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Production Impacts of Proposed EPA Methane Rule

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I. Summary

Here we conduct an analysis that estimates the impact of select requirements of EPA's proposed methane rule (OOOOb and OOOOc) on oil and gas production. We evaluate certain proposed rule requirements that could have the largest impact on operational costs, estimate the number of wells that could be shut-in in response to those requirements if finalized as proposed, and estimate the fraction of oil and gas production that could be precluded by a stringent application of the proposed associated gas flaring requirement. We evaluate future production out to 2027, where it is assumed that OOOOc would be implemented nationally, for a scenario of production and prices based on the Energy Information Administration (EIA) Annual Energy Outlook (AEO) reference and high oil price cases. Currently, oil and gas prices and production are midway between these scenarios, so while they offer appropriate bounding boxes on impacts to production in the future, we developed a Middle Case that offers a more realistic view of possible impacts to production upon implementation of OOOOb in the near-term.

We estimate that up to 6% oil production in the Permian Basin and Williston Basins may be precluded from production due to possible limitations on associated gas flaring and takeaway/processing capacity constraints in those basins in the Middle Case scenario. These impacts assume a stringent interpretation of the proposed rule restricting routine associated gas flaring. Neither the Permian or Williston (Bakken) has adequate forecasted takeaway and processing capacity to accommodate the potential limitation on associated gas flaring from new wells under the high oil price scenario. Implementation of OOOOb at the time the rule is finalized will immediately impact all new and modified wells, which are most likely to flare associated gas due to the absence of adequate gathering capacity at the time of initial production. Increasing both processing and takeaway capacity in the basins requires several years lead time and significant capital investments. If the proposed limitation of associated gas flaring is stringently applied, it could have a significant impact on future oil and gas production volumes.

Precluded Oil Production Due to Residue Gas Takeaway or Rich Gas Processing Capacity Gaps (Percent of Total)

	Williston (Bakken)	Permian
2023	4.73%	6.02%
2024	3.74%	2.58%
2025	6.06%	0.00%
2026	0.00%	0.00%
2027	0.00%	0.00%

Nationally, we find that 31% and 29% of existing wells may cease production in response

Impact of implementation of select OOOOc requirements (2027)

Case	Number of Wells Shut In	Percentage of Wells Shut In	Percentage Gas Production Precluded by Rule	Percentage of Oil Production Precluded by Rule
	(count)	(%)	(%)	(%)
EIA Reference Case	228,776	31%	2.8%	1.2%
EIA High Oil Price Case	215,022	29%	2.6%	0.5%

to the cost of implementing a limited set of OOOOc requirements under the reference and high-oil price scenarios respectively in 2027. This impact is concentrated on older, marginal wells and translates into a small impact to national production volumes (1.2% of oil production and 2.8% of gas production in the reference case decreasing to 0.5% of oil production and 2.6% of gas production in the high-oil price case).

The possible impacts of limiting flaring on US oil and gas production due to limited processing and gas takeaway capacity illustrate the critical need for natural gas infrastructure development in order to maintain US oil and gas production growth while also reducing greenhouse gas emissions. Streamlining the permitting, financing, and construction approval process for natural gas infrastructure development will enable the oil and gas industry to meet both of these objectives.

II. Modeled Implementation of Proposed Requirements for EPA Methane Rule

For this analysis we focused on portions of EPA's proposed OOOOb and OOOOc Methane rules that could likely have the largest impacts on both existing wells and new production. For existing sources (subject to OOOOc), we focused on the zero-emitting pneumatic controller requirements as well as revised Leak Detection and Repair (LDAR) requirements. For new and modified wells (subject to OOOOb), we focused on an order of magnitude analysis comparing predicted future associated gas production volumes with basin specific forecasted processing and takeaway capacity in the Permian and Williston (Bakken) basins. EPA expects to finalize OOOOb and OOOOc in August of 2023.

Once finalized, the associated gas requirement in OOOOb is proposed to be applicable to all wells drilled after November 15, 2021. We anticipate that the impact of implementation of the associated gas requirement in OOOOb will be substantially larger than the implementation of the associated gas requirement in OOOOc. In general, the majority of associated gas flaring is from new or refractured wells with high initial production that is either not connected to existing gathering infrastructure or exceeds the design capacity of existing gas-gathering infrastructure. Over time, the natural decline of wells and the development of infrastructure reduces flaring from wells. We therefore focus our analysis of impacts from the proposed associated gas flaring requirements on implementation from OOOOb.

For OOOOc, once the rule is finalized in 2023, states have 18 months to prepare a state plan for compliance, which they will submit to EPA. States then have three years to implement their plan. We therefore assume that OOOOc requirements will be implemented on existing facilities in 2027 and focus our analysis of LDAR and pneumatic controller requirement impacts to that year.

III. EIA Production Scenarios

For this analysis, we use the US Energy Information Administration (EIA) Annual Energy Outlook (AEO) forecasted oil and gas production volumes and prices from 2022 to 2027[1] (Table 1). Over the past year, oil and gas prices have fluctuated midway between these cases and they offer reasonable bounding boxes on future production and pricing, although uncertainty exists in future estimates of volume and pricing. We evaluated both the EIA reference and high-oil price scenarios for the OOOOc LDAR and pneumatic controller requirements, which will not be implemented until 2027 in order to provide bounds on possible future oil and gas production and pricing scenarios, which tend to be uncertain.

Table 1. EIA Forecasted Oil and Gas Prices (AEO)

EIA Forecasted Oil and Gas Prices				
	Oil ($/BBL)		Gas ($/MMBtu)	
Year	**Reference**	**High Oil**	**Reference**	**High Oil**
2023	58.79	120.44	3.49	3.24
2024	63.97	127.15	3.17	2.89
2025	64.73	128.82	3.00	2.81
2026	65.99	132.74	2.98	2.76
2027	67.86	135.66	3.08	2.84

For our analysis of the impacts of the proposed associated gas requirement in OOOOb, which are scheduled to be implemented later in 2023, we evaluated a Middle Case production scenario for the Permian and Williston (Bakken) basins that is midway between the reference and high-oil price cases. This was necessary due to the divergence between actual production

[1] https://www.eia.gov/outlooks/aeo/

in these basins in 2022 relative to both the EIA AEO reference and high-oil price cases and better represents the likely near-term production (and flaring) situation for immediate implementation of this requirement when the proposed rule is finalized this year.

To generate the Middle Case used in the associated gas flaring analysis in the Permian and Williston (Bakken) the AEO 2022 Reference case production was replaced by actual 2022 (average bbls/day) production and then multiplied by growth percentages, specific to each basin, that were midway between the reference and high-oil price case growth percentages out to 2027.

IV. Evaluating Production Impact of Associated Gas Requirement

The EPA's proposed rule associated gas[2] requirements, published December 6, 2022, aim to restrict and reduce routine flaring of associated gas from oil wells and prohibit venting of associated gas from oil wells. The scope of the flaring constraints includes both existing routine flaring and routine flaring from new or modified wells except for narrow cases. The proposed rule would apply to all wells drilled or modified after November 2021 when it is finalized later in 2023 and would apply to all existing wells in 2027. Short term flaring for upsets or gas infrastructure failures is allowed subject to restrictions, recordkeeping, and reporting requirements. Venting of associated gas, even for short durations, is prohibited. For this analysis we assume an implementation of maximum stringency under which persistent routine flaring is essentially prohibited.

The proposed rule requires that associated gas from wells be:

1. Routed into a gas gathering flow line or collection system to a sales line.
2. Used as an onsite fuel source.
3. Used for another useful purpose that a purchased fuel or raw material would serve.
4. Reinjected into the well or into another well for enhanced oil recovery.

The proposed rule includes a provision that enables operators to make a demonstration that it is not technically feasible or safe to route the associated gas to a sales line, utilize it onsite, or reinject it. This demonstration is required for each well and must include a detailed and comprehensive analysis documenting the technical or safety infeasibility of complying with the rule requirements. This analysis must include a minimum of routing to sales, using as an onsite fuel source, reinjecting the gas, and using the gas for *"another useful purpose that a purchased fuel or raw material would serve includes, but is not limited to, methane pyrolysis,*

[2] Associated gas is natural gas produced in conjunction with oil from oil wells

compressing the gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas."[3] EPA notes elsewhere in the proposed rule discussion that they will require analysis of emerging technologies as well. EPA requires an annual certification, for each well, that nothing has changed that would impact the infeasibility determination or an updated analysis if something has changed or the well is modified.

> *This demonstration must be certified by a professional engineer or another qualified individual with expertise in the uses of associated gas. The following certification, signed and dated by the qualified professional engineer of other qualified individual shall state: "I certify that the assessment of technical and safety infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted, and this report was prepared pursuant to the requirements of §60.5377b(b)(1). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."*[4]

Additionally, EPA is seeking comment whether they should ban routine flaring completely or restrict it more heavily.

The OOOOb (new and modified wells) & OOOOc (existing wells prior to November 2021) associated gas requirements could constrain three categories of flaring and venting of natural gas which in turn may require shutting in oil production or precluding/delaying new production to comply with the proposed rule. The three categories are:

1. Flaring all associated gas from new or modified wells due to unavailable or uneconomic connection to sales. The proposed rule would require that these wells be shut-in, connected to sales, the gas fully used, the gas reinjected, or a demonstration and certification of the technical and/or safety infeasibility of complying with the rule requirements in order to produce. Flaring in this category is considered to be persistent routine flaring in our analysis.
2. Flaring excess gas from new or modified wells due to delayed connection to sales/gathering or limited capacity of sales/gathering, processing, and/or residue gas transport (takeaway). In this case, demonstrating the technical or safety infeasibility is not likely viable. The proposed rule would require that gas gathering infrastructure and approval are in place prior to beginning production and that initial production be throttled to limit gas production to the capacity of the gathering system. New

[3] Proposed rule, Section 60.577b (b) (1)
[4] Proposed rule, Section 60.577b (b) (2)

well drilling and new production development will need to be paced to match the gas processing and residue gas transport capacity. This may delay development. Flaring in this category is considered to be persistent routine flaring in our analysis.

3. Venting gas from the casing/tubing annulus for legacy old oil wells to reduce backpressure on the formation and enhance flow into the wellbore. The rule will require that such wells connect to sales, flare the gas, use the gas, or shut-in. Although the number of wells in this category is quite large, the production is not a significant portion of either oil or gas production.

Since venting of gas from the casing/tubing annulus is minor in terms of potential production impact, our analysis focuses on an evaluation of the potential impact of constraining persistent routine flaring. This analysis is limited to the potential impacts in the Permian basin and the Williston (Bakken) basin since they represent 93% of the associated gas flaring reported into the GHGRP for 2019.[5]

Potential impacts to production are evaluated for existing routine flaring and potential future routine flaring due to development of new wells/production which exceeds the rich gas processing capacity or the dry gas transport capacity from each basin. Gathering system capacity constraints are not evaluated since they are central to the required demonstrations for each new or modified well which plans to routinely flare. Potential impacts to production are estimated for 5 years (2023-2027).

Existing flaring was determined for each basin using the most recent credible data available publicly. Routine flaring was determined using persistent vs. episodic flaring percentages from an ESS flaring study conducted for API and finalized in early 2022. In this study, flaring in major basins was categorized as persistent or episodic based on VIIRS satellite data. Persistent flaring was assumed to be routine flaring for this analysis. It is assumed that current routine flaring will be constrained or eliminated by the EPA rule once it is implemented although the timing depends on the date the rule is finalized and whether the facilities flaring predate November 2021.

Potential future routine flaring was determined by comparing the EIA Annual Energy Outlook (AEO) 2022[6] derived forecast oil production multiplied by the GOR for each basin (rich gas production) to the rich gas processing capacity and comparing the EIA AEO derived dry (residue) gas production to the dry gas transport (takeaway) capacity. If the forecast rich gas production exceeds the forecast rich gas processing capacity or forecast residue gas exceeds the dry gas transport capacity, it is assumed that the difference represents potential routine

[5] EPA-HQ-OAR-2021-0317-0166_attachment_13_2021 Associated Gas

[6] EIA 2022 AEO: https://www.eia.gov/outlooks/aeo/

flaring and could be constrained or eliminated by the by the EPA rule when fully implemented. Essentially, new well development would be limited to filling the decline wedge plus balanced transport/processing additions after first eliminating existing routine gas flaring.

Average bbls/day and rich gas production in 2022 for each basin/region was determined for 2022 from the EIA's Drilling Productivity Report (DPR) for each area and the current gas:oil ratio (GOR) for each basin was determined from the same source.[7]

Rich gas production forecasts were constructed for each basin by multiplying the forecast oil production by the GOR in each basin for each year through 2027. Residue gas forecasts for each basin were constructed by multiplying the rich gas forecast volumes by the 2022 average residue gas percentage of rich gas (2022 average residue gas production[8] / 2022 average rich gas production).

Permian Basin

Currently, operators in the Permian basin flare about 1.6% of the natural gas produced.[9] The ESS 2022 Flare Study found that ~50% of the Permian flaring was persistent (routine) and that about 50% was episodic based on VIIRS satellite observations (Table 2).

Table 2 – Estimated Existing Routine Flaring in the Permian Basin

Permian Basin - 2022	Gas Production mcfd (Dec. 2022)	% of gas production flared	Flaring mcfd	GOR mcf/bbl	Oil bbls/day
Persistent Flaring (50% - ESS Flare Study 2022)	21,496,856	0.80%	171,975	3.8	45,256
Episodic Flaring (50% - ESS Flare Study 2022)	21,496,856	0.8%	171,975	3.8	45,246
Wells flaring/venting casing/tubing annulus gas	**Not Material**				

Given the assumption that the proposed EPA rule would constrain or eliminate the routinely flared gas, shutting in gas production for those wells not connected to sales and/or curtailing production rate from those wells connected to sales in order to constrain or eliminate routine flaring could result in a potential reduction of oil production of about 45,000 bbls/day. Note that the some of the episodic flaring is likely within the scope of the proposed rule and the rule may have somewhat higher impacts on oil production.

[7] EIA Drilling Productivity Report; February 2023; report data aggregated by region, available at https://www.eia.gov/petroleum/drilling/

[8] EIA https: Dry shale gas production estimates by play; https://www.eia.gov/naturalgas/data.php; shale_gas_202301.xlsx

[9] Forbes Article February 2022; https://www.forbes.com/sites/ianpalmer/2022/02/15/flaring-of-gas-falls-off-in-permian-and-bakken--and-why-thats-good-news/?sh=2889f2fb4642

Future potential impacts of the proposed rule were projected by comparing the 2022 indexed Reference case, Middle Case, and High Oil Price case forecasts of natural gas production with forecasts of the rich gas processing and residue gas transport capacities for each year to 2027. Since the proposed EPA rule may preclude flaring to enable new development/production, we assume that production growth in excess of the rich gas processing capacity or residue gas takeaway capacity would be constrained.

Middle Case Results

Forecast gaps in the residue gas transport capacity in the near term have a potential to preclude up to 361,000 bbls/day of oil production (6.02%) although this impact would not begin until the rule is finalized later in 2023 (Table 3). Residue gas pipelines scheduled to come online later in 2023 and 2024 will eliminate the takeaway capacity gap for the 2025 – 2027 time period. Forecast rich gas processing capacity does not present a constraint for the Middle Case.[10]

Table 3 – Possible Permian Basin Precluded Oil Production Due to Takeaway Capacity or Processing Limitations

Permian Basin - Potentially Precluded Oil Production Due to Residue Gas Takeaway or Rich Gas Processing Capacity Gaps		
	Middle Case	
	bbls/day	% of Production
2023	361,910	6.02%
2024	164,101	2.58%
2025	0	0
2026	0	0
2027	0	0

In summary, some reduction in oil production in the Permian basin is plausible due to the possible constraints imposed by the proposed EPA rule when it becomes final later in 2023 in both the Middle Case and the High Oil Price case (Appendix I). Under the stringent assumptions of this analysis, the impacts in the high oil price case are projected to be large and the EPA rule could severely limit production in the high oil price case.

[10] East Daley Analytics 2023; https://www.eastdaley.com/

Williston Basin (Bakken)

Currently, operators in the Bakken flare about 5.6% of the total gas produced with about 2% of the total being gas produced and flared from wells with no connection to sales and the remaining 3.6% from wells with a connection to sales[11] (Table 4).

Table 4 – Estimated Existing Routine Flaring in the Williston Basin (Bakken)

Bakken (Williston Basin) 2022					
	Gas Production mcfd (Avg. 2022)	**% of gas production flared**	**Flaring mcfd**	**GOR mcf/bbl**	**Oil Bbls/day**
Wells not connected to sales	3,046,748	2.00%	60,935	2.72	22,403
Persistent Flaring (89% of Total Flaring Minus Wells Not Connected To Sales	3,046,748	3.60%	109,683	2.72	40,325
Episodic Flaring (11% - ESS Flare Study 2022)	3,046,748	0.44%	13,556	2.72	4,984
Wells flaring/venting casing/tubing annulus gas	Not Material				

Of the 4% of produced gas flared from wells with connections to sales, 89% was classified as persistent/routine in the 2022 ESS Flaring Study Bakken analysis. The combination of flaring from wells not connected sales and the 89% persistent flaring from wells with connections to sales adds up to just over 170,000 mcfd of gas flared. Dividing this total gas flared by the GOR derived from the DPR report shows that about 63,000 bbls per day of oil production per day is associated with the volume of gas flared. Given the assumption that the proposed EPA rule would constrain or eliminate the current routinely flared gas, shutting in this gas production for those wells not connected to sales and/or curtailing production rate from those wells connected to sales in order to eliminate routine flaring may result in a potential reduction of oil production of about 63,000 bbls/day for elimination of this flaring.

Future potential impacts of the proposed rule were projected by comparing the forecast natural gas production with forecasts of the rich gas processing and residue gas transport capacities for each year to 2027. Since the proposed EPA rule likely precludes flaring to enable new development/production, production growth in excess of the rich gas processing capacity or residue gas takeaway capacity may be constrained or not allowed.

[11] JJ Kringstad - North Dakota Pipeline Authority; North Dakota Midstream Update; 10/22/2022

Middle Case Results

Forecast 2023 production in the Williston (Bakken) was slightly lower than in the 2022 indexed Reference case and year on year growth rates were more moderate going forward. Forecast gaps in the residue gas transport capacity through 2025 have a potential to preclude up to 79,000 bbls/day (6%) of oil production (Table 5). The potential impacts will not begin until the rule is finalized later in 2023. Residue gas pipelines scheduled to come online later in 2023 and late 2025 will eliminate the takeaway capacity gap in 2026-2027. Forecast rich gas processing capacity does not present a constraint for the Middle Case.[12]

Table 5 - Possible Williston Basin (Bakken) Precluded Oil Production Due to Takeaway Capacity or Processing Limitations

Bakken - Potentially Precluded Oil Production Due to Residue Gas Takeaway or Rich Gas Processing Capacity Gaps		
Middle Case		
	bbls/day	% of Production
2023	58,265	4.73%
2024	47,262	3.74%
2025	79,390	6.06%
2026	0	0
2027	0	0

In summary, some reduction in oil production in the Williston (Bakken) is plausible due to possible constraints imposed by the EPA rule when it becomes final later in 2023 in all cases. The potential impacts in the high oil price case are projected to be severe and the EPA rule may preclude the high oil price case. Further details can be found in Appendix I.

North Dakota, which constitutes the bulk of Bakken oil and gas production, has State rules which require certain gas utilization percentages and partially restricts the ability to routinely flare gas. In view of the State rules, the likely impact of the proposed rule associated gas requirements on Bakken production may be less than projected due to constraints imposed by the State rules. However, the State of North Dakota has shown a willingness in the past to

[12] North Dakota Pipeline Authority; NDPA Website Data; Natural Gas Processing Capacity; https://northdakotapipelines.com/datastatistics/ . & JJ Kringstad - North Dakota Pipeline Authority; North Dakota Midstream Update; 10/22/2022

be flexible in their flaring and gas utilization rules to enable oil production growth. If the EPA rule is finalized as proposed and stringently applied, this flexibility may be curtailed.

Episodic Flaring

Routine flaring does not include short episodes of flaring due to malfunction/breakdown of the gas gathering infrastructure. The proposed rule includes provisions to enable such flaring but imposes requirements. For such episodes, the well must be shut-in or the gas must be routed to a combustion device with 95% efficiency. EPA notes that a permanent combustion device (flare) will have to be installed at all facilities (wells) that anticipate periods when the gas gathering infrastructure is not available. Since all wells are exposed to gathering system disruptions, the proposed rule essentially requires a flare be installed at all sites or that a well (s) be shut-in any time such a gathering disruption occurs. EPA further notes that venting gas, even short term, is a violation.

The costs of either installing permanent flares on well-sites or shutting-in wells (and subsequently restarting them) when gathering system disruptions occur will be significant. Also, the prohibition of any venting, no matter how minor, will likely make restarting some wells very difficult.

V. Evaluating the Production Impact of Pneumatic Controller and Leak Detection and Repair (LDAR) Requirements with Implementation of OOOOc

In order to evaluate the impact of the implementation of requirements from OOOOc in 2027, it is necessary to construct a modeled population of US onshore wells (and associated equipment) at that time. We develop this population by starting with the current population of wells, declining individual well oil and gas production in the future, evaluating timing of well shut-in due to uneconomic operating conditions, and adding new wells to compensate for decline in oil and gas production from existing wells as well as forecasted growth in production. We estimate the count of relevant equipment (such as pneumatic controllers) by applying basin specific equipment count information derived from EPA's Greenhouse Gas Reporting Program. We then apply select rule costs to this future population of wells and evaluate the impact of those costs on revenue. This approach allows us to conduct a detailed evaluation of possible impacts from implementation of the methane rule, by allowing us to estimate costs vs. individual wells future predicted revenue from oil and gas production.

Well Populations and Production Decline

We characterized the population of onshore US oil and gas wells using the Enverus database.[13] Enverus extracts oil and gas production data from state agencies and produces a uniform record of well oil and gas production volumes, date of completion, date of first production and production status of well (i.e. active, shut-in, P&A) as well as many other parameters. They retain long-term records of well production that can be used to estimate decline curves for both oil and gas that are specific to an area of interest. We extracted all wells that were designated as oil, gas, oil and gas, or coal bed methane (CBM) wells in the database. This ensured that we did not include other types of wells such as water injection wells. Wells and associated production were allocated to EPA Greenhouse Gas Reporting Basins (GHGRP) defined basins using a GIS layer provided by EPA.[14]

For each GHGRP defined basin, we calculated basin average oil and gas decline curves by estimating the hyperbolic decline curve parameters following the procedure described by EIA in their AEO analysis.[15] This entails grouping wells by basin, averaging the production over time beginning with the initial production date, and fitting a hyperbolic decline curve to the averaged basin-wide production volumes. These basin-average decline curves were then applied to each well designated as actively producing in the Enverus database to estimate future production of oil and gas from each well out to 2027. We then calculated the annual revenue from oil and gas production for each well under both the EIA reference and high oil price scenarios.

In each basin, we also estimated average production volumes for new wells based on historical data. For the subset of wells with first production dates between 2020 and 2022 we averaged the first 12 months of oil and gas production volume in each basin per well. This initial production volume for new wells was used to constrain the number of new wells that would be added in future timesteps to meet forecasted production volumes after accounting for existing well decline.

Future Production and Allocation to Basins

EIA forecasts annual production volumes under different scenario assumptions. We took several steps to allocate EIA forecasted production volumes from the reference and high-oil price cases to basin specific production volumes. First, we removed the offshore component of oil and gas production volume from the EIA forecasts because we are solely focused on onshore production for this analysis. EIA reports future production of natural gas as production

[13] https://www.enverus.com/solutions/energy-analytics/land/drillinginfo-and-rigdata/
[14] https://edg.epa.gov/metadata/catalog/search/resource/details.page?uuid=%7B19F20B68-AEBC-4A16-A59B-BFF5ECB5EEED%7D
[15] https://www.eia.gov/analysis/drilling/curve_analysis/

volume of dry natural gas. We used EIA reported dry natural gas production and gross gas withdrawals from 2021[16] to estimate a 1.207 scaling factor that grosses up EIA forecasted dry production to gross natural gas withdrawals.

In order to allocate the gross EIA forecasted oil and gas production to individual GHGRP basins, we developed basin-specific factors based on historical data. We used total oil and gas production from 2020 to 2022 from the Enverus database along with the EPA GHGRP Basin boundaries to calculate the fraction of total production from each basin. These basin specific fractions were applied to the EIA forecasted production volumes to allocate future production by basin. This procedure assumes that future allocation of oil and gas production volume by basin will remain constant in the future, and there is no feedback between oil and gas pricing or future basin-specific operating costs in this model.

In each annual timestep between 2023 and 2027, we calculated the difference between the projected production volume of oil and gas from existing wells in each basin and the EIA forecasted production volume for both oil and gas. We then used the average oil and gas production volumes of new wells for each basin to estimate the number of new wells that would be added annually to meet production forecasts. Oil and gas were treated separately due to the decoupled nature of the decline curves, and if there was a discrepancy between the number of wells that would be added to meet forecasted oil or gas production volumes, we chose the larger number of wells to ensure that both oil and gas forecasts were met. New well production from each timestep was then declined using the basin average decline curves for each subsequent year in the future, and the increment between declined production for wells was recalculated after decline in each timestep, and new wells were estimated following the same procedure for each future year.

Estimating Revenue Threshold for Shut-In of Wells

In order to estimate a revenue threshold below which it becomes non-economic to continue operating a well, we examined historical records of well shut-ins. For all wells shut-in between 2020 and 2022 we extracted the last three months of reported production volume prior to shut-in. For oil, we used historical pricing information from EIA and calculated revenue based on West Texas Intermediate (WTI) prices[17]. For natural gas we calculated revenue based on historical pricing data for Henry Hub spot prices.[18] We found that the historical revenue was not normally distributed, and that there were a few very high outliers that significantly impacted average revenue per shut-in well. We therefore chose to use the median revenue of

[16] https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm
[17] https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm
[18] https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

the population of shut-in wells nationally to characterize a threshold below which wells would be considered non-economic to operate. Nationally, we estimate that wells with revenue below $5460 per year are non-economic to continue operating based on this procedure. In each timestep of production decline defined above, we estimate the number of wells that would shut-in due to revenue decline below this value in the future. These wells and their associated oil and gas production volume are removed from future timesteps. This approach assumes a uniform dollar threshold below which it becomes non-economic to operate wells across all basins, which may not accurately represent divergent operation costs across basins. In future analyses, we suggest refining the revenue threshold for shut-ins to be basin-specific.

Estimating Site Characteristics

In order to estimate the number of sites in each basin, as well as the distribution of wells per site, we used the ESS inventory of oil and gas infrastructure along with the Enverus database of wells nationally. The ESS inventory of oil and gas infrastructure contains information about permitted sources including tank batteries, and is particularly robust in the Permian, Williston and DJ basins. We spatially clustered individual wells, tank batteries, and other permitted sources in order to estimate the distribution of the number of sites with single wells, two or more wells, and more than two wells (both with and without additional permitted equipment) in each basin. We then assigned each well in the Enverus database a site scaling factor based on the basin-specific distribution of wells per site. This scaling factor was used to distribute the costs associated with implementation of proposed methane regulations that are incurred at a site level to individual wells. For example, if there are estimated to be 5 wells on a site, the initial capital costs and annual recurring costs for proposed regulations are divided by 5 when applied to the individual well.

Estimating Population of Pneumatic Controllers and Control Costs for Existing Wells

In order to estimate the costs associated with the pneumatic controller requirements in OOOOc, we constructed basin-specific populations of natural gas-powered pneumatic devices using a combination of data from the Enverus database and EPA Greenhouse Gas Reporting Program (GHGRP) Subpart W reporting. In each basin we calculated basin average counts of Subpart W reported pneumatic controllers per Subpart W reported well, yielding a basin specific controller per well factor. This factor was then applied to each basin's Enverus total well count, which is larger than the GHGRP reported well count. Pneumatic controllers were distributed to sites in the model based on the number of wells per site and the basin specific controller per site factor. For single-well sites, we assumed that 25% of sites did not have any affected pneumatic controllers.

We developed custom cost estimates for implementation of the zero emission pneumatic controller requirements (Appendix II)[19]. We evaluated several options for control including installing instrument air systems or converting controllers to electric control and actuation. Costs were evaluated for sites with existing electricity, sites within 500 feet of the electric grid, sites within 0.25 miles of the electric grid and solar powered options. We assumed that 25% of sites had existing electricity, 25% were within 500 feet of the electric grid and 50% were within 0.25 miles of the electric grid. These assumptions could be improved by surveying operator asset distributions relative to the electric grid, but we did not identify a readily available source of information to improve this assumption.

We calculated an average electricity weighted site cost for implementation of the pneumatic controller requirement that is scaled based on the number of controllers (and therefore gas demand) per site (Table 6).

Table 6 – Weighted Cost per Site for Zero Emission Pneumatic Controller Requirement

Weighted (by electricity % of sites) Cost per Site			
Range Controllers/Site		**Capital**	**Annual**
1 ≤ Total < 5		$44,670	$5,592
5 ≤ Total < 10		$70,696	$6,340
10 ≤ Total < 15		$96,843	$15,022
15 ≤		$142,740	$38,954

For each site in the model, costs were assigned based on the predicted number of pneumatic controllers on the site. Both capital and annual recurring costs were distributed to individual wells by dividing the cost per site by the number of wells per site.

Estimating the Population of Sites and LDAR Costs for Existing Wells

Using the clustered basin specific site characteristics described above, we grouped wells into three categories to estimate LDAR costs. First, we assigned single wellheads in the data and single wells without associated permitted tanks to the ‘Single Wellhead and Small Well’ category. Sites with more than two wellheads and no other associated permitted equipment were assigned to the ‘Wellheads with 2+ wells’ category. Finally, all other sites were assigned

[19] See detailed information sources and calculations in PneumaticCosts2023.xlsx

to the 'Complex Site' category. We used EPA defined costs for both OGI and AVO presented in the documentation for the 2021 TSD 2021[20]. Single wellheads and small wells were subject to a quarterly AVO inspection, wellheads with 2+ wells were subject to both quarterly AVO and semiannual OGI surveys and the Complex Site wells were subject to bimonthly AVO and quarterly OGI. As with pneumatic controllers, the recurring costs of the required LDAR program was distributed to individual wells by dividing the site estimated costs by the number of wells per site.

Estimating Shut-In of Wells and Production Impact to Compliance Costs of OOOOc LDAR and Pneumatic Controller Requirements

For each active well, we estimate the cost of compliance for the OOOOc requirements on pneumatic controllers and LDAR in 2027. If the projected 2027 revenue of the well minus the annual recurring cost of compliance with the LDAR and pneumatic controller requirement is below the shut-in threshold, we assume that the well has shut-in due to cost of complying with the rule. Additionally, if the upfront capital cost of implementing the requirement in 2027 exceeds 50% of the revenue of the well in that year, we assume that an operator will not choose to comply with the rule and will instead choose to shut-in the well. This assumption could likely be improved by surveying operators.

We estimate that approximately 30% of wells will shut-in in response to the limited set of OOOOc requirements modeled here (Table 7). Under these assumptions the overall impact on production of oil and gas would be limited, however, because the vast majority of these wells are low production marginal wells.

Table 7 – Impact of Implementation of Select OOOOc Requirements in 2027

Impact of implementation of select OOOOc requirements (2027)

Case	Number of Wells Shut In	Percentage of Wells Shut In	Percentage Gas Production Precluded by Rule	Percentage of Oil Production Precluded by Rule
	(count)	(%)	(%)	(%)
EIA Reference Case	228,776	31%	2.8%	1.2%
EIA High Oil Price Case	215,022	29%	2.6%	0.5%

[20] LDAR EPA-HQ-OAR-2021-0317-1539_attachment_15.xlsx

Possible impacts of implementing a limited set of OOOOc requirements vary by basin. In general, impacts are more severe in basins with larger populations of older marginal wells and lower in basins dominated by newer high producing shale assets (Table 8).

Table 8 – Selected Basin Specific Impacts of Modeled OOOOc Impacts

Basin	Shut Ins - Reference			Shut Ins - High Oil		
	% of Wells	% Oil Production	% Gas Production	% of Wells	% Oil Production	% Gas Production
Anadarko Basin	44.6%	2.5%	6.6%	41.4%	0.7%	6.1%
Appalachian Basin	17.9%	10.6%	6.0%	21.1%	7.6%	5.4%
Appalachian Basin (Eastern Overthrust Area)	12.6%	2.5%	0.6%	13.9%	1.9%	0.5%
Denver Basin	37.4%	0.7%	3.0%	31.4%	0.3%	2.0%
Gulf Coast Basin (LA, TX)	27.2%	0.9%	2.1%	24.1%	0.3%	1.8%
Permian Basin	36.0%	0.9%	1.3%	29.8%	0.3%	1.0%
Piceance Basin	63.1%	6.3%	20.1%	62.4%	4.3%	19.1%
Powder River Basin	36.5%	1.2%	4.1%	31.4%	0.4%	3.8%
San Joaquin Basin	33.2%	5.6%	4.7%	22.6%	1.6%	3.1%
San Juan Basin	50.7%	3.1%	22.6%	51.1%	1.9%	22.2%
South Oklahoma Folded Belt	47.2%	6.6%	2.5%	44.8%	2.9%	2.2%
Uinta Basin	53.0%	2.0%	8.8%	46.0%	0.7%	7.7%
Williston Basin	12.6%	0.1%	0.8%	10.7%	0.0%	0.7%
Total (All GHGRP Basins - See Appendix II)	31.3%	1.2%	2.8%	29.4%	0.5%	2.6%

Conclusions

Here we have estimated the impact of a limited set of requirements in the proposed EPA Methane Rule on the production of oil and gas. We find that implementation of the pneumatic controller and LDAR requirement on existing wells in 2027 could result in a decrease in forecasted oil production (1.2% to 0.5%) for the EIA Reference and High Oil Price scenarios respectively. Although the projected impact to production volume is small, we estimate that approximately 30% of onshore wells nationally could shut-in in response to the LDAR and pneumatic controller requirements required in the rule. Additionally, if we assume that the limits on associated gas flaring will be interpreted with maximum stringency, and will generally not allow routine persistent flaring of natural gas, we find that takeaway and processing capacity limitations in the Permian and Williston Basins would limit oil production by approximately 6% (up to 79,390 bbl/day in the Williston and 361,910 bbl/day in the Permian). This limitation would increase substantially if oil production approaches the EIA high-oil price case scenario (up to 220,809 bbl/day in the Williston and 719,947 bbl/day in the Permian). If substantial gas can be diverted for beneficial uses, or if the technical infeasibility demonstration requirement in the final rule is not as stringent as assumed here, the production impacts could be substantially lower than forecasted.

The possible impacts of limiting flaring on US oil and gas production due to limited processing and gas takeaway capacity illustrate the critical need for natural gas infrastructure development in order to maintain US oil and gas production growth while also reducing greenhouse gas emissions. Streamlining the permitting, financing, and construction approval process for natural gas infrastructure development will enable the oil and gas industry to meet both of these objectives.

Appendix I – Associated Gas Flaring

EIA Middle Case Scenario

In order to accurately represent current Permian and Williston (Bakken) production we developed a Middle Case Scenario that better reflects current production volumes.

1. The AEO 2022 Reference case production was replaced by actual 2022 (average bbls/day) production and then multiplied by the Reference case year on year growth percentages, specific to each basin, to construct a 2022 indexed Reference case through 2027 for each basin.
2. A 2022 indexed High Oil Price case was developed for each basin by using the 2022 actual production for 2022 and then multiplying by the AEO High Oil Price year on year growth percentages to construct basin specific High Oil Price cases.
3. The Middle case for each basin was constructed by again using 2022 actual production as the starting point.
    a. Year on year growth percentages were calculated by subtracting the AEO basin specific Reference case percentage from the L48 High Oil Price case for each year (the High Oil Price Case is only presented at the L48 onshore level) (if this resulted in a negative number it was set to zero), dividing the difference by two to get the midpoint between the two forecasts, and then adding the original L48 Reference case growth percentages to the midpoint.
    b. The 2022 production was multiplied by the calculated year on year growth percentages to construct a production forecast through 2027.

Permian Basin

<u>Reference Case</u>

There were no forecast gaps in the rich gas processing or residue gas transport capacities for the 2022 indexed Reference case hence there were no forecast constraints on production.

<u>AEO High Oil Price Case</u>

Production is projected to be significantly higher in the high oil price case and there are forecast gaps in both the rich gas processing and residue gas takeaway capacity for all years through 2027. The residue gas takeaway constraint dominates for all years in the analysis although significant rich gas processing constraints exist in all years. There is a potential for the preclusion of significant volumes of oil production (peaking at 719,947 bbls/day in 2023) across the entire analysis period.

Permian Basin - Potentially Precluded Oil Production Due to Residue Gas Takeaway or Rich Gas Processing Capacity Gaps		
High Oil Price Case		
	bbls/day	% of Production
2023	719,947	11.08%
2024	611,863	8.78%
2025	141,888	1.99%
2026	306,255	4.20%
2027	433,496	5.84%

AEO Reference Cases							
		2022	**2023**	**2024**	**2025**	**2026**	**2027**
L48 Onshore	MMbbl/day	9.602	9.967	10.237	10.607	10.725	10.678
Permian	MMbbl/day	5.085	5.225	5.278	5.331	5.370	5.325
L48 Year on Year Production Growth %			3.79%	2.72%	3.61%	1.11%	-0.43%
Permian Year on Year Production Growth %			2.76%	1.01%	1.00%	0.74%	-0.84%

AEO High Oil Price Case (L48)							
		2022	**2023**	**2024**	**2025**	**2026**	**2027**
L48 Onshore	MMbbl/day	10.11	12.43	13.34	13.65	13.97	14.21
	US $/bbl	$111	$120	$127	$129	$133	$136
Year on Year Production Growth %			23.02%	7.26%	2.39%	2.30%	1.74%

2022 Indexed Reference Cases							
		2022	**2023**	**2024**	**2025**	**2026**	**2027**
L48 Indexed to 2022 Average Actual	MMbbl/day	9.675	10.042	10.315	10.687	10.806	10.759
Permian Indexed to 2022 Actual Average	MMbbl/day	5.281	5.427	5.482	5.537	5.578	5.531
Differential Growth Rate: High - Reference Negative Differentials are Set to Zero			20.26%	6.25%	1.39%	1.57%	2.58%
50% of differential			10.13%	3.12%	0.69%	0.78%	1.29%
+ Reference Growth Rate			13.92%	5.84%	4.30%	1.90%	0.86%

Forecast Production - Middle Case

		2022	2023	2024	2025	2026	2027
Permian Indexed to 2022 Actual Average	MMbbl/day	5.281	6.016	6.368	6.642	6.768	6.826

Permian High Oil Price Case							
		2022	**2023**	**2024**	**2025**	**2026**	**2027**
Permian (Indexed to 2022 avg. actual production)	MMbbl/day	5.281	6.497	6.968	7.135	7.299	7.426

2022 Permian Average Actual Production					
	bbls/ day	**MMbbls/day**	**mscf Rich Gas**	**GOR mscf /bbl**	**Source**
Permian Avg 2022 Production per day	5,281,214	5.281	20,492,767	3.88	EIA Drilling Productivity Report; dpr-data.xlsx; https://www.eia.gov/petroleum/drilling/

Residue Gas % of Rich Gas			
	BCF/day	**mscf/day**	**Source**
December 2022 Rich Gas	21.497	21,496,856	EIA Drilling Productivity Report; dpr-data.xlsx; https://www.eia.gov/petroleum/drilling/
December 2022 Residue Gas	16.026	16,026,165	EIA https: Dry shale gas production estimates by play; https://www.eia.gov/naturalgas/data.php; shale_gas_202301.xlsx
Residue Gas % of Rich Gas	74.55%		

Permian Basin 2022					
	Gas Production mcfd (Dec. 2022)	**% of gas production flared**	**Flaring mcfd**	**GOR mcf/bbl**	**Oil Bbls/day**
Persistent Flaring (50% - ESS Flare Study 2022)	21,496,856	0.80%	171,975	3.88	44,319.83
Episodic Flaring (50% - ESS Flare Study 2022)	21,496,856	0.80%	171,975	3.88	44,319.83
Wells flaring/venting casing/tubing annulus gas	Not Material				

Permian Basin: Residue Gas % of Rich Gas	74.55%

Permian Basin 2023-2027 - 2022 Indexed Reference Case											
	Forecast Oil Production MM bbls/day	Forecast Rich Gas mscfd	Forecast Residue Gas mscfd	Forecast Takeaway Capacity mscfd	Forecast Takeaway Capacity Gap mscfd	Forecast Rich Gas Processing Capacity mscfd	Forecast Processing Capacity Gap mscfd	Precluded Oil Production 100% Case	Precluded Oil Production 50% Case	Precluded Oil Production 100% Case	Precluded Oil Production 50% Case
2023	5.427	21,058,394	15,699,033	16,000,000	0	25,000,000	0	0	0	0.00%	0.00%
2024	5.482	21,271,916	15,858,213	17,784,000	0	26,260,000	0	0	0	0.00%	0.00%
2025	5.537	21,485,058	16,017,111	19,784,000	0	27,135,000	0	0	0	0.00%	0.00%
2026	5.578	21,643,182	16,134,992	19,784,000	0	27,135,000	0	0	0	0.00%	0.00%
2027	5.531	21,461,996	15,999,918	19,784,000	0	27,135,000	0	0	0	0.00%	0.00%

Permian Basin 2023-2027 - Middle Case - Forecast by applying adjusted year on year growth percentages											
	Forecast Oil Production MM bbls/day	Forecast Rich Gas mscfd	Forecast Residue Gas mscfd	Forecast Takeaway Capacity mscfd	Forecast Takeaway Capacity Gap mscfd	Forecast Rich Gas Processing Capacity mscfd	Forecast Processing Capacity Gap mscfd	Precluded Oil Production 100% Case	Precluded Oil Production 50% Case	Precluded Oil Production 100% Case	Precluded Oil Production 50% Case
2023	6.016	23,345,839	17,404,323	16,000,000	1,404,323	25,000,000	0	361,910	180,955	6.02%	3.01%
2024	6.368	24,709,274	18,420,764	17,784,000	636,764	26,260,000	0	164,101	82,051	2.58%	1.29%
2025	6.642	25,771,852	19,212,916	19,784,000	0	27,135,000	0	0	0	0.00%	0.00%
2026	6.768	26,260,315	19,577,065	19,784,000	0	27,135,000	0	0	0	0.00%	0.00%
2027	6.826	26,485,896	19,745,236	19,784,000	0	27,135,000	0	0	0	0.00%	0.00%

Permian Basin 2023-2027 - 2022 Indexed High Oil Price Case											
	Forecast Oil Production MM bbls/day	Forecast Rich Gas mscfd	Forecast Residue Gas mscfd	Forecast Takeaway Capacity mscfd	Forecast Takeaway Capacity Gap mscfd	Forecast Rich Gas Processing Capacity mscfd	Forecast Processing Capacity Gap mscfd	Precluded Oil Production 100% Case	Precluded Oil Production 50% Case	Precluded Oil Production 100% Case	Precluded Oil Production 50% Case
2023	6.497	25,209,417	18,793,620	16,000,000	2,793,620	25,000,000	209,417	719,947	359,974	11.08%	5.54%
2024	6.968	27,039,865	20,158,219	17,784,000	2,374,219	26,260,000	779,865	611,863	305,931	8.78%	4.39%
2025	7.135	27,685,569	20,639,592	19,784,000	855,592	27,135,000	550,569	141,888	70,944	1.99%	0.99%
2026	7.299	28,323,364	21,115,068	19,784,000	1,331,068	27,135,000	1,188,364	306,255	153,127	4.20%	2.10%
2027	7.426	28,817,101	21,483,148	19,784,000	1,699,148	27,135,000	1,682,101	433,496	216,748	5.84%	2.92%

Permian Basin - Potentially Precluded Oil Production Due to Residue Gas Takeaway or Rich Gas Processing Capacity Gaps									
	Middle Case					**Adjusted High Oil Price Case**			
	bbls/day		**% of Production**			**bbls/day**		**% of Production**	
	100%	**50%**	**100%**	**50%**		**100%**	**50%**	**100%**	**50%**
2023	361,910	180,955	6.02%	3.01%		719,947	359,974	11.08%	5.54%
2024	164,101	82,051	2.58%	1.29%		611,863	305,931	8.78%	4.39%
2025	0	0	0.00%	0.00%		141,888	70,944	1.99%	0.99%
2026	0	0	0.00%	0.00%		306,255	153,127	4.20%	2.10%
2027	0	0	0.00%	0.00%		433,496	216,748	5.84%	2.92%

Williston Basin (Bakken)

Reference Case

Actual 2022 production in the Bakken was lower than the EIA AEO's Reference case forecast for 2022 production. Indexing the AEO Reference case to 2022 lowered the forecast oil production through 2027. Despite the lower forecast production, residue gas transport capacity gaps were forecast for every year through 2027 and potential oil production reductions were forecast for each year. Due to the high AEO Reference case forecast year on year growth for 2023 - 2025 (10.45%; 12.12%; & 8.62% respectively) the forecast gaps and potential production impacts grow annually through 2025 peaking at 216,165 bbls/day in 2025. Forecast rich gas processing capacity does not present a constraint for the Reference case.[21]

Bakken (Williston Basin) - Potentially Precluded Oil Production Due to Residue Gas Takeaway or Rich Gas Processing Capacity Gaps		
2022 Indexed Reference Price Case		
	bbls/day	% of Production
2023	61,210	4.96%
2024	132,059	9.54%
2025	216,165	14.37%
2026	72,516	4.76%
2027	64,540	4.26%

High Oil Price Case

Production is projected to be significantly higher in the high oil price case and there are forecast gaps in the residue gas takeaway capacity for all years through 2027. Forecast rich gas processing capacity does not present a constraint for the High Oil Price case. There is a potential for the preclusion of significant volumes of oil production across the entire analysis period peaking at 220,809 bbls/day in 2025 .

[21] North Dakota Pipeline Authority; NDPA Website Data; Natural Gas Processing Capacity; https://northdakotapipelines.com/datastatistics/ . & JJ Kringstad - North Dakota Pipeline Authority; North Dakota Midstream Update; 10/22/2022

Bakken - Potentially Precluded Oil Production Due to Residue Gas Takeaway or Rich Gas Processing Capacity Gaps		
High Oil Price Case		
	bbls/day	% of Production
2023	160,188	11.64%
2024	195,989	13.28%
2025	220,809	14.62%
2026	87,237	5.64%
2027	106,215	6.75%

AEO Reference Case							
		2022	**2023**	**2024**	**2025**	**2026**	**2027**
L48 Onshore	MMbbl/day	9.602	9.967	10.237	10.607	10.725	10.678
Bakken	MMbbl/day	1.237	1.366	1.532	1.664	1.687	1.674
L48 Year on Year Production Growth %			3.79%	2.72%	3.61%	1.11%	-0.43%
Bakken Year on Year Production Growth %			10.45%	12.12%	8.62%	1.36%	-0.74%

AEO High Oil Price Case (L48)							
		2022	**2023**	**2024**	**2025**	**2026**	**2027**
L48 Onshore	MMbbl/day	10.11	12.43	13.34	13.65	13.97	14.21
	US $/bbl	$111	$120	$127	$129	$133	$136
Year on Year Production Growth %			23.02%	7.26%	2.39%	2.30%	1.74%

2022 Indexed Reference Cases							
		2022	**2023**	**2024**	**2025**	**2026**	**2027**
L48 Indexed to 2022 Average Actual	MMbbl/day	9.675	10.042	10.315	10.687	10.806	10.759
Bakken Indexed to 2022 Actual Average	MMbbl/day	1.118	1.235	1.385	1.504	1.525	1.513
Differential Growth Rate: High - Reference Negative Differentials are Set to Zero			12.57%	0.00%	0.00%	0.94%	2.49%
50% of differential			6.28%	0.00%	0.00%	0.47%	1.24%
+ Reference Growth Rate			10.08%	2.72%	3.61%	1.58%	0.81%

Forecast Production (Middle Case)							
		2022	**2023**	**2024**	**2025**	**2026**	**2027**
Bakken Indexed to 2022 Actual Average	MMbbl/day	1.118	1.231	1.264	1.310	1.331	1.341

Bakken High Oil Price Case							
		2022	**2023**	**2024**	**2025**	**2026**	**2027**
Bakken (Indexed to 2022 avg. actual production)	MMbbl/day	1.118	1.376	1.475	1.511	1.546	1.572

2022 Bakken Production					
	bbls/ day	**MMbbls /day**	**mscf Rich Gas**	**GOR mscf/ bbl**	**Source**
Bakken Avg 2022 Production per day	1,118, 234	1.118	3,046,74 8	2.72	EIA Drilling Productivity Report; dpr-data.xlsx; https://www.eia.gov/petroleum/drilling/

Residue Gas % of Rich Gas			
	BCF/ day	**mscf/ day**	**Source**
Average 2022 Rich Gas	3.047	3,274, 661	EIA Drilling Productivity Report; dpr-data.xlsx; https://www.eia.gov/petroleum/drilling/
Average 2022 Residue Gas	2.146	2,146, 204	EIA https: Dry shale gas production estimates by play; https://www.eia.gov/naturalgas/data.php; shale_gas_202301.xlsx
Residue Gas % of Rich Gas	70.44 %		

Bakken (Williston Basin) 2022					
	Gas Production mcfd (Avg. 2022)	**% of gas production flared**	**Flaring mcfd**	**GOR mcf/b bl**	**Oil Bbls/day**
Wells not connected to sales	3,046,748	2.00%	60,935	2.72	22,403
Persistent Flaring (89% of Total Flaring Minus Wells Not Connected To Sales)	3,046,748	3.60%	109,683	2.72	40,325
Episodic Flaring (50% - ESS Flare Study 2022)	3,046,748	0.44%	13,556	2.72	4,984
Wells flaring/venting casing/tubing annulus gas	Not Material				

Bakken: Residue Gas % of Rich Gas	70.44%

Bakken (Williston Basin) 2023-2027 - 2022 Indexed Reference Case											
	Forecast Oil Production MM bbls/day	Forecast Rich Gas Reference mscfd	Forecast Residue Gas mscfd	Forecast Takeaway Capacity mscfd	Forecast Takeaway Capacity Gap mscfd	Forecast Rich Gas Processing Capacity mscfd	Forecast Processing	Precluded Oil Production 100% Case	Precluded Oil Production 50% Case	Precluded Oil Production 100% Case	Precluded Oil Production 50% Case
2023	1.235	3,359,467	2,366,490	2,200,000	166,490	4,277,000	0	61,210	30,605	4.96%	2.48%
2024	1.385	3,766,481	2,653,201	2,294,000	359,201	4,277,000	0	132,059	66,030	9.54%	4.77%
2025	1.504	4,091,239	2,881,969	2,294,000	587,969	4,277,000	0	216,165	108,082	14.37%	7.19%
2026	1.525	4,146,992	2,921,243	2,724,000	197,243	4,277,000	0	72,516	36,258	4.76%	2.38%
2027	1.513	4,116,195	2,899,548	2,724,000	175,548	4,277,000	0	64,540	32,270	4.26%	2.13%

Bakken (Williston Basin) 2023-2027 - Middle Case - Forecast by applying adjusted year on year growth percentages											
	Forecast Oil Production MM bbls/day	Forecast Rich Gas Reference mscfd	Forecast Residue Gas mscfd	Forecast Takeaway Capacity mscfd	Forecast Takeaway Capacity Gap mscfd	Forecast Rich Gas Processing Capacity mscfd	Forecast Processing Capacity Gap mscfd	Precluded Oil Production 100% Case	Precluded Oil Production 50% Case	Precluded Oil Production 100% Case	Precluded Oil Production 50% Case
2023	1.231	3,348,096	2,358,481	2,200,000	158,481	4,277,000	0	58,265	29,133	4.73%	2.37%
2024	1.264	3,439,053	2,422,553	2,294,000	128,553	4,277,000	0	47,262	23,631	3.74%	1.87%
2025	1.310	3,563,111	2,509,942	2,294,000	215,942	4,277,000	0	79,390	39,695	6.06%	3.03%
2026	1.331	3,619,477	2,549,648	2,724,000	0	4,277,000	0	0	0	0.00%	0.00%
2027	1.341	3,648,859	2,570,345	2,724,000	0	4,277,000	0	0	0	0.00%	0.00%

Bakken (Williston Basin) 2023-2027 - 2022 Indexed High Oil Price Case											
	Forecast Oil Production MM bbls/day	Forecast Rich Gas Reference mscfd	Forecast Residue Gas mscfd	Forecast Takeaway Capacity mscfd	Forecast Takeaway Capacity Gap mscfd	Forecast Rich Gas Processing Capacity mscfd	Forecast Processing Capacity Gap mscfd	Precluded Oil Production 100% Case	Precluded Oil Production 50% Case	Precluded Oil Production 100% Case	Precluded Oil Production 50% Case
2023	1.376	3,741,654	2,635,712	2,200,000	435,712	4,277,000	0	160,188	80,094	11.64%	5.82%
2024	1.475	4,013,334	2,827,090	2,294,000	533,090	4,277,000	0	195,989	97,995	13.28%	6.64%
2025	1.511	4,109,171	2,894,601	2,294,000	600,601	4,277,000	0	220,809	110,405	14.62%	7.31%
2026	1.546	4,203,835	2,961,284	2,724,000	237,284	4,277,000	0	87,237	43,618	5.64%	2.82%
2027	1.572	4,277,117	3,012,905	2,724,000	288,905	4,277,000	117	106,215	53,108	6.75%	3.38%

Bakken (Williston Basin) - Potentially Precluded Oil Production Due to Residue Gas Takeaway or Rich Gas Processing Capacity Gaps				
	2022 Indexed Reference Case			
	bbls/day		% of Production	
	100%	50%	100%	50%
2023	61,210	30,605	4.96%	2.48%
2024	132,059	66,030	9.54%	4.77%
2025	216,165	108,082	14.37%	7.19%
2026	72,516	36,258	4.76%	2.38%
2027	64,540	32,270	4.26%	2.13%

Bakken (Williston Basin) - Potentially Precluded Oil Production Due to Residue Gas Takeaway or Rich Gas Processing Capacity Gaps									
	Middle Case					2022 Indexed High Oil Price Case			
	bbls/day		% of Production			bbls/day		% of Production	
	100%	50%	100%	50%		100%	50%	100%	50%
2023	58,265	29,133	4.73%	2.37%		160,188	80,094	11.64%	5.82%
2024	47,262	23,631	3.74%	1.87%		195,989	97,995	13.28%	6.64%
2025	79,390	39,695	6.06%	3.03%		220,809	110,405	14.62%	7.31%
2026	0	0	0.00%	0.00%		87,237	43,618	5.64%	2.82%
2027	0	0	0.00%	0.00%		106,215	53,108	6.75%	3.38%

Appendix II – Pneumatic Controller Cost Information

Please see associated excel workbook ‘PneumaticCosts2023.xlsx’

Appendix III – Full Basin Results for OOOOc Requirements

Basin	Shut Ins - Reference			Shut Ins - High Oil		
	% of Wells	% Oil Production	% Gas Production	% of Wells	% Oil Production	% Gas Production
Anadarko Basin	44.6%	2.5%	6.6%	41.4%	0.7%	6.1%
Appalachian Basin	17.9%	10.6%	6.0%	21.1%	7.6%	5.4%
Appalachian Basin (Eastern Overthrust Area)	12.6%	2.5%	0.6%	13.9%	1.9%	0.5%
Arkla Basin	32.5%	12.8%	0.8%	38.0%	6.8%	0.7%
Arkoma Basin	47.2%	11.8%	10.3%	48.0%	4.3%	11.1%
Central Western Overthrust	65.1%	18.4%	12.9%	64.5%	11.9%	11.8%
Chautauqua Platform	46.3%	11.7%	4.4%	38.7%	4.4%	3.7%
Denver Basin	37.4%	0.7%	3.0%	31.4%	0.3%	2.0%
East Texas Basin	47.1%	9.7%	3.4%	44.9%	4.1%	3.1%
Fort Worth Syncline	42.1%	18.6%	11.1%	43.6%	10.5%	10.9%
Green River Basin	33.4%	4.6%	5.5%	31.6%	2.4%	5.0%
Gulf Coast Basin (LA, TX)	27.2%	0.9%	2.1%	24.1%	0.3%	1.8%
Los Angeles Basin	0.5%	0.0%	0.0%	0.3%	0.0%	0.1%
Ouachita Folded Belt	16.7%	14.3%	5.3%	24.3%	13.3%	5.0%
Palo Duro Basin	33.3%	17.1%	8.4%	37.8%	8.4%	7.0%
Paradox Basin	33.0%	1.0%	0.8%	29.8%	0.2%	0.8%
Permian Basin	36.0%	0.9%	1.3%	29.8%	0.3%	1.0%
Piceance Basin	63.1%	6.3%	20.1%	62.4%	4.3%	19.1%
Powder River Basin	36.5%	1.2%	4.1%	31.4%	0.4%	3.8%
San Joaquin Basin	33.2%	5.6%	4.7%	22.6%	1.6%	3.1%
San Juan Basin	50.7%	3.1%	22.6%	51.1%	1.9%	22.2%
South Oklahoma Folded Belt	47.2%	6.6%	2.5%	44.8%	2.9%	2.2%
Strawn Basin	32.2%	11.4%	6.1%	34.1%	8.1%	6.5%
Uinta Basin	53.0%	2.0%	8.8%	46.0%	0.7%	7.7%
Williston Basin	12.6%	0.1%	0.8%	10.7%	0.0%	0.7%
Wind River Basin	36.2%	3.8%	2.2%	34.4%	1.5%	2.0%
Total	31.3%	1.2%	2.8%	29.4%	0.5%	2.6%