TO: Kate Cardamone, U.S. EPA

FROM: Hemant Mallya, Ryan Abraham, ICF International

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SUBJECT: Mandatory Greenhouse Gas Reporting: Changes in National Cost Estimates Associated with Final Amendments to 40 CFR Part 98, Subpart W – Petroleum and Natural Gas Systems of the Greenhouse Gas Reporting Program

On November 8, 2010, Administrator Jackson signed a rule that finalizes reporting requirements for the petroleum and natural gas industry under 40 CFR Part 98, the regulatory framework for the Greenhouse Gas (GHG) Reporting Program (11/30/10; 75 FR 74458).

This final rule requires petroleum and natural gas facilities that emit 25,000 metric tons or more of carbon dioxide (CO_2) equivalent per year to report annual methane (CH_4) and CO_2 emissions from equipment leaks and venting, and emissions of CO_2, CH_4, and nitrous oxide (N_2O) from gas flaring and from onshore petroleum and natural gas production stationary and portable combustion emissions and combustion emissions from stationary equipment involved in natural gas distribution.

EPA is amending specific provisions in Subpart W of the GHG rule to resolve issues and questions raised during implementation, and to correct technical and editorial errors that have been identified since publication. This memorandum documents how these proposed revisions would affect the estimated compliance costs presented in the Economic Impact Analysis for the 2010 final rule.[1]

Amendment to Gas Well Completion Sampling Requirement: Estimated Change in Compliance Cost

EPA has revised the methodology for onshore production facilities' gas well venting during completions with hydraulic fracturing and workovers with hydraulic fracturing. Instead of requiring the sampling from at least one gas well completion and workover per field ("field method"), the proposed methodology would require sampling of the average flow rate of gas based on a graded scale within a sub-basin category ("sub-basin method"). A sub-basin has been defined as:

> *a subdivision of a basin into the unique combination of wells with the surface coordinates within the boundaries of an individual county and subsurface completion in one or more of each of the following five formation types: oil, high permeability gas, shale gas, coal seam, or other tight reservoir rock. The distinction between high*

[1] See http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_EIA.pdf for the Economic Impact Analysis.

permeability gas and tight gas reservoirs shall be designated as follows: high permeability gas reservoirs with >0.1 millidarci permeability, and tight gas reservoirs with ≤0.1 millidarci permeability. Permeability for a reservoir type shall be determined by engineering estimate. Wells that produce from high permeability gas, shale gas, coal seam, or other tight reservoir rock are considered gas wells; gas wells producing from more than one of these formation types shall be classified into only one type based on the formation with the most contribution to production as determined by engineering knowledge. All wells that produce hydrocarbon liquids and do not meet the definition of a gas well in this sub-basin category definition are considered to be in the oil formation. All emission sources that handle condensate from gas wells in high permeability gas, shale gas, or tight reservoir rock formations are considered to be in the formation that the gas well belongs to and not in the oil formation.

While this change from field to sub-basin method does not change the cost per sample estimated in the November 2010 final rule, it decreases the total number of samples that will be reported from well completions and workovers. Specifically, the number of samples expected from reporters in the first year will decrease for completions and workovers from 1,970 to 1,670. Accordingly, the average compliance cost in the first year will decrease from $14,356 to $14,182 per onshore production facility. In addition, the compliance cost in subsequent years will decrease from $7,425 to $7,338 per facility. The table below summarizes the change in compliance costs associated with the proposed sub-basin method.

Table 1. Summary of First Year Compliance Cost for Field and Sub-Basin Methods (Gas Well Completions and Workovers with Hydraulic Fracturing)

Costs and Samples for Reporters	**Field Method** (Nov 2010 Final Rule)	**Sub-Basin Method** (December 2011 Final Rule)	**Difference between Methods**
First Year Cost per Facility ($)	$14,356	$14,182	($174)
Subsequent Year cost Per Facility ($)	$7,425	$7,338	($87)
Total National Cost ($ million)	$10.7	$10.6	($0.1)
Cost Effectiveness ($/tonneCO2e)	0.05	0.05	-
Number of Samples for Completions and Workovers with Hydraulic Fracturing (Count)	1,970	1,670	(300)

†The cost figures in this table include costs associated with reporting both process and combustion emissions.

Amendment to monitoring at transmission-distribution transfer station instead of custody transfer stations: Expected impact on the number of stations monitored on an annual basis.

The November 2010 Final Rule required natural gas distribution reporters to conduct leak detection at "custody transfer" stations. Under that rule, EPA estimated a total of approximately 9,500 "custody transfer" stations would be monitored nationally; EPA's analysis was based on the best available data and accounted for the monitoring cost of these stations. In response to confusion about what constitutes a "custody transfer" station, EPA proposed in the September 2011 technical corrections rule to require monitoring of "transmission-distribution transfer." American Gas Association (AGA) and several other natural gas distribution companies in their comments to the September 2011 proposal agreed that they clearly understood the term "transmission-distribution transfer" (T-D transfer) station. However, AGA pointed out that a survey of 42 of their "larger member" natural gas distribution companies indicated that these 42 companies have 20,781 T-D transfer stations. EPA has determined that 24 of the largest natural gas distribution company reporters for Subpart W account for about 50 percent of the total miles of mains from all reporters. Assuming that miles of mains are correlated with the number of T-D transfer stations for a natural gas distribution company, EPA expects that approximately 35,000-40,000 T-D transfer stations will have to be monitored. However, given the large number of T-D transfer stations that would need to be monitored, EPA in the December 2011 final rule allows reporters to spread their monitoring at these stations over a maximum five year period. Therefore, on an annual basis less than 9,500 stations will need to be monitored. Therefore, the cost estimate for the November 2010 final rule (based on 9,500 stations per year) provides a conservative estimate of the annual monitoring required under the December 2011 final rule (less than 9,500 stations per year).

Amendment to monitoring of non-compressor driver internal combustion equipment.

The December 2011 final rule provides an equipment threshold of 1 MMBtu/hr for internal combustion equipment located in onshore production and natural gas distribution facilities. This equipment threshold does not apply to compressor drivers. Equipment under this threshold does not have to be monitored for emissions and reporters only need to report a count of equipment by type (i.e. activity data only). Since this equipment threshold does not add any new reporting requirements and only excludes certain small non-compressor combustion equipment from emissions monitoring, there is no cost increase from this change.

Other Amendments to December 2011 Technical Revisions to Subpart W

EPA has revised several other provisions in Subpart W. EPA has determined that these revisions do not affect the compliance costs estimated in the Economic Impact Analysis for the 2010 final rule. These revisions are categorized as follows:

1. Provide additional flexibility for reporters based on questions raised during implementation.
2. Simplify existing monitoring methods.
3. Clarify existing industry segment definitions.

4. Correct and clarify inconsistencies in monitoring methodologies.
5. Correct and clarify data reporting requirements.
6. Change STP definition for temperature.
7. Add and clarify other existing definitions.

See Appendix A for an elaboration on each of these revisions and examples from the revisions.

Appendix A: Revisions that Do Not Affect Cost Estimates

1. **Provided additional flexibility for reporters:** Based on alternative monitoring methods requested by trade associations, questions submitted by potential reporters, and comments received on the September 2011 proposal, EPA has provided additional flexibility in the monitoring methods for estimating emissions from the following sources:
    - Pneumatic devices and pneumatic pumps – use a default 8760 hours of operation per year when actual operating hours may not be available.
    - Calibration of acid gas recovery CEMS/ vent stack meter – use manufacturer's instructions or industry standard practice instead of using Subpart A meter calibration requirements.
    - Gas well liquids unloading - measure the natural gas flow rate of a liquids unloading event for each **sub-basin**, pressure range, and unique tubing diameter, instead of measuring the natural gas flow rate of a liquids unloading event for each well tubing diameter and producing horizon/formation combination in each gas producing **field**.
    - Gas well completions and workovers - use an alternative method where each completion or workover flowback volume is measured using a meter for all the wells in a sub-basin category as opposed to using a one-time flow rate measurement for one well in each sub-basin category.
    - Blowdown vent stacks – track the volume of each blowdown occurrence instead of estimating the annual average for all blowdown occurrences. Flare stacks – measure emissions using continuous emission monitoring systems (CEMS), instead of not allowing reporters to determine flaring emissions using CEMS.

    These methods do not replace any of the lowest cost methodologies that were modeled in the cost analysis for the final rule and therefore do not impact the final rule's cost estimate. In short, EPA expects only those reporters that already have high cost options in place to use them; other reporters have been assumed to use the low cost option as in the final rule.[2] EPA therefore expects that they will not incur the entire cost of even the low cost option. That is, the EPA cost assumption is conservatively higher for these reporters that already have the high cost options in place.

[2] Potential reporters will still be able to determine emissions from liquids unloading and flare stacks using an engineering calculation, which EPA determined to be the lowest cost methodology. Potential reporters can also still use the low cost option to determine the annual average emissions from blowdown volumes.

2. **Simplified existing monitoring methods:** EPA has made several changes to the monitoring methods that will potentially simplify monitoring and reporting emissions, as follows:
    - Pneumatic devices and pneumatic pumps – determine type of pneumatic device using engineering estimate based on best available data instead of not specifying how to determine the type of pneumatic device and pneumatic pump.
    - Transmission storage tanks – measure emissions from vent stack without performing leak detection versus requiring the leak detection before measuring a leak. An additional option to use calibrated bags and high flow samplers in addition to the existing options to use meters. Also, an additional option to use stethoscope type acoustic devices to detect leaks.
    - GHG volumetric emissions – use default gas composition for CH_4 and CO_2 in natural gas for onshore natural gas transmission, underground natural gas storage, LNG storage, LNG import and export terminals, and natural gas distribution instead of requiring facilities to either use existing gas composition to estimate average annual values or sample gas to determine composition.

    These simplifications do not impact the cost analysis for the final rule because they do not significantly change the assumptions made for how potential reporters will comply with the rule.

3. **Clarification of existing industry segment category definitions:** Based on questions and inputs received from potential reporters and trade associations during implementation, EPA has clarified the definitions for the following industry segments: onshore petroleum and natural gas production; onshore natural gas processing; onshore natural gas transmission; and natural gas distribution. These proposed revisions do not change any of the segment boundaries and will not have any impact on who reports or the total number of reporters. Consequently, these revisions do not change the cost estimates. A list of these revisions is provided in the Background Technical Support Document for the December 2011 Subpart W Final Rule.

4. **Corrections and clarifications to equations and calculation methodologies:** Based on input from potential reporters and EPA internal review, EPA had identified several inconsistencies and opportunities for clarification to the calculation methodologies in §98.233 and proposed them in the September 2011 proposal. In addition, commenters identified several necessary corrections and clarifications. EPA has made necessary corrections and provided clarification to these equations. A detailed list of corrections to the Equations is available in the Background Technical Support Document for the December 2011 Subpart W Final Rule. These equation changes provide clarity only and do not change

the inputs required to perform the calculations. Therefore, these revisions do not change the cost estimates.

5. **Change standard temperature and pressure (STP) definition for temperature:** Based on inputs from reporters, EPA has changed the STP definition for temperature from 68 °F to 60 °F. This change resulted in the adjustment of emissions factors from 68 °F to 60 °F. Since emission factors are static numbers within equations there is no cost impact from this change. Also, industry meters are calibrated at 60 °F per input from commenters on the September 2011 rule proposal. Hence, there is no overall cost impact from this change.

6. **Corrections and clarifications to data reporting requirements:** Potential reporters had raised questions and identified several inconsistencies in the reporting requirements in §98.236. EPA has made corrections and provided clarifications as follows:
    - Gas processing plant facility threshold – Clarify that the 25 MMScfd facility threshold is an annual average daily throughput.
    - Dehydrator equipment threshold – Clarify that the 0.4 MMScfd equipment threshold is an annual average daily throughput.
    - Emergency blowdowns – Clarify that only emergency blowdowns with human intervention need to be reported.
    - Separator equipment threshold – Clarify that the 10 barrels per day equipment threshold is an annual average daily throughput.
    - Gas well testing venting and flaring – Clarify that gas wells use dry gas production rate to calculate emissions because gas to oil ratio is not available in such cases.
    - CH_4, CO_2 and N_2O emissions – Clarify that emissions for each gas must be reported separately.
    - Flared and vented emissions – Clarify that flared and vented emissions must be reported separately.
    - Recovered emissions – Clarify that any recovered emissions must be reported separately.
    - Level of reporting – Clarify whether a specific requirement is on a per equipment basis, facility level, annual average, or any other applicable level of reporting in Subpart W.
    - Unique ID name or ID number – Addition of unique ID name or ID number for applicable source types, other than in onshore production segment.

    There is no change in the cost estimates from these proposed corrections and clarifications. Also, there is only one addition to the data reporting requirement. EPA has added an overarching requirement for each onshore production facility to report average API gravity, gas-to-oil ratio (GOR), and low pressure separator pressure for each sub-basin within the facility for the oil sub-basin. However, EPA understands that this information is already available to the facility operators because it is needed to conduct business. Oil and gas operators know the GOR and API gravity because they are determined at least once a year to pay taxes, royalties, and in general for selling oil and gas. Those operators who use method 1 in 98.233(j) to estimate emissions from tanks will already collect their low pressure separator pressure. Also, those who do not use method 1 for estimating tank emissions can still collect this information when they collect equipment counts for estimating fugitive emissions. Finally, the data documentation and report submission costs in the final rule already account for any post processing of data collected and reporting. That is, the final rule already accounts for time to collect equipment count at each well pad; collecting one more piece of information at that stage does not increase the cost estimate. Therefore, EPA does not expect additional costs for reporting this data. A list of new definitions and changes to the reporting requirements is provided in the Background Technical Support Document for the Subpart W December 2011 final rule.

7. **Added and clarified existing definitions:** EPA provided new definitions and clarified existing definitions. The proposed addition of these definitions are meant to help reporters understand the monitoring and reporting requirements finalized in the November 2010 rule; they do not add new requirements and therefore do not change the cost estimates.