



Risks for New Natural Gas Developments in Appalachia

March 2021

Peter Erickson
Ploy Achakulwisut
Stockholm Environment Institute U.S.



Risks for New Natural Gas Developments in Appalachia

Peter Erickson and Ploy Achakulwisut
Stockholm Environment Institute U.S.

March 2021

KEY FINDINGS

- The gas industry in the Appalachian region of Pennsylvania, Ohio, and West Virginia is vulnerable to sustained, low prices of domestic gas and natural gas liquids (NGL).
 - Recent prices are not high enough to support widespread investments in gas and NGL infrastructure – including new gas fields, pipelines, and export terminals.
 - Governments around the world, including the United States, have committed to deep decarbonization under the Paris Agreement. This suggests profound changes to oil and gas markets that would render new Appalachian gas fields unprofitable, on average.
-

INTRODUCTION

The modern U.S. oil industry began in Appalachia in 1860, with a frenzied boom in northwest Pennsylvania (Yergin 2009) and, a decade later, the Ohio founding of Standard Oil, which later spawned both ExxonMobil and Chevron. But by the turn of the 20th century, Appalachia's status as a major oil producer had crested. As the region's oil production dwindled, the industry shifted its attention to new discoveries in Texas and other western states.

Then, starting just over a decade ago, Pennsylvania, Ohio, and West Virginia witnessed a revival of its petroleum industry. Improved extraction techniques – particularly horizontal drilling and hydraulic fracturing, or “fracking”, which uses pressure to split the hydrocarbon-bearing underground formations – unlocked previously inaccessible reserves, boosting Appalachia's production of natural gas and associated liquids to all-time highs.

There are now signs that Appalachia's gas boom may soon run out of steam. Key global

energy markets, including the United States, are quickly shifting to inexpensive renewables and other forms of low-carbon energy (IEA 2020b). The global pandemic seems to have accelerated these trends: fossil fuel demand, prices, and investment have all declined during the pandemic, even as renewable investments have continued their ascent (IEA 2020b).

The risks of a ‘bust’ in natural gas follows closely on the heels of the ongoing collapse of Appalachia’s coal industry. These disruptions to coal were caused in part by the fracking boom, which encouraged electric utilities to shift from coal to inexpensive gas. Now there are signs that gas itself could get passed up for lower-carbon and lower-cost renewables, introducing new risks for communities that rely on gas extraction for employment and tax revenue. This paper explores trends affecting the

economic viability of the gas industry in Pennsylvania, Ohio, and West Virginia as they recover from the pandemic. It finds that northern Appalachia should rethink its reliance on the gas industry, and instead foster a more resilient economy insulated from the booms and busts of fossil fuels.

OVERVIEW OF GAS – RELATED TRENDS

Over the past decade, fracking has driven natural gas (hereafter, just *gas*) production in Pennsylvania, Ohio, and West Virginia to all-time highs (Figure 1).

The rapid increase in gas production – not just in Appalachia, but also in other parts of the country where gas was often extracted as a

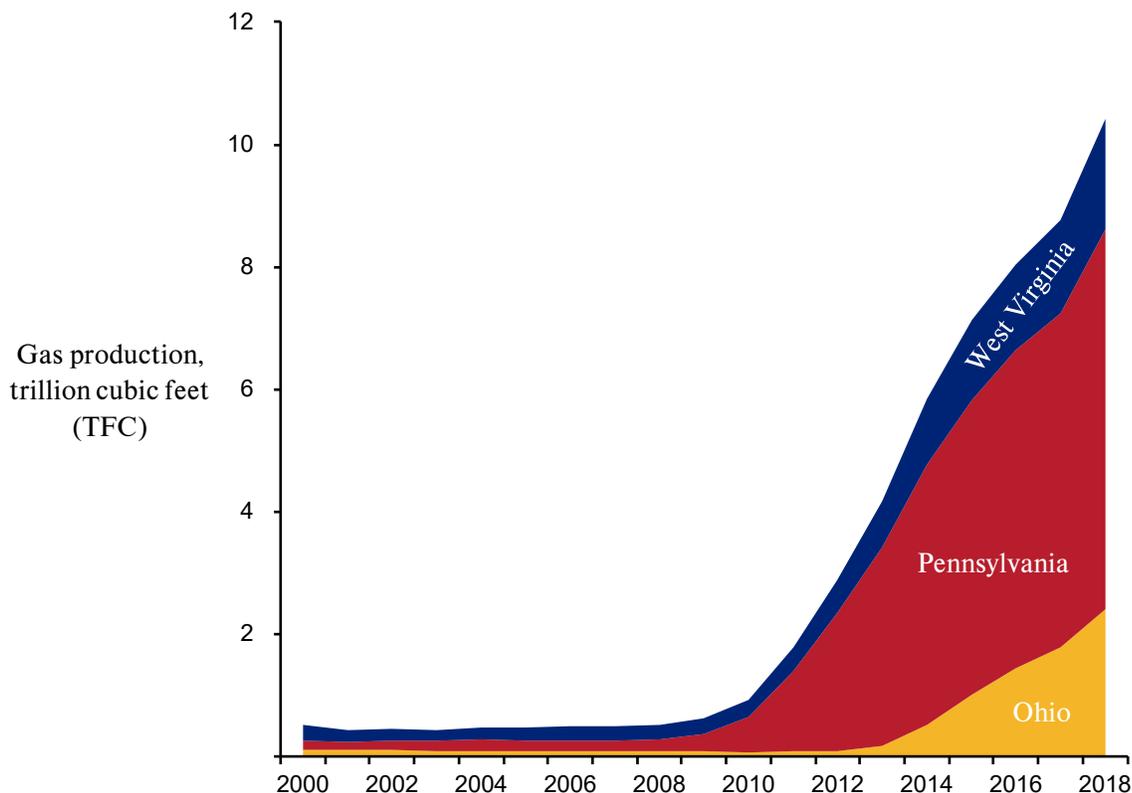


Figure 1. Gas production since 2000 in Ohio, Pennsylvania, and West Virginia. Source: U.S. EIA (Source: U.S. Energy Information Administration 2020d)

by-product of more-profitable oil extraction (e.g. in west Texas) – has caused prices to collapse. Gas prices in the mid-2000s, immediately before the fracking boom began, typically stood at \$8 per million btu (Mbtu) or higher, as measured at the Henry Hub pricing point (U.S. EIA 2020). At the beginning of 2020, just before the coronavirus pandemic began, gas prices were hovering around \$2 per Mbtu. This drop stemmed from basic economics: supply increased faster than demand, forcing producers to compete aggressively, putting downward pressure on prices.

Gas itself is mostly methane (CH_4), and is the chief product sold to utilities, homes, and businesses. Other hydrocarbons extracted from gas wells, including ethane (C_2H_6), propane (C_3H_8), and higher-carbon butanes and pentanes, are pressurized, condensed, and transported to end markets as natural gas liquids (NGLs). Prices for ethane – the NGL produced in greatest quantity (U.S. Department of Energy 2020) – have, like for gas, dropped sharply since the mid-2000s (U.S. EIA 2020).

The drop in prices for gas has helped it compete with other fuels, especially coal, and has led to an increase in gas consumption for electricity generation. But the low prices have also raised questions about the viability of continued expansion in gas extraction. Bankruptcies in the industry are increasingly common (Williams-Derry et al. 2020), and supermajors ExxonMobil, Shell, and Chevron have all steeply written down or sold assets (Hipple et al. 2020). The Atlantic Coast Pipeline from West Virginia to North Carolina has been cancelled. Without it, producers may have to compete more aggressively for existing pipeline capacity in the future (Barth et al. 2020). Add the uncertainty in economic

outlook associated with the coronavirus, and the result is a cloudy outlook for gas producers and the communities in which they are based.

If the prospects of growth in gas extraction in Appalachia are to be revived, gas prices would need to rebound and increase. Investors would need to see price forecasts that allow them to cover the costs of drilling new gas wells and meet profit targets. However, any increase in prices will require an improvement in underlying market conditions. The question we look at in this paper, therefore, is: what are the major drivers of gas demand that will influence future price outlooks for gas?

As the economy moves past the coronavirus, future long-term demand for gas (and related NGLs) will be determined not just by the pace of economic recovery, but also by trends in technology (e.g. renewables, which compete with gas) and competition from other gas (and petrochemical) producers in other parts of the country and the world.

Government policies will also play a role, including those that the U.S. federal government, U.S. states, and trading partners (especially in Europe) put in place to follow through on their announced intentions to dramatically reduce greenhouse gas emissions (such as in the Paris Agreement). Policies to improve local air and water pollution from natural gas – such as limits where new gas wells can be drilled – could also affect gas demand and supply (Iaconangelo 2020).

In the next section, we describe the largest four factors we see affecting gas development. We then synthesize our findings into an assessment of the financial outlooks for Appalachian gas production.

MAJOR FACTORS AFFECTING DEMAND FOR APPALACHIAN GAS

Four factors will set the course for Appalachian gas demand in the years ahead. Since most gas produced in Appalachia has been (and will continue to be in the near future) consumed in the United States, the most important factor is how *domestic* U.S. gas demand might evolve.

The other three factors relate to *international* demand for gas and NGLs and, therefore, the prospects for export markets; the pace of global decarbonization; the availability of facilities that can export LNG abroad; and the strength of the petrochemical market.

Future of U.S. gas demand

U.S. gas consumption has risen steadily for years, and has helped displace coal for electricity generation (Houser et al. 2017). However, that increase may not continue. The U.S. Department of Energy foresees gas consumption staying flat over the next decade, at about 31 trillion cubic feet (TCF) annually (U.S. EIA 2021), as shown in the gray line in Figure 2.

Furthermore, as the cost of renewable energy continues to drop (Henze 2020), and policy momentum builds for serious efforts to address climate change (including by the new presidential administration), U.S. gas demand could decline, perhaps steeply.

Several studies have quantified the prospective declines in demand for U.S. gas under a decarbonizing economy, including one consistent with the globally agreed goal to limit warming to “well below 2°C” while striving to hold warming to 1.5°C.

Most of the low-carbon studies we reviewed find U.S. gas consumption declining to less than 20 TCF by 2040 (Feijoo et al. 2020; Haley et al. 2019; IEA 2020b; Larson et al. 2020; The White House 2016) (Figure 2). Reducing gas consumption to this level would be a reduction of more than 14 TCF compared to the currently foreseen reference case by the U.S. Department of Energy, and about 11 TCF below recent (e.g., 2019) levels.

As shown in Figure 2, these studies collectively show that a U.S. energy transition consistent with holding warming to globally agreed levels would mean substantial reductions in U.S. gas demand over the next two decades. The studies differ primarily in how quickly they foresee policy action, and the degree to which they take into account the recent sharp increase in gas consumption in 2018 (Figure 1). Studies that show an earlier (in some cases, no longer plausible) reduction in gas demand, beginning before 2020, show more modest rates of year-on-year decline, whereas more recent studies that begin action instead in the next few years, show that decline rates would need to be even steeper.

The reduction in U.S. gas demand as the economy decarbonizes could also have consequences for NGLs. The economics of wells that produce NGLs depend heavily on the price of gas, since most wells produce considerably more gas than NGLs (Rystad Energy 2020). If new gas fields and wells cannot go forward because of insufficient demand for gas, then fewer NGLs would be extracted as by-products, in which case NGLs may not be available in sufficient quantities to support planned expansion of infrastructure, like petrochemicals, that depend on these liquid feedstocks. We will return to uncertainties in petrochemical markets below.

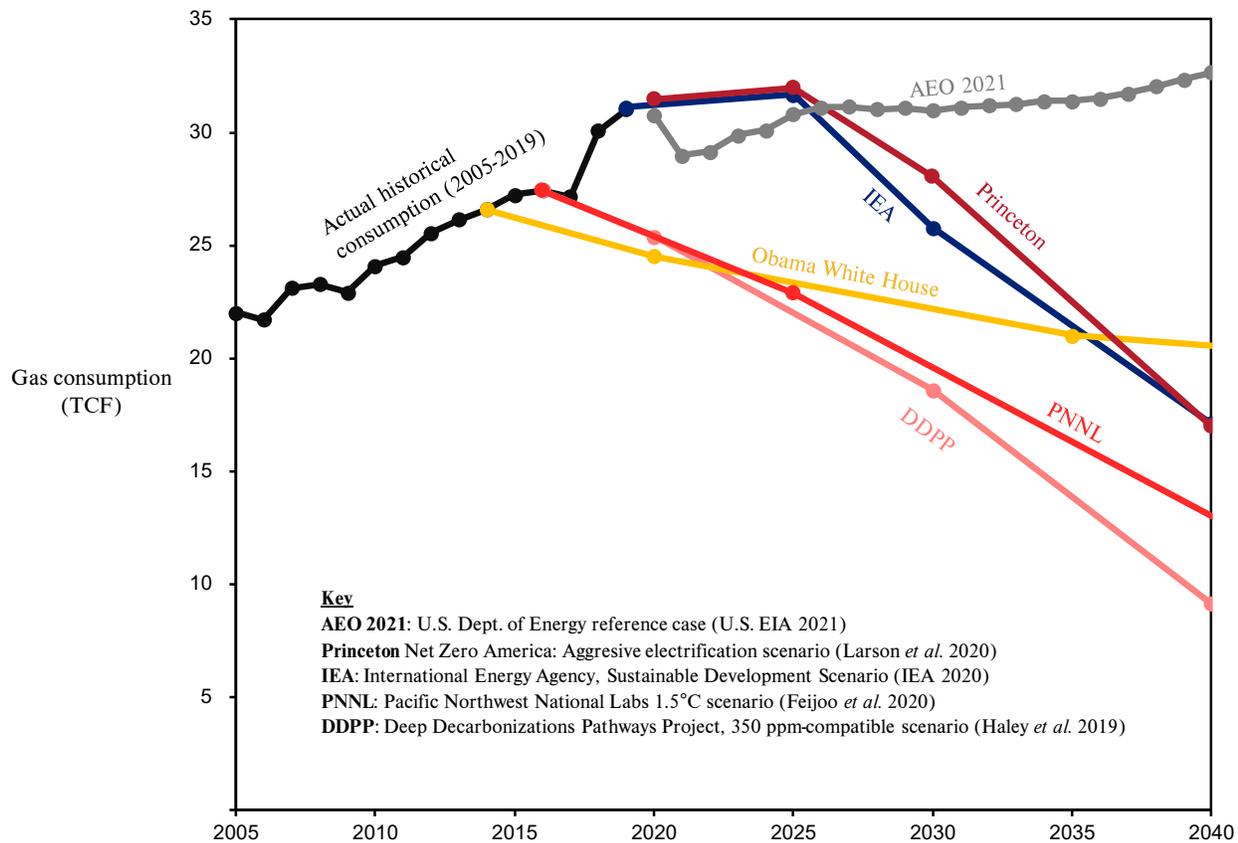


Figure 2. Scenarios of U.S. gas consumption through 2040. The U.S. Energy Information Administration reference case, shown in gray and labelled AEO 2021 reference case, is the “business-as-usual” scenario. All other future scenarios are low-carbon scenarios.

Lastly, it is important to note that, if the U.S. were to continue expanding gas production, instead of following the low-carbon pathways displayed in Figure 2, it could “lock in” an energy system that is too high-carbon to meet national and international climate goals.

Building out too much low-cost gas now makes it more difficult to transition to renewable and other low-carbon energy, increasing emissions in the long term (Erickson *et al.* 2015; Gillingham and Huang 2019; Shearer *et al.* 2014; Shearer *et al.* 2020).

Pace of global decarbonization

A move to global decarbonization consistent with the climate limits of the Paris Agreement would see a move away from gas across the

world, not just in the U.S. (Rogelj *et al.* 2018; SEI *et al.* 2019). That would likely mean decreasing long-term demand for U.S. gas.

However, the role of gas in low-carbon transitions may not be quite that simple. Even in the context of a global move away from gas, some countries could see temporary increases in gas consumption, as part of fulfilling their increasing energy demands for power and industry while transitioning away from even higher-carbon coal.

For example, gas consumption could, in principle, increase rapidly in Asia (and parts of Africa), even under global decarbonization consistent with the Paris Agreement (BloombergNEF *et al.* 2020; BP 2020; Holz *et al.* 2015; IEA 2020b; Walsh *et al.* 2019).

Because some of these countries have little gas themselves and limited access to gas via trans-continental pipelines, they would need to get this gas from overseas, mainly in the form of liquified natural gas (LNG).

Nevertheless, despite possible near-term increases in LNG, the use of traded gas in low-carbon scenarios may peak well before 2050. For example, BP sees LNG use peaking before 2040 in its 2°C scenario (BP 2020). And, if gas producers are not able to get gas leakage and loss under control, there would be even less of a case for LNG to displace higher-carbon alternatives (Gilbert and Sovacool 2017). That is because gas itself (methane) is a highly potent warming pollutant; whatever gas is lost leads to even more global warming, undercutting any climate benefits of using gas. One prospective U.S. LNG importer recently cancelled a deal because of concerns with methane leakage in the U.S. (McFarlane 2020).

These findings indicate that, for LNG to play a constructive role in 2°C scenarios (let alone 1.5°C scenarios), its expansion would need to be – at best – short-lived. In other words, LNG export terminals, which are normally expected to be in use for 20 years or more, may need to be shutdown “prematurely” (BP 2020).

Any move towards limiting warming to 2°C or 1.5°C is going to take some time, and there is little evidence, so far, that the pace of decarbonization will have much effect on the demand for LNG exports over the next decade. As a result, the prospect of global decarbonization here may not be much of a material risk to Appalachian gas in the short term. However, in the longer term, LNG has a limited role to play in global decarbonization, and pursuit of a 1.5°C degree temperature limit would leave much less opportunity for U.S. LNG exports.

Global decarbonization would likely have an even bigger effect on oil markets than on gas markets. Global scenarios for oil that are consistent with the Paris Agreement almost uniformly show declines in oil consumption (Huppmann et al. 2018; SEI et al. 2019). Accordingly, oil prices may stay low for a long time, never exceeding \$60/barrel on a prolonged basis and perhaps reaching much lower (Harvey 2017; IEA 2020b; Jaccard et al. 2018). This too could affect the economics of new gas wells in Appalachia since, historically, prices for propane (the second most plentiful NGL after ethane) have closely tracked oil prices (U.S. Department of Energy 2020).

Availability of LNG exports

How much LNG can be exported outside the U.S. is important for the economics of future gas production in the U.S. Since there is more prospective gas supply in the U.S. than demand, having access to a broader market allows producers, in principle, both to extract more (for export), as well as to charge more for their production (increasing profits) than they would be able to if exports were constrained.

In 2015, there was still very little LNG export capacity in the U.S. Then, in 2016, a major facility in Louisiana – Sabine Pass LNG – started coming online. Since then, LNG export capacity has expanded steadily, with an average of 0.9 trillion cubic feet (TCF) annual export capacity added each year. In 2019, total permitted export capacity was 3.1 TCF (U.S. EIA 2020c), and gross U.S. LNG exports amounted to 1.8 TCF of gas in that year (U.S. EIA 2020b). EIA estimates that gross LNG exports in 2020 exceeded 2019 levels, despite a precipitous drop over the summer due to COVID-19 (U.S. EIA 2020b), and that export capacity will continue expanding at an average rate of about 0.5 TCF per year.

Several economic analyses have evaluated the extent to which the availability of LNG exports affects the price that producers see for their gas. The studies vary widely, with growing LNG exports increasing the market price of U.S. gas by \$0.10/Mbtu to about \$0.50/Mbtu for each added TCF of LNG exports (U.S. Commodity Futures Trading Commission 2018). However, the estimated price impacts have become more muted over time as the cost of producing U.S. gas has dropped, making gas extraction (and therefore price) less sensitive to changes in prospective demand, including demand for increased LNG exports (Rystad Energy 2020; U.S. Commodity Futures Trading Commission 2018).

LNG export permits compiled by the U.S. Department of Energy indicate that at least 1.5 TCF (0.54 bcf/day) of LNG export infrastructure has been approved in the U.S., but has not yet started construction (U.S. EIA 2020c). If these facilities never get built, it is possible that LNG export capacity in 2030 could be 1.5 TCF less than the nearly 6 TCF projected in the agency's reference-case LNG outlooks (U.S. EIA 2020a).

In fact, this possibility could be deemed *likely* when one considers the near-term global oversupply of LNG, a condition that has been further exacerbated by COVID-19 (BloombergNEF et al. 2020; IEA 2020a), and which could persist for years if COVID recovery is delayed (IEA 2020b). This structural oversupply of LNG has pushed prices down, in some cases below the point needed to justify new export facilities; by contrast, the sharp jump in LNG export prices in early 2021 is likely due to a temporary convergence of factors (Denning 2021). In this context, it seems unlikely that LNG exports would be even higher than the Department of Energy's reference scenario of nearly 6 TCF.

Strength of global petrochemical markets

Globally, oil and gas producers are counting on rapidly expanding demand for petrochemical products, especially plastics, to be a major – perhaps the *only* major – source of oil and gas demand growth over the next couple decades (IEA 2020b). Producers in the Appalachian region have likewise been planning on petrochemical demand growth (U.S. Department of Energy 2020), including from the large complex under construction by Royal Dutch Shell in Beaver County, Pennsylvania, among others.

However, while global outlooks do generally show rising demand for petrochemicals over the next couple decades (IEA 2020b), that growth may take years to materialize (IEA 2020a; Malik et al. 2020). Even before the COVID-19 pandemic was putting the brakes on rising global plastics consumption (IHS Markit 2020b; Malik et al. 2020), the market was oversupplied: increases in global capacity for production of ethylene, a chief plastic building block, have far outpaced growth in demand for ethylene in the last couple years.

Prospective Appalachian gas producers hoping to sell their natural gas liquids, especially ethane, to petrochemical markets could be especially susceptible to a global over-supply in ethylene and, relatedly, to an over-supply of oil. The promise of a cost advantage for Appalachian ethylene producers is that they have access to low-cost ethane feedstock that is extracted largely as a by-product of gas extraction. Ethane is broken into smaller molecules, including ethylene, at a “cracker”, such as what Shell is building in Pennsylvania. However, the cost advantage of making ethylene by cracking ethane diminishes in a low-cost oil price environment, due to competition with other feedstocks and world regions (IHS Markit 2020b; Malik et al. 2020; Wood Mackenzie 2020).

When the cost of oil is low, so is the cost of making ethylene out of oil. For example, a low oil price means lower costs of naphtha, the dominant feedstock for making ethylene outside the United States, especially in Asia (IHS Markit 2020b; International Energy Agency 2018). Since low oil prices mean increased supply of low-cost naphtha-based ethylene, ethylene prices would drop.

In particular, petrochemical industry consultants have been exploring the possibility that, if the COVID-19 recovery is weak or delayed, then low oil prices (in the range of \$40/barrel or lower) could continue and that petrochemical demand could stay weak. In that possibility, global ethylene prices might not exceed about \$500 to \$600 per ton on a sustained basis, which is much lower than recent (pre-pandemic) prices of around \$800 to \$900 per ton (Malik et al. 2020; S&P Global Platts 2020; Wood Mackenzie 2020).

Prices in the \$500 to \$600 per ton range would challenge the economics of new ethane crackers in Appalachia, since new crackers need to receive at least that much to break even for their investors (Jones et al. 2016). This risk to ethylene markets helps explain why the proposed PTTGC ethane cracker in Ohio has continued to delay its final investment decision, and why some analysts doubt the project will proceed (Sanzillo et al. 2020).

Unfortunately, little detailed information about ethane cracker costs is publicly available. Still, based on the industry consultant reports described above, there appears to be substantial

risks for new cracker economics when oil prices hover around \$40/barrel or lower (IHS Markit 2020a; Jones et al. 2016). The risk to new crackers would be especially acute if oil prices were this low *and* ethane feedstock costs were about \$3/Mbtu (\$0.20/gallon) or more.

This danger zone for crackers adds to the risk for gas producers. If new petrochemical plants in the Appalachian region do not go forward, then demand for ethane, the dominant NGL extracted from Appalachian wells, would be reduced. Gas producers would then have to find other markets for their ethane; the most straight-forward option for them would simply be to leave ethane in the gas they sell, in a process known as ethane “rejection”. Doing this, however, would effectively increase the supply of gas by about 3% nationally, putting downward pressure on price by up to \$0.1/ Mbtu (assuming similar price relationships hold as discussed in the export section above).

Summary of future changes in U.S. gas demand

In the table below, we summarize the prospective effects of changes in demand for U.S. gas and petrochemicals that we discussed above. For each factor, we rate the effect on the most important driver of U.S. gas well economics – the price of gas – as well as on a secondary driver, the price of oil. Given the uncertainties, we rate each factor simply as having a *high*, *medium*, or *low* effect. The caption to Table 1 describes the rating process in more detail.

Factor	Potential reduction in Henry Hub gas price in 2030	Potential reduction on global oil price in 2030
Fast pace of domestic decarbonization	High (Reduction in gas demand of 6-13 TCF, relative to reference case, could hold price of gas to well below \$3/Mbtu compared to around \$3.50/Mbtu in reference case outlooks)	Low (Oil markets are global, muting price effect of decreasing U.S. oil consumption)
Fast pace of global decarbonization	Low (but uncertain)	High (Could hold oil prices to well below \$60/bbl and also drive down naphtha prices)
Unavailability of LNG exports	Medium (Reduction in gas demand for exports of ~1.5 TCF could reduce price of gas by ~\$0.15-\$0.20/Mbtu)	-
Weakness in global petrochemical markets	Low (Oversupply of petrochemicals, especially if spurred by low oil prices, would decrease demand for U.S. ethane, decreasing price by up to \$0.1/Mbtu)	-

Table 1. Summary of market effects of risk factors for Appalachian gas development. For gas prices, we assign a rating of “High” when we believe the factor could reduce the Henry Hub gas price by \$0.50/Mbtu or more, a rating of “Low” if we believe the factor would affect the price by less than \$0.10/Mbtu, and a rating of “Medium” if we believe the effect to be between \$0.10/Mbtu and \$0.50/Mbtu. Similarly, for oil prices, a “High” rating means an effect of more than \$20/barrel, a “Low” rating means an effect of less than \$5/barrel, and a “Medium” rating means something in between.

ANALYSIS & DISCUSSION

After assessing the factors above, we now synthesize the findings to evaluate the conditions under which continued build-out of new gas production and infrastructure would be profitable in Appalachia. This future of the gas industry is of great importance to the region, not just for questions of economic recovery and growth, but also for understanding other outcomes of gas extraction, such as the local health effects (Mayfield et al. 2019).

To conduct this evaluation, we first analyze the economics of around 200 prospective new gas (and gas-condensate) fields in Pennsylvania, Ohio, and West Virginia, using data from Rystad Energy (as of September 2020) (Rystad Energy 2020). We gather Rystad's estimates of

each field's capital costs, operating costs, and prospective gas and NGL production, and use this information to calculate what combination of gas and prices would allow each field to break even (i.e., be profitable, assuming a 10% discount rate).

We then construct a curve that shows the combinations of gas and oil prices under which new fields would, on average across the three-state region, break even and therefore make sense for investors to develop. This curve, which captures the trade-off, or "frontier", for how different gas and oil prices affect average profitability, is illustrated by the blue line in the middle of Figure 3. If prices are expected to be above and to the right of the blue break-even line, fields will tend to go forward and be developed as they are expected to be profitable.

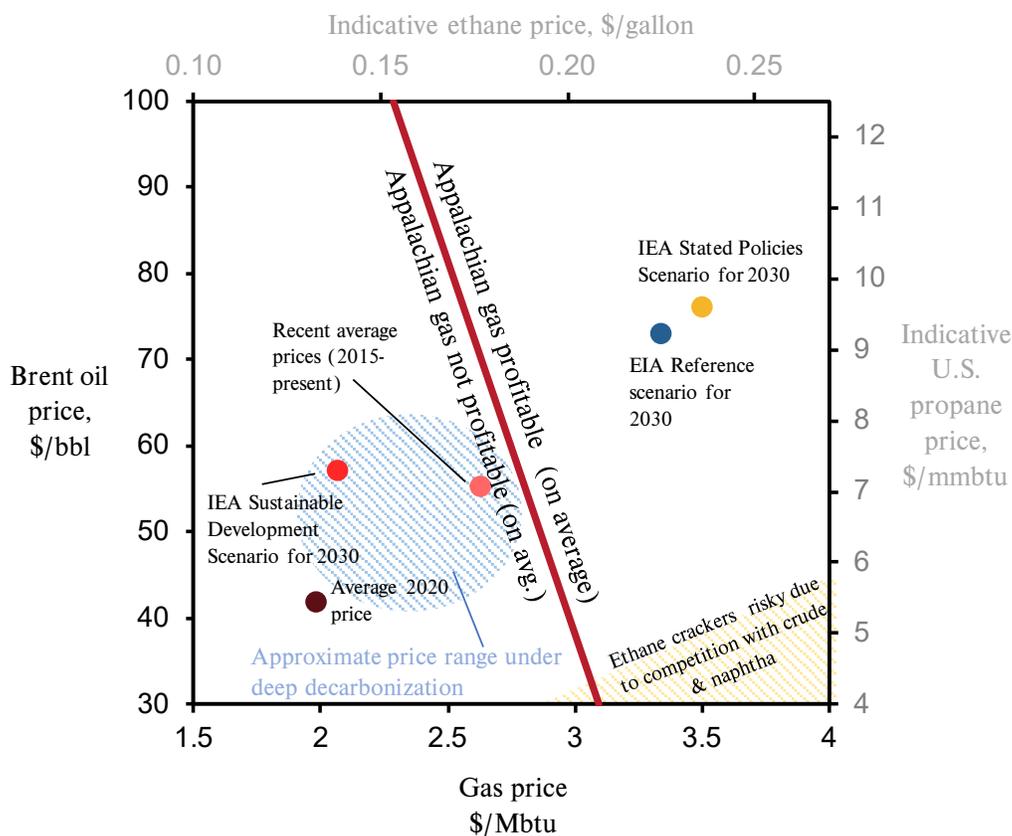


Figure 3. Analysis of profitability of new gas fields in Appalachia under different price outlooks; Profitability is gauged here as weighted-average (by gas production) net present value (NPV), assuming a 10% nominal discount rate, of 216 prospective new gas and gas-condensate fields in the region.

As shown in Figure 3, if gas prices are high enough (e.g., \$3/MBtu or higher; right side of the chart), new gas fields would be profitable even if oil prices (and, by extension, propane prices) were low (e.g., less than about \$40/barrel, or about \$5/Mbtu propane).

If gas prices are instead less than \$3/MBtu, higher oil prices can help compensate, at least up to a point. For example, if oil prices were more than \$80/barrel (equivalent to propane prices above around \$10/Mbtu), then new gas fields could be profitable even if gas prices were around \$2.50/Mbtu.

Of course, this analysis represents average conditions across the three-state region, and the economics of each state and individual field may not conform to this average. In particular, because of the rock formations they access, gas fields in West Virginia and Ohio tend to produce more liquids, and therefore are more able than fields in Pennsylvania to compensate for low gas prices with higher oil and propane prices.

Regardless, getting a sense of the average economics helps to understand the region-wide potential and risks, something that should be of great interest to policymakers. Critically, these average economics show that new gas fields may not end up being profitable.

For example, as shown in Figure 3, average 2020 prices for gas (about \$2/Mbtu) and oil (about \$40/barrel) are substantially to the left of the blue “frontier” line. This means that recent prices do not support continued, widespread expansion of gas wells and infrastructure in Appalachia. Note that, pricing environments on the left side of Figure 3 that do not support new Appalachian gas fields would also put at risk new petrochemical facilities such as ethane crackers, since those

facilities depend on ethane from the gas fields. However, reference price forecasts over the next decade, both those from the U.S. Department of Energy’s Energy Information Administration (EIA) as well as from the International Energy Agency (IEA), are both high enough to support a build-out of Appalachian gas production. That is the future that Appalachian gas producers are counting on.

Which future will emerge? As described in the previous section, the biggest factor could well be how quickly the energy system decarbonizes in the U.S., since a swift move to decarbonize the U.S. would see gas prices remain well below \$3/Mbtu for the foreseeable future.

Of course, *how* much below \$3/Mbtu depends on the speed and scale of the move away from gas demand in the U.S. To show a range of potential oil-gas price outcomes under different decarbonization scenarios, Figure 3 shows a blue oval, representing the possible alternative outcomes identified in our research (Table 1). For example, in the IEA’s recent Sustainable Development Scenario (IEA 2020a), Brent oil prices remain below \$60/barrel, with gas prices just above \$2/MBtu, as shown in Figure 3.

This finding has important implications for policymakers in Appalachian states and in the U.S. federal government. The necessary effort to stabilize the climate, by domestic and international governments, would create economic conditions unlikely to support major new gas development in Appalachia. Our findings therefore suggest that policymakers should take serious pause when faced with decisions to continue supporting new gas development in the region. (They do not mean, however, that economic development opportunities for Appalachia are lacking. We will address those briefly in the Conclusions section.)

There are, of course, other factors that could improve the fortunes for Appalachian gas. Low-carbon scenarios with greater-than-foreseen LNG exports could see gas prices pushing closer to \$3/Mbtu, crossing the line into greater gas viability in Figure 3. And, as mentioned above, future reference case outcomes that do not attempt to limit climate disruption, as untenable as those are for the broader economy and welfare of society, could still see a strong, near-term future for gas development in Appalachia.

Nonetheless, there are also other pathways under which Appalachian gas reliance becomes even riskier. For example, the assessment above assumes a cost of capital (required investment return, or hurdle rate) for new gas fields of 10%. However, increasing risk perceptions in the industry have already started to raise this cost of capital, such that hurdle rates may now be about 15% instead of 10% (Fattouh et al. 2019). A higher discount rate would push the breakeven curve up and to the right in Figure 3, substantially raising the bar for new field development (The appendix includes a supplemental figure showing a version of the chart at 15% cost of capital).

Furthermore, there are other factors that our analysis has not yet considered. For example, should new policies be developed to address the local pollution and health effects of gas production (Bamber et al. 2019; Li et al. 2020; Mayfield et al. 2019; Ogneva-Himmelberger and Huang 2015), the path for new gas production could be narrower yet. Some communities have begun discussing regulations that would restrict new gas wells within particular distances (e.g., 2,500 feet) of homes and community centers, which could leave a substantial fraction of the subsurface geology inaccessible, especially in or near suburban communities in southwestern Pennsylvania (Ericson et al. 2019).

CONCLUSIONS

Our analysis shows that an expansion of gas supply from Appalachia requires a large increase in gas prices compared to the current situation. That outcome, in turn, requires stable U.S. gas demand and increased LNG export possibilities. These outcomes, however, are in doubt. U.S. and global decarbonization trends are underway, and, as we show, they challenge the economic case for expanding gas and NGL production in Appalachia.

Furthermore, the breakeven economics shown in Figure 3 assume a stable investment climate for new gas projects, where capital is fairly low cost and low risk, and project hurdle rates are about 10%. If investors were to demand higher returns to compensate for higher perceived risk, as evidence suggests is currently the case, new Appalachian gas would be at even higher risk. In other words, on financial metrics alone, the case for new gas development in Pennsylvania, Ohio, and West Virginia is a risky bet for gas producers and the communities and governments that support them.

It may be tempting, for some, to try to get through the current, COVID-induced market shock by subsidizing the gas and petrochemical industry, in hopes of better times ahead. However, there could well be better ways of putting people back to work and, especially, for building a long-term economic foundation.

As one recent study led by the University of Pittsburgh recommended, the boom-bust cycle of fossil fuel extraction has “underscored the need for structural economic change that provides alternative employment opportunities better aligned with globally growing markets” (Marshall and et al. 2020). Major new public and private investment in the region can build new infrastructure, and develop new

manufacturing sectors, to provide durable employment in a more resilient and low-carbon way.

This paper provides a view on the long-term fundamentals of gas and petrochemical demand and supply, in order to help inform the debate about further development of these industries

in Ohio, Pennsylvania, and West Virginia. There are, of course, many perspectives and considerations when making decisions on energy, investment, and infrastructure. The substantial risks to economic development (as well as climate and health) from further dependence on gas and petrochemicals, as described in this report, should be among them.

ABOUT THE AUTHORS

Peter Erickson is the Climate Policy Program Director at Stockholm Environment Institute's U.S. Center. His research focuses on oil and gas under low-carbon transitions, as well as on low-carbon transitions in cities.

Ploy Achakulwisut is a Scientist with Stockholm Environment Institute's U.S. Center. She contributes to SEI's Initiative on Carbon Lock-in, focusing on how fossil fuel supply can be aligned with climate goals and the effects of subsidies on U.S. oil and gas production.

Stockholm Environment Institute is an international non-profit research organization with U.S. offices in California, Massachusetts, and Washington State. SEI conducts research and engages with decision-makers on energy, water and climate policy. sei.org

The Ohio River Valley Institute is an independent, nonprofit research and communications center founded in 2020. The Institute is designed to equip Appalachia's residents and decision-makers with the policy research and practical tools they need to advance long-term solutions to some of the region's most significant challenges. ohiorivervalleyinstitute.org

The authors would like to thank Steven Carbó, Anne Keller, and Clark Williams-Derry for reviewing a draft of this report and the Schmidt Family Foundation / 11th Hour Project for supporting the work.

APPENDIX

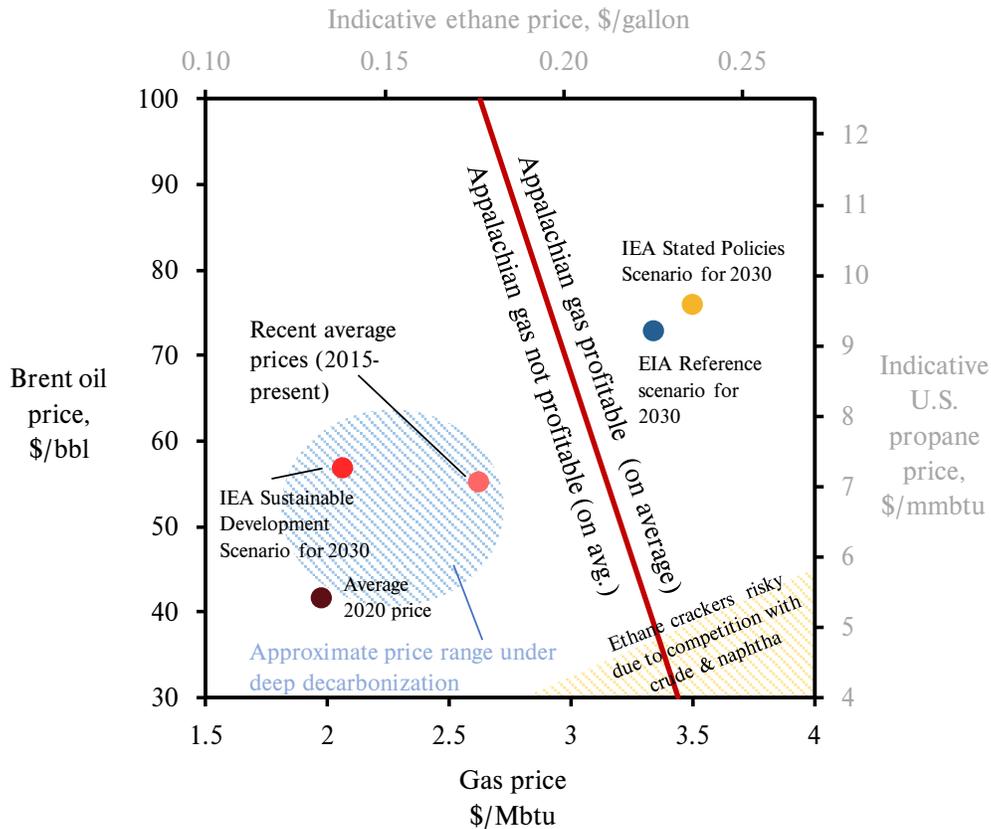


Figure 4. Analysis of profitability of new gas fields in Appalachia under different price outlooks. Profitability is gauged here as weighted-average (by gas production) net present value (NPV), assuming a 15% nominal discount rate, of 216 prospective new gas and gas-condensate fields in the region.

REFERENCES

- Bamber, A. M., Hasanali, S. H., Nair, A. S., Watkins, S. M., Vigil, D. I., Van Dyke, M., McMullin, T. S. and Richardson, K. (2019). A Systematic Review of the Epidemiologic Literature Assessing Health Outcomes in Populations Living near Oil and Natural Gas Operations: Study Quality and Future Recommendations. *International Journal of Environmental Research and Public Health*, 16(12). 2123. DOI: 10.3390/ijerph16122123
- Barth, A., Dediu, D., Hong, A. and Nojek, A. (2020). *The End of the Atlantic Coast Pipeline: What Does It Mean for the North American Natural Gas Industry?* McKinsey & Company
- BloombergNEF, International Gas Union, and Snam (2020). *Global Gas Report*. BloombergNEF. <https://igu.org/resources/global-gas-report-2020/>
- BP (2020). *Energy Outlook 2020 Edition*
- Denning, L. (2021). Winter Is Still Coming for U.S. Gas Exporters. *Bloomberg.Com*, 15 January 2021. <https://www.bloomberg.com/opinion/articles/2021-01-15/soaring-winter-natural-gas-prices-look-temporary>
- Erickson, P., Kartha, S., Lazarus, M. and Tempest, K. (2015). Assessing carbon lock-in. *Environmental Research Letters*, 10(8). 084023. DOI: 10.1088/1748-9326/10/8/084023
- Ericson, S. J., Kaffine, D. T. and Maniloff, P. (2019). *Costs of Increasing Oil and Gas Setbacks Are Initially Modest but Rise Sharply*. Colorado School of Mines
- Fattouh, B., Poudineh, R. and West, R. (2019). *Energy Transition, Uncertainty, and the Implications of Change in the Risk Preferences of Fossil Fuels Investors*. The Oxford Institute for Energy Studies. <https://www.oxfordenergy.org/publications/energy-transition-uncertainty-implications-change-risk-preferences-fossil-fuels-investors/?v=7516fd43adaa>
- Feijoo, F., Iyer, G., Binsted, M. and Edmonds, J. (2020). U.S. energy system transitions under cumulative emissions budgets. *Climatic Change*. DOI: 10.1007/s10584-020-02670-0
- Gilbert, A. Q. and Sovacool, B. K. (2017). U.S. liquefied natural gas (LNG) exports: Boom or bust for the global climate? *Energy*, 141(Supplement C). 1671–80. DOI: 10.1016/j.energy.2017.11.098
- Gillingham, K. and Huang, P. (2019). Is abundant natural gas a bridge to a low-carbon future or a dead-end? *The Energy Journal*, 40(2). DOI: 10.5547/01956574.40.2.kgil
- Haley, B., Jones, R., Kwok, G., Hargreaves, J., Farbes, J. and Williams, J. H. (2019). *350 PPM Pathways for the United States*. Evolved Energy Research
- Harvey, L. D. (2017). Implications for the floor price of oil of aggressive climate policies. *Energy Policy*, 108. 143–53. DOI: 10.1016/j.enpol.2017.05.045
- Henze, V. (2020). Scale-up of Solar and Wind Puts Existing Coal, Gas at Risk. BloombergNEF Press Release. <https://about.bnef.com/blog/scale-up-of-solar-and-wind-puts-existing-coal-gas-at-risk/>
- Hipple, K., Williams-Derry, C. and Sanzillo, T. (2020). *Despite Drastic CapEx Cuts, Appalachian Frackers Spill Red Ink in Third Quarter—Again*. Institute for Energy Economics and Financial Analysis. http://ieefa.org/wp-content/uploads/2020/12/Appalachian-Frackers-Spill-Red-Ink-in-Q3-Despite-Drastic-CapEx-Cuts_December-2020.pdf
- Holz, F., Richter, P. M. and Egging, R. (2015). A Global Perspective on the Future of Natural Gas: Resources, Trade, and Climate Constraints. *Review of Environmental Economics and Policy*, 9(1). 85–106. DOI: 10.1093/reep/reu016
- Houser, T., Bordoff, J. and Marsters, P. (2017). *Can Coal Make a Comeback?* Columbia University, Center on Global Energy Policy and Rhodium Group, New York. <http://energypolicy.columbia.edu/publications/report/can-coal-make-comeback>
- Huppmann, D., Rogelj, J., Kriegler, E., Mundaca, L., Forster, P., Kobayashi, S., Séferian, R. and Vilariño, M. V. (2018). Scenario analysis notebooks for the IPCC Special Report on Global Warming of 1.5°C. DOI: 10.22022/SR15/08-2018.15428
- Iaconangelo, D. (2020). As natural gas bans go national, can cities fill the gap? *Energywire*, 3 August 2020. <https://www.eenews.net/stories/1063674561>
- IEA (2020a). *World Energy Investment 2020*. Organisation for Economic Co-operation and Development, Paris, France. <https://webstore.iea.org/world-energy-investment-2019>

- IEA (2020b). *World Energy Outlook 2020*. IEA Publications, Paris. www.iea.org/weo2020
- IHS Markit (2020a). *Managing Petrochemicals with Confidence Despite Energy Volatility and an Uncertain Global Economy*. <https://ihsmarkit.com/research-analysis/ethylene-market-outlook-considering-the-impact-of-covid19.html>
- IHS Markit (2020b). *Ethylene Market Outlook Considering the Impact of COVID-19*. <https://ihsmarkit.com/research-analysis/ethylene-market-outlook-considering-the-impact-of-covid19.html>
- International Energy Agency (2018). *The Future of Petrochemicals: Towards more sustainable plastics and fertilisers*. , 2018.
- Jaccard, M., Hoffele, J. and Jaccard, T. (2018). Global carbon budgets and the viability of new fossil fuel projects. *Climatic Change*, 150. 15–28. DOI: 10.1007/s10584-018-2206-2
- Jones, C., LaRoche, T. and Ginyard-Jones, C. (2016). *The Economics Behind Monetizing Cost-Advantaged U.S. Ethane Reserves*. U.S. Ethane Crackers and Ethylene Derivative Capacity Additions. Honfleur LLC, Houston
- Larson, E., Greig, C., Jenkins, J., Mayfield, E. N. and et al. (2020). *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*. Princeton University, Princeton, NJ. <https://environmenthalfcentury.princeton.edu/>
- Li, L., Blomberg, A. J., Spengler, J. D., Coull, B. A., Schwartz, J. D. and Koutrakis, P. (2020). Unconventional oil and gas development and ambient particle radioactivity. *Nature Communications*, 11(1). 5002. DOI: 10.1038/s41467-020-18226-w
- Malik, D., Manchanda, P., Simons, T. J. and Wallach, J. (2020). *The Impact of COVID-19 on the Global Petrochemical Industry*. McKinsey & Company
- Marshall, L. and et al. (2020). *Marshall Plan for Middle America Roadmap*. Center for Sustainable Business, University of Pittsburgh
- Mayfield, E. N., Cohon, J. L., Muller, N. Z., Azevedo, I. M. L. and Robinson, A. L. (2019). Cumulative environmental and employment impacts of the shale gas boom. *Nature Sustainability*, 2(12). 1122–31. DOI: 10.1038/s41893-019-0420-1
- McFarlane, C. E. and S. (2020). France's Engie Backs Out of U.S. LNG Deal. *Wall Street Journal*, 3 November 2020. Business. <https://www.wsj.com/articles/frances-engie-backs-out-of-u-s-lng-deal-11604435609>
- Ogneva-Himmelberger, Y. and Huang, L. (2015). Spatial distribution of unconventional gas wells and human populations in the Marcellus Shale in the United States: Vulnerability analysis. *Applied Geography*, 60. 165–74. DOI: 10.1016/j.apgeog.2015.03.011
- Rogelj, J., Shindell, D., Jiang, K., Fifita, S., Forster, P., et al. (2018). Chapter 2: Mitigation pathways compatible with 1.5°C in the context of sustainable development. In *Global Warming of 1.5 °C: An IPCC Special Report on the Impacts of Global Warming of 1.5 °C above Pre-Industrial Levels and Related Global Greenhouse Gas Emission Pathways, in the Context of Strengthening the Global Response to the Threat of Climate Change, Sustainable Development, and Efforts to Eradicate Poverty*. https://www.ipcc.ch/site/assets/uploads/sites/2/2019/05/SR15_Chapter2_Low_Res.pdf
- Rystad Energy (2020). *Cube Browser*, Version 2.1.21. <https://www.rystadenergy.com/Products/EnP-Solutions/UCube/Default>
- Sanzillo, T., Hipple, K. and Mattei, S. (2020). Proposed PTTGC Petrochemical Complex in Ohio Faces Significant Risks. https://ieefa.org/wp-content/uploads/2020/03/Proposed-PTTGC-Complex-in-OH-Faces-Risks_March-2020.pdf
- SEI, IISD, ODI, Climate Analytics, CICERO, and UNEP (2019). *The Production Gap Report 2019*. <http://productiongap.org/>
- Shearer, C., Bistline, J., Inman, M. and Davis, S. J. (2014). The effect of natural gas supply on U.S. renewable energy and CO2 emissions. *Environmental Research Letters*, 9(9). 094008. DOI: 10.1088/1748-9326/9/9/094008
- Shearer, C., Tong, D., Fofrich, R. and Davis, S. J. (2020). Committed Emissions of the U.S. Power Sector, 2000–2018. *AGU Advances*, 1(3). DOI: 10.1029/2020AV000162
- S&P Global Platts (2020). *Global Petrochemical Trends: H1 2020*
- The White House (2016). *The United States Mid-Century Strategy for Deep Decarbonization* Washington, D.C. https://obamawhitehouse.archives.gov/sites/default/files/docs/mid_century_strategy_report-final.pdf
- U.S. Commodity Futures Trading Commission (2018). *Liquefied Natural Gas Developments and Market Impacts*

- U.S. Department of Energy (2020). *The Appalachian Energy and Petrochemical Renaissance: An Examination of Economic Progress and Opportunities*. https://www.energy.gov/sites/prod/files/2020/06/f76/Appalachian%20Energy%20and%20Petrochemical%20Report_063020_v3.pdf
- U.S. EIA (2020a). *Annual Energy Outlook 2020*. U.S. Energy Information Administration, Washington, DC. <http://www.eia.gov/forecasts/aeo/>
- U.S. EIA (2020b). *Short-Term Energy Outlook Data Browser*. <https://www.eia.gov/outlooks/steo/data/browser/>
- U.S. EIA (2020c). *U.S. Liquefaction Capacity*. United States Energy Information Administration
- U.S. EIA (2020). *Monthly Energy Review*. U.S. Energy Information Administration, Washington, DC. <http://www.eia.gov/totalenergy/data/monthly/archive/00351605.pdf>
- U.S. EIA (2020d). *State Energy Data System*. United States Energy Information Administration, Washington, D.C. <https://www.eia.gov/state/seds/>
- Walsh, C., Lazarou, N.-J., Traut, M., Price, J., Raucci, C., et al. (2019). Trade and trade-offs: Shipping in changing climates. *Marine Policy*, 106. 103537. DOI: 10.1016/j.marpol.2019.103537
- Williams-Derry, C., Hipple, K. and Sanzillo, T. (2020). *Shale Producers Spilled \$2.1 Billion in Red Ink Last Year*. Institute for Energy Economics and Financial Analysis
- Wood Mackenzie (2020). *The Global Ethylene Cost Curve in a \$30/Bbl World*. Wood Mackenzie, Houston, TX. <https://www.woodmac.com/news/opinion/how-will-the-oil-price-crash-affect-the-ethylene-cost-curve/>
- Yergin, D. (2009). *The Prize: The Epic Quest for Oil, Money & Power*. Free Press, New York, NY