American
Petroleum
Institute

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GHG Inventory at:
Environmental Protection Agency,
Climate Change Division (6207A),
1200 Pennsylvania Ave. NW,
GHGInventory@epa.gov

Re: API Comments on EPA's Updates under Consideration for the 2021 GHGI: Mud Degassing and Produced Water Emissions (EPA memos, September 2020)

Dear EPA,

The American Petroleum Institute (API) appreciates the opportunity to review and provide comments on the proposed updates the U.S. EPA is considering for estimating greenhouse gas (GHG) emissions for the 2021 GHG Inventory (GHGI). The current set of comments addresses the methodologies outlined in the EPA September 2020 technical memos on Mud Degassing and Produced Water operations associated with Onshore Oil & Gas Production. API comments are primarily focused on responding to the feedback the U.S. EPA is seeking from industry as part of the stakeholders' engagement process.

API represents all segments of America's oil and natural gas industry. API was formed in 1919 as a standards-setting organization. In our first 100 years, API has developed more than 700 standards to enhance operational and environmental safety, efficiency and sustainability. Our more than 600 members produce process and distribute most of the nation's energy. Most of our members will be directly impacted by the way emissions from their operations are depicted in the national GHGI.

API's aim is to make sure that the GHGI emission estimates used are based on the best and most current data available, reflect actual industry practices and activities, and are technically correct. To assist EPA in the endeavor API has participated in EPA's stakeholders' process and expert review phases of the GHGI development process, providing comments and recommendations on the agency's proposed methodologies.

The comments below consist of brief general observations on the information provided by EPA, with responses to specific requests for stakeholders' feedback outlined in the EPA's September 2020 technical memos. API notes that the updated methodology proposed by EPA for estimating emissions from mud degassing and produced water is based largely on decades old data sources that may no longer be representative of U.S. industry practices. API recommends that EPA reconsider the merit of adopting the proposed revised methodologies, at this time, without allowing additional time for obtaining information about applicable practices.

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Mud Degassing Memo

General API comments:

Since 1977, drilling of oil and gas wells has progressed steadily, with the time required to drill a well decreasing substantially. Additionally, onshore practices are not the same as offshore practices and EPA's assumption that offshore practices are transferable to onshore are not appropriate.

- The 1977 EPA mud degassing estimates appear to be based on EPA's simplifying assumptions regarding wellbore parameters, with no reference to prior information or studies.
- It appears that in 1977, EPA calculated the volume of pore space in the drilling section (described as consisting of 12 inch diameter, 400 feet long, 25% porosity, 4,000 psi pressure), and assumed it was filled with hydrocarbon gas. It then calculated the mass of hydrocarbons and methane per drilling day in the hydrocarbon bearing formation. EPA states that compressibility was ignored in their calculations. However, considering compressibility would lower the calculated volume of hydrocarbon gas.
- EPA assumes that onshore drilling wells have drilling mud degassing systems, which are commonly used offshore, and that returning drilling mud has entrained gas equivalent to that assumed in the 1977 estimate for offshore well drilling.
  - API member companies have anecdotally stated that current onshore practices are to drill with balanced or slightly over-balanced mud systems that keep gas from being entrained in the drilling mud and that mud degassing systems are rarely needed or used.
  - EPA should gather additional information to inform current mud degassing practices for onshore drilling wells. API suggests that some of the major onshore rig companies could provide information to address this question. Another source may be the International Association of Drilling Contractors (IADC).
- API has not had sufficient time to evaluate the validity of the proposed methodology that is based on the 1977 estimates, nor to gather additional current information to inform an updated methodology.
- API recommends that EPA delay including mud degassing emissions in the GHGI until more current information becomes available.

1. *EPA seeks feedback on using the EFs in Table 1 to estimate emissions for onshore mud degassing.*

API Observations:

- The estimated emission factor (EF) presented in Table 1 of the EPA memo on mud degassing emissions represents an adjustment of the data from a 1977 U.S. EPA publication "Atmospheric Emissions from Offshore Oil and Gas Development and Production". The estimates were derived decades ago and rely on parameters for mud degassing operations at offshore gas wells using a water-based mud, which may not be representative of current practices in onshore production.

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- The oil-based emission rate was calculated by assuming emissions from oil-based drilling mud were equivalent to emissions from diesel fuel stored in a fixed-roof storage tank with a turnover factor of 0.5, which is – at best – an outdated order of magnitude estimate.
- The resulting CH4 emission factors are based on default GHGI gas content for associated gas production, of 61.2 Wt.% CH4, which may not account for nationwide variability.

2. *EPA seeks information on other available data sources that evaluate emissions from drilling mud.*

API Comments:

- API does not have recent publicly available data sources to evaluate emissions from drilling muds and has not had sufficient time to evaluate the validity of the methodology which is based on 1977 estimates.
- Clearly more current data from onshore operations is needed for updating the GHGI methodology. API supports EPA making an effort to collect such information, while API stands ready to assist in reviewing the results.

3. *EPA seeks feedback on potential adjustments to the EFs to reflect changes in drilling over time. For example, the factor was calculated assuming 400 ft/day drilling rate. The current average drilling rates might be different than what was used to develop the EF. The equation used to calculate the original EF is unavailable, so it will not be possible to update the drilling rate data and recalculate the EF. Can/should another approach be applied to adjust the EF? Further, has the increased prevalence of directional drilling increased the time that exploratory drilling travels through a rock containing exploitable quantities of hydrocarbons?*

API Comments

- The assumptions (offshore based) used in EPA's derivation of EFs are not representative of onshore drilling practices in the U.S. The derivation assumes that typical wells have a 12" diameter bore hole and 25% porosity.
  - For most current onshore wells, the bore hole size is around 8", which is 44% of the bore cross section assumed in the EPA derivation
  - The porosity for most current onshore wells is generally below 10% (tight sands, shales, and other tight formations), which is 40% of the porosity used for the EF derivation
- The activity data used for the preliminary national emissions estimate assumes an average of 26 drilling days per well.
  - Comments from API member companies indicate that a current Marcellus well (EPA's 26 day estimate was based on a 2014 report of average drilling days for a Marcellus well) takes about 10 days to drill with 2-3 of those days drilling the horizontal lateral section in hydrocarbon bearing formation.
  - EIA provides a specific example for Southwestern Energy, in the Fayetteville shale, where the field time required for drilling a well dropped from 20 days in the first quarter of 2007 to 11 days by the second quarter of 2009[1].

[1] John Cochener, Quantifying Drilling Efficiency, U.S. Energy Information Administration, June 28, 2010

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- In accordance with EPA's 1977 estimate, when accounting for drilling activity, the derived EFs should be applied only to the number of days in the hydrocarbon containing (producing) formations. In the proposed update, it appears the EPA mistakenly uses the outdated full drilling time for a Marcellus well of 26 days rather than just the amount of time drilling in hydrocarbon bearing formations.
- **Adjusting EPA's proposed estimate to account for the smaller diameter hole, lower porosity, and using an assumed (high) days of drilling in hydrocarbon bearing formation of 6 days (double the API member's highest anecdotal comments) yields a national estimate of about 6,000 metric tons of CH4 rather than EPA's estimate of around 140,000 tons.**

4. *EPA seeks feedback on the most appropriate methane content (wt%) to apply to the THC EFs to calculate CH_4 EFs for gas and oil wells. A default methane content of 61.2 wt% is used in the preliminary estimates presented in this memo. This default value is from a 1996 API report (Calculation Workbook For Oil and Gas Production Equipment Fugitive Emissions, API publication 4638, July 1996). The 1996 API report also cites a value of 68.7 wt% CH_4 for gas streams (Table 2 in the report). EPA is considering applying 68.7 wt% CH4 to gas wells and 61.2 wt% CH_4 to oil wells, but seeks feedback on the methane content values and other data sources that should be reviewed to estimate these values for oil wells and gas wells.*

API Comments:

- The default methane content used in the API Compendium for mud degassing is 65.15 Wt.%, which is based on BOEM's 2007 guidance.
- API recommends that EPA consider using available data for gas composition by NEMS region (as done elsewhere in the inventory) in order to represent the variability of methane content across the U.S.

5. *EPA seeks feedback on the split between water and oil use, and if there is regional or temporal variability in mud type usage (i.e., water, oil, and synthetic) that should be incorporated into the methodology.*

API Comments:

- Verbal information received from API members indicate that for horizontal/lateral drilling mainly oil-based muds are used, while for vertical drilling water-based muds are more frequently used.
- More quantitative information could be obtained from producers' mud engineers or from drilling support staff and mud suppliers. As indicated above, major onshore rig companies and the International Association of Drilling Contractors (IADC) may be able to provide information to help address this question.

6. *EPA seeks feedback on the variance of drilling duration over the time series and for each well type.*

API Comments:

- The time required to drill an onshore well, including a horizontal lateral, has steadily decreased as drilling technology has progressed.

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- Drilling time varies in different areas and plays across the US onshore production segment.
- Drilling time in hydrocarbon bearing formations is a fraction of the total well drilling time.
- Drilling time in hydrocarbon bearing formations is substantially lower for vertical wells than for wells with extended horizontal laterals.
- EPA should develop current information regarding well drilling times for both vertical wells and wells with horizontal laterals.
- EPA should develop current information regarding the percentage of new wells that are vertical and the percentage of wells with horizontal laterals.
- API currently does not have this information but is willing to discuss potential sources of information with EPA and would be prepared to review the data collected by EPA.

7. *EPA seeks feedback on the usage of flares on mud gas separators. Are there other pollution control devices that are in use other than flares? How should these be taken into account?*

API Comments:

- API Standard 53 on "Well Control Equipment Systems for Drilling Wells" delineates a composite of the practices employed by various operating and drilling companies in drilling operations . The standard specifies, among other requirements, that wellbore fluid sent to the mud degassing system – if such exists - shall be flow controlled. Maintenance and inspection of the mud degassing system shall be in accordance with the equipment owner's maintenance system.
- The Bureau of Land Management (BLM) Onshore Oil and Gas Order No. 2 provide details of uniform national standards for the minimum levels of performance expected from lessees and operators when conducting drilling operations on Federal lands. The details of the mud program requirements are spelled out in section III C and consists - among other requirements - of:
  - Item 2 – installation of visual mud monitoring equipment to detect volume changes;
  - Item 3 – electronic/mechanical mud monitoring equipment is required when abnormal pressures are anticipated;
  - Item 6 – Installation of gas detecting equipment in the mud return system is required for exploratory wells or when abnormal pressure is anticipated;
  - Item 7 - All flare systems shall be designed to gather and burn all gas;
  - Item 8 - A mud-gas separator (gas buster) shall be installed and operable for all systems of 10M or greater.
- As a general practice, ambient combustible gas detectors are typically placed at various locations around the drill site to measure the levels of combustible gas in the atmosphere and serve as safety alarms near the shale shaker and mud pits, among other locations. From API members' experience it seems that they almost never alarm, since the hydrostatic head of the mud column – for balanced or slightly overbalanced wells - keeps the formation gas in the formation rather than in the mud and ambient concentrations rarely reaches the alarm level.

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Produced Water Memo

1. *EPA seeks feedback on the fraction of oil wells that are low pressure, including whether it is reasonable to apply an average of 73 percent of oil wells using artificial lifts*.

API Observations:

- EPA's September 2020 memo states that it is using data developed for the 2017 NEI to quantify the amount of produced water generated by oil and gas drilling activities.
- EPA cites a survey of produced water management practices that was conducted by the Ground Water Protection Council in 2015. The survey results seem to indicate that around 84% of the produced water is reinjected into formations (38.9% for disposal and 45.1% for EOR) and the remaining 16% is discharged via surface activities.
- API does not have any additional publicly available data to further support the distribution of produced water management activities, or the fractions of low pressure or high pressure oil wells and what is the fraction of oil wells using artificial lifts.

2. *EPA seeks feedback on the percent of produced water that releases emissions (e.g., through tank flashing or evaporation in a pond), including whether the assumption that 30 percent of produced water undergoes tank flashing is reasonable*.

API Observations:

- As defined, produced water consists of any water trapped in underground formations and which is brought to the surface (produced) along with oil, gas and condensate. Once the stream is brought to the surface it is separated into oil, gas, condensate and water fractions and routed to an applicable tank battery (tank storage facility).
- Current regulations under 40CFR60 subpart OOOOa require that each storage vessel that exceed an emissions threshold of 6 tons of VOC per year should be controlled to reduce emissions of VOCs by routing the emission vapors to a recovery device, a flare or other control device that are at least 95% efficient.
- The regulatory requirement specified above should be addressed in conjunction with the produced water management practices. Based on the produced water management practices survey performed by the Ground Water Protection Council, it is possible that only 16% of produced water have the potential of being stored in a tank battery that could potentially flash; though these emissions may be controlled in accordance with recent regulatory requirements.

3. EPA seeks feedback on updating the current GHGI EF for gas wells, currently applied to only certain CBM formations to instead use the updated EF for all gas well produced water.

API Comments:

- API supports using a combined EF to represent emissions from CBM and gas formations.

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API reiterates that the data available for updating the emission estimation from mud degassing and produced water, as presented in the two EPA memos, is sparse and relies on dated information. These source categories have previously not been considered large emitting sources, so it might be best to defer the inclusion of these sources in the 2021 GHGI while EPA collects more information.

API plans to continue to compile and analyze greenhouse gas (GHG) emissions data for petroleum and natural gas systems and is committed to working with EPA in the future on utilizing data provided through EPA's mandatory GHG reporting program (GHGRP) and other relevant information sources.

API welcomes EPA's willingness to work with industry to improve the data used for the national inventory, and would welcome follow-up discussions to help chart a path forward. API encourages EPA to continue collecting new information through these collaborative discussions and focused surveys.

API and its members are committed to continue their collaboration with EPA to make best use of the information available under the GHGRP, or other appropriate information/data collected by EPA, to improve the national greenhouse gas emission inventory.

Sincerely,

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