Philadelphia Energy Solutions

PHMSA: Pipeline and Hazardous Materials Safety Administration

RBOB: Reformulated blendstock for oxygenate blending

RFS: Renewables Fuels Standard

RIN: Renewable identification number

RVP: Reid vapor pressure

WTI: West Texas Intermediate

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EIA

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PHMSA. Hazardous Liquids Pipeline Data.

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Finance

Energy infrastructure investment provides the promise of productivity-enhancing investments that spill over to the broader economy.[47] Infrastructure is capital intensive and hence almost always requires external financing. While there can be certain exceptions to this, such as internal financing being used for oil and gas exploration, this section focuses on external financing and how various types of infrastructure are, or can be, financed. Managing market risks is an important dimension of the financing decision. So too is consideration of the necessary permits that must be obtained to proceed with projects; because such permits are often obtained after capital is committed, uncertainty and delays in permitting impose a financial burden.

External financing can come from capital markets, banks, and private credit. Any discussion of how external financing conditions affect infrastructure investment in the United States must include a discussion of how costs are recovered for different types of projects. Considering how builders get paid back is important in understanding the cost recovery horizon and financing constraints that may arise as a result. Greater financialization of the energy sector has come with greater reliance on risk management tools,[48] in part to lower financing barriers. There are important differences between upstream and midstream projects. Future uncertainty, which plays an important role in determining these financing conditions, arises from three different sources: market forecasts, the regulatory and policy environment, and climate risk.

1. Financing Upstream Infrastructure

Upstream energy infrastructure projects are almost exclusively intermediate goods purchased by suppliers to final customers.[49] Most producers of oil or natural gas and electricity generators (both renewable and non-renewable) sell their product into wholesale markets, or the equivalent. In the case of wholesale oil and gas markets the product is typically sold at competitive prices. For electricity generation, wholesale prices can be competitive or subject to regulatory approvals or caps, depending on the local market of the project. This variation of wholesale electricity prices is due to the fragmented nature of local electricity markets and their regulation in the United States.

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[47] For further explanation of the macroeconomic effects of infrastructure investment, see Glaeser, E.L. and Poterba, J.M. eds., 2021. *Economic analysis and infrastructure investment* (Vol. 28215). University of Chicago Press.

[48] Spence, D.B. and Prentice, R., 2012. The transformation of American energy markets and the problem of market power. *BCL Rev.*, *53*, p.131.

[49] In certain cases, (large) customers may invest in their own infrastructure to ensure access to supplies, but most customers rely on infrastructure provided by suppliers or other intermediaries.

Regardless of the market structure, the price signals from the wholesale markets determine the value of infrastructure projects and provide important information to developers.

A. Market Forecast Uncertainty

For upstream producers that sell their product at competitive market prices, volatility due to a mismatch of supply and demand, which often manifests itself in sudden falls/spikes in price, can lead to revenue uncertainty and therefore financing conditions. The 2014 oil price shock precipitated by OPEC's decision to protect its market share provided a good opportunity to understand how upstream oil infrastructure financing is sensitive to market changes.[50] Because upstream oil firms obtain financing by using their oil reserves as collateral, volatility in the spot and future oil price can affect the collateral valuation of these firms and negatively affect their access to credit. Similar scenarios apply to upstream natural gas firms. Indeed, the analysis of the 2014 oil price shock has found worsening credit conditions for upstream oil firms in the form of both reduced access and higher financing costs. However, this effect seems to be limited to firms with a poor credit rating and firms that do not have a rating at all.[51] This can be interpreted as lending conditions being tightened on lower quality borrowers as a result of the price shock. Since unrated firms and firms with poor credit ratings usually lack access to bond markets, the tighter bank lending conditions will likely lead to lower investment spending. The lack of a high-quality rating can also be an indicator of the upstream firms operating with high leverage even before the price shock, which has been shown to decrease investment spending during negative shocks.[52]

Looking beyond bank financing for upstream oil and gas infrastructure projects, internal financing may be a more important source of funding compared to bond issuances. The degree of market leverage can significantly vary across larger and publicly traded producers,[53] implying that at least some oil and gas companies have previously undertaken new investments without raising additional debt. Along similar lines, the International Energy Agency (IEA) notes that between 2010 and 2019, oil and gas firms typically invested 75 percent of their cash outflows in new supply, implying a high degree of correlation between revenue and upstream investment in oil and gas extraction. It is possible that revenue uncertainty is already affecting such internal financing of oil

[50] Sengupta, R., W. B. Marsh and D. Rodziewicz, 2017. "Do Adverse Oil Price Shocks Change Loan Contract Terms for Energy Firms?", *Federal Reserve Bank of Kansas City Economic Review*, Fourth Quarter.
[51] Sengupta, Marsh and Rodziewicz (2017).
[52] Gilje, E. P. and J. P. Taillard, 2017. "Does Hedging Affect Firm Value? Evidence from a Natural Experiment", *The Review of Financial Studies*, 30(12), 4083-4132.
[53] Gilje, E. P., E. Loutskina and D. Murphy, 2020. "Drilling and Debt", *The Journal of Finance*, 75(3), 1287-1325

and gas extraction infrastructure as well. According to the IEA, in 2023 "less than half of the oil and gas industry's unprecedented cash flow from the energy crisis is going back into traditional supply and only a small fraction to clean technologies."[54] While a number of different factors could have contributed to a change in how much of energy firms' cash flows are used to fund upstream investment projects, revenue uncertainty is certainly one factor. Along these lines, the IEA also notes that a "key dilemma for investors undertaking large, capital-intensive gas supply projects is how to reconcile strong near-term demand growth with uncertain and possibly declining longer-term demand."[55]

For some decades a trifling academic indulgence was to try to predict the time of peak oil supply,[56] which conventional wisdom suggested would be followed by a steady decline in petroleum production due to physical constraints. When the shale revolution and increasing concerns about climate change drove nails in the coffin of peak oil, a related pastime of predicting the timing of peak oil demand has served as a replacement. In the face of natural scarcity, improving substitutes, and climate policy, some analysts expect a time in the not-too-distant future when the demand for oil reaches an all-time high.[57] Oil has historically been viewed as a good macroeconomic indicator. The quantity of oil produced and consumed is not as volatile as prices, which balance supply and demand and are a primary feature of the industry and its contracting.

In a similar vein, and as pointed out in chapter 3, electricity markets have seen little net load growth over the past couple decades. That trend of flat consumption is breaking, renewing the need for load forecasting. This is a classic form of market uncertainty. At this point it is not clear how various factors affecting load growth, including electrification, electric vehicles, artificial intelligence, and industrial and manufacturing demand will interact to comprise the net load forecast.

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[54] International Energy Agency (IEA), 2023. "World Energy Investment 2023".
[55] IEA (2023)
[56] See Deffeyes, K.S., 2006. *Beyond oil: The view from Hubbert's peak*. Hill and Wang. Holland, S.P., 2008. Modeling peak oil. *The Energy Journal*, *29*(2), pp.61-80. provides a more formal model, while Boyce, J.R., 2013. Prediction and inference in the Hubbert-Deffeyes peak oil model. *The Energy Journal*, *34*(2), pp.91-144. offers and ex post analysis.
[57] Halttunen, K., Slade, R. and Staffell, I., 2022. What if we never run out of oil? From certainty of "peak oil" to "peak demand". *Energy Research & Social Science*, *85*, p.102407.

In the context of the energy transition, oil investment faces two competing long-term dynamics.[58] One is the "green paradox," by which owners of a resource facing a long-term demand decline will front-load extraction. The paradox is that long-term decline leads to a short-term increase in production. The second effect works in the opposite direction and recognizes that many energy investments are fixed and have long production profiles. A long-term decline in demand can reduce investment immediately, providing a different trajectory of production and consumption than the green paradox. The theoretical ambiguity can play out differently across coal, petroleum, and natural gas.

It is common for oil and gas producers to hedge future price uncertainty and lock in a price for their output for a certain time horizon. However, such strategies are unlikely to fully alleviate the impact of market forecast uncertainty on financing conditions. First, hedging strategies are not costless and hedging costs can indeed rise with higher price volatility. Higher hedging costs, in turn, can have a negative effect on the value and creditworthiness of a project. Second, for projects involving long cost recovery horizons, the derivatives market for the long end of the time horizon may be too thin for price discovery, reducing the effectiveness of the hedge. Finally, hedging is subject to basis risk, suggesting that even with a hedge in place, there can be considerable uncertainty regarding future cash flow if the basis changes.[59] Basis differentials can be affected by infrastructure.

Shale oil and gas have relatively high decline rates compared to conventional reservoirs and therefore short cost recovery horizons. These projects may find it cheaper to hedge future price uncertainty and therefore find it a more valuable risk management tool. With shorter time periods between investment and first production and most of the production taking place during the first few years,[60] more activity occurs on the relatively deep portion of the forward curve. This production profile not only reduces the project's susceptibility to oil price volatility far into the

[58] Kellogg, R. 2024. The End of Oil? Working Paper, Harris School of Public Policy, University of Chicago.
[59] According to Gilje and Taillard (2017), basis risk exists "when the standardized asset used in a financial derivatives contract, known as the reference asset does not correspond precisely to the underlying risk a firm is exposed to. This imperfection can significantly reduce the effectiveness of the hedging instrument if the price dynamics of the reference asset do not comove with a firm's risk exposure." Gilje and Taillard (2017) also find that an increase in basis risk is associated with lower investment spending among oil producers, especially for those with high levels of operating leverage.
[60] Wachtmeister, H. and M. Höök, 2020. "Investment and Production Dynamics of Conventional Oil and Unconventional Tight Oil: Implications for Oil Markets and Climate Strategies", *Energy and Climate Change*, 1

future, but it can also make hedging strategies cheaper and more effective. A more extreme version of this same logic is the use of volumetric production payments, which provide an even more immediate risk management strategy by monetizing expected future revenue streams and allow immediate reinvestment.[61]

By the virtue of being less susceptible to future oil price uncertainty, featuring more effective hedging strategies, and being less exposed to the risk of being stranded, unconventional oil and gas projects may have more favorable financing conditions compared to conventional projects. One study argues that upstream tight oil projects might provide a "more flexible pathway in face of future uncertainty in the development of substitute technology."[62]

Financing fossil power generation projects face similar concerns. The transition to renewable power generation implies a substantial risk of non-renewable power generation assets eventually being stranded or abandoned before the end of their useful life. The pace of energy transition is not clear and so stranding risk is hard to evaluate as a matter of forecasting, especially because some fossil power assets are needed to integrate renewables. Upstream power generation projects with shorter lead times and lower capital intensity—such as gas-fired generators—can fill this need without being exposed to substantial stranded asset risk and hence find it easier to obtain financing. A "pure play merchant" business model, or a utility that "owns and operates generation assets and sells power into competitive wholesale markets at market clearing prices, or through negotiated bilateral contracts with other generators or large industrial consumers. This entity occupies a very narrow portion of the value chain and competes within the riskiest part of the business when markets are volatile and positions are uncovered. Assets are built and financed by investors on a speculative basis, pre-contracted in part or in full or acquired from another generator. Pure play merchants have traditionally developed baseload or peaking plants with mature generation technologies from gas, which also enables participation in ancillary grid services markets. However, wind merchant plants have increased in popularity over the last decade and solar merchant plants are starting to emerge" (emphasis added).[63] This idea of speculatively built natural gas generation aligns with the idea of being easier to finance. However, it should also be noted that government subsidies de-risking renewable projects, especially

[61] Munoz, J.S., 2008. Financing of oil and gas transactions. *Tex. J. Oil Gas & Energy L.*, *4*, p.223.
[62] Wachtmeister and Höök (2020)
[63] PwC, 2014, "The Road Ahead: Gaining Momentum from Energy Transformation", PwC Global Power & Utilities

investment subsidies granted at the start of the project,[64] can eliminate the cost recovery advantage enjoyed by such natural gas merchant plants.[65]

There are important complementarities between upstream and midstream infrastructure, and without matching takeaway capacity infrastructure constraints can affect prices so as to undermine revenue and cost recovery. While this concern applies to all types of upstream infrastructure, including oil and gas, it can be especially salient for renewable electricity generation projects. Renewable energy is often generated far from areas with high demand, which requires ample transmission capacity for electricity exports. The absence of such midstream capacity leads to excess supply and low, or even negative, electricity prices in areas rich in renewable resources, reducing incentives for entry.[66] Although existing studies have not explicitly considered project financing while analyzing this issue, it is reasonable to conclude that such revenue uncertainty due to inadequate midstream capacity will have a negative impact on financing conditions for upstream projects. Furthermore, as discussed in detail below, even if midstream capacity exists, the rents resulting from transporting output from low price to high price markets are not always captured by infrastructure project owners. This can add yet another potential layer of revenue uncertainty that can affect financing conditions.

B. Regulatory and Policy Environment

Unlike oil and gas extraction, where both price and quantity volatility are relevant to financing decisions, the regulatory and policy environment may be playing a more prominent role in the financing conditions for upstream power generation, primarily based on the source of the electricity (renewable vs. non-renewable). Fossil electricity generation is significantly less capital intensive compared to renewables, as measured by the amount of investment needed to generate a specified amount of power. Figure 73 depicts the range of capital intensities across generation types. While costs have converged across generation types, capacity factors remain very different (refer to table 1 in chapter 3 for detail).[67] While the substantial federal (and sometimes state)

[64] Aldy, J.E., Gerarden, T.D. and Sweeney, R. L., 2023, "Investment versus Output Subsidies: Implications of Alternative Incentives for Wind Energy", *Journal of the Association of Environmental and Resource Economists*, 10(4), 981-1018.

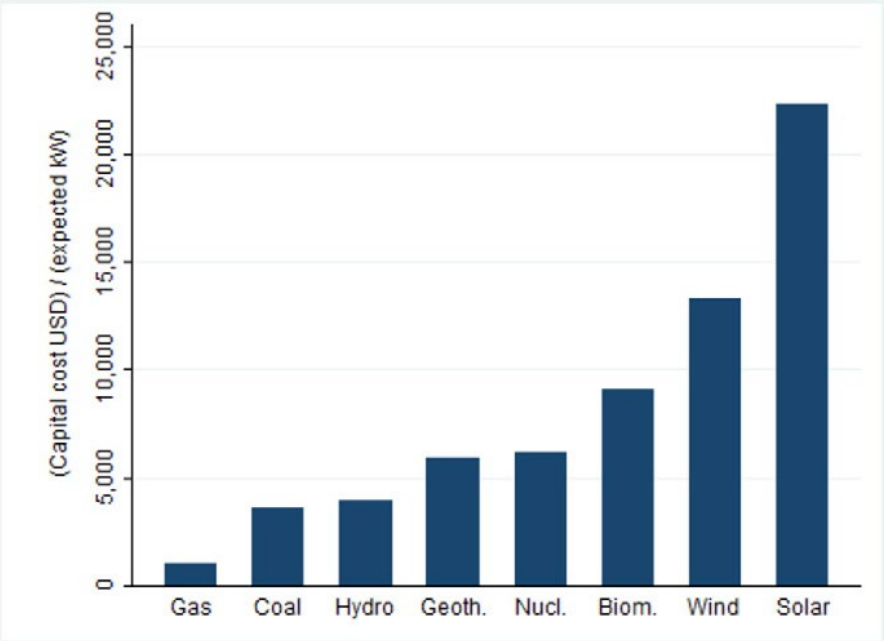
[65] The reference to the increasing share of wind and solar merchant plants in the PwC (2014) report can also be seen as supporting this assertion.

[66] Gonzales, L. E., K. Ito and M. Reguant, 2023. "The Investment Effects of Market Integration: Evidence from Renewable Energy Expansion in Chile", *Econometrica,* 91(5), 1659-1693.

[67] Technological change that increases capacity factors will reduce capital intensity over time.

subsidies directed at renewable projects reduce this capital intensity gap, they are unlikely to completely eliminate it.

FIGURE 17: CAPITAL INTENSITY BY ELECTRICITY GENERATION TYPE



Sources: Best (2017), drawing on US EIA (2015a, 2015b) and Timmons et al. (2014). Notes: Capital intensity is calculated as capital cost per kilowatt (US EIA, 2015a) divided by assumed capacity factor (US EIA, 2015b)). Oil is not included.

In addition to their higher capital intensity, many upstream renewable energy projects (such as geothermal[68]) tend to also involve long lead times. This combination of high financing needs and long lead times implies a high level of uncertainty for upstream renewable power generation projects. The net effect is to increase financing costs. Bonds issued by utilities to finance renewable power generation projects have been found to have longer maturities and higher yields compared to bonds of utilities financing projects using non-renewables.[69]

Issuing long-maturity bonds, long a cornerstone of traditional utility financing, is no longer the primary mechanism for financing upstream electricity projects. As electricity markets have deregulated, market forecast factors discussed above have also become more prominent,

[68] Best, R., 2017. "Switching towards Coal or Renewable Energy? The Effects of Financial Capital on Energy Transitions", *Energy Economics*, 63, 75-83.

[69] Hong, H., J. D. Kubik and E. P. Shore, 2023. "The Cost of Climate Policy to Capital: Evidence from Renewable Portfolio Standards". National Bureau of Economic Research Working Paper 31960.

providing flexibility in financing models. For example, speculatively built electricity generation projects are not financed via long-maturity bonds but with shorter term investor financing instead. Such additional financing options might be especially important in the renewable electricity generation space, given the longer lead times and high capital costs.

Given the headwinds faced by renewable generation, public options play an important role in alleviating cost recovery uncertainty and promoting adoption. Multiple federal, state, and local policy instruments implicitly or explicitly subsidize renewable power projects. Some of these instruments are investment subsidies that are designed to reduce the initial capital costs and make financing easier to obtain. Examples of these are upfront grants such as the Section 1603 tax credit, and loans or loan guarantees such as those provided by the Department of Energy. Other instruments are output subsidies, which provide incentives for greater output once the project is implemented while also reducing future revenue uncertainty. One of the primary renewable energy subsidies are production tax credits "for electricity generated by qualified energy resources and sold to an unrelated party during the tax year."[70] Often, firms engaged in renewable energy generation projects convert these tax credits (i.e. output subsidies) into initial investment financing through tax equity investment. Tax equity investment involves the firm agreeing "to assign the rights to claim the tax credits to another party in exchange for an equity investment (i.e., cash financing)."[71] By securing part of the investors' future cash flow (i.e., the tax credits), these arrangements can potentially improve access to financing, compensating for the higher capital intensity and longer lead times of renewable upstream power projects.

New entrants have capitalized on these newly available financing channels for electricity generation. Private equity and foreign investors have led the way in adopting renewable generation assets. Between 2005-2020, the share of generating assets owned by public corporations fell from 70 to 54 percent, while private equity, institutional, and foreign publicly listed corporations increased from 7 to 24 percent.[72] By 2020, those investors owned 60 percent of wind, 45 percent of solar, and 28 percent of natural gas generation capacity, disproportionately in restructured markets. This shift in ownership and finance has also led to more efficient operation as measured

[70] Aldy, Gerarden and Sweeney (2023).
[71] Congressional Research Service (CRS), 2019. "Tax Equity Financing: An Introduction and Policy Considerations", Report# R45693
[72] Andonov, A., and J. Rauh, 2024. The Shifting Finance of Electricity Generation. Stanford University Graduate School of Business Research Paper No. 4287123.

by heat rate and higher average prices for wholesale power (by $2.21 per MWh). These effects are achieved in part by contractual differences featuring shorter duration, incremental pricing, and more peak generation.[73]

C. Climate and Weather Risk

There now exists a substantial body of academic literature on the impact of climate risk on financing conditions. Climate risk can be separated into three components: (i) physical climate risks arising from an increase in firms' costs due to climate events such as droughts or rising sea levels, (ii) technological climate risks due to technological innovations spurred by climate change disrupting revenue streams of traditional firms and (iii) regulatory risks faced by firms whose business models and cash flows sensitive to policies or regulations enacted to combat climate change.[74] The evidence suggests that investors, especially institutional investors, consider the regulatory climate risks a more immediate concern, followed by technological risks.[75] Consequently, the discussion of the impact of climate risk on energy infrastructure financing will primarily focus on regulatory and technological climate risks.

Existing evidence from the academic literature suggests that firms that are subject to climate risk face more unfavorable conditions across all types of financing. Evidence suggests that exposure of highly polluting firms to environmental regulations and enforcement actions lead to a "pollution premium."[76] The idea behind the pollution premium is that stock market investors discount high polluting firms' stock prices, since they expect to receive a higher return from these stocks compared to low polluting firms' equity. This additional return is their compensation for the regulatory risk they are taking on by investing in high pollution firms. Similarly, a carbon premium also appears to exist, where investors demand a higher return from stocks of firms with high and direct carbon emissions—also known as scope 1 emissions.[77, 78]

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[73] Andonov & Rauh (2024)

[74] Krueger, P., Z. Sautner and L. T. Starks, 2020. "The Importance of Climate Risks for Institutional Investors", *The Review of Financial Studies*, 33(3), 1067-1111

[75] Krueger, Sautner and Starks (2020)

[76] Hsu, P., K. Li and C. Tsou, 2023. "The Pollution Premium", *The Journal of Finance*, 78(3), 1343-1392.

[77] Greenhouse gas (GHG) emissions of a firm can be divided into three categories. Scope 1 emissions are emissions made by the firm directly, for example by burning fuel. Scope 2 emissions are those the firm causes indirectly, for example by buying energy generated by another firm that burns fuel. Scope 3 emissions are those that are not caused by the activities of the firm itself, but the firm is indirectly responsible for them by the virtue of its value chain. The academic literature has mainly focused on scope 1 emissions.

[78] Bolton, P. and M. Kacperczyk, 2021. "Do Investors Care about Carbon Risk?", *Journal of Financial Economics*, 142(2), 517-549

Meanwhile, analysis of the corporate bond market finds that firms with high scope 1 carbon emissions have lower credit ratings and pay higher yields on their bonds. Furthermore, longer horizon institutional investors such as insurance companies appear to avoid bonds issues by high emitting firms, effectively reducing the investor base for these firms.[79] Finally, within the bank credit space, firms with environmental concerns (defined as "hazardous chemical, substantial emissions, and climate change concerns") are found to pay higher interest rates on their loans.[80] Similarly, banks that have publicly committed to reduce their exposure to carbon in their loan portfolios have been found to reduce their lending to firms with high scope 1 emissions.[81] Finally, firms that use their fossil fuel reserves as collateral in bank borrowing -- such as upstream oil and gas -- pay higher interest rates on their loans, have to borrow more, presumably to make up for a larger loss of market-based financing opportunities, and borrow at longer maturities.[82]

For infrastructure projects involving oil and gas extraction, the climate risk-related factors can exacerbate the difficulties in accessing credit caused by future price and quantity uncertainty discussed above. Meanwhile, for electricity generation projects, the picture remains more nuanced. While projects powered by non-renewables have some built-in features that make financing cheaper and easier to obtain, climate risk-related factors can worsen financing conditions for such projects. Combined with the presence of public financing options for renewables, it is difficult to perform an exact comparison of financing availability and cost for renewable versus non-renewable upstream electricity projects.

1. Financing Midstream Infrastructure

The revenue stream, and therefore financing concerns, of midstream projects can substantially differ from upstream projects. Most midstream infrastructure operates on a fee-for-service or margin model. The source of underlying economic value for midstream infrastructure, which processes and transports the output of upstream producers, is congestion rent, which is the

[79] Seltzer, L. and L. T. Starks and Q. Zhu, 2022. "Climate Regulatory Risks and Corporate Bonds", Federal Reserve Bank of New York Staff Reports Number 1014
[80] Chava, S., 2011. "Environmental Externalities and Cost of Capital", Working Paper.
[81] Kacperczyk, M. T. and J-L Peydró, 2022. "Carbon Emissions and the Bank-Lending Channel", Center for Economic Policy Research (CEPR) Discussion Paper No. DP16778
[82] Delis, M. D., K. de Greiff, M. Iosifidi and S. Ongena, 2018. "Being Stranded with Fossil Fuel Reserves? Climate Policy Risk and the Pricing of Bank Loans", Swiss Finance Institute Research Paper No 18-10

difference net of costs between the marginal prices at origination and destination nodes.[83] In many cases the price and value of transportation differ, with regulated or posted transport rates that do not reflect scarcity. This misalignment of economic incentives can lead to suboptimal levels of investment. Compounding that incentive is the network nature of midstream, in which the whole may have greater value than the sum of the parts.

Midstream firms that transport oil (mostly via pipeline) "typically enter into long-term (multiyear or multidecade) contracts with upstream producers and are paid on the volume, not the value, of the product transported. Most contracts include a 'take-or-pay' clause, which requires upstream firms to pay for transportation even if volumes are lower than originally contracted."[84] Revenue streams for gas pipelines follow broadly similar patterns (with less emphasis on take-or-pay provisions after FERC reforms discussed in chapter 2), because natural gas pipelines are "built mostly on a decentralized, contract-based framework, with private pipeline developers building projects paid for by pipeline customers. The simplicity, speed, and flexibility of this approach enabled the growth of a vast US network of interstate pipelines."[85]

Revenue streams of large-scale interstate electricity transmission projects, however, can differ from oil and gas pipelines. Similar to oil and gas pipelines, congestion rent is a source of economic value for transmission lines.[86] However, these congestion rents are often not sufficient to recover the capital and operating costs of a electricity transmission project "because a regionally efficient expansion of the transmission system will tend to reduce congestion below the levels necessary for such cost recovery."[87] While these costs can either be allocated among just the beneficiaries of the new transmission line or across all existing users of the network, "[s]preading costs over all existing users, in contrast, is much simpler and avoids what might be arbitrary assumptions and judgments about benefits."[88] For projects identified under the auspices of Independent System Operators ("ISOs") or Regional Transmission Operators ("RTOs"), cost socialization usually occurs through wholesale transmission rates that are approved by the Federal Energy Regulatory

[83] Metcalf, G. E., 2010. "Financing a National Transmission Grid: What are the Issues?", Center for Energy and Environmental Policy Research Working Paper 10-015
[84] Sengupta, Marsh and Rodziewicz (2017).
[85] Davis, L. W., C. Hausman and N. L. Rose, 2023. "Transmission Impossible? Prospects for Decarbonizing the US Grid", *Journal of Economic Perspectives*, 37(4), 155-180
[86] Metcalf (2010)
[87] DeLosa III, J., J. P. Pfeifenberger and P. Joskow, 2024. "Regulation of Access, Pricing, and Planning of High Voltage Transmission in the U.S.", National Bureau of Economic Research Working Paper 32254
[88] Metcalf (2010)

Commission (FERC), which then are passed on into state-approved higher retail rates.[89] In regions without deregulated electricity markets, or regions served by publicly owned power companies that fall outside the FERC's jurisdiction, this cost recovery often involves increases in retail electricity rates as approved by state regulators.[90]

Interstate electricity transmission projects can also be built by merchant transmission providers, who "do not serve captive retail customers and assume all market risk of a transmission project."[91] Furthermore, unlike utility companies, "merchant transmission developers have no obligation to build transmission projects, and will only do so where they are financially viable."[92] The revenue model for these midstream electricity projects is similar to oil and gas pipelines, due to the presence of longer-term contracts with upstream generators for transmission rights.

A. Market Forecast Uncertainty

Given their revenue model, midstream oil and gas infrastructure such as pipelines may be less affected by price blowouts that cause short term volatility without affecting long term price expectations. Financing for midstream firms was found to be largely unaffected by the 2014 decline in oil prices, suggesting that they "are somewhat insulated from near-term price volatility, but can be exposed to changes in volumes in the long run."[93]

In the case of natural gas, congestion rent does not always accrue to pipeline owners and is captured by primary capacity owners instead.[94] To first order, this reduces owner revenue and lengthens the cost recovery horizon. The incentives of primary capacity owners to bid strategically in subsequent open seasons may prevent additional capacity from being built. Furthermore, natural gas shippers can sometimes take advantage of storage capacity to avoid any high transportation charges that may arise due to high spot price differentials between two nodes.[95] Although the reduction of congestion rents through storage capacity can be seen as an increase in

[89] DeLosa III, Pfeifenberger and Joskow (2024)
[90] Sightline Institute, 2023. "Who will Pay for Cascadia's Transmission Lines?"
[91] H. Werntz, 2011, "*Let's Make a Deal: Negotiated Rates for Merchant Transmission",* Pace Environmental Law Review, 421
[92] Werntz (2011)
[93] Sengupta, Marsh and Rodziewicz (2017)
[94] Avalos, R., T. Fitzgerald and R. R. Rucker (2016). "Measuring the Effects of Natural Gas Pipeline Constraints on Regional Pricing and Market Integration", *Energy Economics*, 60, 217-231.
[95] Oliver, M. E., C. F. Mason and D. Finnoff (2014). "Pipeline Congestion and Basis Differentials", *Journal of Regulatory Economics*, 46, 261-291

market efficiency, this can again lead to a longer cost recovery horizon for natural gas pipelines, making financing costly.

Even with the price certainty provided by longer-term contracts, uncertainty regarding future quantity appears to play a major role in financing conditions for midstream oil and gas firms. For instance, infrastructure funds (i.e. non-bank financing providers) have consistently lowered their average target internal rate of return from infrastructure investments by 4-5 percent a year since 2009 (from 15 percent in 2009 to approximately 10 percent in 2021).[96] Although these investment funds increased their assets under management during the same period, a sustained decline in expected returns will likely lead to less funding for midstream oil and gas infrastructure projects in the future. The quantity-related risk of an infrastructure project turning out to be a stranded asset seems to be a current concern among some finance providers: "Gas networks carrying methane hydrocarbons, which in a net-zero transition would potentially need to be phased out in regions where gas is substituted for low-carbon alternatives: While hydrogen can potentially utilize some of these assets, the general view is that gas distribution will be required less, and that additional money will need to be spent to repurpose the networks. These risks mean that gas distribution is moving from super core to core or even core-plus."[97] Incompatibility between existing pipelines and technical specifications needed for hydrogen compound fears of asset stranding.

Stranding risk impacts financing conditions. Long lifetimes and low margins necessitate a long amortization period for asset owners, increasing the chance that the energy system evolves away from particular facilities, and creates an expectation by investors to be compensated for the risk, which increases financing costs.[98] It should also be noted, however, that while the asset value of some midstream fossil fuel infrastructure (such as oil pipelines) may fall, other types of midstream infrastructure may not be stranded. For example, electricity transmission capacity can be used with fossil or renewable generation, provided suppliers and loads are located in the same places.

It should also be noted, however, that underinvestment in midstream projects due to price uncertainty or stranding risk can contribute to even more price and quantity volatility. Such

[96] McKinsey & Company, 2022. "Infrastructure Investing Will Never be the Same"
[97] McKinsey & Company (2022)
[98] Fitzgerald, T. Forthcoming. Infrastructure for the Energy Transition. 75 Case Western Law Review.

additional volatility can lead to further constraints on financing, creating a negative feedback loop. What might be seen as a stranded asset by investors can also represent the midstream version of flexible capacity akin to the context of upstream projects. The existence of flexible capacity can prevent sudden price spikes due to unforeseen demand or supply factors, at least during the transition to more renewables.

Financing conditions for electricity transmission projects can also be affected by quantity uncertainties. Some of the quantity uncertainty stems from the often-long lead times associated with the upstream infrastructure investments, where the electricity to be transmitted will originate, which creates uncertainty over the quantity of transmission line usage, even in the absence of price volatility. For example, a March 2023 article mentions that "transmission developers now have confidence that solar or wind projects that may be five years away from operations will actually use their lines, providing some needed revenue assurance."[99] It appears that availability of public funding for upstream renewable electricity infrastructure projects can reduce quantity uncertainty for midstream electricity projects in addition to improving upstream financing conditions.

Even when the upstream generation capacity is not in question, the nature of renewable electricity generation can still create additional financing constraints on associated midstream transmission projects. The main issue appears to be "whether transmission lines will be used enough to justify the required capital costs. With a typical fossil fuel or nuclear power plant, it is possible to size transmission to guarantee that the lines are used at close to full capacity, 24 hours a day, 7 days a week. This is not the case for renewables: a transmission line connecting a solar-rich area to the rest of the grid may be operated only 30 percent of the time, for example."[100] This will undoubtedly increase the cost recovery horizon and potentially make financing for such projects harder and costlier to obtain. This suggests that in addition to subsidies for upstream renewables, more subsidies are needed to promote transmission construction for intermittent generation.

[99] Eckhouse, B., N. S. Malik and D. Merrill, 2023. "Billion-Dollar Power Lines Finally Inching Ahead to Help US Grids". Bloomberg News https://www.bloomberg.com/news/articles/2023-03-06/billion-dollar-power-lines-finally-inching-ahead-to-help-us-grids?sref=SlNIX8A9 (accessed May 30,2024)
[100] Davis, Hausman and Rose (2023)

B. Regulatory and Policy Environment

Just like the case of upstream infrastructure, financing conditions for midstream electricity infrastructure are subject to regulatory uncertainty.[101] For electricity transmission, this manifests itself in uncertainty regarding regulated electricity prices. As discussed above, for ISO and RTO directed transmission projects, cost socialization via higher retail electricity prices is often the main source of cost recovery. However, in certain markets, utilities "cannot recoup their investment in transmission lines through state-approved electricity rate increases until the line is 'used and useful' to ratepayers."[102] Given the long lead times for these projects, rate increases may not take place for a number of years. As a result, utilities often "do not know if state regulators will ultimately allow them to recoup their investments by raising retail rates"[103] at the start of any project. Revenue uncertainty based on this regulatory cost recovery process undermines the financial attractiveness of projects.

For merchant electricity transmission lines, FERC rules regarding permitting can also play an important role in contracted volume and pricing. FERC requires that such midstream projects demonstrate that there is a need for them. As a part of this market assessment, pipeline developers host an open season to solicit bids and to determine if there are enough upstream producers willing to commit to long-term contracts for capacity. If the developers cannot demonstrate sufficient market interest, the project does not move forward. Some potential bidders may have an interest in withholding bids or strategic bidding that does not reflect the returns to a developer.[104] For merchant electricity transmission lines, the project must also be approved for negotiated transmission rates for their customers. However, having a large shipper (i.e., an anchor customer) commit to buying capacity even before the open season is necessary for the developers to demonstrate interest in the project, and (perhaps more importantly) secure financing.[105] The inability for a project to find an anchor consumer or lack of FERC approval for the pre-open season contract with the anchor consumer can impact financing conditions for such midstream projects. On the other hand, if an anchor customer can only be secured by offering discounts or other

[101] Coleman (2018)
[102] Sightline Institute (2023)
[103] Sightline Institute (2023)
[104] Hausman (2024)
[105] Werntz (2011)

favorable contract terms, then the project developer will not be able to fully capture the congestion rent, leading to a longer cost recovery horizon as discussed above.[106]

Another consideration for midstream electricity infrastructure is the fragmented nature of the grid and the consensus-based approach to interstate transmission. As discussed above, transmission lines move electricity from low marginal cost to high marginal cost markets. However, this creates winners and losers, with the losers being electricity generators in high price areas, who profit from such allocative inefficiencies. This incentive to slow down new transmission line development by certain stakeholders, combined with the consensus-based approach to transmission planning can extend the cost recovery horizon and tighten financing constraints.[107]

Publicly owned utilities including federal power marketing administrators can circumvent any private financing constraints by borrowing from the U.S. Treasury at advantageous rates.[108] Investor owned utilities (IOUs), on the other hand, can either obtain unsecured corporate debt in the form of loans or bonds that are not project-specific and hence unsecured, or can issue project-specific bonds that are backed by a specific project's cashflows.[109] In spite of these challenges, the market considers transmission, including merchant transmission, as a low-risk class. Power networks "typically have a regulated return and stable revenues, are seen as super core: However, growing investment demands create deployment and regulatory risks that need to be taken into account."[110] Meanwhile, "[t]ransmission lines are well-understood by institutional investors and are deemed to be low-risk assets. They typically entail simple operating processes and predictable performance: their ability to generate revenues does not depend on the production of any form of output, their operation does not rely on any input subject to market risks, and they are typically heavily regulated assets subject to limited competition. This predictability is frequently further enhanced by projects' underlying contracts with built-in mitigation mechanisms for demand risk, asset use risk, and price risk – such as concession agreements or other long term service contracts similar to operating leases, under fixed tariff regimes and cost-plus compensation

[106] Avalos, Fitzgerald and Rucker (2016) and Oliver, Mason and Finnoff (2014)
[107] Hausman, C., 2024. "Power Flows: Transmission Lines, Allocative Efficiency, and Corporate Profits", National Bureau of Economic Research Working paper 32091
[108] Sightline Institute (2023)
[109] Credit Agricole, 2019. "Project Bonds: Power Transmission Lines"
[110] McKinsey & Company (2022)

mechanisms."[111] This sentiment is also confirmed by the fact that several large transmission projects are moving ahead,[112] with the possible exception of the Pacific Northwest.[113]

C. Climate and Weather Risk

Climate risk-related financing issues faced by upstream oil and gas projects are also faced by midstream projects such as pipelines. As noted above, many of the academic studies have looked at financing conditions conditional on scope 1 emissions, which primarily take the form of methane leaks.[114] Methane gas leaks in such midstream infrastructure can occur both as a part of day-to-day operations and also through accidents.[115] Recent studies found non-trivial amounts of such scope 1 emissions in both oil[116] and natural gas[117] pipelines that might exceed previously estimated amounts. It is possible that pipeline accidents will become more frequent due to the increase in the number and severity of extreme weather events, especially floods, due to climate change.[118] Government programs, such as the recently announced U.S. Department of Transportation grants, exist to provide funding for gas pipeline upgrades that can lead to both lower day-to-day emissions and make accidents less frequent by increasing the resiliency of pipeline networks.

Currently, no study or report appears to have specifically investigated the impact of lender concerns over such scope 1 emissions on financing conditions for midstream oil and gas pipelines. Nonetheless, given the preponderance of academic evidence suggesting unfavorable financing conditions for scope 1 emitting firms, it is conceivable that such climate risk-related concerns will make financing for midstream oil and gas projects more difficult and costlier to obtain moving forward.

Climate risk can negatively affect financing conditions by lengthening the cost recovery horizon. The risks include reduced transmission efficiency due to higher temperatures and physical

[111]Credit Agricole (2019)
[112] Eckhouse, Malik and Merrill (2023)
[113] Sightline Institute (2023)
[114] Please see https://www.nationalgrid.com/stories/energy-explained/what-are-scope-1-2-3-carbon-emissions for a natural gas pipeline example.
[115] Lu, H., Xu, ZD., Song, K. *et al.,* 2023. "Greenhouse gas emissions from U.S. crude oil pipeline accidents: 1968 to 2020", *Scientific Data*
[116] Lu, Xu, Song, *et al.* (2023)
[117] McVay, R., 2023, Methane Emissions from U.S. Gas Pipeline Leaks, Environmental Defense Fund Report
[118] Cruz, A. M. and E. Krausmann, 2013. "Vulnerability of the Oil and Gas Sector to Climate Change and Extreme Weather Events", *Climactic Change*, 121, 41-53

damage due to severe weather events including wildfires.[119] Available data suggests that the frequency of climate-related grid disruptions have shown a steady increase between 2000 and 2017.[120,121] As discussed above, electricity transmission projects involve high capital costs, along with lengthy and often uncertain cost recovery horizons. Any additional increases in operating costs due to climate-related events will likely introduce even more cost recovery uncertainty, negatively affecting the availability and cost of financing.

3. Systemic Macroeconomic and Regulatory Issues Affecting Financing

In addition to the energy sector-specific issues discussed above, changes to the overall credit supply can also have direct implications regarding the financing of physical infrastructure projects. All types of firm capital expenditures are sensitive to shocks to the supply of bank-[122] and market-based[123] credit. Recent analysis has found that green investments including renewable energy generation projects and other types of energy infrastructure are especially sensitive to changes in the overall credit supply, presumably due to their high levels of capital intensity.[124] Given the differences in financing uptake and models across energy sources, changes to the overall credit supply can have outsized impacts on the financing conditions of some types of physical infrastructure projects.

Monetary policy has been identified as one of the factors that can cause two shocks to the credit supply. The credit channel of monetary policy affects the availability of credit to willing borrowers in two ways. First, monetary policy affects the balance sheets, and hence the creditworthiness, of borrowers—the "balance sheet channel" Second, monetary policy affects banks' willingness and ability to make more and riskier loans—the "bank lending channel". This credit channel of monetary policy affects credit supply, while the more traditional channel of

[119] Zamuda, C., B. Mignone, D. Bilello, K. C. Hallett, C. Lee, J. Macknick, R. Newmark and D. Steinberg, 2013. "U.S. Energy sector vulnerabilities to climate change and extreme weather", U.S. Department of Energy
[120] Zamuda, et al. (2013)
[121] Shield, S. A., S. M. Quiring, J. V. Pino and K. Buckstaff, 2021. "Major Impacts of Weather Events on the Electrical Power Delivery System in the United States", *Energy*, 218
[122] Peek, J. and E. S. Rosengren, 2000. "Collateral damage: Effects of the Japanese Bank Crisis on Real Activity in the United States", *American Economic Review*, 90(1), 30-45.
[123] Lemmon, M. and M. R. Roberts, 2010. "The Response of Corporate Financing and Investment to Changes in the Supply of Credit", *Journal of Financial and Quantitative Analysis*, 45(3), 555-581.
[124] Accetturo, A., G. Barboni, and M. Cascarano, E. Garcia-Appendini and M. Tomasi, 2022. "Credit Supply and Green Investments", Working Paper.

monetary policy it works in tandem with influences credit demand by changing interest rates.[125] Furthermore, existing evidence suggests that banks become more willing to grant loans to riskier borrowers during expansionary monetary policy periods.[126]

A straightforward, but admittedly speculative application of the literature on the credit channel of monetary policy suggests that financing conditions for physical infrastructure projects can significantly deteriorate during contractionary monetary policy episodes. Not only does the overall credit supply contract, the reduced willingness of banks to take on risk can have an additional impact on projects with uncertain cost recovery horizons. On the other hand, during periods of expansionary monetary policy, one can expect financing conditions to improve.

Another factor that can affect the overall credit supply is financial regulations, especially those concerning bank capital requirements. The link between higher capital requirements and bank credit is not theoretically obvious, making it an empirical question. On the one hand, it is possible that higher capital requirements lower banks' cost of borrowing in the long run, by making them less risky in the eyes of depositors and other lenders. In this case, higher capital requirements will increase banks' ability to make loans.[127] On the other hand, banks can choose to meet higher capital requirements by reducing their risk-weighted assets, as opposed to raising more equity. In this case, there will be a decrease in the supply of bank credit. Existing empirical evidence remains mixed: Higher capital requirements in Europe (including the implementation of Basel III[128]) have been found to have a negative impact on the supply of credit,[129] while annual stress tests in the United States were associated with better capitalized banks and higher loan growth.[130] Therefore, the potential impact of proposed Basel III Endgame requirements on the

[125] There exists a substantial literature on the credit channel of monetary policy. For an overview of the main mechanisms at work, especially in the US context, please refer to Bernanke, B. and M. Gertler, 1995. "Inside the Black Box: The Credit Channel of Monetary Policy Transmission", *Journal of Economic Perspectives*, 9, 27-48.
[126] Jimenez, G., S. Ongena, J.-L. Peydro and J. Saurina, 2014. "Hazardous Times for Monetary Policy: What Do Twenty-Three Million Bank Loans Say About the Effects of Monetary Policy on Credit Risk-Taking?" *Econometrica*, 82(2), 463-505
[127] Galardo, M. and V. Vacca, 2022. "Higher Capital Requirements and Credit Supply: Evidence from Italy", Bank of Italy Working Paper No. 1372.
[128] Galardo and Vacca (2022)
[129] Gropp, R., T. Mosk, S. Ongena and C. Wix, 2019. "Banks Response to Higher Capital Requirements: Evidence from a Quasi-Natural Experiment", *The Review of Financial Studies*, 32(1), 266-299
[130] Bassett, W. F. and J. M. Berrospide, 2018. "The Impact of Post Stress Tests Capital on Bank Lending", Board of Governors of the Federal Reserve System Finance and Economics Discussion Series 2018-087

overall credit supply, and therefore on the financing conditions of physical energy infrastructure projects remains difficult to forecast.

However, it also should be noted that specific capital requirements on certain types of bank activities can have indirect impacts on the financing conditions for specific types of energy infrastructure. In the specific case of the currently proposed Basel III Endgame regulations, banks being required to hold more capital against operational risk can limit the ability of upstream energy projects to hedge their market risks via derivative positions taken by banks. Higher capital requirements could reduce participation in risk management markets. Banks that participate in OTC markets through swaps and other bilateral contracts would also likely be affected. Taken together, these effects can reduce risk management opportunities and raise costs, effectively increasing revenue uncertainty and hence make project funding more scarce and costlier. Similarly, a higher risk weight—and hence a higher capital requirement—for tax equity financing by banks can make it more difficult for renewable energy projects to obtain financing. Nevertheless, in the absence of a final version of the proposed regulations and the mixed evidence on the link between bank capital and the supply of credit, a confident forecast remains elusive.

4. Permitting

Physical energy infrastructure requires permits from an often-overlapping set of federal, state, and local authorities. Permitting has grown increasingly contentious, particularly around energy projects. At least three issues arise in the context of permitting. Lengthening delays are an issue for successful financing of projects as both the uncertainty of whether permits will be issued and the timing impose financial costs. Second, overlapping permitting authorities introduce the prospect of regulatory holdup wherein some but not all permits can be obtained. Third, permitting decisions have become a proxy for policy debates, transforming a debate about how a project should be conducted into one about whether a project should be constructed. This adds additional uncertainty and cost to the financing of projects.

Required permits are granted by a wide range of authorities. In some cases multiple levels of permits are required. Table 12 outlines the primary and secondary permitting authorities required for different types of projects. Even a cursory review of the necessary permits highlights the maze that permitting presents and lends sympathy to the oft-expressed sentiment that permitting reform

focused on streamlining reviews would help more projects advance to construction.[131] With multiple layers of permitting, it is not always clear in advance which will be the most stringent. That raises the prospect of projects being held up by additional permits even after initial permits are granted.

TABLE 1: PRIMARY PERMITTING AUTHORITIES FOR DIFFERENT TYPES OF PHYSICAL ENERGY INFRASTRUCTURE

Type of Project	Primary Permitting Authority	Additional Permits
Oil/Gas Production and Processing	State	Local land use ordinances may apply (e.g., setbacks); federal permitting required on federal minerals
Oil/Products Pipeline	State (unless crossing international boundary)	
Natural Gas Transmission	FERC (interstate and certain intrastate), otherwise state	
LNG Export Facility	Dept. of Energy & FERC	Coast Guard, Maritime Administration, State/local permits needed for facility
Natural Gas Distribution	State	
Electric Transmission	Regional implementation of federal (FERC) standards	RTO/ISO/Regional Authority planning process
Electric Distribution	State	
Electric Generation	State; Interconnection from RTO/ISO/Regional Authority	Local land use ordinances may apply (e.g., wind zoning)

Sources: Federal Environmental Review and Authorization Inventory,

Constitution Pipeline is an example of complete blockage by New York State. The Constitution proposal was a relatively modest 124 miles with a substantial 650 MMcfd from the Marcellus production in northeastern Pennsylvania to an existing pipeline junction near Albany, New York.[132] FERC ultimately overrode the state authority after finding it took too long to reach a determination, but not in time to save the project. The project was intended to be constructed in three years but was cancelled after eight years. Building the pipeline would have provided the gas-short Northeast with suppliers who often face substantial discounts due to lack of takeaway capacity.

One high profile permitting example is the Sun Zia transmission line in the Southwest. The Sun Zia project has been hailed as a large-scale renewable integration project that many transition advocates see as a blueprint for a future grid. As such, the long permitting delays are indicative of the problems such projects pose. Initially approved in 2016 after a ten-year planning process, the

[131] E.g., see the Energy Permitting Reform Act of 2024 (EPRA).
[132] www.naturalgasintel.com/a-sunk-cost-constitution-pipeline-cancelled-after-eight-year-battle/

3.5 GW HVDC line is under construction since 2023 and will help deliver power from a large wind facility in eastern New Mexico to load centers further west in Arizona. One reason for the permitting delays of the Sun Zia project is amendments to the design of the project. Sun Zia was initially proposed as an AC line that would have allowed for more local integration, and later converted to a DC design. Even after receiving its permits and starting construction the project has been subject to multiple litigations. The history of the project over more than 15 years underscores the complexity involved in permitting large transmission projects, in this case spanning two states. The permitting and litigation delays have required the developers to obtain additional financing.[133]

A third illustrative example of challenges with permitting is the TransWest Express (TWE) transmission project that is currently under construction across Wyoming, Colorado, Utah, and Nevada. Like Sun Zia, the TWE line is intended to link wind generation in rural areas with customers in urban areas. The challenge for TWE was obtaining permits across multiple states for its 732-mile route. The initial permitting application came in 2007. The final required permit was granted in 2023. TWE helped solve some of its problems by using existing, rather than new, corridors and public lands and rights of way where possible. This proved simpler than a more direct route would have been. Construction began in 2023 and is expected to be completed in 2029. TWE will deliver 3 GW of power from Wyoming to Utah, with about half of that continuing to Las Vegas and some then continuing on into Southern California. All told the investment is expected to be about $2.9 billion.[134]

Developers recognize the impediment that slow and unsuccessful permitting creates for project finance construction. A common proposed solution is to declare certain projects as "critical infrastructure" that does not require permitting. The definition of critical infrastructure changes depending on who makes the suggestion. Various proposals to streamline and fast-track infrastructure projects have been mooted.[135] Building the infrastructure required for an energy transition may require relaxing the grand compromise inherent in the imposition of a wave of environmental legislation in the 1970s.[136]

An important source of opposition to many infrastructure projects, from fossil extraction to renewable electricity generation to linear infrastructure like pipelines and powerlines, is local

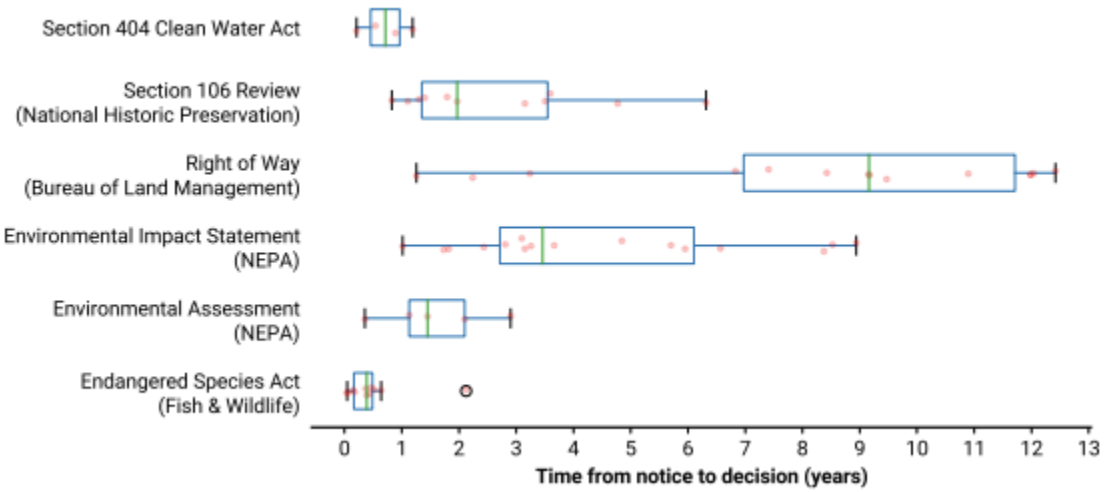
[133] https://www.utilitydive.com/news/pattern-energy-sunzia-transmission-wind/703508/
[134] https://www.transwestexpress.net/index.shtml
[135] Coleman, J.W. 2023. Permitting the Energy Transition. 75 Case Western Law Review.
[136] Ruhl, J.B. and Salzman, J., 2023. The Greens' dilemma: Building tomorrow's climate infrastructure today. *Emory LJ*, *73*, p.1.

residents worried about adverse effects to health, environment, and property values. Greater awareness of environmental justice issues has strengthened this resistance. Because local residents often receive only a small share of economic benefits, or more often none or nearly none at all, there is little incentive for local residents to support projects in which there are any costs. Larger-scale projects such as long-distance electric transmission or relatively acreage-intensive uses like renewable electricity generation have the potential to affect many people who might not benefit from a particular project. In those cases local resistance is likely to be stronger.

A. Permitting Delays

Permitting reviews can take a substantial amount of time. Part of this is due to the complexity of permit reviews, and part may be due to the relatively high costs of false positives relative to false negatives. Figure 74 shows the mean time for various federal permitting reviews, with multiple years as the norm. Many projects may require multiple reviews, with non-concurrent reviews further extending the period during which a proposal is pending. The variation in permitting times is also relevant. A proposal subject to NEPA review might expect a couple of years to complete the process, though some projects take several years to reach a final decision. Capital dedicated to a proposal sits idle as the permitting process plays out.

FIGURE 18: TIME TAKEN FOR FEDERAL PERMIT REVIEWS



Source: Sud et al. 2023

One major issue with permitting is the significant resources required to comply with the National Environmental Policy Act (NEPA). A recent empirical study of pre-development litigation

over NEPA violations found that energy projects, including solar and wind projects, pipelines, and electric transmission lines had the highest incidence of litigation.[137] That provides strong support for the notion that physical energy infrastructure is among the most controversial type of project.

Litigation is not the only cause of permitting delays. Permitting reviews can take extended periods of time. The propagation of unconventional oil and gas development into regions unfamiliar with the industry led to local resistance to land use change. For the most part, local government found that received law prevented local preemption of mineral development. Renewable electricity developers have not been so fortunate as to have a strong legal upper hand. Local land use regulations restricting or encumbering development of wind and solar have spread widely.[138]

As the energy transition progresses, bringing additional emissions-free electric generation capacity into the generation mix has renewed interest in nuclear power. The Nuclear Regulatory Commission (NRC) is a special government permitting body for construction and operation of all power reactors, but also for all research and test reactors. NRC has been conservative in granting new licenses, effectively imposing a crucial permitting barrier for the sector. For all of the interest that small modular reactors have created, one design has been permitted after a three-and-a-half-year review. One additional design is currently under review, and five more are in a pre-application queue.

The longer a permit application waits before approval, the greater the chance that a disqualifying objection will be raised. The uncertainty around successfully completing the permitting process adds cost as capital is tied up with projects that ultimately fail to clear the hurdle. Clear criteria and the ability to accurately predict the success or failure of a project advancing through all necessary permits help reduce overall costs.

B. Overlapping Permitting Authorities

One of the frustrations of permitting is the overlapping jurisdictions and need to obtain multiple permits. This creates the chance for holdup. The proposed Keystone XL crude oil pipeline is one example. Oil pipelines are generally permitted at the state level. Keystone XL was slightly different in that it needed to obtain a federal permit for the international boundary crossing. That federal permit became politicized, with the Obama and Trump Administrations taking differing views. Even after the Trump Administration granted the permit, the project needed to obtain state level

[137] Bennon, M. and Wilson, D., 2023. NEPA Litigation over Large Energy and Transport Infrastructure Projects. *Env't L. Rep.*, *53*, p.10836.

[138] Lawrence Susskind et al., "Sources of opposition to renewable energy projects in the United States" *Energy Policy* 165 (2022): 112922. Eisenson

permissions. The developers were able to entice some states, including Montana and North Dakota, to approve the permits by altering the project to allow on-ramps for locally-produced oil in those states. Winning support in Nebraska was a greater challenge, in part because there was nothing to offer a non-producing state in terms of local benefits. Nebraska ultimately approved the permit for Keystone XL after the application was amended, even after earlier efforts to tie together the state and federal approvals.[139] That strategy would have made little ultimate difference as the federal permits were revoked by the Biden Administration and the project was abandoned.

The maze of environmental regulations is another example of how permit review can be triggered by project characteristics. As an example, a project transecting a floodplain requires a floodplain assessment, just as projects affecting endangered species or archaeological sites on public lands can require other kinds of supplementary reviews. Multiple layers of additional review can be triggered by particular circumstances around a project. Even when a developer has a mitigation plan to avoid adversely affecting an endangered species, as one example, the time and uncertainty associated with the review process can add cost to the project.

A variety of potential remedies have been proposed to avoid and resolve conflicts between different permitting authorities.[140] One proposed remedy for the permitting conundrum is expanded federal oversight.[141] Given the variation in the federal position, that solution may not resolve differences in policy views that express themselves through the permitting process.

C. Permitting as Policy

In the absence of a unified energy policy in all corners of the country, permitting has developed into an opportunity for opposition to voice its disapproval with particular projects. Open meetings and a complex intersection of energy and environmental law with administrative procedures create opportunities for procedural delays. Using these strategies may more accurately reflect broad policy differences rather than narrow permitting concerns. The same processes that can be exploited to delay permitting provide important mechanisms for citizens and other concerned parties to raise objections and voice concerns about proposed projects that may affect them. Proposals to streamline permitting by reducing ability to contest by presenting alternative points of view or removing standing are unlikely to be popular. Citizens concerned about siting and adverse impacts rely on permitting processes to share their views in hopes of gaining support.

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[139] Klass, A.B. and Meinhardt, D., 2014. Transporting oil and gas: US infrastructure challenges. *Iowa L. Rev., 100*, 978-9.

[140] James W. Coleman, Pipelines & Power-lines: Building the Energy Transport Future, 80 Ohio St. L.J. 263 (2019)

[141] Liscow (2024)

Though most permitting is an administrative law process, permitting decisions and surrounding issues can become the subject of litigation. Some observers identify litigation delays as more consequential than permitting itself.[142] A recent analysis of transmission projects found about one quarter of projects encountering litigation. In most cases the litigation as resolved in favor of the project, but only after the time and expense was incurred.[143] The overlapping jurisdictions between administrative and civil law add to uncertainty about the ability to obtain a permit and successfully proceed without an injunction.

Much as local residents who do not share project benefits organize resistance to a wide variety of projects, climate activists have focused on permitting processes as a mechanism to effect policy changes they have been unsuccessful in making through alternate means. Blanket opposition to permitting fossil pipelines, sometimes cited as a mechanism to "keep it in the ground" or prevent extraction, relies on an economic logic. By making projects more expensive, some will not be viable and fossil reserves will be rendered subeconomic. While this may hold in certain cases, many projects are not completely undermined.[144] The net effect is longer permitting delays, higher costs, and less infrastructure contributing to price volatility and higher costs for energy users.

Abbreviations

FERC: Federal Energy Regulatory Commission

IEA: International Energy Agency

IOU: investor owned utility

ISO: independent system operator

MMcfd: million (standard) cubic feet per day

MWh: megawatt hour

NEPA: National Environmental Policy Act

NRC: Nuclear Regulatory Commission

[142] ClearPath

[143] Baranoff & Norris (2024)

[144] Kellogg, R. and Covert, T., 2023. Environmental Consequences of Hydrocarbon Infrastructure Policy. *University of Chicago, Becker Friedman Institute for Economics Working Paper*, (2023-138).

OPEC: Organization of Petroleum Exporting Countries

RTO: regional transmission organization

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