

Prepared For:
Ministry for the Environment
Environment House,
23 Kate Sheppard Place
WELLINGTON



REVIEW OF DEFAULT EMISSIONS FACTORS IN THE DRAFT STATIONARY ENERGY AND INDUSTRIAL PROCESSES REGULATIONS: GAS

Proposed By:
New Zealand Centre for Advanced Engineering
University of Canterbury Campus
39 Creyke Road, Private Bag 4800
Christchurch 8004, New Zealand

Date: 18 June 2009

1. Introduction

As part of development of a New Zealand Emissions Trading Scheme (ETS), draft Climate Change (Stationary Energy and Industrial Processes) Regulations have been developed to set out methods for those involved in Stationary Energy and Industrial Process sectors to monitor and calculate emissions¹ from their activities.

The initial draft regulations, released for comment in October 2008, include a schedule of default emissions factors for participants to use when calculating their total emissions from particular activities. In the case of gas, this includes default factors to be used when calculating emissions for importing different types of gas, mining gas from New Zealand gas fields and purchasing gas as an opt-in participant under the NZ ETS. The calculation methodology needs to be reviewed to find the simplest point of measurement for the ETS obligation that will provide environmental integrity and equity in the gas sector.

In addition, the draft regulations foreshadowed allowing participants the possibility of applying for a unique emissions factor to apply instead of the default factor when calculating their total emissions for importing, mining or purchasing gas.

The Ministry for the Environment has contracted CAENZ to provide expert advice and to review the methodologies and calculations behind the existing emissions factors for importing, mining or purchasing gas so as to ensure the methodology for determining emissions can be consistently applied and that all emissions are correctly accounted for. To this end the report:

1. Reviews the methodology and measurement points for the equation for calculating greenhouse gas emissions from natural gas mining.
2. Provides information on methodologies, testing and verification processes/procedures (including standards) that can be used to assess greenhouse gas emissions to enable participants to apply for a unique emissions factor for importing, mining or purchasing mined gas.
3. Provides an assessment of the likely variability associated with the emission factor determination and the relevant standards and analytical requirements for measuring the constituent emission sources.

2. Review of the Methodology for Calculating Emissions

The current Draft Regulations details the methodology for determining emissions from the production (described as mining) of natural gas, including all emissions from the production, processing and subsequent combustion of the gas.

In the first instance it is the miner of the gas who has the obligation for the emissions. However, under the Climate Change Response (Emissions Trading) Amendment Act 2008 a purchaser of more than 2 PJ of gas can opt-in to the trading scheme, assuming the obligation for the emissions from the combustion of the gas purchased from the producer plus associated unaccounted for losses during transmission.

¹ The project is only concerned with emissions of the greenhouse gases carbon dioxide (CO₂), nitrous oxide (N₂O) and methane (CH₄).

The Regulations require the following information (denominated in gigajoules) to be collected for each field (class) listed in the Regulations:

- natural gas mined, as recorded at the point of valuation
- natural gas flared before the point of valuation
- natural gas vented to the atmosphere before the point of valuation
- natural gas exported
- specification natural gas delivered to opt-in participants and associated unaccounted-for gas
- processed natural gas delivered to opt-in participants and associated unaccounted-for gas
- commercial propane, commercial butane, liquid petroleum gas exported
- natural gas held in storage, injected and extracted into/from a gas storage facility

The Regulations also require the following information to be collected in relation to gas purchased by opt-in participants (denominated in gigajoules):

- processed natural gas received and exported and associated unaccounted-for gas
- specification natural gas received and stored and associated unaccounted-for gas

Emissions of tonnes of carbon dioxide equivalent are calculated from the above data using emissions factors contained in the Schedule to the Regulations. These factors are denominated in tonnes CO₂-e/GJ and are specified for each gas field for each of the gas streams listed above. Formulae contained in the Regulations for gas production and opt-in calculate emissions, following the general format:

Emissions = Σ GJ of each stream * Emission Factor for each stream + Storage Adjustment

A comprehensive list of emission factors for each field and gas stream has been scheduled in the Regulations. Lacking specific up-to-date information on individual gas fields, these emissions factors were set by officials 35% above estimated levels². The emissions factors scheduled in the Regulations are the ones which the participants must apply when calculating emissions and are therefore commonly referred to as default emissions factors (DEF) and will be applied regardless of whether they reflect the actual emissions from the field.

There is provision in the Act to set procedures to determine unique emissions factors (UEF) which apply to specific fields based on actual emissions. These procedures had not been devised when the draft regulations were released in October 2008.

2.1 Review of Methodology

Based on the CAENZ team's experience in the natural gas industry, review of the submissions on the Regulations made by the gas industry and consultations with the industry a number of key concerns with the existing methodology were identified:

- Measurement of natural gas mined (presumably well-stream⁴ gas, as its EF in the regulations relates to "unprocessed" gas) is inaccurate because of multi-phase flow and is not an appropriate point to calculate what is in most fields the source of the great majority of emissions
- The point of valuation⁶ is not at a common point for all gas fields in their gas production and processing regimes, resulting in inconsistencies in the formula contained in the Regulations as in some cases processing occurs after the point of valuation
- Some terms are not defined in the Regulations, such as unprocessed and processed gas
- Because of very significant differences between fields in the composition of well-stream gases, there should be specific emissions factors for each field. Also, there is considerable variation in

² 10% for Kapuni because of its high carbon dioxide content

⁴ Well-stream gas: gas from the production wells which may or may not contain liquids

⁶ The point at which royalties calculations are based

the composition of well-stream gases for each field over time, indicating that reporting should reflect these variations

- The opt-in provisions for gas consumers were viewed as potentially unworkable. These concerns generally were beyond the scope of the Regulations, in particular accounting for gases from different fields mixed in the transmission pipeline system and an interpretation of the Act which if correct, made opt-in gas consumers accountable for emissions from the gas processing plant.

The gas production and processing industry has sophisticated data acquisition and processing capability to optimize its own operations and profitability. Potentially there is sufficient information to quantify all emissions either through directly measured or derived gas flow and qualities. Much information is already submitted to either central or local government for royalty determination, environmental reporting etc.

2.2 Gas Producers

2.2.1 Points of Measurement

Before determining emissions factors it is important to identify the most appropriate place in the gas stream to measure gas flow and composition and to base the emissions factors on that information which can be most accurately obtained. The methodology should reflect the practicalities of measuring gas quantities and qualities and the reporting already undertaken by gas producers to central and local government.

Basing emissions factors on well-stream gas compositions is impractical because of the implicit difficulties and inaccuracies associated with their measurement. Consequently this requirement should be removed from the Regulations.

It is recommended that the key point at which to base emission determinations and derive emissions factors is the point of sales meters where the gas leaves the gas producers' processing /production facilities and is shipped to consumers, either directly or through the transmission network where gases from a number of sources are mixed. The reasons for this choice are:

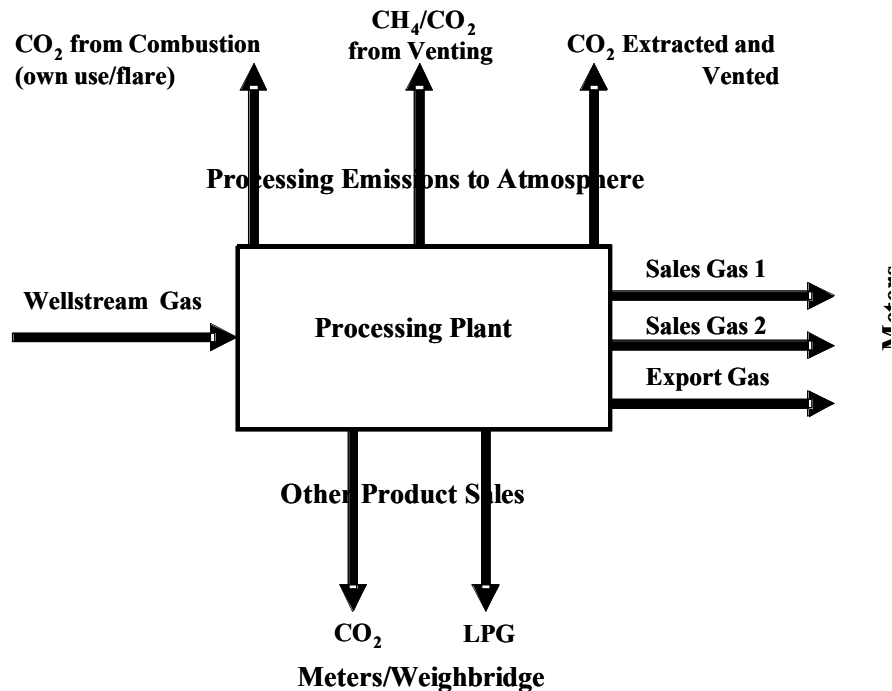
- It is the point at which gas flows are most accurately measured (for fiscal reasons) and where the large majority of emissions are determined (emissions implicit in the un-combusted sales gas)
- Gas volume (by fiscal meter) and molar composition (by gas chromatograph) are measured on a near continuous basis at the point of sale, from which the calorific value and carbon content of the gas can be calculated
- Unlike the point of valuation it is a common point in the gas production/processing stream for all producers, ie downstream of all processing and where custody of gas is transferred to consumers
- Records of this information are already kept by producers
- Carbon dioxide and methane emissions from flaring, own use gas and venting during processing further upstream can be added to the carbon contained in the gas at the point of sale based on the companies' hydrocarbon accounting data.

The gas at the point of sale will be referred to as sales gas in this report. Sales gases from different fields will have different emissions factors even if delivered into the same gas transmission system because the composition of well-stream gas varies considerably between fields, resulting in different levels of carbon dioxide and methane emissions during processing and somewhat different gas compositions being delivered into the transmission network.

Some fields, notably Kapuni with a high carbon dioxide content in its well-stream gas, produce more than one quality of sales gas. Emissions factors should reflect the differences in the qualities of sales gas and the different levels of emissions during processing.

2.2.2 Sources of emissions/carbon from producers' operations

The following schematic summarises the key emissions during processing:



The data required to quantify the CO₂ and CH₄ emissions/carbon load from each field and its associated processing and to subsequently determine emissions factors will include, *inter alia*:

- Quantity, carbon content and calorific value of the sales gas passing through each point of sale meter
- Quantity of CO₂ from combustion of hydrocarbons during processing: flaring and own use gas, determined from the carbon contained in the gases combusted
- Quantity of CH₄ and CO₂ from venting of gas streams
- Quantity of CO₂ extracted from the gas and vented to atmosphere (this operation is currently performed at Kapuni only)
- Quantity of carbon contained in LPG extracted (measured in tonnes of LPG at the road/rail load out points)
- Quantity of CO₂ extracted and sold (measured in tonnes of CO₂ at the road/rail load out points).

This information pertaining to the sales gases will be determined by direct measurement at the point of sale. Other quantities will be determined by direct measurement or derived in the case of smaller or intermittent processing waste streams which are more difficult to accurately measure. This is described in more detail in Section 4 of this report.

2.2.3 Emissions Factors

The data described in Section 2.2.1 will be the basis for determining the emissions factors specific to each field (denominated as tonne CO₂-e/TJ_{sales gas, field n}):

- EF_{sales gas, field n} (from carbon in sales gas, this will not be the same for each field)
- EF_{specification gas} (weighted average of emission factors of sales gases metered into the transmission system and taken by the opt-in consumer as specification gas)⁹
- EF_{CO2 emissions, field n} (from gas processing operations)
- EF_{CH4 emissions, field n} (from gas processing operations, including x21 weighting)
- EF_{LPG, field n} (from carbon in LPG, expressed as tonne CO₂-e/tonne LPG for the LPG quality sold at the particular field)

⁹ If required, refer discussion on opt-in emissions in Section 3

Emissions factors will be determined using the following general formulae:

- $EF_{sales\ gas, field\ n} = \text{mass carbon in sales gas (tonnes)} * (44/12) / \text{TJ contained in the same mass of sales gas} * \text{OHF}$
- $EF_{CO_2\ emissions, field\ n} = \{(\text{mass carbon in gas combusted during processing (tonnes)} * (44/12) + \text{mass CO}_2 \text{ vented during processing}) / \text{TJ contained in sales gas metered over the same period}$
- $EF_{CH_4\ emissions, field\ n} = \text{mass CH}_4 \text{ vented during processing (tonnes)} * 21 / \text{TJ contained in sales gas metered over the same period.}$

“OHF” refers to emissions “overheads” which must be added to the sales gas emissions factor. These relate to the subsequent transportation and combustion of the sales gas after it has passed through the point of sales meter (refer Section 2.2.4)¹⁰.

If there are two or more qualities of sales gas metered from any field, eg LTS and “specification” gas from Kapuni, emission factors will have to be determined for each sales gas stream. The gas producer/processor must allocate CO₂ and CH₄ emissions from processing between the sales gas streams to reflect a “fair” carbon load to the respective consumers. Some wash-up arrangement may be required to ensure all carbon is accounted for.

2.2.4 Sales Gas Emission Overheads

Emissions of CO₂ and CH₄ will occur during the transportation and combustion of sales gas after it passes the point of sales meters. These emissions are encapsulated in the OHF factor included in the sales gas emission factor and will be composed of the following elements:

Emissions from sales gas combustion: These arise from three sources which are functions of the application of the gas rather than its production:

- Unburnt carbon during combustion which effectively reduces CO₂ emissions
- Emissions of methane during combustion
- Emissions of nitrous oxide during combustion.

Each of these is small compared to the CO₂ emitted by the sales gas during combustion and IPCC default factors are being used in New Zealand in each case. They are discussed in more detail in Section 5.

Unaccounted-for gas: UFG is the gas lost during the transportation of the sales gas to consumers through the transmission and distribution systems. Under the draft Regulations it is only included when gas is taken by an opt-in consumer and added to its emissions obligations. This creates an inconsistency between the with- and without opt-in cases, the former being slightly higher because of the inclusion of UFG. Under the Regulations UFG is defined 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 relevant transmission agreement”. Such payments relate primarily to errors in metering rather than physical losses which are very small in the transmissions network. The large majority of gas leakages occurs in the lower pressure distribution networks, which are outside the scope of the Regulations, and will be difficult to reconcile back to gas producers or wholesalers. To provide consistency within the Regulations, UFG should be applied as a factor added to the sales gas emission factor which can be transferred to opt-in consumers as necessary.

¹⁰ Strictly speaking, an OHF factor should apply for the combustion products of processing own use and flared gases but because these gas quantities are relatively small and the OHF factor itself is small, it has been ignored as insignificant.

2.2.5 Emissions from Gas Production

As it is proposed that sales gas quantity be a new and common denominator for determining emissions factors for both emissions from the processing operations and carbon in sales gas and LPG, it will be necessary to reconfigure the equations contained in Section 16 of the Regulations. The new equations must also discriminate between emissions upstream and downstream of the point of sales meter to allow opt-in gas purchasers to assume the obligation for emissions from the combustion of the gas purchased but not the obligation for the emissions from processing the gas purchased which will remain with the gas producer. The proposed equations are as follows:

The emissions from field n , $E_{field\ n}$ (denominated in tonnes CO₂-e), can be expressed as:

$$E_{field\ n} = G_{field\ n} * (EF_{sales\ gas,\ field\ n} + EF_{CO2\ emissions,\ field\ n} + EF_{CH4\ emissions,\ field\ n}) + L_{field\ n} * EF_{LPG,\ field\ n} + O_{field\ n} - X_{field\ n} * EF_{sales\ gas,\ field\ n}$$

Where:

- $G_{field\ n}$ is the amount of sales gas (TJ) metered out of field n
- $L_{field\ n}$ is the amount of LPG (tonnes including commercial propane and butane) metered out of field n
- $O_{field\ n}$ is the amount of carbon dioxide (tonnes) metered (sold rather than vented to atmosphere) out of field n
- $X_{field\ n}$ is the amount (TJ) of opt-in gas taken from field n during the same period.

If there is more than one sales gas stream from the field, $E_{field\ n,i}$, the emissions from stream i , can be expressed as (denominated in tonnes CO₂-e):

$$E_{field\ n,i} = G_{field\ n,i} * (EF_{sales\ gas\ i,\ field\ n} + EF_{CO2\ emissions,\ stream\ i,\ field\ n} + EF_{CH4\ emission,\ stream\ i,\ field\ n}) - X_{field\ n,i} * EF_{sales\ gas\ i,\ field\ n}$$

And for a field with I sales gas streams:

$$E_{field\ n} = \sum_I E_{field\ n,i} + L_{field\ n} * EF_{LPG,\ field\ n} + O_{field\ n}$$

Where:

- $G_{field\ n,i}$ is the amount of sales gas in stream i (TJ) metered out of field n
- $X_{field\ n,i}$ is the amount (TJ) of opt-in gas taken from stream i of field n during the same period.

Total emissions from producing gas for each producer with N fields is (TE denominated in tonnes CO₂-e):

$$TE = \sum_N E_{field\ n}$$

2.2.6 Gas exports

Emissions from carbon contained in gas exports will not be accounted for under UNFCCC reporting:

- When gas is sold directly to export by producers, the quantity of gas exported, as measured at the point of sale, need not be included in the equations in section 2.2.5. Under Section 16 of the draft Regulations, potential combustion emissions contained in the gas exported are deducted from those in the well-stream gas (gas mined), which is equivalent to not accounting for the exported gas at the point of sale. Emissions from processing the exported gas will then remain the obligation of the gas processor in New Zealand
- If gas is sold by the producer to a third party who subsequently exports the gas, the exported gas will be included in the emissions equations as it is a domestic transaction between the producer and the third party. A mechanism needs to be put in place to credit the producer with the emissions associated with any subsequent exports by the third party. This can be simply based on the quantity and sales gas emission factor of the gas involved
- Any LPG exports would be treated in a similar manner to natural gas exports. The quantity " $L_{field\ n}$ " in the above equations will apply to domestic sales of LPG only with subsequent adjustments for exports by third parties.

2.2.7 Default and Unique Emissions Factors

To capture the variation in gas composition between fields and within fields over time, this report recommends that periodic data be submitted by each gas producer showing the carbon load from processing and sales gas and LPG. This data will allow emission factors to be regularly updated. As the updated emission factors are specific to each field, they are effectively UEFs and should replace those contained in the Schedule to the Act.

It is proposed therefore:

- the methodology proposed in this report for determining emission factors be used as the process for determining UEFs
- a process be included in the Regulations whereby emission factors can be regularly updated based on new emissions data submitted by the gas producers
- default emissions factors, determined by government, only be applied in cases where producers do not submit the requisite information or the information fails the scrutiny of an audit.

New producers can be captured by requiring that submission of this data be part of the condition of issuing a mining permit¹³. However, it must be recognized that without experience of producing from a field such data will be provisional only.

2.3 Opt-in Gas Consumers

The opt-in provisions in the Act and Regulations have created considerable uncertainty in the gas industry, particularly in respect to the reconciliation of the transfer of emissions obligations from gas producers to opt-in gas consumers. In reviewing the methodology contained in the Regulations the following criteria were applied:

- Consistency in carbon load between carbon in sales gas delivered by producers and received by opt-in consumers is essential for an equitable and transparent methodology and the avoidance of orphan emissions obligations
- Opt-in participants will not be responsible for emissions from gas processing¹⁴
- It is not necessary that opt-in gas consumers account for the precise carbon load of the gas actually received. Instead, the important criterion should be to match the combustion emissions liability of the gas purchased with that of the gas sold by the producer.

Three alternatives for allocating emissions obligations between opt-in consumers and gas producers have been considered, each of which presents reporting and reconciliation difficulties:

- Allocation of consumers' opt-in gas to gas fields is made at the producers' point of sales meters, done by requiring the consumer to nominate the source of its opt-in gas. This potentially provides a direct basis for reporting opt-in gas quantities and for making purchasing and opt-in decisions. This is recommended as the preferred means of reconciling opt-in emissions
- Aggregating the sales gas entering the transmission network into a mixed "specification" gas, with a chemical composition and emission factor varying with the composition and proportion of the sales gases metered into the network by the gas producers. The opt-in consumer can take this transmission pipeline gas or specific sales gas streams, such as Kapuni LTS. Allocation of the specification gas taken by opt-in gas consumers to the gas producers must be calculated to ensure a constant emissions load with and without opt-in, a potentially complex and time-consuming process
- Measuring the carbon load in the gas received by the opt-in consumer and reconciling with the carbon load in the sales gas streams metered into the transmission system. Whilst this directly measures the carbon load of the consumer, allocation to sales gas streams will be extremely complex even if the composition of all opt-in gas received can be measured

¹³Section 204 of the Act requires participants to hold a permit to produce gas.

¹⁴It is the preference of both the industry consulted and Officials that gas producers be responsible for all emissions from gas production and processing, including such emissions associated with gas taken by opt-in consumers. However, some representatives of the gas companies interpret Section 212 of the Act as requiring opt-in participants to assume the obligation associated with processing the gas received.

- Also, the consumer will have little control over the gas it actually receives from the transmission system. This option is not discussed further.

Equations for the first two alternatives are presented below. It should be noted that each is attended with a condition to ensure total emissions remain the same with and without opt-in.

2.3.1 Opt-in Gas Taken From Specified/Nominated Sales Gas Streams

When opt-in gas consumers buy gas from specified sales gas streams, the transfer of emissions obligations from gas producers to opt-in consumers can be made on the basis of the carbon contained in the sales gas at the point of sales meters. Note that the consumer will not physically receive the gas being purchased if delivered through the transmission network, only the same amount of energy (joules)¹⁶.

Emissions for an opt-in consumer, E_{opt-in} (denominated in tonnes CO₂-e), purchasing gas from J gas streams at M fields will be:

$$E_{opt-in} = \sum_M \sum_J (Y_{field\ m,j} * EF_{sales\ gas\ j,\ field\ m})$$

Where:

- $Y_{field\ m,j}$ is the amount (TJ) of opt-in gas taken from stream j of field m .
- $EF_{sales\ gas\ j,\ field\ m}$ is the emission factor (tonne CO₂-e/TJ) of sales gas stream j of field m .

To ensure consistency of emissions in the with- and without opt-in situations, the following conditions must be met:

$$X_{field\ n,i} = \sum_C Y_{field\ n,i,c} \text{ for all sales gas streams } i \text{ and all fields } n.$$

Where:

- $Y_{field\ m,j,c}$ is the amount (TJ) of opt-in gas taken from stream j of field m by opt-in consumer c .
- C is the total number of opt-in consumers.

2.3.2 Opt-in Gas Taken From Mixed Gas Stream in Transmissions Network

If all opt-in gas is taken from the mixed specification gas in the transmission network, the emissions for an opt-in consumer, E_{opt-in} (denominated in tonnes CO₂-e) will be:

$$E_{opt-in} = (Z * EF_{specification\ gas})$$

Where:

- $EF_{specification\ gas} = \sum_N \sum_I (T_{field\ n,i} * EF_{sales\ gas\ i,\ field\ n}) / \sum_N \sum_I (T_{field\ n,i})$
- Z is the amount (TJ) of opt-in gas taken from the gas in the transmission network by the consumer
- $T_{field\ n,i}$ is the amount sales gas (TJ) from stream i of field n delivered into the transmission network during the same period
- $EF_{sales\ gas\ i,\ field\ n}$ is the emission factor (tonne CO₂-e/TJ) of sales gas stream i of field n .

To ensure consistency of emissions in the with- and without opt-in situations, the following condition must be met:

$$\sum_C Z_c * EF_{specification\ gas} = \sum_N \sum_I (X_{field\ n,i} * EF_{sales\ gas\ i,\ field\ n})$$

Where:

- Z_c is the amount (TJ) of opt-in gas taken from the transmission network by opt-in consumer c
- C is the total number of opt-in consumers
- $X_{field\ n,i}$ is the amount (TJ) of opt-in gas taken from stream i of field n during the same period.

¹⁶ This is consistent with the Maui Pipeline Operating Code

This condition is met when the opt-in gas is allocated to the sales gas streams in the same proportions as the sales gas streams contribute to the mixed specification gas in the transmission network, ie when:

$$X_{field\ n,i} = T_{field\ n,i} * \sum_C Z_c / \sum_N \sum_I (T_{field\ n,i})$$

2.4 Further Considerations

Some elements of the methodology included in the Regulations have not been addressed in this section. These are briefly commented on:

- **Gas imports** and exports appear to be adequately accounted for in Sections 12 and 13 of the Regulations. These returns will need to be complemented by evidence of the composition of the gases involved with provision for audit checks. Quantity measurements will be available from shipping documentation. The composition and calorific value and hence emissions factors for commercial propane, butane and 60/40 LPG are effectively constant and are accurately represented in the existing Regulations. Those for LNG may be subject to greater variation but the requisite information should be readily available from the LNG shipper (refer Sections 6 and 7)
- **Adjustments for storage effects** should be incorporated into the methodology ensuring consistent accounting of carbon load in storage inputs and outputs
- **Definitions** are required for point of sale and sales gas. Under the proposed methodology there is no need for definitions for processed and unprocessed gas, point of valuation and delivery point. Specification gas only requires definition if the second opt-in alternative is included in the methodology.

3. Gas Production Activity in New Zealand

The Energy Data File (MED 2008a) records annual gas production and consumption for New Zealand. In 2007, 181 petajoules of natural gas were produced, of which 39% was from Pohokura, 31% was from Maui, 14% from Kapuni and 16% from at least ten other fields. Of this gas, MED estimated that 1.6PJ was reinjected, 5.5PJ of LPG was extracted, 4.0PJ was flared and production losses and own-use accounted for 4.4PJ.

For 2007, MED estimated that 101.0PJ was used for power generation, 23.7PJ for non-energy use (mainly methanol and urea production), 30.8PJ for the industrial sector, 4.8PJ for the commercial sector and about 7.4PJ total for the agriculture and residential sectors.

A brief summary of the different gas field processes and other variables likely to influence gas compositions for each of the current and near future gas fields are set out below.

Maui (STOS)

Gas condensate from Maui B wells flows to Maui A via a multiphase pipeline where it is mixed with gas condensate from the Maui A wells. A primary separation is carried out and the gas and liquids sent via separate pipelines to the Maui Production Station (MPS) at Oaonui. Until recently, oil from the Maui B oil wells was separated on a FPSO and shipped out directly.

Full treatment and processing is carried out at MPS to produce specification gas, LPG's, naphtha and enhanced condensate. The liquids are piped to Port Taranaki (via the Omata tank farm) for export. LPG for the local market is distributed both by road tanker and pipeline, from MPS to the New Plymouth port.

Kapuni (STOS)

Well fluids from the Kapuni wells, after simple separation at the well heads, are piped to the Kapuni Production Station (KPS) for separation and processing. High CO₂ content, crude gas (44%) is sent to Vector next door for further processing. The liquids are stabilised and then piped to Port Taranaki (via the Paritutu tank farm) for export. Gases from the distillation process are also sent to Vector for further processing. Note that KPS also receives LPG's from Vector for distribution by rail. KPS also exports some gas to the Fonterra cogen plant at Hawera, this is unprocessed non-specification gas).

Vector Plant (Kapuni)

Vector receives crude, high CO₂ gas from KPS along with gases from the distillation columns. The crude gas is first treated in the Benfield Units to remove CO₂. Some of the CO₂ is recovered, purified and distributed to the market as liquid CO₂ in road tankers. The excess CO₂ is vented to atmosphere. The gas from the Benfield units, together with other gas streams from KPS (see above), is treated to yield spec gas, LPG's and NGL's. The liquids are distributed by road tanker or are returned to KPS. Gas (both spec gas and high CO₂ gas) is exported to the Balance plant next door. Treated gas is also exported to the distribution network.

Gas is also used in the cogen units (to produce electricity and steam. Some steam is exported to a local plant). The cogen plant is operated as a separate entity.

Pohokura (Shell)

Well fluids from both the off-shore and on-shore wells are commingled and treated in the Pohokura Production Station (PPS) to yield specification gas and stabilized condensate. The condensate is piped to Port Taranaki (via the Omata tank farm) for export and the gas is delivered to the Maui pipeline

McKee and Mangahewa (Todd)

Mangahewa is essentially a gas field whilst McKee is an oil field. The Mangahewa well stream fluids are treated to yield specification gas and light condensate. The McKee well fluids, from a number of wells, are mixed and then treated to yield spec gas and waxy oil. The liquids from both plants are trucked to Port Taranaki for export. Both plants are interconnected to optimise equipment utilization. At present no LPG production facilities are available.

Rimu and Kauri (Origin)

Well fluids from the Rimu and Kauri fields are commingled and treated at the Rimu Production Station (RPS) near Hawera. Specification gas, LPG's and stabilized condensate are produced. The gas has a very low CO₂ content and an inert gas generator is installed to drop the Wobbe number to specification. The specification gas is directed to the southern pipeline linked to Wellington in the south and north to the Kapuni area. The liquids are trucked out by road tanker. LPG's go to the local market and the liquids are exported via Port Taranaki.

TAWN (Origin)

The well fluids from the Tarihi, Ahuroa, Waihapa and Ngaere (after some local processing) are treated at the Waihapa production station to produce specification gas, LPG's and stabilized fluids (the Waihapa field is an oil producer). The stabilized liquids are exported via Port Taranaki and the LPG's are trucked to the local market. Note however, that facility is currently shutdown for modifications to allow some of the depleted fields to be used for gas storage for Contact Energy.

Kupe (Origin)

The Kupe facilities (off shore unmanned platform and onshore processing facilities) are nearing completion and are scheduled to come on line this year. The Kupe field well composition apparently varies significantly and contains both gas condensate and oil areas. The well fluids are wet, waxy and have high CO₂ content. They will be piped to shore via a multiphase pipeline and treated at the production station to yield specification gas, LPG and stabilized liquids.

Tui (AWE)

The well fluids are collected via subsea facilities and are treated on a Floating Platform Storage and Offloading (FPSO) unit. The stabilized liquids exported directly by tanker. The excess gas is used as fuel and lift gas. The excess is flared. The possibility piping the gas to one of the Maui platforms is under study.

Maari (OMV)

The well fluids will be treated on a FPSO as for Tui (see above).

Minor Onshore Fields (Greymouth Petroleum and Austral Pacific Energy)

Greymouth Petroleum own Kaimiro, Ngatoro, Windsor, Radnor, Turangi and Surrey fields. Austral Pacific Energy (which is in receivership) own Cheale, Cardiff and Kahili. These are small fields and, those that are still active, process the well fluids to non-spec gas and stabilized liquids. The gases pass to one of the local pipelines for further treatment (eg the Vector gas gathering line) and the liquids are trucked out to the Omata tank farm for export.

Variability in Field Composition

The production stations process well fluids collected from a number of wells. The composition of the well fluids can vary substantially:-

- Between wells
- For individual wells with time.

As an example, there are a relatively large number of wells supplying the Maui platforms and:

- The composition of the Maui A and B wells varies significantly (eg CO₂ content etc)
- As time progresses, the production ratios from the A and B wells changes (and can be changed by the Operator)
- As a general rule the well fluids become lighter over time as production proceeds (eg less liquids as the well life extends)
- New wells are usually drilled as the life of the facility extends and more exploration is carried out. For example, oil producing wells were drilled from Maui B. The oil was extracted on a FPSO and the gas returned to Maui B facilities
- New wells can be drilled to different structures within the vicinity of the platform and the well fluids piped to existing facilities. For example, one of the potential fields close to the Maui platforms may have a much higher CO₂ content than the existing Maui facilities. Another example is the potential piping of the Tui gas to the Maui system (see above).

Another variability may be driven by the processing requirements and market economics of the production station. For example, it may be desirable to either produce more or less LPG or one of its components (eg butane) thereby making the spec gas lighter or heavier. Similar, STOS could decide to either sell full range condensate or a mix of naphtha and enhanced condensate, thereby possibly

affecting the quantity of LPG's in the spec gas and the production of LPG. The production of LPG at either Pohokura or McKee might also affect the composition of the spec gas.

Other factors affecting the composition of the products include equipment maintenance (scheduled or unscheduled). Together these factors can significantly impact on upstream operations but, again, it must be emphasised that this variability is largely accounted for in the sales gas quality and the other measured sales streams, as discussed in section 5. Hydrocarbon accounting is briefly examined in the following section.

4. Hydrocarbon accounting

The oil and gas industry is a high-risk high reward industry. Developing and producing oil and gas fields optimally, and reservoirs within, is therefore one of the primary focuses. In reality this can only be achieved by high quality data gathering, which data is used to build sophisticated reservoir and processing models. These models require accurate production data and significant processing capability to properly calculate mass, volume and energy flows from and within the reservoir(s).

Because virtually all wells produce a mixture of oil, gas and water, measuring the production of each well near the wellhead is virtually impossible (i.e. multi-phase flow metering tends to be extremely difficult and unreliable). Consequently, production measurements are made during and after processing/treatment, and hydrocarbon accounting systems (HAS) are used to back-calculate/allocate production to each well (and each reservoir).

Proper reservoir management, and the associated requirement to account for the hydrocarbon flows, is driven not only by the above-described value drivers, but also by permit/licence obligations. The Crown Minerals Act 1991 (and its predecessor The Petroleum Act 1937) and the Crown Mineral (Petroleum) Regulations (last updated in 2007) prescribe that permit holders conduct mining operations in accordance with recognised good exploration and mining practice.

Permit holders also need a HAS to meet other compliance requirements, including:

- Royalty obligations
- Energy Resource Levy (ERL) liabilities
- Consent obligations

Attached to this report is a compilation of the current regulatory reporting regimes adhered to by industry players. The most salient reporting obligation is the half-yearly report submitted to the Ministry of Economic Development – Crown Minerals, the content of which is specified in the Crown Minerals (Petroleum) Regulations 2007 – Schedule 6, Part 2. Companies rely heavily on their HAS for provision of the quantitative content of these reports, which amongst other things includes data relating to “the fuel gas or oil used and gas or oil flared in the extraction of petroleum”.

In addition to direct measurements and the automatic uplift of data from the online process monitoring hydrocarbon accounting relies upon formulae, search tables, correlations and constants to allocate the total of outputs (being sales + fuel + flare + vent (and disposed water)) to the individual wells and reservoirs. Process simulation modelling, sampling, and relevant general science are used to derive process stream components, correlations and constants, and they are also used to regularly calibrate and validate the complex accounting systems required to fulfil the above existing regulatory requirements.

While these internal models have a finite accuracy, and metering accuracy varies, it should be noted that absolute accuracy is not a pre-requisite, especially not for relative small flows. However, it is also important that the system does not contain structural errors, and that residual uncertainties statistically balance out over time.

It is the understanding of the study team the many of these models have been audited once or more by the Treasury and/or the Ministry of Economic Development for royalty and/or ERL purposes as large sums of money are involved in those financial liabilities.

5. Gas Testing and Standards Relating to Gas Properties

To understand how natural gas emission factors are influenced by various gas properties, it is important to summarise the different ways that gas geologists, suppliers and users around the world assess the relevant gas properties.

Natural gas occurs in underground accumulations often in association with crude petroleum or condensate (covered separately in the ETS regulations). It consists mainly of methane, but may also contain substantial quantities of ethane, propane, butane, other longer chain hydrocarbons, trace quantities of unsaturated hydrocarbons (ethylene, propylene, etc.), carbon dioxide, nitrogen, (occasionally) hydrogen sulphide and (in raw gas only) moisture (CAENZ 2008). Dry gas consists mainly of methane and ethane, but wet gas can contain substantial amounts of the longer chain hydrocarbons that can be condensed to form various natural gas liquids, including Liquefied Petroleum Gas (LPG).

Sales gas streams contain C₁ to C₆ hydrocarbons as well as nitrogen and CO₂. Fluctuations in the composition of the gas being processed mean that sales gas streams are usually controlled according to the Wobbe Index specification¹⁹. The allowable Wobbe range makes it possible to accommodate more LPG in the sales gas streams when prior separation creates a surplus of LPG (CAENZ 2008).

The heat of combustion of a gas sample is usually measured in New Zealand as the gross calorific value, expressed in megajoules per standard²⁰ cubic metre of fuel (MJ/m³). The calorific value of the hydrocarbons is effectively diluted by the quantities of CO₂ and nitrogen (expressed as percentage by volume).

Gas sampling and testing according to various standard methods are well established in New Zealand for many of the relevant analyses relating to CO₂ emissions from gas mining, importing and utilisation. IANZ (International Accreditation NZ) has a procedure for accrediting laboratories²¹ by checking regularly that their methods follow various standards or appropriate in-house methods. There are likely to be similar accrediting agencies in any country that LNG may be imported from in the future.

5.1 Gas sampling

The most important step in gas testing is to ensure that correct sampling procedure has been used and commercial requirements should be sufficient assurance for officials' audit requirements.

It must be recognised that the most accurate measurements of gas volumes and quality occur at points of sale for commercial reasons. Measurements of dry gas at upstream points are also likely to be highly accurate but there are difficulties in measuring gas quantities and quality near the wellhead, mainly because of multi-phase flow and water content in particular.

Baker Petrolite (former operators of the Vector lab at Kapuni) (King 2009) said they collect gas samples in stainless steel containers using the Gas Processing Association sampling methods²² (which take into account key factors such as temperature, pressure, gas wetness). There are

¹⁹ NZS 5552:1999 Specification for reticulated natural gas.

²⁰ Standard conditions are 15°C and 101.325 kPa (absolute pressure)

²¹ NZS ISO/IEC 17025: 2005 General requirements for the competence of testing and calibration laboratories.

²² GPA 2166:2005 Obtaining natural gas samples for analysis by gas chromatography. Parts 1 to 8.

generally more sampling problems when there is a high proportion of heavier hydrocarbons, which may condense in the sample container. If the company has not collected the sample, it sends a copy of the sampling procedure to the client and reports the analysis “as received” (but can not guarantee that sampling procedure has been adhered to). The representative did not believe that any laboratory would be IANZ accredited for gas sampling and that appears to be confirmed from the IANZ website.

5.2 Gas analysis

Gas analysis using gas chromatography (GC) is so well established that quantities such as calorific value and density are calculated from the GC analysis. In the past, adiabatic gas calorimeters were used to measure the heat of combustion of a certain volume of gas, but these have been phased out and chromatographs are now used exclusively.

On-line gas analyses are carried out continuously at all the points where gas is injected in to the gas transmission system, and also at major customer sales points (such as the power stations) and a number of other strategic locations, using gas chromatographs. These carry out an analysis about every ten minutes, and the data is fed to the flow computer and also to the SCADA (Supervisory Control and Data Acquisition) system which records it. These “field” devices (as distinct from laboratory instruments) are considered very accurate, with a claimed uncertainty of the order of 0.1% of computed calorific value. However as with any gas chromatograph, they are only as accurate as the calibration gas used to calibrate them. The field chromatographs carry out an automatic calibration weekly, and it is common to carry out a monthly one manually as well. The calibration gas is usually supplied by BOC.

Samples of gas are also analysed periodically by Vector at their laboratory at Kapuni, and occasionally by Independent Petroleum Laboratories (IPL) at the NZ Refining Company using laboratory chromatographs.

It appears that the ASTM standard²³ is used in some laboratories and a series of ISO standards²⁴ are considered to be equivalent.

The IANZ website lists only the BOC laboratory as accredited for gaseous fuel analysis in New Zealand. BOC prepares a range of calibration gas samples gravimetrically and these are used by other laboratories as their means of calibration. A BOC representative (Jacobsen 2009) described their laboratory accreditation as just for their general laboratory procedures rather than for the specific GC in-house analysis method they follow (based on ISO 6143:2001). They choose single point calibration using the standard closest to the sample composition and measure standards and samples in triplicate. A replicate would be rejected if it differed by more than 4% relative from the mean.

The Vector laboratory manager (Fowlie 2009) stated that they were accredited for general laboratory procedures and had recently gone through the process to obtain IANZ accreditation for their gas analysis according to ASTM D1945. She said that standard has a precision requirement that all measured gas components must total 100 mol%²⁵ \pm 1%. Duplicate analyses would be carried out for gas samples with unknown composition but single analysis is considered sufficiently precise for routine samples. For 95% confidence levels, the uncertainty for methane levels is \pm 0.5-1.0% relative, \pm 1-2% relative for low level (5%) CO₂ samples, \pm 1.7-2.5% relative for high level (40%) CO₂ samples, \pm 1-2% relative for ethane and \pm 1.5-3.0% relative for propane and butane in treated gas once LPG has been removed.

²³ ASTM D1945-03 Analysis of natural gas by gas chromatography.

²⁴ ISO 6974:2000 Natural gas - Determination of composition with defined uncertainty by gas chromatography – Parts 1-6 e.g. Part 3: Determination of hydrogen, helium, oxygen, nitrogen, carbon dioxide and hydrocarbons up to C8 using two packed columns and ISO 6976:1995 Natural gas - Calculation of calorific values, density, relative density and Wobbe index from composition.

²⁵ Mole percent is equivalent to volume percent (but mass percent is quite different, depending on molecular weights of each gas component).

The STOS MPS laboratory at Oaonui measures its LPG, naphtha and condensate composition and it takes gas samples for dispatch to Baker Petrolite for gas analysis (Austin 2009). The laboratory is IANZ accredited for its general procedures and has recently started to estimate uncertainties on the analyses it carries out. Baker Petrolite send the samples to IPL for GC analysis and Baker Petrolite undertake the calculations from those analyses to obtain quantities such as calorific value.

IPL undertakes general-purpose fuels analysis but is mainly focused on servicing the oil refinery (Hockings 2009). The laboratory is IANZ accredited for its general procedures but not for its gas analysis because "precision and accuracy have not been identified to the level that accreditation would require." The gas analysis is performed using an in-house method associated with the Perkin Elmer instrument they use. This US Arnel methodology relies on multi-point calibration that is validated each run on a single gas sample. With a wide range of gases and concentrations in refinery gas streams, the laboratory is set up for a diverse set of analytical methods. About 10 of their 22 calibration gases (prepared in the US by Arnel) are relevant for natural gas analysis.

CO₂ analysis using thermal conductivity detection is a little less sensitive than hydrocarbon analysis using flame ionisation detection. They quote a 5% relative precision level (for 95% confidence for most gases) but this is somewhat high to recognise that sampling error is the key component. Actual measurement uncertainty would be more like 3% relative for methane and ethane but with replicates (normally single measurement) and extra calibration (normally single point) it could be as low as 1%. In contrast, the same uncertainty on a CO₂ measurement is considered to be $\pm 5\%$.

The ASTM standard states repeatability and reproducibility levels for various concentration ranges determined by the statistical examination of inter-laboratory test results for gas samples of pipeline quality 38 MJ/m³. Repeatability (r) is defined as the maximum difference between two successive results obtained by the same operator with the same apparatus under constant operating conditions on identical test materials – higher differences should be considered "suspect". Reproducibility (R) is defined as the maximum difference between two successive results obtained different operators in different laboratories on identical test materials – again higher differences should be considered "suspect".

For methane (or CO₂ higher than 10%), ASTM specifies r of 0.10 and R of 0.15 mol%. For gases in the concentration range 1-5% (usually ethane and CO₂), ASTM specifies r of 0.07 and R of 0.101 mol% (and 0.04 and 0.07 respectively for components in the range 0.1-1%). These limits appear to be very stringent compared with the precision and accuracy levels quoted by one or two of the New Zealand laboratories that could estimate them. BOC (Jacobsen 2009) commented that such levels were unrealistic in normal practice (and BOC appeared to CAENZ to have the most robust analysis procedure in New Zealand).

One means of determining inter-laboratory reproducibility of results is to participate in international round robin gas analysis on a regular basis. A laboratory can compare its results for each type of analysis with the range of results found for all participants. There has been some discussion of the possibility of such a study in New Zealand but it has not yet been undertaken.

5.3 Gas monitoring and reporting

The major gas field operators all have hydrocarbon allocation models to understand their resource and to prepare their resource reporting to Crown Minerals and to Taranaki Regional Council. Since they already have the responsibility to manage the resource wisely (and the commercial pressure to minimise any losses), this should provide adequate tracking for greenhouse gas liability purposes.

These hydrocarbon allocation models include estimates of gas flaring and own-use (mainly CO₂ emissions) and venting (mainly methane emissions) as well as the LPG and higher hydrocarbons that are associated with a volume of sales gas.

The Vector laboratory manager (Fowlie 2009) commented as well as the on-site GC mass spectrometry monitoring they typically take a grab (rather than continuous) gas sample weekly for monitoring, depending on compliance requirements.

It is clear from the OATIS website (with daily gas compositions), there is a wealth of information currently collated for sales gases because of the importance of gas properties for different gas users. Some STOS analyses for Kapuni LTS show coefficients of variation (standard deviation/mean) of 0.1% for CO₂ (but up to 10% for lower CO₂ gas streams), 0.3% for methane (but up to 3% for other gas streams), 1 to 3% for other hydrocarbons and 0.3% for calculated calorific value. Without inter-laboratory comparisons it was not possible in this report to characterise measurement variability. Again, it must be emphasised that uncertainty (not variability) in gas composition will be dominated by changes in gas field composition over time and day-to-day operating parameters.

Within the limited time allocated to this review it was not possible to calculate the variability of CO₂ emission factors that thus arises within a gas field. However, it is likely for most fields (assuming relatively low inherent CO₂ ranges), the variability of CO₂ emission factors will be very low (similar to that of calorific value). Further assessment of variability, over a typical operating life for a field, would require a significant effort, and would probably be of limited value. The methodology suggested takes field variability into account as part of the process measurement.

5.4 Establishing emission factors where required (to be reviewed)

As previously described it is proposed to replace the existing methodology outlined in the draft regulations with the new methodology outlined in this report.

However, it is recognised that in some instances it may be desirable to derive a CO₂ equivalent emission factor. To do so, the direct or downstream CO₂ component is multiplied by the IPCC default oxidation factor and added to the indirect or upstream CO₂ and methane components and the combustion methane and nitrous oxide components (IPCC default values discussed above, multiplied by 21 and 310 as their respective 100 year Global Warming Potentials²⁶).

For the national greenhouse gas inventory, MED estimates the minor methane and nitrous oxide emissions resulting from combustion of coal and other fuels.

Formation of nitrous oxide is minimised when combustion temperatures are kept high (above 860°C). Nitrous oxide emissions from gas combustion are not significant. Methane emissions vary with the firing configuration, highest during periods of incomplete combustion, but are generally insignificant.

MED (2008b) has used IPCC (2006) default values (corrected to gross calorific value basis) for its combustion methane and nitrous oxide inventory estimates. Because there is no specific data for NZ boilers or kilns, these should be the appropriate values for calculation of default values.

No review of recent data has been found but Australia's national greenhouse and energy reporting guidelines (ADCC 2008) use the default values for gross methane and nitrous oxide emission factors for pipeline gas combustion: 4.8 tCH₄/PJ and 0.1 tN₂O/PJ for power generation.

IPCC (1996) stated that evaluations at natural gas fired boiler installations indicated that combustion efficiency is often 99.9% at units reasonably well maintained. On that basis, IPCC recommended a default oxidation factor of 0.995.

²⁶ These GWPs have been revised in the scientific literature but for accounting purposes they are currently kept at the levels agreed when the Kyoto Protocol was developed.

5.5 Combustion methane and nitrous oxide measurement

After requesting the Energy Library to search various measurement standard websites, there appears to be a lack of standards for measurement of combustion methane or nitrous oxide. The USEPA methods for measuring flue gas concentrations would be the most likely basis for developing such measurements to sufficient accuracy to be meaningful for this purpose. As a prerequisite, Methods USEPA 1 (sample and velocity traverses for stationary sources) and USEPA 2 (determination of stack gas velocity and volumetric flow rate) or ISO 10780 (measurement of velocity and volume flow rate of gas streams in ducts) would be necessary to demonstrate adequate sampling. Method 3C (determination of carbon dioxide, methane, nitrogen, and oxygen from stationary sources) could be used to measure methane by gas chromatography. Method 7 (determination of nitrogen oxide emissions from stationary sources) does not mention nitrous oxide but there are methods in the scientific literature for automated gas chromatography, one claiming a practical detection limit of 0.1 part per million.

K2 Environmental (2009) offers a service using this method that claims to obtain a detection limit of 1 ppm for methane and 0.1% (1000ppm) for nitrous oxide. The company could purchase for about \$150,000 an infrared detection instrument that would provide greater accuracy and precision for much lower concentrations but it is considered unlikely that clients would be prepared to pay for such an expensive service.

5.6 Deriving an emission factor

To capture the variation in gas composition between fields and within fields over time, this review recommends that periodic data be submitted by each gas producer showing the carbon load from processing and sales gas and LPG. This data will allow emission factors to be regularly updated. The following sampling and analytical requirements would be reasonable:

- a) Evidence that a representative sample of the gas was obtained and prepared by an organisation accredited for sampling according to GPA 2166:2005 (or equivalent in the view of International Accreditation New Zealand or by an overseas accreditation agency recognised under New Zealand's mutual recognition arrangements).
- b) GC analysis for the following properties of the gas that have been carried out according to stated methods by a laboratory accredited (by IANZ or equivalent) to carry out those tests according to ISO 17025:
 - Methane, ethane (and other hydrocarbons) content
 - CO₂ (and nitrogen) content
 - Calculated gross calorific value
 - Calculated carbon emission factor

Laboratory accreditation provides only limited assurance of continuing good quality management of analytical procedures. Regular participation in round robin inter-laboratory gas testing is the best way of providing ongoing quality assurance. Consequently, the provision of such evidence of good performance for a non-standard, in-house method may be considered adequate justification of its use for establishing a unique emission factor.

It is not appropriate for CAENZ to advise on how frequently a UEF should be confirmed or whether there should be some threshold for differences between the UEF and the default emission factor. However, the provision of variability information for gas fields and for GC tests should assist officials to make any such decisions.

The following table illustrates the methodology used to determine emission factors based on the processing configuration shown in the diagram in Section 2.2.2. Gas from a hypothetical well-stream gas containing 20% vol CO₂ is processed to remove 90% of the CO₂ and produce gas and LPG for sale. About 15% of total energy in the well stream gas is consumed during processing²⁷.

²⁷ Note that the energy balance over the gas processing and the gas properties do not represent any existing or proposed gas fields or operations and are just provided to illustrate the calculation process.

	Sales Streams		Processing Streams				Total
Measured or Derived Data							
Gas Flow	Sales Gas	LPG	Fuel	Flare	Vented	CO2	All
m3 standard 000	274.12	3.89	49.13	0.98	0.63	72.92	
or Tonnes	221.34	8.10	40.80	0.82	0.54	135.7	
TJ	11.00	0.40	2.02	0.04	0.03	5	13.50
Gas Properties							
density kg/m ³ std conditions	0.807	2.086	0.830	0.830	0.862	1.862	
Gross Calorific Value (MJ/m3std)	40.13	104.20	41.21	41.21	42.74	0.00	
Mass CO ₂ /Mass Gas	2.59	3.01	2.61	2.61	2.63	1.00	
Calculated Emissions: CO2 and CH4 Produced from Sales Gases and Processing Streams							Process
CO2 tonnes	573.69	24.39	106.50	2.13	0.03	135.7	244.40
CH4 tonnes					0.35	5	0.35
Point of Sale: Calculated Emissions Factors for Sales Gas and LPG							
CO2 EF before OHF (tCO ₂ /TJ)	52.15	60.23					
Sales Gas Overhead Factor (OHF)	0.99717	0.99830					
Total CO ₂ e EF (tCO ₂ e/TJ)	52.01	60.13					
Processing: Allocation of Emissions to Sales Streams							Process
Energy Proportion in Sales Products	96.4%	3.6%					
CO2 tonnes before oxidation factor	235.73	8.68					244.40
CH4 tonnes	0.34	0.01					0.35
CH4 tonnes as CO ₂ -e	7.15	0.26					
Processing Emissions: Calculated Emissions Factors Allocated to Sales Streams							
CO2 EF (tCO ₂ /TJ)	21.43	21.43					
CH4 EF (tCO ₂ e/TJ)	0.65	0.65					
Total CO ₂ e EF (tCO ₂ e/TJ)	22.08	22.08					

Reported data, either directly measured or derived, will show gas flows from sales products and processing emissions over a common timeframe. Key outputs calculated from the gas quantities and properties will be the energy content (TJ or GJ) of the sales gas and LPG (LPG may alternatively be denominated in tonnes) and the CO₂ and CH₄ emissions (tonnes), which may be actual in the case of processing emissions or implicit in the case of sales gas and LPG.

Emissions factors for the CO₂ implicit in the sales gas and LPG can be directly calculated from this output data. For example, in the case illustrated, the emission factor for the sales gas will be 573.69 (tonnes CO₂)/11.00 (TJ gas) = 52.15 tonne CO₂/TJ of sales gas.

Emissions during the transportation and combustion of sales gas after it passes the point of sales meters must be added to the emissions implicit in the sales gases. These emissions are encapsulated in the OHF factor included in the formula in Section 2, the determination of which is illustrated in the following table:

	Natural Gas			LPG			
	PJ	tCH ₄ /PJ	tN ₂ O/PJ	tCO ₂ e/TJ	tCH ₄ /PJ	tN ₂ O/PJ	tCO ₂ e/TJ
Electricity Generation	95.4	2.75	0.09				
Commercial	4.5	1.08	2.07				
Residential	5.5	0.90	0.09				
Transport	0.3	567.00	0.09				
Other (mainly industrial)	56.2	1.26	0.09				
Average		3.25	0.15		1.045	0.57	
GWP		21	310		21	310	
CH ₄ and N ₂ O Emissions from Combustion				0.113			0.199
Oxidation factor				0.995			0.995
Sales Gas EF (before OHF) tCO ₂ /TJ				52.15			60.23
Overhead Emission Factor (OHF)				0.99717			0.99830

N₂O and CH₄ emission factors from combustion and oxidation factors are taken from “New Zealand’s Greenhouse Gas Inventory 1990–2005, MfE”, and gas consumption data from “New Zealand Energy Data File June 2008, MED”. Weighted averages expressed as tCO₂/TJ are determined from consumption data and global warming potential (GWP) of the emission species. The emission factor for sales gas will be $52.15 * 0.99717 = 52.01$ tonne CO₂/TJ of sales gas ($60.23 * 0.99830 = 60.13$ tonne CO₂/TJ LPG)²⁹.

Emissions from the processing operations will be allocated between the sales gas and LPG. In this example this has been done on the basis of the energy contained in the sales products. In practice other bases may be more appropriate. CH₄ from venting is converted to CO₂ equivalent (using the factor of 21), providing a total tonnage of CO₂-e to each sales stream. From this, the emission factors for processing for both sales gas and LPG can be derived, for example for LPG it will be $(8.68 + 0.01 \times 21) / 0.40$ (TJ gas) = 22.08 tonne CO₂-e/TJ of sales gas.

6. LPG and LNG

LPG is imported by Liquigas (for various companies) from Australia (sourced from Saudi) and it is landed at Manukau (mostly) and Christchurch (Lyttleton) and Dunedin. It is commercial Propane rather than Mix³¹.

LPG is produced principally from Kapuni and Maui, with relatively small quantities from time to time from other sources. LPG is exported from Port Taranaki by ship only (no road or rail tank car facilities).

CAENZ (2008) lists the average properties of LPG Mix as having a gross calorific value of 50.0 MJ/kg and a CO₂ emission factor of 60.4 tCO₂/TJ.

The STOS MPS laboratory at Oaonui samples its LPG according to ASTM D4057-06 for on-site analysis (Austin 2009).

For LNG, Australia’s national greenhouse and energy reporting guidelines (ADCC 2008) use the same default value as pipeline gas of 51.5 tCO₂/TJ for gross CO₂ emission factor (before an oxidation factor is applied). This is based on a default calorific value of 25.3 GJ/kL.

Gas imports and exports appear to be adequately accounted for in Sections 12 and 13 of the Draft Regulations. These returns will need to be complemented by evidence of the composition of the gases involved with provision for audit checks. Quantity measurements will be available from shipping documentation. The composition and calorific value and hence emissions factors for commercial propane, butane and 60/40 LPG are effectively constant and are accurately represented in the existing Regulations. Those for LNG may be subject to greater variation but the requisite information should be readily available from the LNG shipper.

7. Coal Seam Gas

Has not been addressed in this report. We would anticipate that any coal seam gas development could readily adhere to the methodology outlined in Section 2.

³¹ Note that these calculations do not include UFG.

³¹ There are 3 types of LPG specified in NZS 5435:2008 - these are Commercial Propane, Commercial Butane, and Mix, which can be up to 50% butane.

8. References

ADCC (2008) *National Greenhouse and Energy Reporting (Measurement) Technical Guidelines 2008 v1.1*, Department of Climate Change, Australia.

Baines, J.T. (1993) *New Zealand Energy Information Handbook*, Taylor Baines and Associates, Christchurch, NZ.

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MED (2008a) *New Zealand Energy Data File (June 2008 edition)*, Ministry of Economic Development, Wellington.

MED (2008b) *New Zealand Energy Greenhouse Gas Emissions 1990-2007*, Ministry of Economic Development, Wellington.

MfE (2008) *Emissions trading bulletin No. 8, (October 2008) Climate Change (Stationary Energy and Industrial Processes) Regulations 2008: draft for consultation*, Ministry for the Environment, Wellington.

Personal Communication:

Austin P. (2009) communication with Paul Austin on the STOS MPS gas sampling methods.

Fowlie D. (2009) communication with Denise Fowlie on Vector's experience with gas sampling and gas chromatography analysis.

Hockings A. (2009) communication with Tony Hockings on IPL's experience with gas chromatography analysis.

Jacobsen R. (2009) communication with Richard Jacobsen on BOC's experience with gas standard preparation and gas chromatography analysis.

King B. (2009) communication with Brian King on Baker Petrolite's experience with gas sampling and gas chromatography analysis.

Appendix A. Summary of data received

SUMMARY OF DATA RECEIVED (AS AT 13/5/09)

COMPANY	FIELDS	DATA RECEIVED	COMMENTS
TODD	McKee Mangahewa	Hourly gas composition data from 1/1/09 for McKee, Pohokura and Mangahewa gas fields Hydrocarbon Accounting and Emissions Liability note Hydrocarbon accounting system summary Compliance requirements (ie reports issued to external organisation) Typical energy flows and emission factors Metering description and accuracies Block flow diagram	
VECTOR		Hydrocarbon accounting system summary Compliance requirements (ie reports issued to external organisation) Typical energy flows and emission factors Metering description Block flow diagram Energy balance around Kapuni GTP and GCP for 2008 Gas composition data (CO2, N2, CV and SG only) 1 may 08 to 1 may 09 (all gas types exiting the system)	
STOS/SHELL	Maui Kapuni Pohokura	LTS gas composition data 1 to 6 may 09 LTS composition 12 month trends (graphical) Metering uncertainty calculations ETS Scheme Maui offshore flow diagrams Global warming potential from non sales gas streams Energy components diagram Hydrocarbon accounting system summary(schematics for MPS daily and monthly balances) Compliance requirements (ie reports issued to external organisation) Compositions for some Maui and MPS streams (gas and LPG) Block flow diagram for Maui and Pohokura with relative carbon contributions	Further data has been promised
ORIGIN ENERGY	TAWN Rimu/Kauri Kupe	Compliance requirements and example of reports issued to external organisations Compositions and emission factors for Rimu and TAWN sales gas Flow schematic for Rimu and Tawn Metering summary	Typical energy flow and emission factors promised
AWE	Tui	Compliance requirements and example of reports issued to external organisations Typical production, fuel and flare flows Flow schematic	
OMV	Maari	Nothing requested yet	
GREYMOUTH	Kalmiro Ngatoro Windsor Radnor Turangi Surrey	Nothing requested yet	
AUSTRAL PACIFIC	Kahiri Cheele Cardiff	Nothing requested yet	In receivership
OATIS website		gas composition data (CO2, N2, CV and SG only)	

Appendix B. Current Regulatory Reporting Requirements.

HALF YEARLY REPORTS

At the completion of each six month period a Half Yearly report is required for all Petroleum permits under the Crown Minerals (Petroleum) Regulation 2007.

Refer <http://www.crownminerals.govt.nz/cms/petroleum/legislation> - Part 4 and Schedule 6

These must be supplied in the format required by the Petroleum Digital Data Submission Standards September 2008.

Refer: <http://www.crownminerals.govt.nz/cms/petroleum/legislation>

Data submissions are to be delivered to:

Data Submission
Crown Minerals
PO Box1473
Wellington

Or if the total files size of the data submission is less than 12 Mb it can be emailed as an attachment to:

crown.minerals@med.govt.nz Subject: Data Submission

ERL

Monthly reports are provided to the Ministry of Economic Development

Refer: <http://www.legislation.govt.nz/act/public/1976/0071/latest/DLM439695.html> - Sections 4 & 6

Asset monthly statistics reports

Monthly reports are provided to the Ministry of Economic Development (Hein Dang) and Statistics New Zealand (Cecilia Chiu)

Gas Statistics

Recent request for information under the Gas (Statistics) Regulations 1997.

Refer: <http://interim.legislation.govt.nz/regulation/public/1997/0128/latest/DLM235094.html> - Section 5

Also supply flare and vented data to Taranaki Regional Council each month.