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Where Does the Marginal Methane Molecule Come From? Implications of LNG Exports for US Natural Gas Supply and Methane Emissions

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Abstract

Surging exports of US liquefied natural gas (LNG) over the past decade have raised concerns about their potential to increase domestic gas prices and spur environmental impacts, both local and global, especially because methane, a potent greenhouse gas, commonly leaks from US oil and gas infrastructure. Yet methane leak rates vary widely—up to an order of magnitude—across sources of US oil and gas supply, creating uncertainty in the carbon footprint of US LNG. This paper models the impacts of increased US oil and gas export demand on domestic oil and gas prices, marginal oil and gas supply by US basin, and the implied methane intensity of that marginal supply. Each 1 billion cubic feet per day (Bcf/d) increase in gas export demand is estimated to increase domestic natural gas prices by approximately 2.5% while reducing crude oil prices by 0.5% due to the induced supply of coproduced oil. The US supply response to gas export demand comes disproportionately from basins with low estimated methane leak rates, led by Appalachia, yielding an effective methane intensity of the gas supply anticipated to meet export demand (1.7% leak rate) that is lower than the average US gas supply (3.1%). The supply response to an increase in oil demand shows the reverse pattern, with high-leak Permian supply crowding out low-leak basins like Appalachia, yielding a very high effective methane leak rate (9.1%). These widely varying effective methane leak rates suggest that the 2015 repeal of the US crude oil export ban may have been a bigger driver of US methane emissions than expanded LNG exports would be. In particular, model results suggest that US crude oil exports over 2015–23 drove methane emissions twice as large as those driven by US LNG exports over the same period, with the former's induced emissions equivalent to those expected to be caused by more than 20 Bcf/d of gas exports.

Contents

1. Introduction

US exports of liquefied natural gas (LNG) have grown rapidly over the past decade, rising from effectively zero in 2015 to more than 13 billion cubic feet per day (Bcf/d) in December 2023 (EIA 2024b), equivalent to more than 10% of US gas supply. With 14 Bcf/d of peak LNG export capacity already built as of the fourth quarter of 2024 (2024Q4), an additional 11 Bcf/d commissioned or under construction, and another 16 Bcf/d already greenlit by the Department of Energy (DOE) (see EIA 2025), the United States could see export capacity rise to more than 40 Bcf/d, nearly 40% of current US production levels, even if no additional export terminals are approved. This has raised concerns about the impacts a large export demand pull might have on US gas prices and the life-cycle greenhouse gas emissions of the exported LNG, all of which contributed to the Biden administration's decision to pause the approvals of LNG export terminals in January 2024 to reassess whether expanded exports are in the "public interest," per the direction of the Natural Gas Act.

The carbon intensity of exported LNG has received particular attention, with one much cited paper, Howarth (2024), arguing that LNG sourced from the Permian Basin in west Texas/southeast New Mexico, where leaks of methane from oil and gas infrastructure are high, would have a higher life-cycle carbon intensity than that of coal. However, it is possible that economic forces will drive US gas supply not just in the Permian Basin but in other basins as well. For example, the Appalachian Basin is the largest contributing basin to total US gas supply and has substantially lower methane leak rates—as much as 10 times lower, according to empirical observations from Sherwin et al. (2024), which range from a low of 0.75% in parts of Appalachia to a high of 9.63% in parts of the Permian. Yet those two basins are the two largest sources of US gas supply, together contributing about half in 2022. This suggests that their relative contributions to the incremental gas supply that rises to meet export demand—that is, marginal supply—is key to the debate around the carbon intensity of LNG exports, including whether it is indeed more carbon-intensive than coal.

This paper addresses this question by expanding the Dynamic Oil and Gas Market Analysis (DOGMA) model (Newell et al. 2019; Newell and Prest 2019; Prest 2022; Prest et al. 2024b) to analyze the implications of increased US oil and gas export demand for marginal oil and gas supply by US basin, its weighted-average methane intensity, and impacts on domestic oil and gas prices. I use DOGMA to estimate the response of US oil and gas supply to changes in prices induced by increased export demand for US oil and gas. This yields estimated marginal oil and gas supply separately by basin, which I couple with basin-level estimates of methane leak rates based on Sherwin et al. (2024) to compute the weighted-average methane leak rates associated with marginal gas supply that rises in response to gas export demand (or to oil export demand).

I find three key results. First, supply of both oil and gas from the Permian Basin responds strongly to oil prices (and hence oil demand shocks), whereas Appalachian production, which is predominantly a gas play, responds strongly to gas prices (and hence gas demand shocks). These two basins dominate the overall response of US gas supply to increased prices, together representing 59% of marginal gas supply in response to an exogenous increase in gas prices, holding oil prices constant, with Appalachia contributing 45 percentage points and the Permian contributing 14 percentage points. Moreover, an exogenous increase in gas export demand increases gas prices but modestly decreases oil prices due to induced coproduction of oil; this leads to a larger response from Appalachia (58% of marginal supply) in response to gas demand relative to the Permian (2%) because of the latter's greater sensitivity to oil prices, rather than gas prices.

The second finding follows from these dynamics: The marginal gas supply brought on in response to increased gas export demand has lower methane emissions intensity (1.7% leak rate) than average (3.1%) because of the disproportionate contribution of the low-leak Appalachian Basin. By contrast, the marginal gas supply induced by oil export demand is substantially more carbon-intensive (9.1% leak rate) than average (3.1%) due to a combination of the direct effect of the disproportionate contribution of the gas supply from high-leak Permian Basin and an indirect, knock-on effect of crowding out production in low-leak Appalachia.

The consequence of the very high effective methane intensity of marginal gas supply in response to oil demand suggests that the 2015 repeal of the US crude oil export ban may have had larger, but less appreciated, consequences for driving US methane emissions than the arguably higher-profile LNG export pause may have. Specifically, model results suggest that US oil exports during 2015 to 2023 may have driven more than twice as much methane emissions as did US LNG exports over the same period, with the former's emissions equivalent to those expected to be caused by more than 20 Bcf/d of gas export demand, which is the approximate range of future export capacity under consideration.

Third, each +1 Bcf/d shift in export demand is estimated to increase gas prices by approximately 2.5% while reducing crude oil prices by 0.5%. This effect is close to linear with respect to larger demand shifts. For context, approximately 11 Bcf/d of new LNG terminals are under construction as of 2024Q4, for which I estimate an increase in domestic natural gas prices of 30% alongside a 5% reduction in crude oil prices. An analogous thought experiment for a 0.1 million barrel per day increase in oil export demand increases US crude oil prices by 0.8% while reducing gas prices by 0.6%.

The main caveats to my results owe to uncertainty in future US methane leakage rates. The methane intensity estimates I use are based on Sherwin et al. (2024), whose study reflects nearly 1 million aerial site measurements taken across six major oil and gas producing US basins during 2016–21, including Appalachia and the Permian. However, some extrapolation to other basins is necessary. Further, improvements in methane capture could change those leak rates in the future, although the likely near-term relaxation of methane regulations in the United States could slow those improvements.

Finally, because my model does not feature a representation of the global substitution patterns of LNG, my results do not speak fully to the global emissions effects of LNG, which could increase or decrease global carbon emissions depending on how much LNG use represents increased consumption of energy services and how much it substitutes for other fuels with potentially higher or lower carbon intensities.

Beyond the immediate policy questions around the likely effects of LNG exports, this paper also contributes to the literature on the economics of US oil and gas supply. I provide basin-level estimates of the elasticity of drilling with respect to oil and gas prices, new estimates of the elasticity of well productivity with respect to drilling activity, and time-varying own-price and cross-price elasticities of US oil and gas supply.

2. Literature

This paper sits at the intersection of three literatures. The first is that of the economics of US oil and gas supply in the shale era, with a focus on supply elasticities. The second context is methane emissions from US oil and gas supply and the potential impacts of LNG exports on those emissions. The third regards recent analyses of the potential effects of LNG exports on US gas prices. I discuss each of these in turn.

2.1. Regional US Oil and Gas Supply Elasticities

While there is a broad literature on elasticities of oil and gas supply (see Prest et al. 2024a for a review of oil supply elasticities), much of that literature is not at the spatial or temporal scale necessary to address the question in this study, which requires estimating long-run equilibrium supply responses at the basin level or finer. By contrast, most estimates of oil and gas supply elasticities in the literature focus on short-run supply responses or are aggregated to a national or global scale (Hausman and Kellogg 2015; Balke and Brown 2018; Caldara et al. 2019; Kilian 2022). While some studies do consider specific US regions (Mason and Roberts 2018; Gilbert and Roberts 2020), they tend to be case studies of a single basin or a small number of regionally clustered basins, rather than nationally comprehensive estimates.

The new version of the DOGMA model developed here is designed to fill that gap by providing nationally comprehensive basin-level elasticities and supply estimates. DOGMA has its roots in several papers in the economics literature of the shale era (Newell et al. 2019; Newell and Prest 2019; Prest 2022; Prest et al. 2024b). Most relevant to this study are Prest (2022), who use a nationally comprehensive model with US oil and gas supply aggregated into eight suppliers, and Prest et al. (2024b), who use a spatially granular model with 76 suppliers but include only five basins, all of which are in the American West. Those papers traded off regional granularity for nationwide comprehension or vice versa. The version of DOGMA developed in this paper extends the granular model structure to the entire United States.

Prest (2022) models the market interactions between different sources of US oil and gas supply, in that case production on federally owned lands versus non–federally owned (i.e., private, state, and tribal) lands. This paper also analyzes those dynamics, but in a more granular fashion, which is necessary to account for basin-specific methane intensities. More details can be found in Section 4.

2.2. Methane Emissions from Oil and Gas Supply and LNG

Advances in remote sensing technology (both aerial and satellite) have sparked a wave of new research estimating methane emissions from US oil and gas infrastructure (Alvarez et al. 2018; Omara et al. 2018; Zhang et al. 2020; Chen et al. 2022; Omara et al. 2022; Lu et al. 2023; Sherwin et al. 2024). That literature has repeatedly found that empirically estimated methane leak rates are much larger than the estimates in the US Environmental Protection Agency's two databases—the Greenhouse Gas Reporting Program (GHGRP) and the Greenhouse Gas Inventory (GHGI)—which are not based on direct empirical observations. For instance, Sherwin et al. (2024) combine approximately 1 million aerial site measurements across six regions, finding upstream/midstream methane leak rates ranging from 0.75% to 9.63% across regions, with a six-region weighted average of 2.95%, which they report was three times the corresponding GHGI estimate.

Two recent life-cycle analyses of the carbon intensity of LNG exports (Zhu et al. 2024; Howarth 2024) find that these upstream/midstream methane leak estimates are the single largest driver of LNG's total carbon footprint. In particular, in Howarth's central estimates, which assume a leak rate of 2.8% and a 20-year global warming potential (GWP20), upstream/midstream methane emissions are responsible for 36%–38% of LNG's total carbon footprint (and 18%–20% under GWP100) and are the primary driver of that paper's central finding that natural gas is 33% more carbon-intensive than coal. Thus the appropriate methane leak rate is key to the question of whether LNG exports are deemed "worse than coal" from an emissions perspective.

While the Howarth study used a 2.8% leak rate to reflect the Permian Basin, a major December 2024 study from the Department of Energy (DOE 2024) used a central estimate of 0.56% for the national average "production through transmission network" leak rate from Khutal et al. (2024), who authored this report produced by the National Energy Technology Laboratory. The report relied on a combination of the GHGRP and GHGI data, which explains why the 0.56% leak rate is well below the empirical estimates from the literature[1].

While the Howarth and the DOE studies use very different leak rates, neither of those estimates is informed by the economics of the oil and gas markets. Both studies assume constant leak rates, with Howarth using an estimate for the Permian Basin,

1 Despite this low assumed leak rate, the DOE study finds that in four out of the five scenarios, LNG exports increase global emissions (albeit by small amounts ranging from 0.002% to 0.05% of cumulative global GHG emissions in 2020–50), largely due to their model estimates, which suggest LNG would displace primarily lower-carbon energy internationally (including varying combinations of renewables, nuclear, and gas with carbon capture and storage), with displacement of higher-carbon coal playing a smaller role. Updating DOE's analysis to include leak rates more in line with the literature to values above 0.56% would presumably yield larger global emissions effects, but the magnitude would depend on assumed source marginal leak rate.

assuming that Permian gas is the marginal supplier, whereas the DOE study's value is meant to reflect a national average. Neither approach is consistent with economic factors considered in this study. Indeed, my results suggest that very little gas supply expected to rise to meet gas export demand will come from the Permian, yielding a 1.7% marginal leak rate, which is halfway between DOE's 0.56% and Howarth's 2.8%.

The existing study that comes closest to addressing the question of the source of gas supply for LNG exports is that by Roman-White et al. (2024). Their study develops a "gas pathing algorithm" that combines information on gas purchase contracts held by a major LNG exporter and physical pipeline infrastructure to identify 138 potential pathways of natural gas production to two specific large LNG export terminals. While that approach may be appropriate for the purposes of attributional emissions accounting, such as supporting claims about the carbon intensity of a particular LNG exporter's supply chain, it does not alleviate concerns about the consequential emissions effects of LNG demand, which depend on outcomes in economic equilibrium. In particular, reshuffling of high- and low-leak gas supplies among gas purchasers could imply that attributional emissions (i.e., those from contracted supply chains) differ substantially from consequential ones (i.e., those caused in equilibrium across the market as a whole).

2.3. LNG Exports' Impact on Domestic Gas Prices

The DOE (2024) study uses a combination of the GCAM and NEMS models to estimate the impact of LNG exports on domestic gas prices, finding a central estimate of a 31% increase in domestic gas prices at Henry Hub in 2050 caused by a 32.6 Bcf/d increase in LNG exports (see DOE 2024, Table 10 and p. S-33). This implies an approximately 0.95% (=31%/32.6 Bcf/d) increase in Henry Hub prices per Bcf/d of exports.

A separate study was conducted by an independent arm of DOE (EIA 2023) as part of its 2023 Annual Energy Outlook, which also uses NEMS. The study estimates a price increase of 47% in response to about 32.9 Bcf/d increase in 2050. This also corresponds with a somewhat larger 1.4% (=47%/32.9 Bcf/d) increase per Bcf/d of exports. As discussed in Section 5, these estimates are substantially smaller than my results suggest due to much larger implicit gas supply elasticities in the DOE and EIA models.

Finally, a study by S&P Global (Yergin et al. 2024) estimates that an "extended halt" of LNG approvals that would reduce exports by approximately 5 Bcf/d would reduce US gas prices by $0.15/MMBtu on their baseline price of approximately $4/MMBtu, which corresponds to a price impact of about 0.75% per Bcf/d of exports.

3. Data

The main data underlying DOGMA is well-level data from Enverus on the near universe of oil and gas wells in the United States. The data include a cross-sectional dataset on well characteristics—including location (including latitude/longitude), basin, and dates of drilling and first production— and a well-by-month panel of oil and gas production from each well in the cross-sectional data. I supplement these data with West Texas Intermediate (WTI) and Henry Hub price data from the Federal Reserve Economic Data system, which are converted into real 2023 prices using the Consumer Price Index for All Urban Consumers (EIA 2024a; IMF 2024; BLS 2024). Future price scenarios and US oil and gas demand projections are taken from the International Energy Agency's World Energy Outlook 2023 (WEO). GIS data from Esri is used to classify wells as on federal land (Esri 2018). I use EIA data on state-level gross and marketed gas production to convert projected gross withdrawals to marketed production when solving for price equilibria (EIA 2024c). That completes the data necessary for the oil and gas modeling.

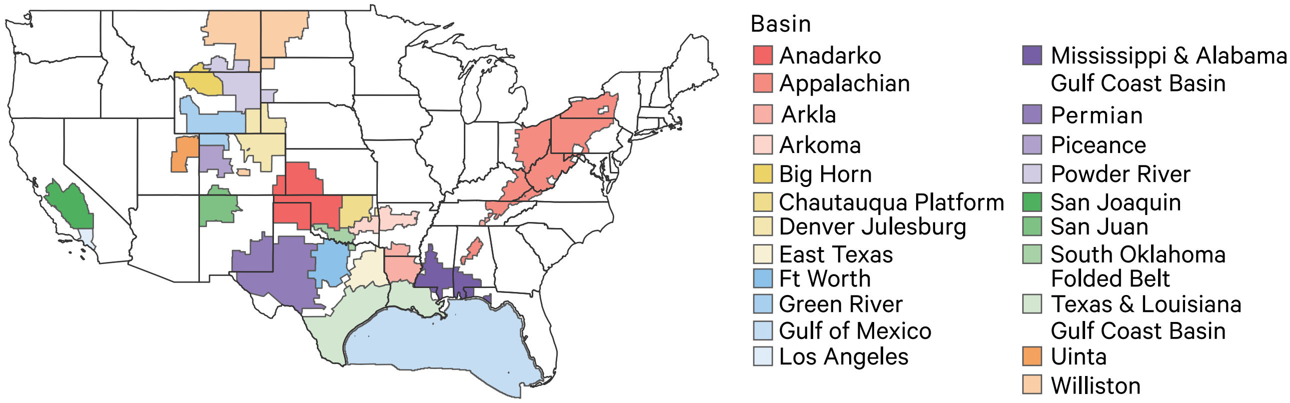
The remaining data input is basin-level methane leak estimates, which are based on Sherwin et al. (2024) and provided by MiQ in the form of the open-source MiQ-Highwood Index (MiQ 2024). The MiQ dataset is based on the empirical measurements for the six basins in the study by Sherwin et al. (Appalachia, Permian, Denver-Julesburg, Fort Worth, Uinta, and San Joaquin). For other gas-focused basins (defined as basins with total gas-oil ratios above 100 thousand standard cubic feet per barrel), MiQ extrapolates the Sherwin et al. study's weighted-average empirical methane measurements of gas systems, and the measurements for petroleum systems are analogously extrapolated to oil-focused basins.

4. Methods

Ultimately, DOGMA projects county-level oil and gas production as a function of trajectories of oil and gas prices. While the core components of DOGMA have been documented in past research (Newell et al. 2019; Newell and Prest 2019; Prest 2022; Prest et al. 2024b), this section provides a concise overview of the model with a focus on the extensions made in this paper. I categorize the dataset's approximately 1.2 million wells into 1,483 "well classes" that represent the permutation of US county and a federal/nonfederal land indicator. These well classes are nested under 24 basins (including one "Other" basin that aggregates 38 low-producing basins). Figure 1 shows a map of the key basins, and Appendix Figure A1 shows a map of the 1.2 million individual wells. I report results primarily at basin-level aggregates, but drilling and production are nonetheless modeled at the well class level. While DOGMA models drilling and oil and gas production separately for each well class, in many cases well classes have inherited basin-level parameter estimates such as drilling elasticities[2]. Sections 4.1–4.4 provide more detail on the model of each stage.

2 In principle, one could compute class-level estimates of certain parameters such as drilling elasticities or production curves, but this would introduce substantial noise in parameter estimates for classes with small numbers of wells in recent years.

Figure 1. Basin Map



Note: Alaska and Other basin categories are not shown for space and clarity.

For each well class, the oil and gas production process is divided into three stages: drilling wells, the time needed to complete them and begin production, and the trajectory of production from each well over time (the "decline curve"). Drilling is modeled using econometrically calibrated dynamic elasticities with respect to oil and gas prices, estimated using time-series distributed lag models separately for each basin. Past work has demonstrated that drilling investment is the key margin of price response for US oil and gas production (Newell et al. 2019; Newell and Prest 2019; Anderson et al. 2018). That literature has also found that the second and third stages are far less price responsive. Accordingly, I model the second stage—the time between the commencement of drilling and initial production—using their empirical distributions at the basin level. Similarly, I model the third stage—the decline curve of production from newly drilled wells—using empirical averages at the basin level, adjusted by an econometrically estimated relationship of initial production and drilling activity, which reflects diminishing resource quality as more wells are drilled.

4.1. Drilling

Historical time-series data have shown a clear relationship between drilling activity and oil and gas prices (Newell et al. 2019; Newell and Prest 2019; Prest 2022; Prest et al. 2024b), with a modest lag. Appendix Figure A2 shows these time series for each of the 24 basins in this paper. Accordingly, the number of wells drilled in basin *b* in month *t* modeled as follows:

$$\Delta \ln (w_{b,t}) = \sum_{\ell=0}^{12} [\eta_{b,\ell}^{oil} \Delta \ln (p_{t-\ell}^{oil}) + \eta_{b,\ell}^{gas} \Delta \ln (p_{t-\ell}^{gas})] + \lambda_{b,moy} + \varepsilon_{b,t} \tag{1}$$

where p_t^{oil} and p_t^{gas} reflect the real (CPI-adjusted) prices of West Texas Intermediate crude oil and Henry Hub natural gas, respectively.[3] As in the related literature (e.g., Prest 2022; Prest et al. 2024b), 12 months of lags are included to reflect the observed delay in the response of drilling decisions to price fluctuations. The model is estimated in first differences because of the failure to reject unit roots in oil and gas prices and in drilling activity for most (22 of 24) basins. The $\lambda_{b,moy}$ parameter is a month-of-year fixed effect to capture seasonality. The $\eta_{b,\ell}^{oil}$ and $\eta_{b,\ell}^{gas}$ parameters are the elasticities of drilling with respect to an ℓ-month lagged oil and gas price, respectively, and the long-run elasticities are $\overline{\eta_b^{oil}} = \sum_{\ell=0}^{12} \eta_{b,\ell}^{oil}$ and $\overline{\eta_b^{gas}} = \sum_{\ell=0}^{12} \eta_{b,\ell}^{gas}$, respectively. Equation (1) is estimated separately for each basin by ordinary least squares over the period February 1992 to July 2023 (378 monthly observations) using Newey-West standard errors.

Certain basins are pure gas plays and produce little to no oil. For example, in the Appalachian Basin, gas makes up 98% of oil and gas production on an energy basis. For the eight basins where gas makes up 90% or more of oil and gas production on an energy basis, I exclude the oil price from equation (1). Similarly, for the one basin where oil makes up more than 90% of production (the Los Angeles Basin), I exclude the gas price from equation (1).

For modeling future drilling, I apply the estimates of equation (1) to alternative International Energy Agency (IEA) scenarios for future oil and gas prices, focusing on the Stated Policies Scenario (STEPS), but in the appendix, I also show how the production projections vary under the Announced Pledges Scenario (APS) and Net Zero Emissions by 2050 Scenario (NZE), which feature lower oil and gas price trajectories. Appendix Figure A3 shows these price trajectories.

I begin with a baseline of current rates of drilling calculated separately by well class, denoted as $d_{j,0}$, as the average number of wells of that class drilled per month during the baseline period of 2022–2023. Then I modify this baseline into the future dynamically using the $\eta_{b,\ell}^{oil}$ and $\eta_{b,\ell}^{gas}$ elasticities over time for future pathways of p_t^{oil} and p_t^{gas} based on the IEA price scenario. For any given price trajectory, this yields a path of wells drilled each month *t* for each well class *j*, which I denote as $d_{j,t}$.

4.2. Well Completion

Wells need to be drilled and completed before they are ready to produce oil and gas, and this process can take several months from the commencement of drilling. For example, the average well in the Permian Basin takes four months from drilling to production. I model this time lag between drilling activity and initial production using the empirical distribution of wells that entered production since 2012, by basin. These distributions are shown in Appendix Figure A4. As in Prest (2022), when computing

3 While in principle one could consider modeling basin-specific gas prices, such as the Eastern Gas South pricing point for Appalachia, in practice regional price movements are highly correlated with those at Henry Hub (see, e.g., EIA 2021) and hence would likely yield comparable results but inject unnecessary complexity into the model.

these distributions I exclude wells with reported drill-to-production times exceeding 2 years onshore or 10 years offshore because investigations suggest these are likely data errors. Denoting the share of wells in basin *b* coming online ℓ-months after drilling commenced as $s_{b,\ell}$, and applying it to the path of wells drilled in each class *j* (in basin *b*) over time $d_{j,t}$ yields the number of wells entering production in each class and month, denoted as $w_{j,t}$, as follows:

$$w_{j,t} = \sum_{\ell=0}^{24} d_{j,t-\ell} s_{b,\ell}. \tag{2}$$

4.3. Production from Newly Drilled Wells

Next, I convert the trajectory of wells entering production for each newly drilled well in well class *j*, $w_{j,t}$, into their production of oil and gas over time, denoted as $Q_{j,t}^{oil,new}$ and $Q_{j,t}^{gas,new}$. This entails generating basin-level production profiles, or "decline curves," reflecting the pathways of oil and gas production from the typical well in each basin. This involves two steps. First, I compute the oil and gas decline curves for each basin by averaging the rates of oil and gas production across wells by the age of the well (in months) among all wells that entered production since 2012. This choice of a 2012 start year ensures enough history to compute at least 10 years' worth of decline curves. These decline curves are shown in Appendix Figure A5. However, because of the strong upward trend in initial production (IP) over the past decade or more, the inclusion of older wells in the calculation of the decline curves has the effect of understating the actual average IP of wells entering production today. Therefore, I rescale each basin's decline curves such that each curve's IP matches the corresponding average basin-level IP, denoted as $q_{b,0}^k$, among wells in each basin that entered production in the baseline years of 2022–23. The result is basin-level decline curves for each basin *b*, age τ, and product *k*, denoted as $q_{b,\tau}^k$. Total production from newly drilled wells ($w_{j,t}$) from well class *j* (which is nested in basin *b*) in month *t* of product $k \in oil, gas$ is then

$$Q_{j,t}^{k,new} = \sum_{\tau=0}^{T} w_{j,t-\tau} q_{b,\tau}^k. \tag{3}$$

Production from these new wells can also be summarized at the basin ($Q_{b,t}^{k,new}$) or national ($Q_t^{k,new}$) level by summing across the appropriate well classes.

I also endogenize the overall production per well, $q_{b,\tau}^k$, to drilling activity to reflect the high-grading mechanism previously identified in the literature (Newell and Prest 2019; Gilbert and Roberts 2020). This reflects the fact that when drilling increases, average IP falls as lower-quality reservoirs are increasingly exploited. To model this effect, I estimate the following equations for the IP of well *i*, denoted as $q_{i,0}^k$ for $k \in oil, gas$:

$$ln(q_{i,0}^k) = \alpha_b^k + \beta^k ln(w_{b,t_i}) + \theta^k t_i + \omega_{i,k} \tag{4}$$

where w_{b,t_i} is the number of wells entering production in basin *b* in month *t*, as in equation (1), and t_i is well *i*'s date of first production. α_b^k are basin IP fixed effects, and θ^k are time trends in IP. Standard errors are two-way clustered on well and month of sample. The object of interest is β^k, which is the elasticity of IP of product *k* (oil or gas) with respect to within-basin contemporaneous wells entering production. β^k is anticipated to be negative, as increased drilling activity reduces average IP. I use these elasticity values to adjust the baseline basin-level average IP values as a function of simulated wells entering production, which in turn depends on prices per equations (1) and (2).

This elasticity parameter has a meaningful impact on the overall elasticity of supply. Conceptually, the long-run elasticity of supply can be decomposed into the effects of price changes on wells entering production, $\overline{w}$, and the production per well, denoted as $\overline{q^k}$, where the bars indicate long-run cumulative values of wells entering production and per-well production.[4] Thus cumulative oil production can be written as $\overline{Q^{oil}} = \overline{w} \cdot \overline{q^{oil}}$. Given this notation, the long-run elasticity of supply for oil (and, by analogy, gas) can be written as follows:

$$\xi^{oil} = \frac{dln(\overline{w} \cdot \overline{q^{oil}})}{dn(p^{oil})} = \frac{dln(\overline{w})}{dln(p^{oil})} + \frac{dln(\overline{q^{oil}})}{dln(p^{oil})} = \overline{\eta^{oil}} + \beta^{oil} \cdot \overline{\eta^{oil}} = \overline{\eta^{oil}}(1 + \beta^{oil}). \tag{5}$$

The first term, $\frac{dln(\overline{w})}{dln(p^{oil})} = \overline{\eta^{oil}}$, follows from equation (1). The second term, $\frac{dln(\overline{q^{oil}})}{dln(p^{oil})} = \beta^{oil} \cdot \overline{\eta^{oil}}$, follows from the combination of equations (4) and (1). Intuitively, in the long run, a 1% increase in the price of oil increases the number of wells drilled by $\overline{\eta^{oil}}$%, but IP per well also changes by β^{oil} %. Presuming $\beta^{oil} < 0$, this mutes the supply response as $\overline{\eta^{oil}}$% more wells are drilled but each produces on average | β^{oil}%| less oil. While equation (5) illustrates how this high-grading effect mutes the supply response, it is nonetheless stylized because it pertains only to production from new wells and does not account for production from existing wells, which has been found in the literature to be effectively completely price inelastic (Newell et al. 2019; Newell and Prest 2019; Anderson et al. 2018). Thus equation (5) represents an upper bound on the overall supply elasticity.[5]

4.4. Production from Existing Wells

Sections 4.1–4.3 pertain to modeling production from newly drilled wells, but production is expected to continue from the approximately 600,000 wells reported as still producing in the data as of 2023–24. For the still-producing wells, I project their production forward to 2050 using Arps curves, a standard method from petroleum engineering. This entails fitting the following pair of nonlinear equations (for $k \in oil, gas$) for each well and projecting it forward:

$$Q^k_{i,t} = \frac{c^k_i}{1 + b^k_i a^k_i (WellAge_{i,t})^{1/b^k_i}} + \epsilon_{i,k,t}. \tag{6}$$

4 Subscripts are omitted in this paragraph and the next because here I am considering long-run, steady-state values.

5 In the long run, production from inelastic existing wells would converge to zero, in which case equation (4) is a reasonable approximation.

The Arps curve parameters, including the initial flow rate c_i^k, initial decline rate a_i^k, and curvature b_i^k, are all estimated by nonlinear least squares separately for each of the approximately 600,000 existing producing wells. In a small number of cases, the nonlinear estimation fails to converge or produces parameters implying implausible exponential growth, rather than decline. In those cases, I impose an exogenous 3% monthly exponential decline from the last observed value, approximately in line with average decline rates. Wells are implicitly plugged and abandoned when their projected production goes to effectively zero.

Total production from existing wells in well class *j* is simply the sum across wells:

$$Q_{j,t}^{k,ex} = \sum_{i \in j} Q_{i,t}^{k}. \tag{7}$$

Production from existing wells can also be summarized at the basin ($Q_{b,t}^{k,ex}$) or national ($Q_t^{k,ex}$) level by summing across well classes. Total oil or gas production simply sums production from new (equation 3) and existing (equation 7) wells, yielding total US production of product *k* in month *t*: $Q_t^k = \sum_j Q_{j,t}^{k,new} + \sum_j Q_{j,t}^{k,ex}$

Finally, two more adjustments must be made. First, as in Prest (2022), I find small discrepancies between total oil and gas production from wells in my dataset versus the national totals reported by EIA, likely because the Enverus data are not a 100% complete census. In particular, for 2022, EIA reports 3.0% more oil production and 3.8% more gas production (on a gross withdrawal basis) than the sum of production across wells in the dataset for that year. Therefore, I scale my total oil and gas production values up by factors of 1.030 and 1.038, respectively.

Second, the gas production in the data and hence all modeled gas production variables up to this point reflect gross withdrawals, not marketed production. While gross withdrawals are the appropriate metric for applying methane leak rates, marketed production is the appropriate metric when modeling market equilibria, discussed in the Section 4.5. Approximately 90% of US gross withdrawals make it to market, but this fraction varies substantially by state. In most states, well over 90% of gas withdrawals is marketed, but in Alaska, that figure is only 10%, with the rest largely being reinjected, in part because of limited pipeline capacity from the Arctic Slope. Therefore, I convert gross gas withdrawals to marketed production by applying the historical 2022 marketed-to-gross production ratios from EIA (2024c) on a state-by-state basis. This affects primarily Alaska (10% marketed), Wyoming (80%), Montana (93%), and Texas (93%).

4.5. Modeling Demand Shocks

Sections 4.1–4.4 detailed how DOGMA models the effect of given oil and gas price trajectories on production at the class and county levels. This produces a baseline pathway of production, discussed in the next section. Against this backdrop, I conduct four types of experiments to assess different notions of marginal supply:

1. Exogenously shift US gas prices up by 1% in all periods, 2023–2050.
2. Exogenously shift US oil prices up by 1% in all periods, 2023–2050.
3. Exogenously shift demand for US gas up by a fixed amount in all periods, 2023–2050.
4. Exogenously shift demand for US oil up by a fixed amount in all periods, 2023–2050.

As noted previously, the central price scenario uses IEA's STEPS trajectories of oil and gas prices, so running the first two experiments simply entails slightly modifying those prices and rerunning DOGMA. These experiments also allow for computing both own-price and cross-price supply elasticities, both time-varying and cumulative.

I conduct the third and fourth experiments multiple times, varying the magnitude of the demand shift. These experiments are more complicated than the first two because they require modeling equilibrium prices. Solving for that equilibrium requires shifting oil or gas demand by some amount (e.g., +1 Bcf/d) and then asking what new oil and gas prices are necessary to clear the market, meaning freeing up an extra net supply (i.e., quantity supplied minus demanded) equal to the specified amount (e.g., +1 Bcf/d). Put simply, the solver seeks the increase in gas prices that is necessary to meet the specified increase in gas demand, induced both from higher US gas quantity supplied (from DOGMA) and lower local US gas consumption. For example, a specified +1 Bcf/d shifted demand could be met in theory by moving up along the supply curve by 0.6 Bcf/d and down along the (now shifted) demand curve by 0.4 Bcf/d, with the relative contributions determined by the implicit slopes of the two curves.

Since this requires modeling not only US oil and gas supply but also demand, I take the US oil and gas demand trajectory from the STEPS scenario. I assume that gas demand each year passes through the STEPS' annual price-quantity pairs with an elasticity of −0.22, which is the simple mean of long-run gas demand elasticity estimates from four studies (Newell and Raimi 2014; Arora 2014; Hausman and Kellogg 2015; Rubin and Auffhammer 2024). The approach for oil demand is analogous with a long-run oil demand elasticity of −0.33, which is the 21-study average from the survey in Prest et al. (2024a).

While the impetus of this paper is to consider the potential for relaxing gas export constraints from permitting additional LNG terminals, I do not model LNG export constraints explicitly, opting instead to model exogenous increases in export demand. So much capacity has already been approved by DOE that there is significant uncertainty about whether additional export approvals today in fact relax any binding constraint. Further, there is additional uncertainty over whether any export constraint is binding due to uncertainty in future US gas demand. For example, if US supply were to rise to 150 Bcf/d at some point in the future, then the approximately 50 Bcf/d of already approved export capacity represents a binding constraint if and only if US demand at that time is below 100 Bcf/d. A final uncertainty is the magnitude of international demand for US LNG, which remains uncertain because of uncertainty in global gas demand amid global decarbonization commitments and other competing LNG suppliers like Qatar. For instance, modeling by DOE and EIA found that in many scenarios considered, the LNG export capacity already approved amounts to more capacity than they project is needed (DOE 2024; EIA 2023).

4.6. Incorporating Methane Leak Estimates

The previous sections complete the description of the oil and gas production modeling, which produces basin-level production projections. I couple this with basin-level estimates of methane leak rates based on Sherwin et al. (2024), provided in the form of the open-source MiQ-Highwood Index (MiQ 2024). Those estimates are already provided at the basin level, but the mapping to the basins in DOGMA is not perfect and requires a few modifications. First, there are two DOGMA basins that each map onto three distinct subbasins in the MiQ data: Appalachia and Fort Worth. For the Appalachian Basin in DOGMA, I take the gas production weighted average leak rate from the three relevant subbasins in MiQ: Appalachian Basin – Pennsylvania (0.75% leak rate, 44% of Appalachian production), Appalachian Basin (Utica) (4.62% leak rate, 3% of Appalachian production), and Appalachian Basin – Other (0.97% leak rate, 53% of Appalachian production). This yields a weighted average Appalachian leak rate of 0.98%. I conduct a similar exercise for the Fort Worth Basin, yielding a 3.1% weighted average leak rate. Finally, there are five basins in the Enverus data that are not in the MiQ data: the offshore Gulf of Mexico (<2% of marginal gas supply), Arctic Slope (also <2%), Los Angeles Basin (<0.01%), Big Horn (<0.01%), and my Other basin category (0.4%). For these, I use the national average methane leak rate from the MiQ data of 2.7%, although this has little effect on the key results because those five basins collectively represent less than 4% of marginal gross gas supply.

Finally, it is important to emphasize that all leak rates reported in this paper correspond to the “unallocated” leak rates in the MiQ data, meaning the percentages represent methane emissions as a percentage of total gas production. This is in line with the values reported in Sherwin et al. (2024). However, an alternative approach would be to use only the portion of the leak rates “allocated” to the gas production, with the remaining emissions attributed to oil production on some basis (e.g., on energy share). I do not allocate leak rate estimates for several reasons. First, emissions allocation is essentially a joint cost allocation problem, and any such cost allocation method (whether on an energy basis or some other basis) ultimately contains some degree of arbitrariness (Lanen et al. 2019). Second, I am seeking to model “consequential” emissions rates—that is, the change in methane emissions caused by given exogenous shocks, and the total emissions caused by such a shock will not depend on whether one decides to assign partial responsibility to one product versus another.

To see why, consider a thought experiment where an exogenous shift in export demand causes 100 units of additional gas production, and 3% of it is emitted to the atmosphere. The effect on methane emissions is clearly +3 units of methane. It does not matter for this conclusion whether the increased gas demand also caused 50 units of additional oil production and we were to allocate the 3 units in proportion to their supply shares (i.e., as 2 units to gas and 1 unit to the oil).[6] In that scenario, a complete accounting of methane emissions would require tracking the contributions of each product, which in either case depends on the full amount emitted, which here is 3 units. Focusing on the gas-allocated share, by contrast, would ignore the share of true emissions attributed to oil.

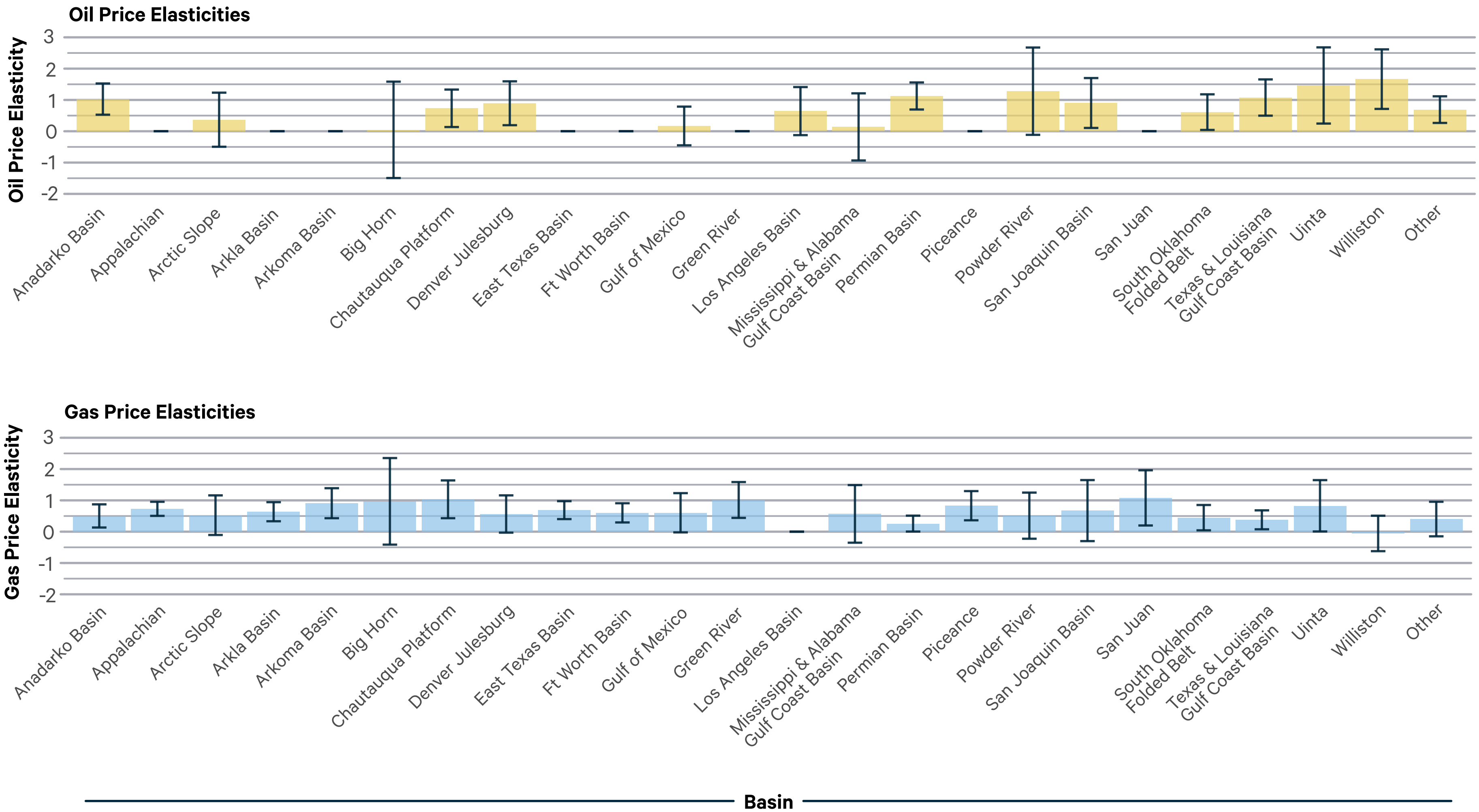
5. Results

5.1. Drilling Elasticities

Figure 2 shows the estimates of the long-run basin-level drilling elasticities from equation (1). The oil-price elasticities $\overline{\eta_b^{oil}}$ are shown in the top panel, and the gas-price elasticities $\overline{\eta_b^{gas}}$ are in the bottom panel. In addition, the point estimates are accompanied by +/– 1.65 standard errors, consistent with a one-sided 95% confidence test. The estimates are broadly in line with expectations. All but one point estimate is positive, reflecting drilling activity increasing when oil and gas prices rise. The only slightly negative point estimate is small and insignificant (a point estimate of –0.06 with standard error [SE] of 0.34) and corresponds to the gas price elasticity in the oil-centric Williston Basin, where the responsiveness to gas prices is expected to be minimal. The Permian Basin's oil price elasticity is substantial and statistically significant at 1.1 (SE = 0.26), and its gas price elasticity is a modest and insignificant 0.26 (SE = 0.15).

6 In fact, in that scenario, the combustion of that additional induced oil would lead to further overall emissions that would need to be accounted for in any comprehensive analysis of the emissions implications of the increased gas demand.

Figure 2. Long-Run Drilling Elasticities with Respect to West Texas Intermediate Oil Prices (top panel) and Henry Hub Gas Prices (bottom)



Note: Error bars represent +/– 1.65 standard errors, consistent with a one-sided 95% confidence test. For basins with less than 10% of supply from oil (gas), the oil (gas) price is excluded from the regression and shown as zero.

Appalachia features a significant gas price elasticity of 0.73 (SE = 0.14). As noted in Section 4.1 , Appalachia is one of the eight basins with very little oil production where oil prices are excluded from equation (1), and hence the oil price elasticity of zero shown in Figure 2 is a consequence of that assumption. Including the oil price in the regression for Appalachia yields a small negative and insignificant long-run oil price elasticity of –0.11 (SE = 0.32) and slightly increases the gas price elasticity to 0.84 (SE = 0.18), confirming the lack of an oil price response in that basin.[7]

These elasticity estimates are mostly in a similar range to those found in Prest (2022), where they can be most easily compared. For example, the onshore oil drilling elasticity estimate with respect to oil prices was 1.24 in Prest (2022), which is similar to this paper's estimate for the Permian Basin (1.13). Similarly, the onshore gas drilling elasticity with respect to gas prices was 0.63 in Prest (2022), which is similar to this paper's estimates of 0.73 and 0.64 for the top two gas-producing basins, Appalachian and Arkla Basins, respectively (where Arkla includes much of the Haynesville Shale). The biggest differences in the elasticities between Prest (2022) and this paper correspond to offshore drilling, which were estimated with the least precision in that study. The improved granularity of offshore basins and additional time series data in this paper suggest the offshore estimates included here represent an improvement on those from Prest (2022).

5.2. Elasticities of Initial Productivity

The estimated initial productivity elasticities, β^{oil} and β^{gas} from equation (4), are shown in Table 1. The results imply elasticities of IP with respect to basin-level drilling activity of approximately –0.3 for oil IP and –0.4 for gas IP, as shown in columns (1) and (2) respectively, both of which are significant at the 1% level. These suggest that for a 10% increase in local drilling, we would expect an average 3% reduction in oil IP and 4% reduction in gas IP.

7 While this result might suggest simply retaining the oil price even in gas plays, including the oil price leads to implausible results in a few other gas plays. In San Juan Basin, including the oil price yields an implausibly large oil price elasticity estimate of 1.90 (SE = 1.02)—larger than in any other basin although San Juan is primarily a gas play (92% gas)—while dramatically changing the gas price elasticity from 1.08 (SE = 0.53) to 0.40 (SE = 0.74). This pattern of statistics suggests that some idiosyncrasy in the San Juan drilling time series is combining with the collinearity of oil and gas prices to load on the a priori "wrong" variable, which is why I drop the oil prices for those basins. However, the results for Appalachia suggest that including it would reinforce the key finding of this paper.

Table 1. Initial Productivity Elasticities with Respect to Drilling

	Dependent variable	
	Log oil IP ($ln(q_{i,0}^{oil})$)	Log gas IP ($ln(q_{i,0}^{gas})$)
Variable	(1)	(2)
Log wells drilled ($ln(w_{b,t_i})$)	−0.282***	−0.414***
	(0.067)	(0.115)
First production date (t_i)	0.0002***	0.0002***
	(0.00005)	(0.00003)
Observations	601,619	820,110
R^2	0.368	0.327

Note: *** $p < 0.01$

5.3. Production Pathways

Figure 3 shows the time paths of basin-level production of oil (top row) and marketed gas (bottom row). The three columns represent production from existing wells ($Q_{b,t}^{k,ex}$), new wells ($Q_{b,t}^{k,new}$), and total wells (their sum, $Q_{b,t}^{k}$). The Permian Basin (in purple) dominates oil supply in the recent past and in the future, followed by the Gulf of Mexico (light blue), Williston (orange), Texas & Louisiana Gulf Coast (light green), and Arctic Slope (light red), which together account for 88% of US oil production in 2050. By contrast, Appalachia (red) dominates gas supply in the recent past and future, followed by an increasing role for the Permian (purple) over time, supported by contributions from Texas & Louisiana Gulf Coast (light green), Arkla (pink; includes the Haynesville Shale), and Anadarko (dark red at top). Those five basins contribute 79% of gas production in 2050. Appendix Figures A7 and A8 show production pathways under lower APS and NZE oil and gas price scenarios, which feature roughly flat production and production declines, respectively.

Figure 3. Projected US Oil and Marketed Gas Production from Existing Wells, New Wells, and Combined, under the STEPS Price Scenario

Notes: The five basins contributing the most to oil supply in 2050 are, in order, the Permian (purple), Gulf of Mexico (light blue), Williston (orange at the bottom), Texas & Louisiana Gulf Coast (light green), and Arctic Slope (light red), which collectively account for 88% of oil production that year. The five basins contributing the most to gas supply in 2050 are Appalachia (red), Permian (purple), Texas & Louisiana Gulf Coast (light green), Arkla (pink), and Anadarko (dark red at the top), which collectively account for 79% of gas production that year.

Since I use the IEA's STEPS price scenarios, a comparison with the US oil and gas production projections in STEPS may be of interest. IEA does not present a distinct US crude oil production time series, making an apples-to-apples comparison difficult. However, it does report US tight oil projections (a subset of total US crude oil) in STEPS rising from 7.5 million barrels per day (MMbbl/d) in 2022 to about 9.5 MMbbl/d in 2030, before peaking and declining to 8.5 MMbbl/d in 2050 (see IEA 2023, 132). IEA also reports US gas supply growing by 90 billion cubic meters/year (about 9 Bcf/d) through 2030 before peaking and declining by 400 bcm (about 40 Bcf/d) through 2050 (see IEA 2023, 138), driven by declining projected US gas demand. In both cases, STEPS envisions peak oil and gas production around 2030, likely driven by its assumptions around global decarbonization efforts. By contrast, my model projects that under STEPS oil and gas prices, US production is likely to continue to rise through the modeling window.

5.4. US Total Oil and Gas Supply Elasticities

As shown in equation (5) in the methods section, the long-run own-price elasticity of supply for product *k* can be approximated as $\overline{\eta^k}\,(1+\beta^k)$. While Figure 1 shows basin-specific drilling elasticity values, $\overline{\eta_b^k}$, Table 2 shows effective cumulative and long-run US-wide oil and gas supply elasticities, both own-price and cross-price. The cumulative (i.e., 2023–50 average) own-price elasticities are 0.61 for oil and 0.24 for gas, which are computed by calculating the total response of total oil or gas production over 2023–50 in response to an assumed permanent 1% increase in crude oil or Henry Hub gas prices. In a sensitivity analysis, I turn off the high-grading effect by not applying the IP elasticities from Table 1. This increases the cumulative supply elasticities to 0.87 and 0.40, accordingly, so only the drilling response, and not declining IP, contributes to the supply change. These results closely align with the formula's approximation: $0.87\,(1-0.28)\approx 0.61$ for oil and $0.40\,(1-0.41)\approx 0.24$ for gas. The cross-price elasticities are small, at 0.19 (oil to gas prices) and 0.26 (gas to oil prices). Perhaps surprisingly, gas supply's cross-price elasticity is similar in size (0.26) to its own-price elasticity (0.24), a result driven in large part by substantial gas production from the Permian, where drilling is relatively inelastic to gas prices (0.26) but highly elastic to oil prices (1.1), as seen in Figure 2.

More generally, the small own-price elasticity of gas supply of 0.24 can be decomposed into three effects. First, a substantial portion of US gas supply is relatively inelastically supplied by the Permian Basin, where oil prices are the main driver. This results in a US-wide gas-production-weighted average drilling elasticity with respect to gas prices

Table 2. Cumulative (2023–50) and Long-Run Own-Price and Cross-Price Supply Elasticities

	Price	
	West Texas Intermediate crude oil price	Henry Hub gas price
Product	(p^{oil})	(p^{gas})
Oil supply (Q^{oil})	0.61	0.19
	(0.68)	(0.22)
Gas supply (Q^{gas})	0.26	0.24
	(0.30)	(0.28)

Note: Cumulative values shown normally, and long-run (2050) values shown in parentheses. Gas supply values correspond to marketed gas supply, but elasticities for gross withdrawals are very similar.

of approximately 0.5, which happens to be halfway between the drilling elasticities with respect to gas prices for the Permian of 0.26 and the Appalachian of 0.73. Second, applying the 40% discount from the gas IP elasticity of −0.4 (per equation 5) yields a gas supply elasticity from new wells of approximately 0.3. Third, including the perfectly inelastic supply from existing wells dilutes the elasticity value further, yielding the 0.24 final value.

Table 2 also shows long-run elasticities, defined as the price response in December 2050 induced by the same permanent 1% increase in price oil or gas prices (during the full 2023–50 window). These long-run elasticities are modestly larger (10%–17%) than the cumulative ones, reflecting the lagged nature of the supply response. More detail on the full time paths of elasticities, both with and without the high-grading effect, can be seen in Appendix Figure A6.

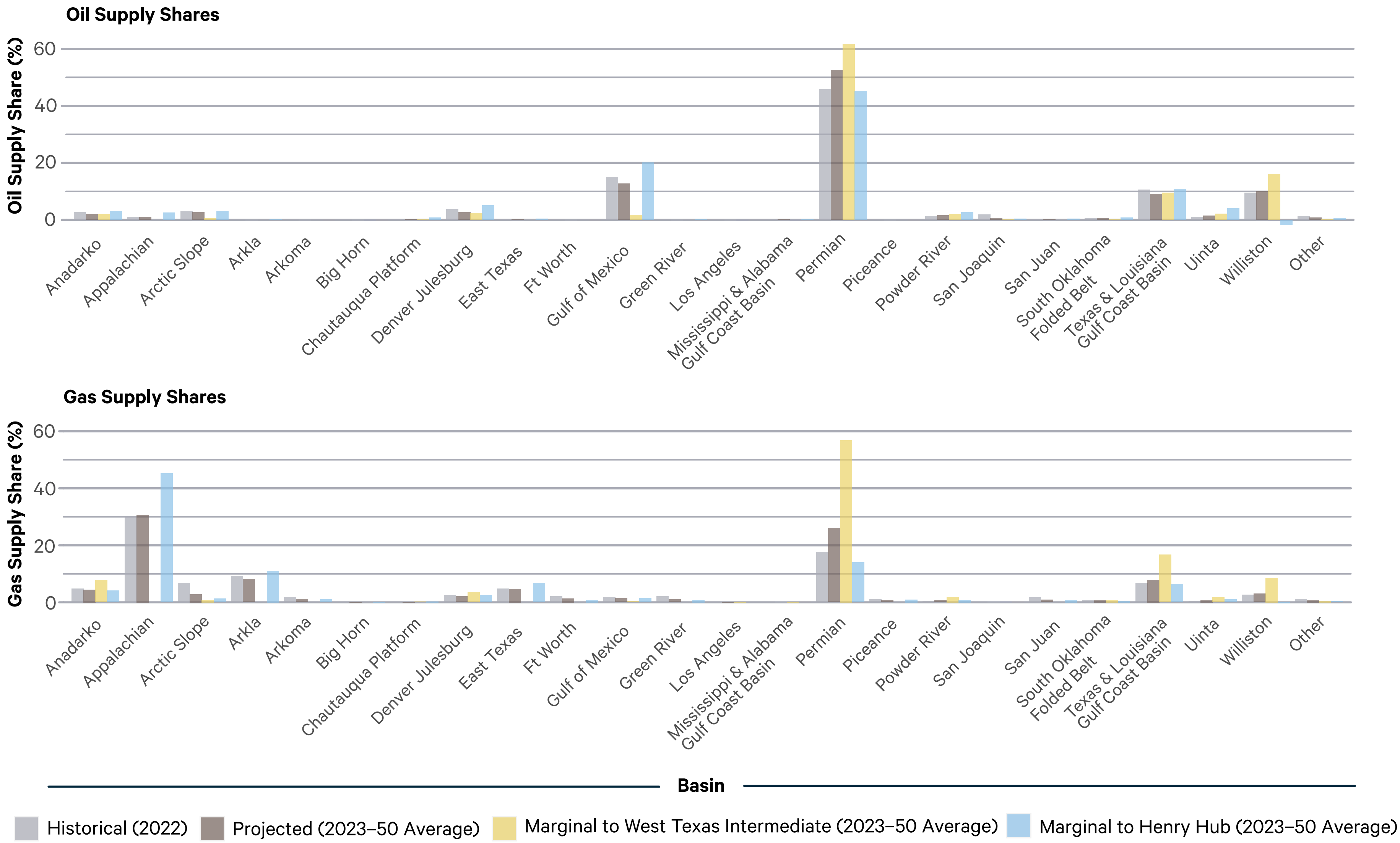
5.5. Effects of Exogenous Price Shocks

Figure 4 shows each basin's contribution to US oil (top) and gross gas (gas) supply in four notions of that concept.[8] The first two bars are average supply shares, historically (for 2022, in grey) and simulated future (2023–50 average, in brown). The other two bars are each basin's share of marginal supply in response to an exogenous 1% increase in WTI oil prices (yellow) or Henry Hub gas prices (blue).

Comparing the first pair of bars, representing averages, with the others reveals which basins punch above or below their weight. Considering the oil supply shares in the top panel, most notable is the Permian Basin, which accounted for 46% of US oil supply in 2022 and 53% of future supply (2023–50 average) but 62% of marginal oil supply in response to an increase in oil prices. This outsize marginal response owes to its above-average drilling elasticity with respect to oil prices (1.1). This effect is even more pronounced in the bottom panel, which shows gas supply shares. The Permian Basin contributed 18% of total US gas supply in 2022 and is anticipated to contribute 26% in the future, but it nonetheless provides 57% of marginal gas supply brought online by an exogenous increase in oil prices. By contrast, the Permian's relatively modest drilling elasticity with respect to gas prices (0.26) means it contributes disproportionately less to gas supply in response to gas prices (14% marginal versus 18% historical and 26% future). A similar pattern can be seen for the Texas & Louisiana Gulf Coast and Williston Basins.

8 All subsequent figures and tables show gas supply shares as a share of gross gas withdrawals, not marketed production, because that is the relevant metric to which to apply the methane leak rate estimates based on Sherwin et al. (2024). However, market equilibrium is always computed using marketed production.

Figure 4. Oil and Gas Supply Shares by Basin: Historical, Projected, and Marginal in Response to Exogenous WTI and Henry Hub Price Shocks



Gas-focused basins like Appalachia, Arkla, and East Texas (the last two encompass the Haynesville Shale) exhibit the reverse pattern, contributing disproportionately to marginal supply in response to gas prices. Appalachia dominates here, contributing 30% of gas supply in 2022, 31% in the future, but 45% in response to gas prices. This effect is driven by Appalachia's relatively large drilling elasticity with respect to gas prices of 0.73. As a gas play, Appalachia's drilling elasticity with respect to oil prices is assumed to be zero, as discussed in Section 4. However, including oil prices in its drilling equation would serve only to reinforce the findings shown here because doing so modestly increases Appalachia's gas price elasticity from 0.73 (SE = 0.14) to 0.80 (SE = 0.35); while also yielding a negative, albeit insignificant, estimate for the oil price elasticity (–0.11, SE = 0.32).

The only anomalous result seen in Figure 4 is that the Gulf of Mexico is found to respond more to gas prices than to oil prices, driven by its small oil price elasticity but nontrivial gas price elasticity (see Figure 2). This could reflect the fact that for much of the sample period underlying the estimation of the drilling elasticities (1992–2023), the Gulf of Mexico was primarily a gas play, even though today it is more oil focused.

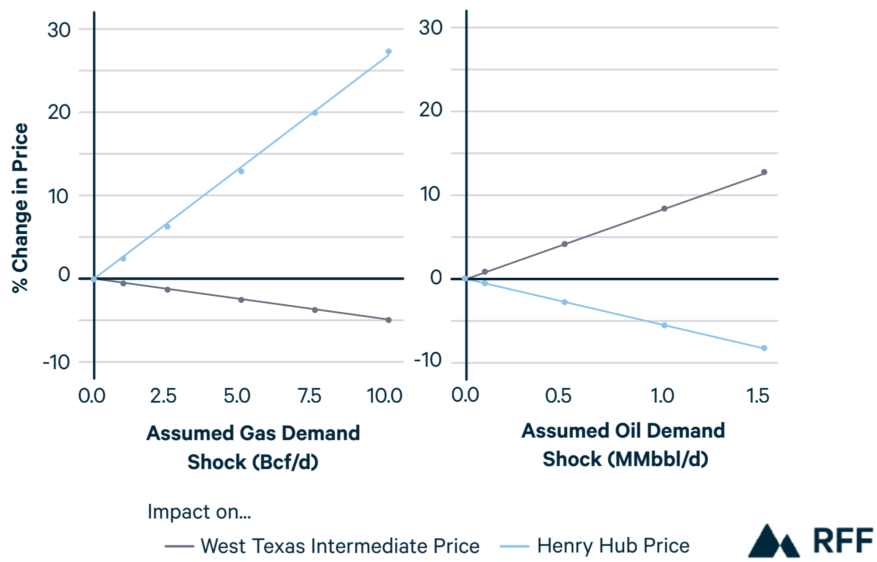
5.6. Effects of Exogenous Demand Shocks

Regarding the demand shock results, Figure 5 shows the price impacts from gas and oil demand shocks of a variety of magnitudes. I show results for gas demand shocks of 1, 2.5, 5, 7.5, and 10 Bcf/d (left panel) and for oil demand shocks of 0.1, 0.5, 1, and 1.5 MMbbl/d (right panel). These loosely range between 1% and 10% of US production levels of each product. The gas demand shocks increase Henry Hub prices by approximately 2.5% for each Bcf/d of demand shock, while the coproduced oil pushes oil prices down by about 0.5% per Bcf/d. The effect is approximately linear, hitting +27% for Henry Hub and –4.9% for WTI under the 10 Bcf/d shock.

The results under the oil demand shock mirror those of the gas demand shocks. For each 100,000 bbl/d in oil demand shocks, oil prices increase by about 0.8%, while gas prices decline by about 0.6%. That the effects for oil are smaller than for gas is likely due to the larger overall estimated oil price elasticities of drilling (and hence oil and gas supply) with respect to oil prices versus gas prices (see Figure 2). This yields a flatter supply curve and hence less price response. The larger assumed elasticity of oil demand (–0.33) relative to gas demand (–0.23) further reinforces this effect.

Figure 5 reveals an important distinction between a pure increase in gas prices and an increase in gas demand: cross-price effects. Increased gas demand stimulates oil coproduction, which puts downward pressure on oil prices. This thereby reduces drilling in basins with strong oil price responses like the Permian Basin. These cross-price effects mute the overall gas supply response from oil plays like the Permian, relative to what would be induced by a pure increase in gas prices. Similarly, increased oil demand stimulates gas coproduction, which puts downward pressure on drilling in gas plays and hence on their gas supply response.

Figure 5. Impacts of Exogenous Gas and Oil Demand Shocks on West Texas Intermediate and Henry Hub Prices



Note: The pairs of points along the x-axis each represent a single model run with an exogenous, permanent assumed shift in export demand in every period 2023–50, which must be met by some combination of higher cumulative US quantity supplied and lower quantity demanded. Demand is price responsive with elasticities of −0.33 for oil demand and −0.23 for gas demand. Best-fit lines are constructed using ordinary least squares, constrained to go through the point at the origin.

This effect can be seen in Table 3, where columns (1–2) show each basin's drilling elasticities, (3) shows methane leak rates based on Sherwin et al. (2024), and (4–9) show gas supply shares under all six notions of that concept: (4) average historical; (5) average future; and marginal with respect to (6) Henry Hub prices, (7) gas demand, (8) WTI prices, and (9) oil demand. For space, Table 3 shows only the 11 largest gas-producing basins, although the weighted average leak rates are computed using all 24 basins.[9] Appendix Table A1 shows the results for all 24 basins, and Appendix Table A2 shows the results for the share of oil supply contributed under each scenario.

9 All gas supply share figures in Table 3 are expressed in terms of share of gross gas withdrawals, not marketed production, as gross withdrawals are the relevant variable for applying leak rates. This affects primarily the interpretation of the Arctic Slope row, which amounts to 1.3% of marginal gross withdrawals but only about 0.14% of marketed supply because in Alaska, about 90% of gross gas withdrawals are reinjected.

Table 3. Basin-Level Drilling Elasticities, Methane Leak Rates, and Gas Supply Shares

Basin	Drilling elasticity with respect to ...			Gross gas supply share (%): Average		Gross gas supply share (%): Marginal in response to ...			
	Henry Hub prices	West Texas Interme-diate prices	Methane leak rate (%)	Historical (2022)	Projected (2023–50)	+1% Henry Hub price	+1 Bcf/d gas demand	+1% WTI price	+100k bbl/d oil demand
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Appalachian	0.73	—	1.0%	30%	31%	45%	58%	0%	–78%
Permian	0.26	1.13	5.3%	18%	26%	14%	2%	57%	131%
Arkla	0.64	—	1.0%	9%	8%	11%	14%	0%	–19%
Texas & Louisiana Gulf Coast	0.38	1.08	4.6%	7%	8%	6%	3%	17%	35%
Arctic Slope	0.53	0.37	2.7%	7%	3%	1%	1%	1%	0%
Anadarko	0.50	1.03	4.6%	5%	4%	4%	3%	8%	14%
East Texas	0.69	—	4.6%	5%	5%	7%	9%	0%	–12%
Williston	–0.06	1.66	4.6%	3%	3%	0%	–3%	9%	24%
Denver Julesburg	0.56	0.89	1.1%	3%	2%	2%	2%	4%	6%
Green River	1.01	—	4.6%	2%	1%	1%	1%	0%	–1%
Fort Worth	0.60	—	3.1%	2%	1%	1%	1%	0%	–1%
Weighted-average methane leak rate in column (3), using columns (4–9) as weights				**2.8%**	**3.1%**	**2.4%**	**1.7%**	**4.9%**	**9.1%**

Note: Basins are sorted in order of column (4), the 2022 gas supply share. Because of space constraints, only the 11 largest gas-producing basins are shown here, but the weighted average leak rates are computed using all 24 basins. The 11 basins shown here made up 90% of US gas supply (and 77% of oil supply) in 2022 and more than 90% of projected average and marginal gas supply. A version of this table including all 24 basins is included in the appendix. All shares correspond to shares of gross withdrawals, not marketed gas. This distinction is important primarily for the Arctic Slope, where only 10% of gross withdrawals make it to market, with most being reinjected.

Appalachia contributes 58% of gas supply in response to gas demand, more than the 45% it would contribute in response to a pure increase in gas prices. Meanwhile, the Permian Basin contributes only 2% of marginal gas supply in response to gas demand, despite contributing 14% in response to a pure increase in gas prices.

This has important implications because the Permian Basin has among the highest estimated methane leak rates (5.3%) and Appalachia has the lowest (1.0%), suggesting that the marginal supply rising to meet export demand is likely to come disproportionately from low-leak Appalachia, not the Permian as is commonly assumed (Howarth 2024; DOE 2024). The bottom row of Table 3, in columns (4–9), shows the supply share–weighted average leak rate using each supply share concept. While the production-weighted average leak rate is 2.8%–3.1%, the more appropriate marginal weighted averages are lower, at 2.4% for a +1% gas price increase and 1.7% for a +1 Bcf/d gas demand increase. This 1.7% value would be the appropriate value to use when modeling the upstream/midstream methane intensity of LNG exports, and it is 40% smaller than the value of 2.8% used by Howarth (2024).

On the other hand, Table 3 also suggests that gas supply induced by oil demand is likely to come disproportionately from the high-leak Permian Basin. In fact, the downward pressure on gas prices induced by increased oil demand causes both increases in coproduced Permian gas and decreases in Appalachian production, such that the Permian Basin contributes more than 100% of incremental gas supply induced by oil demand (see column [9]). In other words, in response to an increase in oil demand, Permian gas crowds out Appalachian gas. This modeled result is consistent with recent observed trends in play-level gas production, where high oil prices have spurred associated gas development in the Permian, while gas production from gas plays have stagnated or declined (see EIA 2024d). The consequence of this crowding-out effect is that the weighted average leak rate of the incremental gas supply is a very high 9.1%. In fact, this crowding-out effect causes the effective weighted-average leak rate to exceed that of any individual basin.[10]

This high leak rate driven by oil export demand suggests that the repeal of the 2015 crude oil export ban may have had underappreciated implications that rival those expected to be driven by LNG exports. In particular, each 1 MMbbl/d of oil export demand induces 1.1 Bcf/d of coproduced gas in my model; at a 9% marginal leak rate, that implies 0.1 Bcf/d of leaked gas, or about 0.64 million metric tons of methane,

10 A simplified thought experiment demonstrates how this can happen. Suppose there are only two sources of gas supply, A and B, where A has a 1% leak rate and B has a 5% leak rate. Suppose that because of the oil demand increase, B ramps up gas production by 2 and A ramps it down by 1, yielding 1 unit of net increased gas production. Given the assumed leak rates, the total amount of methane leaked has increased by +2*5% – 1*1% = 0.10 – 0.01 = 0.09. This +0.09 unit increase is on a 1-unit net increase in gas production, implying an effective leak rate of 9%, closely similar to the actual result. While the actual calculation is more nuanced, this example captures the basic idea. The result is also similar in spirit to the result from the locational marginal emissions literature, where a marginal increase in electricity demand can reshuffle generation from moderately emitting gas plants to high-emitting coal plants, resulting in extremely high marginal emissions rates.

assuming a 90% methane content. By comparison, each 1 Bcf/d of gas export demand induces 0.6 Bcf of gas supply,[11] which at a 1.7% leak rate implies about 0.01 Bcf/d of leaked gas, or about 0.07 million metric tons of methane. Thus the implied US methane emissions caused by each 1 MMbbl/d of oil export demand is nearly 10 times that caused by 1 Bcf/d of gas demand. As a back-of-the-envelope calculation, US crude oil exports have risen by about 2–4 MMbbl/d,[12] implying that oil exports to date may have driven 1.3–2.6 million tons of methane emissions annually, equivalent to what would be caused by 20–40 Bcf/d of gas exports. For context, US export capacity as of 2024Q4 is 14 Bcf/d, with a total of more than 40 Bcf/d approved to date by DOE.

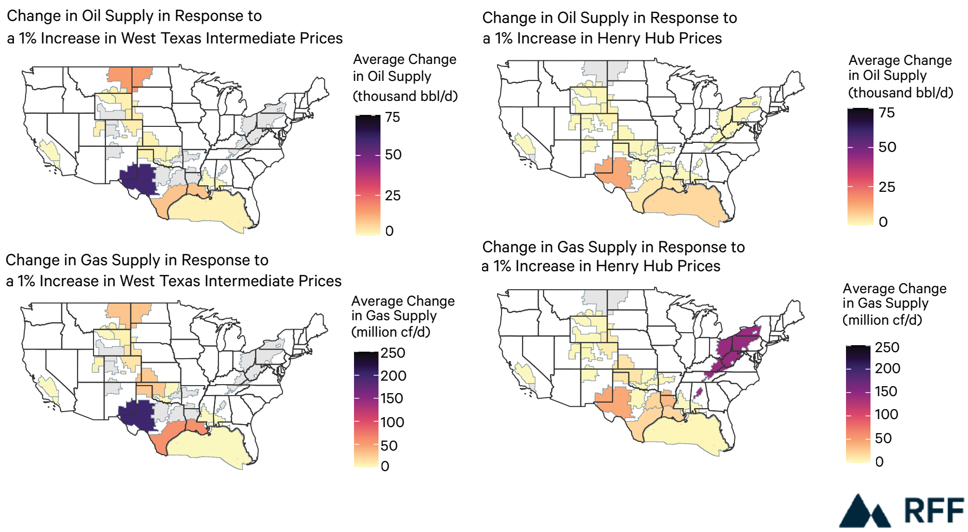
As another point of comparison, the United States exported a total of 18 trillion cubic feet (Tcf) of LNG from 2015 to 2023. The cumulative methane emissions associated with that amount of gas production would be 5.8 million metric tons of methane at a leak rate of 1.7%, assuming 90% methane share. By contrast, during the same period, the United States exported 7.7 billion barrels of crude oil, which my model suggests induced 8.1 Tcf of gas production with the far higher leak rate of 9.1%, implying 13.5 million metric tons of methane, more than twice the 5.8 million figure associated with historical US LNG exports.

Figure 6 shows maps of the marginal supply responses of oil (top row) and gas (bottom row) in response to exogenous +1% increases in WTI prices (left column) and Henry Hub prices (right column). Figure 7 shows the analogous maps for the shocks to oil demand (left column) and gas demand (right column). Setting aside the relative magnitudes, the major difference between these maps is that the supply responses in Figure 6 is (almost) universally positive, whereas those in Figure 7 are positive or negative depending on the relative importance of oil versus gas prices in driving production outcomes across basins. County-level analogues of these maps can be seen in Appendix Figures A9 and A10.

11 The remaining 0.4 Bcf/d of export needs is met by lower domestic gas consumption.

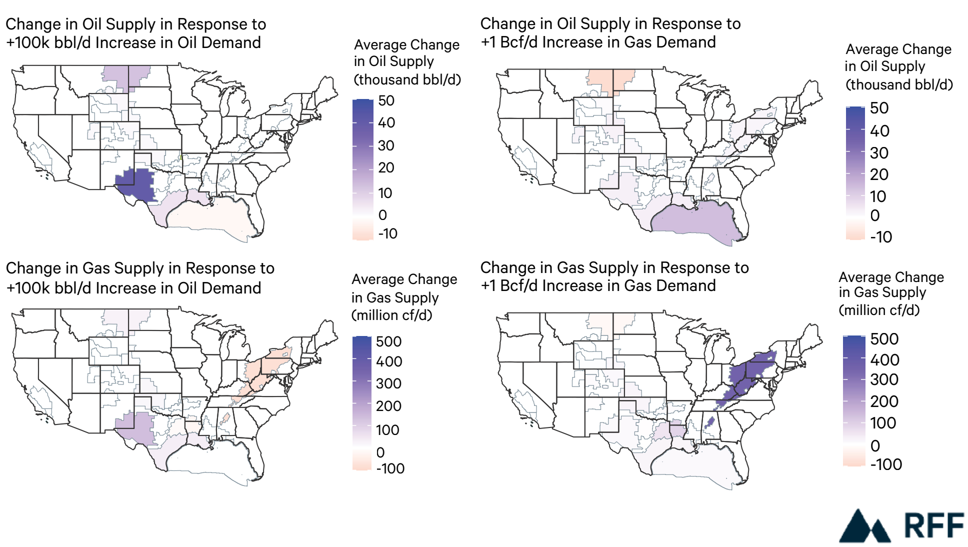
12 Crude oil exports in 2023 were 4 MMbbl/d higher than in 2014 and 2 MMbbl/d higher on average over 2015–23 (see EIA 2023b).

Figure 6. Marginal Supply Responses to WTI and Henry Hub Prices, by Basin



Note: Values are average basin-level supply responses in 2023–50. Basins with no positive marginal supply are shown in gray.

Figure 7. Marginal Supply Responses to Oil and Gas Demand Shocks, by Basin



Note: Values are average basin-level supply responses in 2023–50.

6. Comparison of Results with Those of Other LNG Studies

My results have two key takeaways for the likely impacts of increased LNG exports. First, each +1 Bcf/d of increased demand pull is estimated to increase gas prices by about 2.5%. Second, the incremental gas supply is estimated to come disproportionately (58%) from Appalachia, with very little (2%) coming from the Permian Basin, implying a lower-than-average marginal methane intensity (1.7% versus 3.1%). How do these results compare with the findings of other recent analyses of LNG exports?

First, my estimated gas price impact of about +2.5% per Bcf/d of gas exports is substantially larger than those found in three recent studies. For context, approximately 11 Bcf/d of new US LNG export capacity is under construction as of 2024Q4.[13] EIA (2023a), DOE (2024), and Yergin et al. (2024; based on S&P Global's analysis) estimate price impacts of about +1.4%, +1.0%, and +0.75% per Bcf/d of exports, respectively. While the methods of Yergin et al. are somewhat of a black box, I can use the results of the EIA and DOE studies to compute the implied elasticities of US gas supply and demand. In both cases, the demand elasticities are close to zero (less than −0.1 in magnitude), while the supply elasticities are approximately 0.7 and 1 respectively, both of which appear to be based on the EIA's National Energy Modeling System (NEMS). These elasticities are substantially larger than the gas supply elasticity of less than 0.3 that I estimate, which explains why my estimated price impacts are larger.

Second, the 1.7% weighted average methane leak rate from marginal supply is halfway between the value of 0.56% used by DOE (2024) and the 2.8% value used in Howarth (2024). While Howarth's value is meant to represent methane leak rates in the Permian Basin, my results suggest very little (2%) of marginal gas supply in response to LNG export demand is likely to come from the Permian. The DOE's value, by contrast, is likely too low because it is based on US Environmental Protection Agency inventories that are well known to undercount methane emissions (see, e.g., Alvarez et al. 2018). However, an important caveat is that substantial uncertainty remains about whether observed methane leak rates will improve or persist into the future.

Finally, the very high effective methane intensity of marginal gas supply in response to an increase in oil demand suggests that the 2015 repeal of the crude oil export ban may have had larger, but less appreciated, consequences for driving US methane emissions than those from the arguably higher-profile LNG export pause. Specifically, model results suggest that historical crude oil exports during 2015–23 may have caused more than twice as much methane emissions as US LNG exports over that period, with the former's methane impacts equivalent to those expected to be caused by 20 Bcf/d of gas export demand, which is approximately the amount of future export capacity under consideration.

13 If I model an exogenous 11 Bcf/d increase in gas export demand, I find a 30% increase in gas prices, confirming the roughly linear nature of the price effect.

7. Conclusions

This paper expands the Dynamic Oil and Gas Market Analysis (DOGMA) model to estimate the impacts of increased US oil and gas export demand on domestic oil and gas prices, marginal oil and gas supply by US basin, and the implied weighted-average methane intensity of marginal gas supply. Each exogenous 1 Bcf/d increase in gas export demand is estimated to increase domestic natural gas prices by approximately 2.5%, while reducing crude oil prices by 0.5% as a result of the induced supply of coproduced oil. The US supply response comes disproportionately from basins with low estimated leak rates, led by Appalachia, yielding a weighted-average methane intensity of the gas supply expected to meet export demand (1.7%) that is lower than average gas supply (3.1%). The supply response to an exogenous oil demand increase shows the reverse pattern, with high-leak Permian supply crowding out low-leak basins like Appalachia, yielding a very high weighted-average methane leak rate (9.1%). These results have implications for the debate over expanding LNG exports, suggesting that the 2015 repeal of the crude oil export ban may have had larger consequences for the US methane emissions than LNG exports, driving more than twice as much methane emissions than US LNG exports during 2015 to 2023, with the former equivalent to those expected to be caused by more than 20 Bcf/d of gas exports.

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Appendix

Figure A.1. Well Map

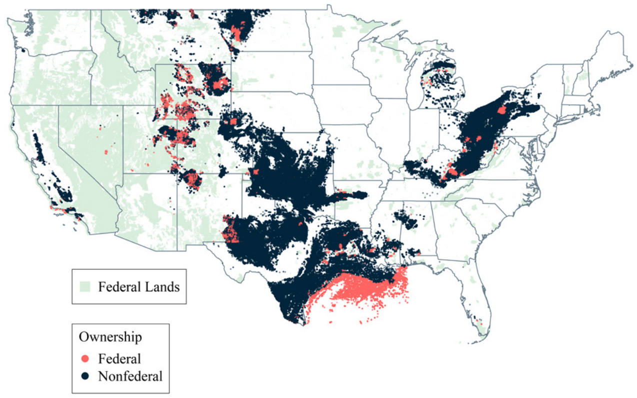
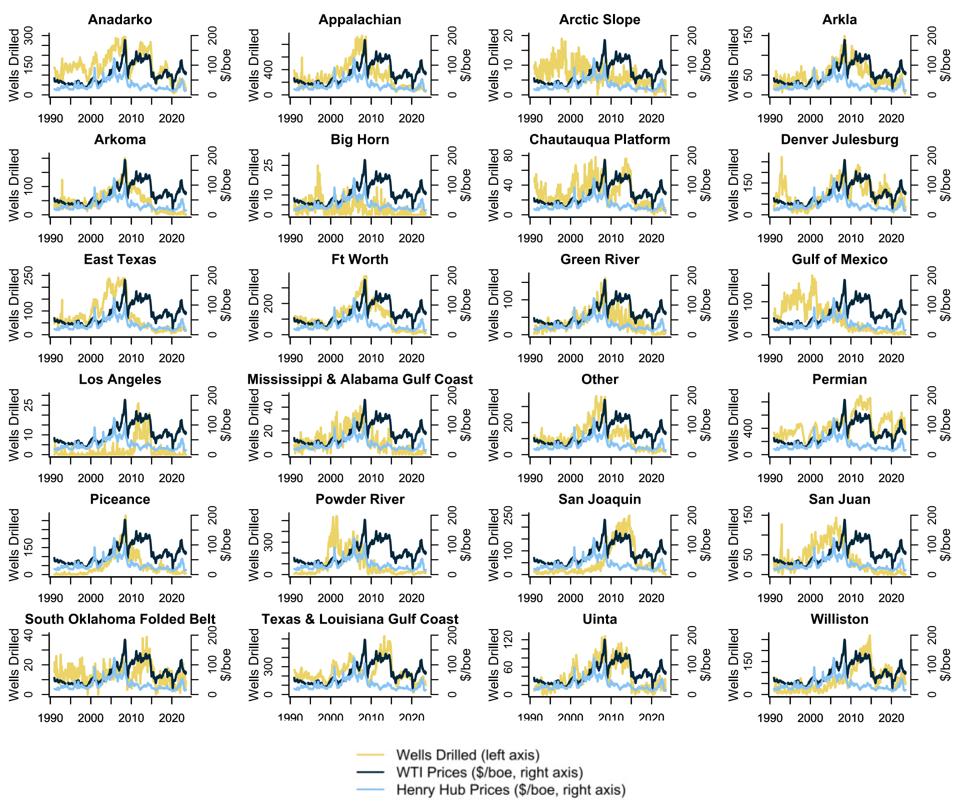
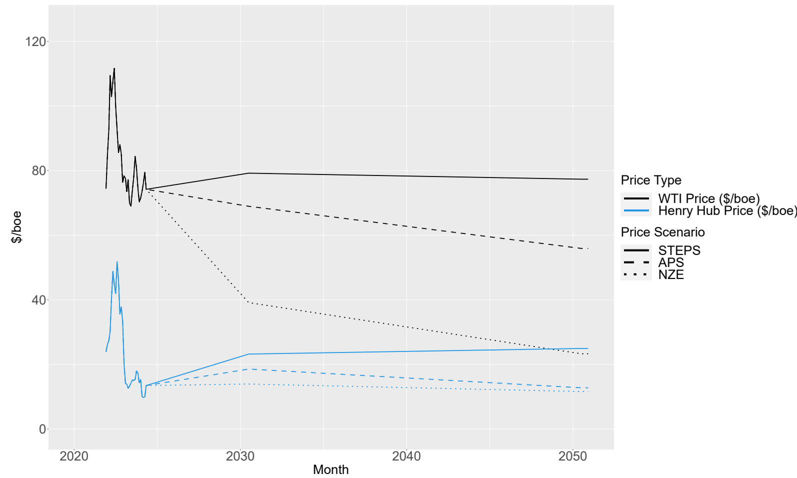


Figure A.2. Drilling Activity, by Basin, Versus West Texas Intermediate (WTI) Crude and Henry Hub Gas Prices



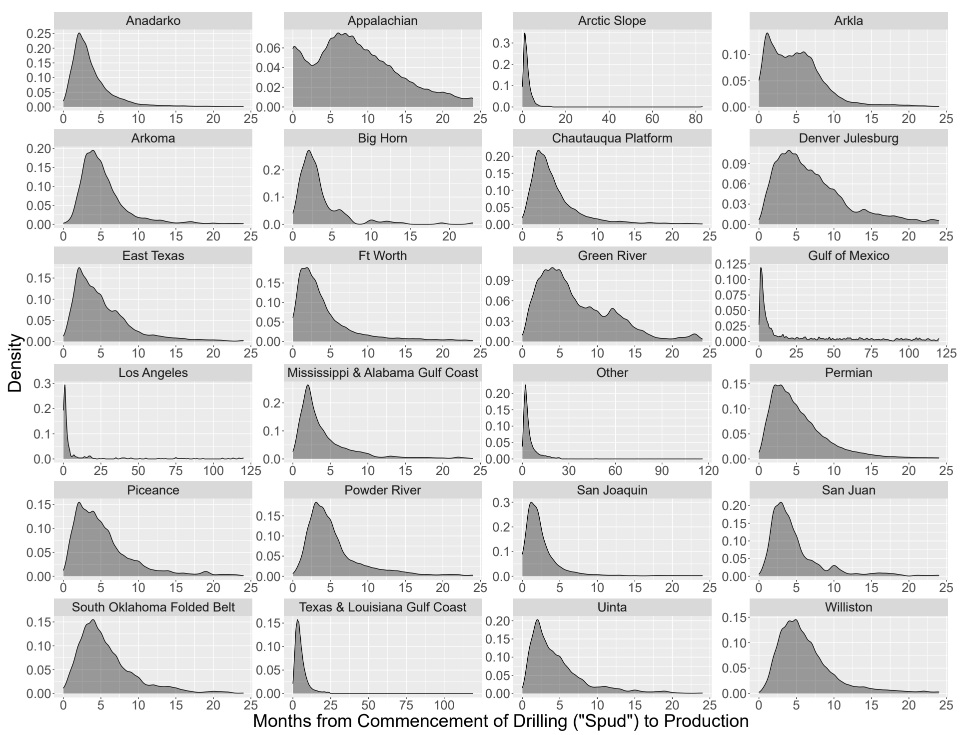
Note: WTI and Henry Hub prices are the same in each panel. Henry Hub prices are converted into barrels of oil equivalent (boe) by multiplying by 5.8 MMBtu/boe.

Figure A.3. Future Price Paths



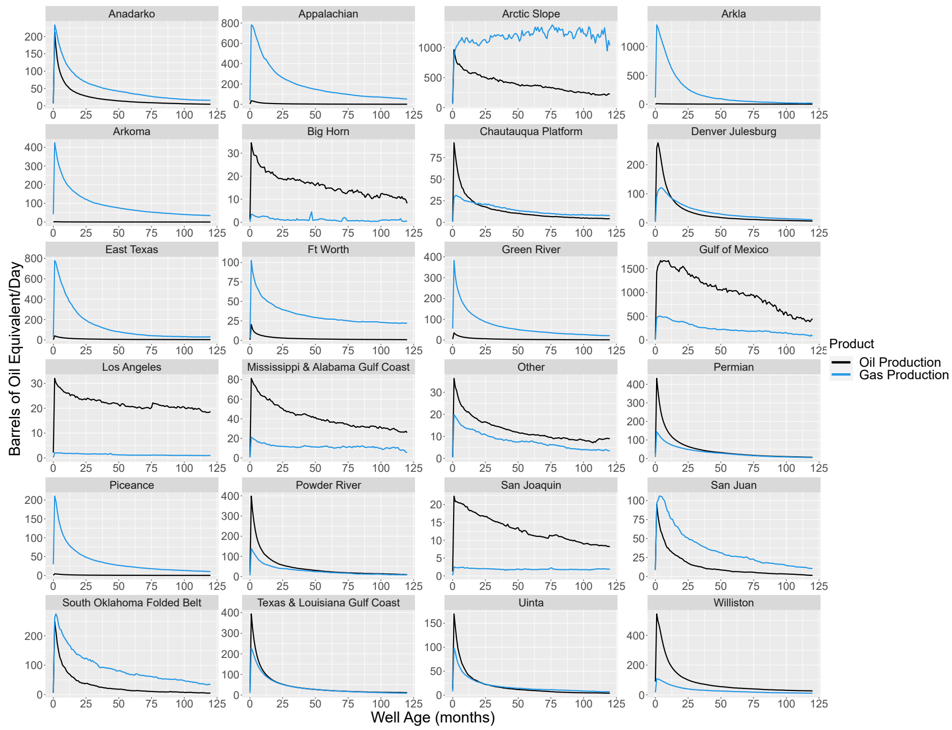
Note: Henry Hub prices are converted into barrels of oil equivalent (boe) by multiplying by 5.8 MMBtu/boe. STEPS = Stated Policies Scenario; APS = Announced Pledges Scenario; NZE = Net Zero Emissions by 2050.

Figure A.4. Densities of Time from Spud to Production, by Basin



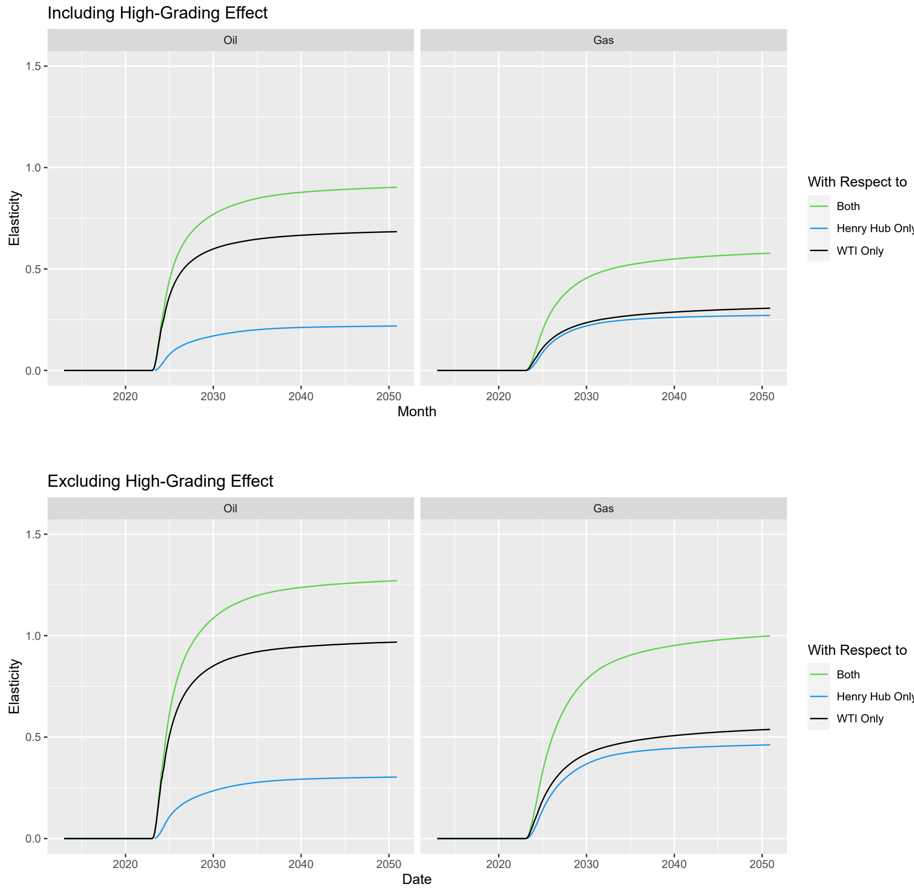
Note: Density bandwidth used is 0.5 months. The x-axis extends to 2 years for onshore-only basins but 10 years for basins with offshore drilling activity (e.g., the Gulf of Mexico, Los Angeles, and Texas & Louisiana Gulf Coast basins). Dataset includes wells entering production since 2012 with spud-to-production times not deemed data errors (≤24 months onshore and ≤120 months offshore).

Figure A.5. Production Profiles, by Basin



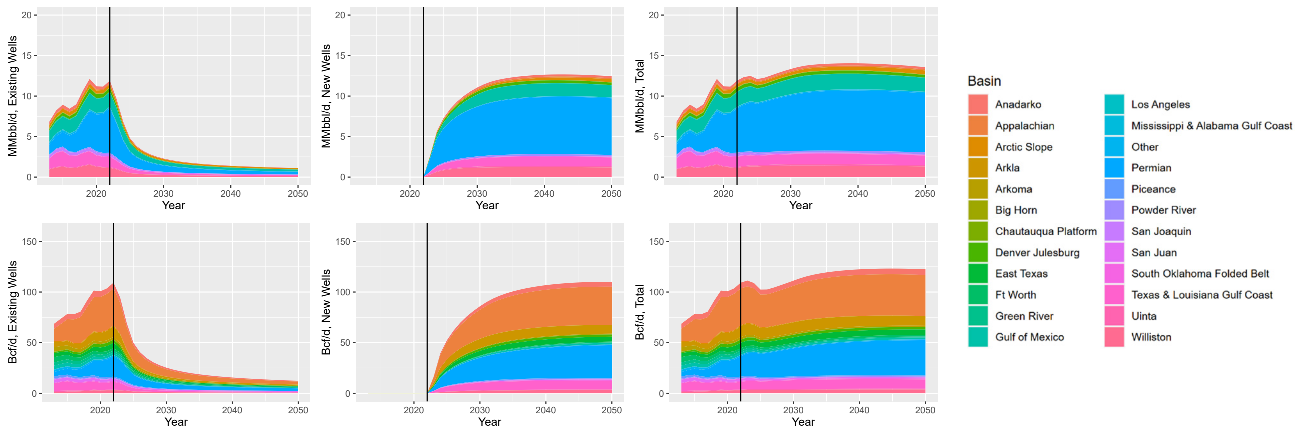
Note: Figures represent within-basin average production rates by month among wells beginning production in 2012–24. Profiles represent gross withdrawals, not marketed production; the distinction between the two is most important in Alaska (Arctic Slope), where only about 10% of gross gas withdrawals are sent to market, as much is reinjected. Gas production is converted to barrels of oil equivalent (boe) by dividing production in thousand cubic feet (mcf) by 6 mcf/boe.

Figure A.6. Time-Varying Response of US Oil and Gas Production to an Exogenous, Permanent 1% Increase in Oil or Gas Prices in 2023, Expressed in Elasticity Terms



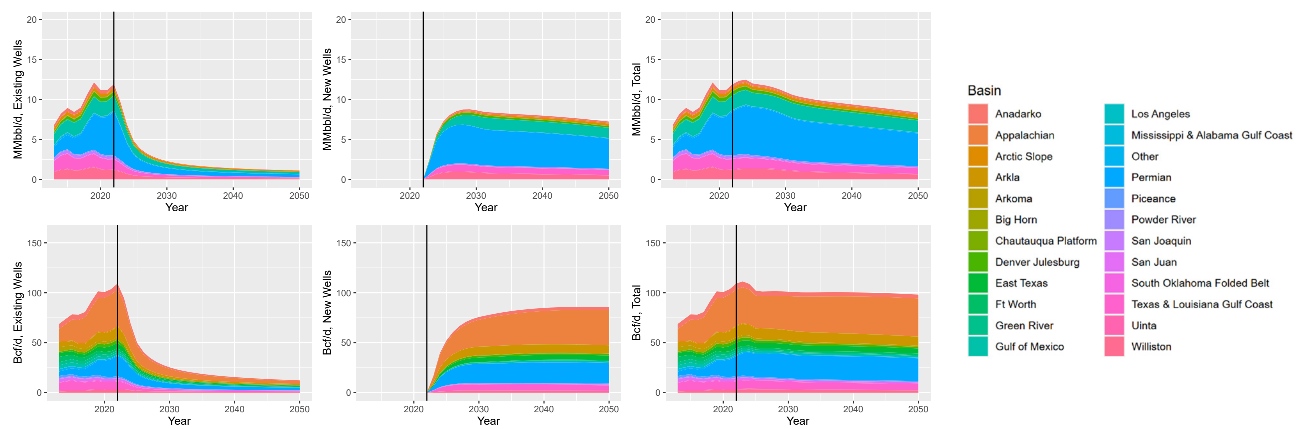
Note: The top panel includes response of initial production to increased drilling ("high-grading"); the bottom panel excludes that effect. WTI = West Texas Intermediate.

Figure A.7. Projected US Oil and Marketed Gas Production from Existing Wells, New Wells, and Combined, Under the APS Price Scenario



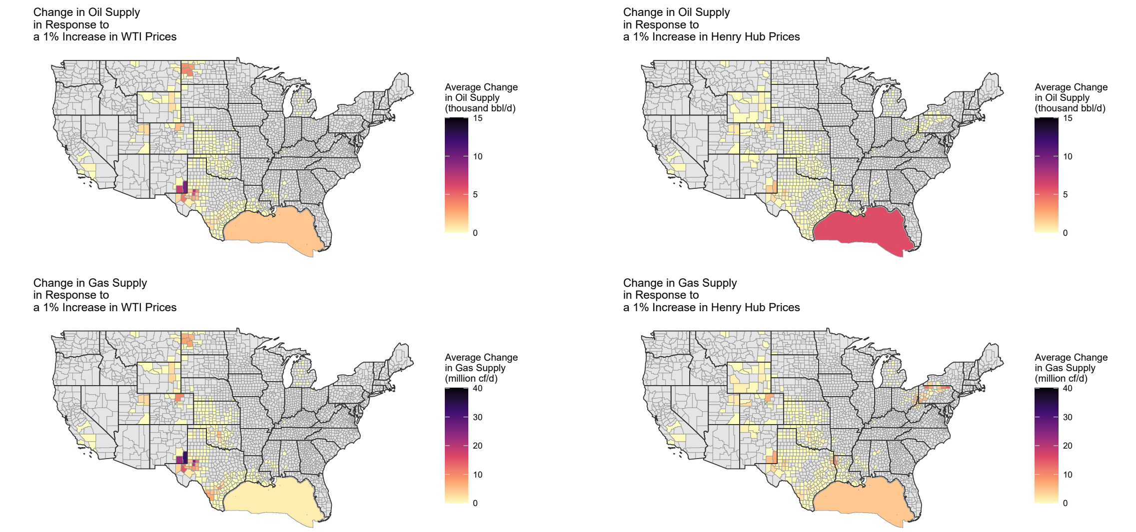
Note: The five basins contributing the most to oil supply in 2050 are, in order, the Permian (blue), Gulf of Mexico (teal), Williston (coral at bottom), Texas & Louisiana Gulf Coast (pink/fuchsia), and Arctic Slope (orange), which collectively account for 88% of oil production that year. The five basins contributing the most to gas supply in 2050 are Appalachia (orange), Permian (blue), Texas & Louisiana Gulf Coast (pink/fuchsia), Arkla (beige), and Anadarko (coral at top), which collectively account for 79% of gas production that year.

Figure A.8. Projected US Oil and Marketed Gas Production from Existing Wells, New Wells, and Combined, Under the NZE Price Scenario



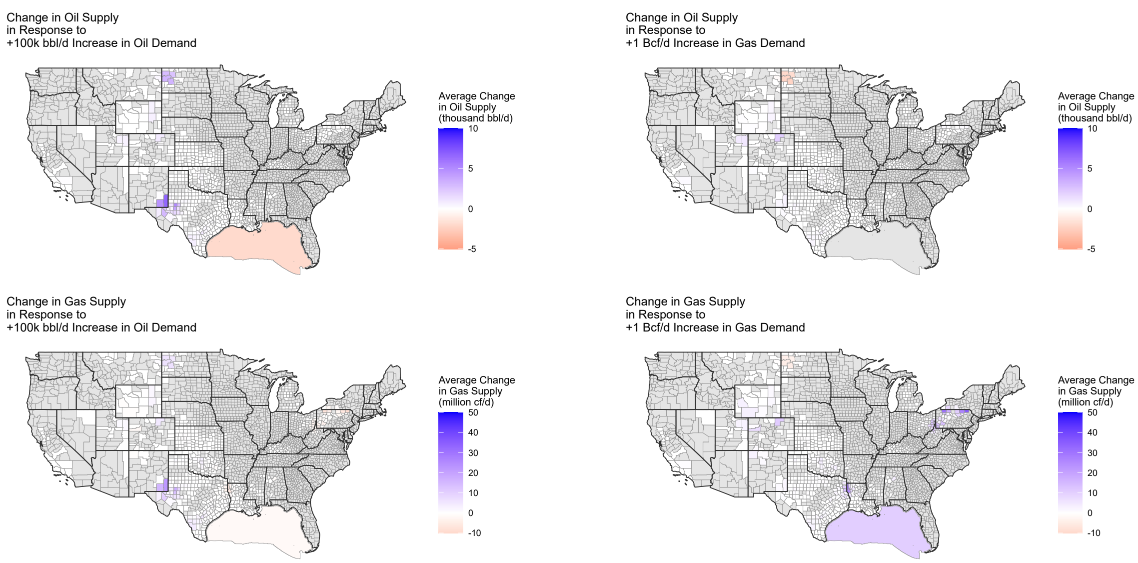
Note: The five basins contributing the most to oil supply in 2050 are, in order, the Permian (blue), Gulf of Mexico (teal), Williston (coral at bottom), Texas & Louisiana Gulf Coast (pink/fuchsia), and Arctic Slope (orange), which collectively account for 87% of oil production that year. The five basins contributing the most to gas supply in 2050 are Appalachia (orange), Permian (blue), Arkla (beige), Texas & Louisiana Gulf Coast (pink/fuchsia), and East Texas Basin (green), which collectively account for 80% of gas production that year.

Figure A.9. Marginal Supply Responses to WTI and Henry Hub Prices, by County



Note: Values are average supply responses in 2023–50. Counties with no positive marginal supply are shown in gray.

Figure A.10. Supply Responses to Oil and Gas Demand Shocks, by County



Note: Values are average supply responses in 2023–50. Counties with zero marginal supply are shown in gray.

Table A.1. Basin-Level Elasticities, Methane Leak Rates, and Gas Supply Shares

	Drilling elasticity with respect to ...			Gross gas supply share (%)					
				Average		Marginal in response to ...			
Basin	Henry Hub prices	West Texas Interme-diate prices	Methane leak rate (%)	Historical (2022)	Projected (2023–50)	+1% Henry Hub price	+1 Bcf/d gas demand	+1% WTI price	+100k bbl/d oil demand
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Appalachian	0.73	—	1.0%	30%	31%	45%	58%	0%	–78%
Permian	0.26	1.13	5.3%	18%	26%	14%	2%	57%	131%
Arkla	0.64	—	1.0%	9%	8%	11%	14%	0%	–19%
TX & LA Gulf Coast	0.38	1.08	4.6%	7%	8%	6%	3%	17%	35%
Arctic Slope	0.53	0.37	2.7%	7%	3%	1%	1%	1%	0%
Anadarko	0.50	1.03	4.6%	5%	4%	4%	3%	8%	14%
East Texas	0.69	—	4.6%	5%	5%	7%	9%	0%	–12%
Williston	–0.06	1.66	4.6%	3%	3%	0%	–3%	9%	24%
Denver Julesburg	0.56	0.89	1.1%	3%	2%	2%	2%	4%	6%
Green River	1.01	—	4.6%	2%	1%	1%	1%	0%	–1%
Fort Worth	0.60	—	3.1%	2%	1%	1%	1%	0%	–1%
Arkoma	0.91	—	1.0%	2%	1%	1%	1%	0%	–2%

Gulf of Mexico	0.60	0.17	2.7%	2%	1%	1%	2%	0%	–1%
San Juan	1.08	—	1.0%	2%	1%	1%	1%	0%	–1%
Other	0.40	0.69	2.7%	1%	1%	0%	0%	1%	1%
Piceance	0.83	—	1.0%	1%	1%	1%	1%	0%	–2%
South Oklahoma Folded Belt	0.45	0.61	4.6%	1%	1%	1%	1%	1%	1%
Uinta	0.83	1.46	5.7%	1%	1%	1%	1%	2%	3%
Powder River	0.51	1.28	4.6%	1%	1%	1%	1%	2%	4%
San Joaquin	0.67	0.90	2.5%	0%	0%	0%	0%	0%	0%
Chautauqua Platform	1.03	0.73	4.6%	0%	0%	0%	0%	0%	0%
MS & AL Gulf Coast	0.57	0.14	4.6%	0%	0%	0%	0%	0%	0%
Big Horn	0.97	0.05	2.7%	0%	0%	0%	0%	0%	0%
Los Angeles	—	0.64	2.7%	0%	0%	0%	0%	0%	0%
Weighted-average methane leak rate in column 3, using columns 4–9 as weights				**2.8%**	**3.1%**	**2.4%**	**1.7%**	**4.9%**	**9.1%**

Note: Basins are sorted in order of column 4, the 2022 gas supply share. Supply share columns 4–9 sum to 100%. Shares represent shares of gross withdrawals, not marketed gas. This distinction is important primarily for the Arctic Slope, where only 10% of gross withdrawals make it to market, with most being reinjected.

Table A.2. Basin-Level Elasticities, Methane Leak Rates, and Oil Supply Shares

Basin	Drilling elasticity with respect to ...			Oil supply share (%)					
				Average		Marginal in response to ...			
	Henry Hub prices	West Texas Interme-diate prices	Methane leak rate (%)	Historical (2022)	Projected (2023–50)	+1% Henry Hub price	+1 Bcf/d gas demand	+1% WTI price	+100k bbl/d oil demand
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Permian	0.26	1.13	5.3%	46%	53%	45%	12%	62%	66%
Gulf of Mexico	0.60	0.17	2.7%	15%	13%	20%	57%	2%	−3%
TX & LA Gulf Coast	0.38	1.08	4.6%	11%	9%	11%	13%	10%	9%
Williston	−0.06	1.66	4.6%	10%	10%	−2%	−37%	16%	21%
Denver Julesburg	0.56	0.89	1.1%	4%	3%	5%	10%	3%	2%
Arctic Slope	0.53	0.37	2.7%	3%	3%	3%	8%	1%	0%
Anadarko	0.50	1.03	4.6%	3%	2%	3%	5%	2%	2%
San Joaquin	0.67	0.90	2.5%	2%	1%	0%	1%	0%	0%
Powder River	0.51	1.28	4.6%	1%	2%	3%	4%	2%	2%
Other	0.40	0.69	2.7%	1%	1%	1%	1%	0%	0%
Appalachian	0.73	—	1.0%	1%	1%	3%	8%	0%	−1%
Uinta	0.83	1.46	5.7%	1%	1%	4%	8%	2%	2%

South Oklahoma Folded Belt	0.45	0.61	4.6%	1%	1%	1%	2%	0%	0%
MS & AL Gulf Coast	0.57	0.14	4.6%	0%	0%	0%	1%	0%	0%
Chautauqua Platform	1.03	0.73	4.6%	0%	0%	1%	2%	0%	0%
East Texas	0.69	—	4.6%	0%	0%	0%	1%	0%	0%
Los Angeles	—	0.64	2.7%	0%	0%	0%	0%	0%	0%
San Juan	1.08	—	1.0%	0%	0%	0%	1%	0%	0%
Big Horn	0.97	0.05	2.7%	0%	0%	0%	0%	0%	0%
Green River	1.01	—	4.6%	0%	0%	0%	1%	0%	0%
Arkla	0.64	—	1.0%	0%	0%	0%	1%	0%	0%
Fort Worth	0.60	—	3.1%	0%	0%	0%	0%	0%	0%
Piceance	0.83	—	1.0%	0%	0%	0%	0%	0%	0%
Arkoma	0.91	—	1.0%	0%	0%	0%	0%	0%	0%

Note: Basins are sorted in order of column 4, the 2022 oil supply share. Supply share columns sum to 100%. Columns are in the same order as in Table 3 in the main text and Appendix Table A1 for comparison.