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National Inventory Systems and International Reporting Branch
Climate Change Division
Department of Industry, Science, Energy and Resources
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(via e-mail to: [redacted]*)*

RE: 2021 NATIONAL GREENHOUSE AND ENERGY REPORTING (NGER) SCHEME AMENDMENTS: APPEA COMMENTS

I refer to your release on 4 May 2021 of a package of proposed amendments/updates to the *National Greenhouse and Energy Reporting Regulations 2008* (NGER Regulations) and the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* (the Measurement Determination), for comment by 21 May 2021.

The Australian Petroleum Production & Exploration Association (APPEA) welcomes the opportunity to provide comments on the draft Amendments and to continue to work with the Department to align domestic and international emissions reporting and to improve the rigour and transparency of aspects of the National Greenhouse and Energy Reporting System (NGER) as it relates to the oil and gas industry.

These comments follow our engagement with the Department on a range of NGER issues in recent years and follow comments provided to you most recently on 19 April 2021. We note responses from the Department to those comments are not reflected in the draft amendments that have been released for public consultation. We look forward to your response to those comments.

GENERAL COMMENTS

Notwithstanding the ongoing consultation that has taken place in recent years, a number of key concerns remain. In addition, the package of amendments released on 4 May 2021 contain a number of new proposals that have not been previously considered and for which the brief consultation period that has been allowed for to respond to this package of amendments means a fully considered response has not been possible. For many of these proposed amendments / updates APPEA recommend further consultation is required.

In summary:

- As noted above, the Department has not yet incorporated the feedback that was provided in APPEA's letter of 19 April 2021. A number of important technical issues that were raised in that letter where further and more detailed consideration is required. While we welcome the responses that were provided by e-mail on 21 May 2021, the day comments were due to the Department, **a number of those comments require more detailed discussion / consultation and these parts of the package of amendments will not be ready for introduction until the issues that have been identified are resolved.** Two responses to the Department's responses, which illustrate (not in an exhaustive manner) areas where further consultation is required, can be found at Attachment 1.

- One of the key issues raised was the proposed methodology on emission factors based on leak detection and repair (LDAR) programs. **While we appreciate the intent behind the proposals to incorporate the results of an LDAR program on emissions reporting, the approach taken in the current drafting is practically unworkable and would very difficult, if not impossible, to implement.** Further details are set out below.
- We also appreciate that the Department has suggested that reporters can use information from forthcoming CSIRO study (due later in 2021-22) from the 2021-22 financial year. To ensure this can occur, **this suggestion needs to be appropriately reflected in the legislation and regulations, otherwise there is a significant risk that there will not be a mechanism under NGER for us to use any CSIRO-based factors that may flow from the results of that study.**
- The package proposes significant updates to fuel combustion emissions that are ambiguous, have a significant upward impact on emissions. While these proposals are based on new US research, the Government is proposing factors based on emission factors published in the 2006 IPCC report sourced from US EPA AP42. In addition, these proposals are new to this package and have been drafted without detailed industry consultation. As we have seen through ongoing consultation with the Department on a range of NGER amendment/update proposals, the final proposed amendments have benefited from ongoing and considered consultation, which has improved both the technical rigour and 'workability' of the proposals. To that end, **APPEA recommends these amendments be removed from the 2021 package and following further consultation and consideration during the course of 2021, be included in a 2022 package of amendments.** Further details are set out below.

SPECIFIC COMMENTS: FUEL COMBUSTION

The Department is proposing a significant change to the mandatory methane emission factors which are applicable if the facility is in oil and gas extraction and the fuel is not combusted for electricity generation.

The methane emission factors are sourced from USEPA AP42 (and republished in IPCC 2006) and are technology specific (for example, turbines, internal combustion engines, boilers). The methane emission factors are not dependent on the industry segment the fuel gas is combusted nor what the energy derived from the combustion is used for, as has been suggested by the Department.

Any updates to fuel combustion should apply to all industries using similar equipment. However, the package of amendments has limited these updates to just the oil and gas industry through the use of the industry classifications contained in the Australian Bureau of Statistics *Australian and New Zealand Standard Industry Classification* publication. The Department suggests that these changes are based on US research into upstream oil and gas facilities, but they have applied to upstream and midstream (that is, including LNG facilities) facilities through the use of the ANZSIC classification. The source of the emission factors, USEPA AP42, does not support this differentiation.

The emission factors are dated (1993-1996) origin and based on a sample of 20 emission tests conducted in the United States between 20-30 years ago. There is a risk that the emission factors do not represent current installed technology. Publication of factors with little consideration of more recent low emissions technology risks a simplistic set of factors that do not reflect modern industry operations and practices. The industry is currently involved in a measurement campaign with CSIRO that includes measurement of methane emission from internal combustion engines currently installed and operating in Australia. This measurement campaign should be extended to other industry sectors to inform improved methane emissions from other industry sectors (for example, internal combustion engines involved in electricity generation).

In addition, the fuel combustion emissions changes are in many cases not clearly drafted and ambiguous and is likely to increase reported fuel emissions by tens of thousands of tonnes, depending on the approach taken by the Regulator in interpreting the legislation. Purely based on the USEPA AP42 factors published in the 2006 IPCC factors, the largest impact would be seen in those facilities with gas-fired lean burn engines, with a lesser impact at those sites with gas-fired rich burn engines.

While the proposed legislation allows substitution of 2006 IPCC factors with site manufacturer specifications (if available) which may provide an opportunity to mitigate some of the impact where low emissions technology is in place, this also creates a significant amount of reporting/compliance burden in researching technology types in operation at facilities and whether the proposed factors are relevant and/or whether there are manufacturer equivalent factors.

APPEA recommends these amendments be removed from the 2021 package and following further consultation and consideration during the course of 2021, be included in a 2022 package of amendments. This will allow the change to methane reporting to be applied to the correct industry sectors/combustion technology types and be informed by Australian measurement data.

SPECIFIC COMMENTS: LDAR ISSUES

APPEA notes the package of amendments includes revised provisions for LDAR, which would enable a reporter to utilise 'non-leaker' LDAR factors for particular components (such as valves, pumps and so on) as a Method 3 fugitive method across the following activities: wellheads; offshore platforms; gathering and boosting stations; natural gas processing; natural gas storage; and natural gas liquefaction.

The provisions require that:

- The LDAR program must survey each component (that is, each valve, each pump) used in the activity area (such as wellheads, gathering and boosting stations and so on) at least once in a reporting year.
- If the LDAR program is adopted it must be used for all of the relevant activities in the NGER facility (that is, wellheads, gathering and boosting stations and so on).
- The LDAR program must be in accordance with either Title 40, Part 98 of the Code of Federal Regulations, US or USEPA Method 21 (which may be different in approach to methods used under certain Australian state-based LDAR programs).
- There is a large differential between a 'non-leaker' versus a 'leaker' factor. For example, for a valve a 'leaker' is ~ 740 times higher than a 'non-leaker'.

- It is not specifically stated in the legislation but it would appear that if you cannot meet the LDAR program coverage/frequency requirements you cannot use the LDAR factors.

While as noted above, APPEA appreciates the intent behind the proposals to incorporate the results of an LDAR program on emissions reporting, the approach taken in the current drafting is practically unworkable and would very difficult, if not impossible, to implement. For example:

- *Overly restrictive LDAR provisions*: the requirement that one can only use an LDAR program if the survey requirements have been met for all relevant activities is impractical. In particular it:
    - Penalises integrated upstream gas NGER facilities which encompass integrated wellhead through to gathering and boosting activities as the proposal is impractical. As an example, at one onshore gas facility in Queensland, the operator of that facility would need to survey every component on hundreds of wells and numerous gathering and boosting stations before it could use any LDAR program results. This requirement is well above the requirements of the relevant LDAR regulatory approach in Queensland and would impose a large and unnecessary reporting and compliance burden on reports. A more pragmatic approach is required in the amendments.
    - Expects the reporter to survey every component at least once a year.
    - Requires the program to be in line with US LDAR programs which may be different to existing State-based and in many cases world-leading programs.
        - For example, reporters may have implemented an LDAR program that does not use an USEPA 21 instrument or optical gas imaging (OGI) camera or use a remote survey method that is not strictly compliant with the requirements of the USEPA method 21[1].
        - APPEA therefore recommends the amendments allow LDAR programs that utilise remote methane detection surveys which may include a combination of drive-by, fixed sensor for example, drive-by and fly-over methane surveys.
        - In addition, APPEA recommends the amendments allow for an LDAR programs based on a remote methane survey approach with a specified concentration that the sensor can detect to identify leakers, allowing reporters to apply the leaker / non-leaker emission factors (subject to the comments below) for the components present at the device (for example, the wellhead) based on the remote survey results[2].
- *Large differential between 'non-leaker' and 'leaker' factors*: for example, reporters have strict, rigorous and robust asset integrity process which includes, for some members, the use of FLIR optical gas imaging cameras.
    - As an example, for one APPEA member, for the FY19 year, a total of 29 leaks across >38,595 methane contacting components have been identified, a leak rate of 0.08 per cent. However, the calculation methodology contained in the proposed amendment package would imply emissions of 25,700 t CO_2-e, which is equivalent to a methane loss

[1] Reporters that operate many hundreds of wells utilise a pragmatic approach to surveying vast areas of well pads and gathering pipelines. It would be impractical to implement a methane survey method where each individual component is tested by using the prescribe USEPA 21 instruments or OGI cameras as specified in the proposed method.

[2] The remote methane detection surveys used for leak detection at well heads and gas gathering pipelines typically have methane detection limits in the range of 2 to 10 ppm. Where methane detection occurs above a given threshold, further investigation takes place to identify the source and enable repair of the identified leak.

rate of 918 t CH_4 per year. This is not a credible result from such a small number of leaks (it would equal 32 t CH_4 per leak per year).

SPECIFIC COMMENTS: FUGITIVE EMISSIONS THAT RESULT FROM DELIBERATE RELEASES FROM PROCESS VENTS, SYSTEM UPSETS AND ACCIDENTS – WELL COMPLETIONS

Subsection 3.3.2.3.1 Method 1 introduces new emission factors based on list of equipment types for well completion (Section 3.46AB) and well workover (Section 3.85P).

Both well completion and well work over consider hydraulic fracturing as an equipment type. Facilities that apply hydraulic fracture stimulation for CSG wells may undertake this process upon completion of drilling of a well prior to well completion, or later on post well completion to improve production from the well. There is often a time lag between hydraulic fracture stimulation and well completion – this could be a number of months – which may result in the wells being hydraulic fracture stimulated in one reporting year whereas the well completion occurs in the following year. The proposed Method 1 therefore would result in double reporting.

APPEA also notes that the proposed Method 4 is the same as the current Measures Determination Subdivision 3.3.2.3 section 3.84 Method 1 which does not refer to hydraulic fracture stimulation of a well during completion or workover.

The proposed amendments also require clarification that:

- The activity of hydraulic fracture stimulation of CSG wells can be considered as a standalone activity independent from well completion or well workover where reporters chose to utilise Method 4.
- Reporters then may estimate emissions from hydraulic fracture stimulation of CSG wells as per current Determination method described in section 3.84 Method 1—emissions from system upsets, accidents and deliberate releases from process vents.

SPECIFIC COMMENTS: DIVISION 3.3.6D 3.73NB METHOD 2— PRODUCED WATER (OTHER THAN EMISSIONS THAT ARE VENTED OR FLARED)

Method 2 allows reporters to use average pressure and salinity to determine the emission factor. The proposed amendment prescribes that the average pressure to determine the emission factor is based on the average pressure for the "*water stream entering the separator*".

The language used in the method description does not consider that CSG wellhead infrastructure does not always have a separator. Consistent with the intention of Division 3.3.6D to report on the volume of entrained gas in produced water that emits from the produced water to atmosphere at some point during the production and processing, APPEA recommends the amendments allow reporters to determine the volume of entrained gas based on the average water pressure of the water line (water gathering pipeline) after the gas and water separation process for gas production, rather than the "water stream entering a separator". In this way, reporters are able to calculate more accurately the volume of entrained gas in produced water that emits to atmosphere downstream of the well, through vents in the water gathering pipelines, at water gathering station, tanks, ponds and/or at water treatment facilities.

APPEA also recommends the Department rephrases the section 2(a) and 2(b) as set out below:

2(a) *if the <u>average water pressure</u> during the year (**WP**) is less than 345 kilopascals and*
2(b) *if the <u>average water pressure</u> during the year (**WP**) is equal to or greater than 345 kilopascals—is calculated under subsection (3);*

APPEA also recommends that the amendments provide for emission reduction measures such as gas capture and recovery systems that are developed to minimise the emission of methane from entrained gas in produced water. There is currently no allowance in the amendments to reflect emission reductions achieved by these types of measures.

SPECIFIC COMMENTS: INTERACTION WITH SAFEGUARD MECHANISM BASELINES

Additionally, for facilities that have a safeguard mechanism established using Method 1, options for re-baselining include maintaining the original baseline. However, under this approach facilities are not allowed to update their emissions calculation method selection. The significant step change in emissions calculated using the new Method 1 compared to the historical Method 1 potentially causes the asset to incur financial liability for the volume of carbon emissions exceeding its baseline, an outcome that is inconsistent with the policy approach of the safeguard mechanism itself.

APPEA looks forward to your response to these comments and to continuing our constructive engagement on these issues.

ATTACHMENT 1

Section	APPEA Comment	DISER Response	APPEA Comment in response to DISER Response
Division 2.3.5 — Method 2 — emissions of methane from the combustion of gaseous fuels	If Method 2 is used for methane emissions from gas combustion and Method 2 is used for estimated CO_2 – the oxidation factor for estimating CO2 emissions should not be 1.0. An oxidation factor of 1.0 indicates there is 100 per cent oxidation of methane to CO_2, if there is significant methane emissions from gas combustion, the oxidation factor cannot be 1.0. Refer to Division 2.33 Subdivision 2.3.3.1, Section 2.22 (1): OF_g is the oxidation factor 1.0 applicable to gaseous fuels. **Recommendation:** Revise the oxidation factor for CO_2 in Division 2.33 Subdivision 2.3.3.1, Section 2.22 (1) where Method 2 for methane is used to ensure the estimation method for CO_2 is accurate. For example:	Thanks for the suggestion. There are pros and cons with this idea. One con is that this kind of suggested approach is meant to work with a higher GWP than what we apply in NGERs. And, for example, we note that the API Compendium provides a detailed example calculation of CO2 and CH4 emissions from gas combusted in engines in section 8-81 to 84. The example calculation shows the CO2 EF fully accounting for all carbon in the fuel – making no adjustment for the carbon in the CH4 EF. Anyway, we'll reflect a bit more on what to do and we'll look forward to seeing your final advice.	The statement that this kind of suggested approach is meant to work with a higher GWP than what we apply in NGERs is not correct. The suggested approach is consistent with a carbon balance over a fuel combustion system. **If significant quantities of methane are passing through the combustion system without being oxidised to CO_2, the oxidation factor for CO_2 cannot be 1.0**. If the methane emission factors are introduced – and the oxidation factor for CO_2 is maintained at 1.0 –**then the amendments will have systematically introduced double counting into the Australian greenhouse emissions inventory.** The suggested approach merely balances the carbon balance from inputs through to outputs and is relatively standard practice for greenhouse emissions reporting. The comparison with the example API example calculation and justification that

	• If the methane emission factor is 15 kg CO_2e/GJ (lean burn gas combustion), the derived oxidation factor is 0.97 not 1.0. • If the methane emission factor is 2.5 kg CO_2e/GJ (rich burn gas engine), the derived oxidation factor is 0.995. The oxidation factor can be calculated using the following formulae: $$OF = 1 - \frac{(EF_{CH4}/GWP_{CH4})}{(\rho/EC)}$$ where: OF = Oxidation factor EF_{CH4} = Emission factor for methan GWP_{CH4} = Global warming potential f methane ρ = Density of gas combustion EC = Energy content of gas comb (high heating value basis)		incorporation of an adjusted oxidation factor is not valid. In the API example, 627x10^6 scf of "fuel gas" is combusted resulting in 39,900 t CO2e (assuming 100% oxidation efficiency). The example calculation shows that 53.5 t CH_4 and 61.3 t CH_4 are released from a mix of rich and lean burn engines. If we back calculate the derived fuel oxidation factor for this example the oxidation factor is 99.23% - so the CO_2 emissions are overstated by <1%. For this example, assuming an oxidation efficiency of 100% is within 1% of the more accurate result. The example is skewed because the bulk of the fuel is combusted in rich burn engines (3 engines at 2,200 hp – whereas the example has only 1 lean burn engine at a lower power rating of 1,200 hp). If we were to look at lean burn engines <u>only</u> and a proposed emission factor of 15 kg CO_2-e/GJ (HHV) (consistent with IPCC, USEPA AP42 and a GWP for methane of 28 kg CO_2-e/kg CH4) – this results in a derived oxidation efficiency of 97.1%. For CSG combustion, a typical CO2 emission factor using Method 2 and 100% oxidation is ~49.5 kg CO_2-e/GJ.

			The proposed methane emission factor for a lean burn engine is 15 kg CO_2-e/GJ and N2O is 0.03 t CO_2-e/GJ. Using this approach, the total GHG emission factor for CSG combustion is **64.53 kg CO_2-e/GJ**. Using the more accurate method, accounting for the 'methane slip' results in a CO_2 emission factor of 48.0 kg CO2e/GJ, methane emission factor of 15 kg CO_2-e/GJ and N2O EF of 0.03 kg CO_2-e – total GHG emission factor for CSG combustion is **63.0 kg CO_2-e/GJ**. The difference for a lean burn only example is significant – and therefore should be considered. The method produces more accurate greenhouse gas emission estimates.
Division 3.3.6A, 3.73B Method 2 — Onshore natural gas production, other than emissions that are vented or flared — wellheads	Note that Method 2 emission factor sourced from API Compendium applies to "metering stations/custody transfer meters" (also referred to as "natural gas customer meters" in the US GRI reports), that is, custody transfer meters which are "mini installations" in themselves, the emission factor does not apply to every single gas meter, of which there are hundreds.	We do not see any discussion in the text of the API Compendium suggesting the need for a limited interpretation of this term as suggested by this comment.	In Appendix C of the API Compendium, where the derivation of the meter emission factor is presented. It states that average counts for fugitive sources for a "meter" includes: • 91 connectors, • 21 valves, • 4 open ended lines Please refer to page C-16.

	Recommendation Define metering stations so that the emission factor is correctly applied.		Similarly, refer to Table C-9 on page C-17 and it can be seen that "meters: consist of many equipment points (valves, connectors, open ended lines). They are not just referring to a flow meter. A "meter" is not just a gas flow meter installed inside a pipe. A "meter" referred to in the API Compendium is a custody transfer metering station. If you reflect on the quantity of emissions estimated coming from an "API meter" it seems obvious this is a significant installation with many possible sources of potential fugitive pathways (for example, a metering station) and not just a flow meter which has minimal fugitive pathways.