

The Secretary
Ministry for the Environment
PO Box 10362
Wellington 6143

Dear Sir

Todd Energy Submission on Draft Climate Change (Stationary Energy and Industrial Processes SEIP) Regulations 2008

Thank you for the opportunity to comment on the draft SEIP Regulations.

Todd Energy (Todd) is a privately owned New Zealand energy company. It is New Zealand's largest domestically-owned energy business and the second largest contributor to the country's energy supply. Todd has diversified interests in oil and gas exploration and production, natural gas and LPG wholesale and retail, electricity generation (gas co-generation, hydro and geothermal) and retail, and solar energy .

1. Overview

Todd has a number of concerns about the proposed regulations, in particular :

- Flawed equation (methodology) for calculation of emissions liability of both mandatory and opt-in participants
- Lack of clear definition of the terms “natural gas mined”, “unprocessed gas”, and “processed gas”, leading to uncertainty
- Whether or not the terms “unprocessed gas” and “processed gas” should even be used
- Use of (generic) default emissions factors
- Serious over-estimate of the emissions factor for “unprocessed gas”
- The proposal to adopt an “average” emissions factor for specification gas
- Several issues surrounding the calculation of the liability for opt-in participants

These concerns are elaborated upon below.

Our general impression is that the proposals embodied in the draft regulations have been cobbled together hastily without adequate consideration being given to the complexities or practicalities of the matters being dealt with. In places it appears that the regulations

have been tailored to accommodate the specific (eg downstream interests at Kapuni) at the expense of the wider upstream situation.

Another general comment is that there appears to be an element of “re-inventing the wheel “.... hydrocarbon accounting is already in place for various Petroleum Act obligations (reserves and reservoir management, royalties calculations, Energy Resource Levies). It would make sense to apply existing principles, data collection points etc to emissions accounting wherever practical.

2. Flawed methodology for calculation of the emissions liability of both mandatory and opt-in participants

The proposed methods for calculation of the emissions liability of both mandatory and opt-in participants are set out in clauses 16 and 49, respectively.

As it stands , the equation for calculating the liability of upstream participants who mine natural gas(clause 16) is flawed because:

- (a) At the point of valuation, which for most fields is at the fiscal gas sales metres at the plant boundary, it does not add in (on the left side of the equation) any carbon removals relating to own use, LPG production or CO₂ removal (assuming such removals occur *before* the point of valuation of the gas stream leaving a production station; see section 3 below), and
- (b) The methodology treats flared and vented gas as if it is gas in addition to mined gas whereas “mined gas” by any reasonable definition would *include* flared, vented and own use gas.

A more appropriate liability equation for mandatory upstream participants is suggested in section 4 below.

We believe that the equation for calculating the emissions liabilities of opt-in participants is also flawed, for reasons set out in section below.

3. Lack of clear definition of the terms “natural gas mined”, “unprocessed natural gas”, and “processed natural gas”

These are key terms in the regulations as currently worded – factors in the proposed methodology for calculating the liabilities of both mandatory (upstream) and voluntary (purchasers) participants in the gas sector—yet none of these terms are specifically defined. There is a consequent lack of clarity concerning what should be measured and where.

Reference to the mining of gas or to “*natural gas mined*” is, in our view, unfortunate because this is not a commonly used expression in the industry (the more common expression is “gas extraction” or “gas production”) and, more significantly, it implies that the gas is being measured at the wellhead, which is almost never the case due to the difficulty of accurately metering multi-phase flow(see below). However, it is

acknowledged that the terminology in the draft regulations reflects the Act's identification of the "mining of natural gas" as an activity requiring mandatory participation in the stationary energy sector (Schedule 3, Part 3). If the term "natural gas mined" is persisted with, it is submitted that it should be clearly defined having regard to the comments below.

The formula for calculating emissions liabilities for a field (clause 16) begins with "the amount of gas mined x the EF for *unprocessed* natural gas". On the face of it, unprocessed gas is being equated with (mined) gas straight out of the well. However, because the definition of "natural gas" in the Act includes all gaseous and liquid hydrocarbons produced from wells (including wet gas and residual gas) remaining after the extraction of condensate and all liquid hydrocarbons (other than condensate) extracted from well gas and sold as natural gas liquids (eg LPG), then it follows that "unprocessed natural gas" must refer to the amount of gas following *separation* of any condensate, that is to the gas prior to the removal of water or the extraction of LPG or carbon dioxide (if it is extracted).

To add to the terminological confusion, clause 15 requires participants to collect information on the gigajoules of gas mined annually as recorded *at the point of valuation*. The latter is defined in the draft regulations as "the point of valuation for determination of royalties in the permit under which the natural gas is mined". The problem here is that whereas some of the early permits (eg Maui, Kapuni) identify the point of valuation as the wellhead, more recent permits (eg for McKee and Pohokura) identify the point of valuation as being at the exit of the gas treatment station (ie the "sale point", the location of the so-called fiscal meter), which does not, of course, equate with unprocessed gas.

Due to the notorious difficulty of directly measuring wellhead streams, it would seem to make sense to derive an upstream participant's obligations by summing *sales volumes* (in gigajoules) x the relevant emissions factor + amount flared x relevant EF + own use x relevant EF... etc. Sales gas equates with specification gas (other than for Kapuni) so the emissions factor for the spec gas for the field/ plant in question (see below) would be applied to the sales gas volumes.

The term "*processed gas*" appears to be used in the emissions liability equation to refer to something other than spec gas. That is, to the field or production station-specific characteristics of a particular gas stream purchased by an opt-in participant. However, this would only differ from spec gas in the Kapuni situation. The reality is that most opt-in participants (gas buyers) will receive a mix of *specification* gases from different fields out of the high pressure pipeline. This point is returned to in section 7 below.

4. Should the terms "unprocessed natural gas" and "processed natural gas" even be used ?

In light of the above, the question needs to be asked—is there any merit in using the terms "unprocessed" and "processed" natural gas? As used, they appear to be misleading. So-called "unprocessed" gas is, counter-intuitively, not measured at the wellhead and

“processed” gas is generally specification gas, so why have a separate term (Kapuni can be accommodated by a specifically worded formula, if necessary) ?

If the terms “unprocessed natural gas” and “processed natural gas” were to be dispensed with, and the comments in section 2.1 and 2.2 above accepted, a more appropriate emissions liability equation for mandatory participants would read:

$$E \text{ (tonnes/yr/field)} = \text{Amount of sales gas (gigajoules)} \times \text{EF spec gas} + \text{gas flared (gigajoules)} \times \text{EF for flared gas} + \text{gas vented (gigajoules)} \times \text{EF for gas vented} + \text{amount of own use gas (gigajoules)} \times \text{EF for own use gas} + \text{amount of LPG produced for domestic market} \times \text{EF for LPG} + \text{CO}_2 \text{ extracted before sale} \times \text{EF for CO}_2$$
$$\text{MINUS [(amount of gas delivered to opt in party} \times \text{EF for spec gas)} + \text{(amount of unaccounted for spec gas allocated to opt in party} \times \text{EF for spec gas)} = \text{amount of gas exported} \times \text{EF for spec gas}].$$

5. Use of generic default emissions factors

The draft regulations contain, in the schedules, proposed default emissions factors for unprocessed gas, flaring, venting, processed gas, LPG, specification gas, and geothermal fluid. However, it is proposed that participants be able to apply for “unique” emissions factors specific to their activity or field. This approach was selected in preference to two alternative approaches (see p2 of explanatory Bulletin for rationale).

In Schedule 2 of the draft regulations it is proposed that all fields (other than Kapuni) have the *same* (generic) default emissions factor for unprocessed natural gas. Putting aside the issue of whether or not there should be an “unprocessed” gas EF (above), this is clearly a contentious proposition as , for example, Maui has on average 3% CO₂ and Pohokura 7%, as well as significant differences in their hydro-carbon content.

It could be argued that the proposed ability of each participant to lodge an application for activity or field-specific “unique” emissions factors covers any concerns in this area. However, our preliminary view is that field-specific (if not activity-specific) factors should be incorporated into the regulations as the standard, unless the production is very small. We say this because under the draft proposals those who are disadvantaged by the default emissions factors will apply for unique factors while those who benefit will not, effectively providing a subsidy for the latter. The approach could result in a significant under-counting of liabilities. Specific EFs are also more transparent than generic EFS, consistent with the underlying objective of changing the behaviour of market participants.

We note that in the Schedules (Table 5) “flared gas” is given the same EF as “unprocessed gas”. As indicated in section 6 below, we believe the estimated EF for unprocessed gas to be an error. We also note that “own use” gas, which has been omitted, will have a substantially lower (field-specific)EF than both vented or flared gas due to the efficient combustion/oxidation of gas in own use applications.

6. Over-estimate of EF for “unprocessed gas”

The Bulletin states that the upstream point of obligation requires use of an emissions factor for *unprocessed* gas that is relevant at the wellhead, and notes that officials currently do not hold information on the emissions factors associated with unprocessed gas in New Zealand. Officials have *assumed* an emissions factor for unprocessed gas that is 35% higher than the weighted average of the EF for spec gas for all gas fields (excluding Kapuni). They use 0.07332606 tonnes CO₂-e/GJ (ie 73 tonnes/ PJ) as opposed to the the EF of .05340436 tonnes CO₂-e/GJ average proposed for specification gas.

The assumed 35% factor appears to be arbitrary and based on a misunderstanding that gas processing (necessarily) reduces the carbon content of the gas. As noted in section 3 above, gas processing does not include separation of condensate.

The consequence of the 35% assumption, if implemented, would be that the liability of mandatory upstream participants would grossly exceed their actual liability based on correct figures. This can be illustrated by reference to the Pohokura field, using figures supplied by STOS. A spreadsheet model was developed and it was assumed that all customers opt in. Application of the 35% assumption results in about 5MT of carbon liability associated with the mined “unprocessed” gas. But the opt-in participants are only liable for the carbon content of spec gas (with the 35% lower EF), that is about 3.6 MT. This leaves the cost of the 1.4 MT difference (\$560 million at \$40/tonne) to be picked up by the JV production partners. Compare this with the approx 20,000 tonnes liability that would result from (just) the flaring of about 0.34 PJ per year, that is about 70x the true liability.

As noted in section above, there is an argument that there is no need to be talking about unprocessed gas. If this is accepted and sales volumes substituted, then the EF for spec gas would be used and the 35% issue would disappear.

7. The proposal to have an “average”EF for spec gas, in the regulations

The draft regulations propose a single (national) average factor for the default emissions factor for specification gas, to be applied to all fields (see Table Part F, Schedule 2). If the arguments above about doing away with the concept of unprocessed gas and making the point of sale the key measurement point for mandatory participants, are accepted, then the emissions factor for spec gas would be pivotal to the calculation of liabilities.

There are a number of issues or concerns surrounding the use of an average figure for spec gas, similar to those raised in connection with the use of the same (generic) default factors for all fields (section 5 above), viz:

- (a) If averages are used, producers with low carbon fields will effectively be subsidizing those with higher carbon fields
- (b) Non-transparency in the market

- (c) The average could change year by year ,as the contribution of different fields varies, potentially creating trading and/or reconciliation problems as the mix is not known in advance.
- (d) Use of an average appears to run counter to the (assumed) underlying objective of putting a premium on the use of low carbon fields
- (e)

As noted in section 3, gas entering the Maui Pipeline is co-mingled and purchasers receive a mix of gas molecules from different fields. We assume that if a gas producer contracts with a purchaser to supply gas from a particular field (with a specific EF), then the only way that the objective referred to in (d) can be achieved is for purchasers to cover the cost of the liability that they have contracted into by pricing the gas that they sell as if they were receiving it directly in a non-comingled state. The integrity of the system seems to depend on this.

8. Issues surrounding calculation of liability of opt-in participants

Under the draft regulations it is proposed that an opt-in participant calculates his liabilities using the following formula (contentious words highlighted) :

$E = [\text{Total gigajoules of } \textit{processed} \text{ natural gas of the class received in a year by the person at the delivery point from a miner of natural gas} + \text{the total no of gigajoules of } \textit{unaccounted for} \text{ processed natural gas of the class allocated in a year}] \times \text{the Emissions Factor EF for the } \textit{processed} \text{ natural gas as specified in Part D of Table 5 in Schedule 2.}$

The lack of clarity surrounding the meaning of processed gas and the suggestion that the concept relates solely to the Kapuni situation has already been referred to, in section 4 above. The gas in question will be specification gas (out of the high pressure pipeline), so the word “processed” should probably be removed and replaced with the words “specification gas or, in the case of Kapuni non-specification gas.”

The “delivery point” is defined in the regulations as “as a point at which a miner’s gas is taken (or made available to be taken) from a pipeline into another pipeline, a gas consuming facility or a distribution system”. We are unsure as to why the opt-in party’s obligation should relate to a defined delivery point. It would seem more appropriate to make the opt in point the point of sale (before the gas enters the high pressure pipeline), which is usually also the point of valuation for royalties; see section 3. This would capture all emissions, including so-called “unaccounted for gas”, and ensure that everyone is using the same data.

“Unaccounted for gas” or UFG is defined in the draft regulations as “the quantity of gas, in addition to delivered gas, for which a person is required to pay under the terms and conditions of any transmission agreement”. It is not clear to us why there needs to be a carbon liability associated with UFG. UFG on a high pressure network is generally considered to be the sum of metering errors, although the term theoretically covers gas leaks as well. The latter are generally minor.

If the above points are accepted, the liability equation for opt-in participants, purchasing gas from a particular field, could be simplified to read:

E = Total gigajoules of specification natural gas of the class received in the year by the person from a miner (or producer) of natural gas as measured at the point of sale x the emissions factor EF for the relevant gas field.

I hope these comments are of some assistance. Please don't hesitate to contact me if there are any matters that you would like to discuss.

Yours faithfully

Bill Armstrong
Environmental Manager
Todd Energy

Phone: (04) 917 8235
Fax : (04) 472 2474
E-mail: barmstrong@tpm.co.nz