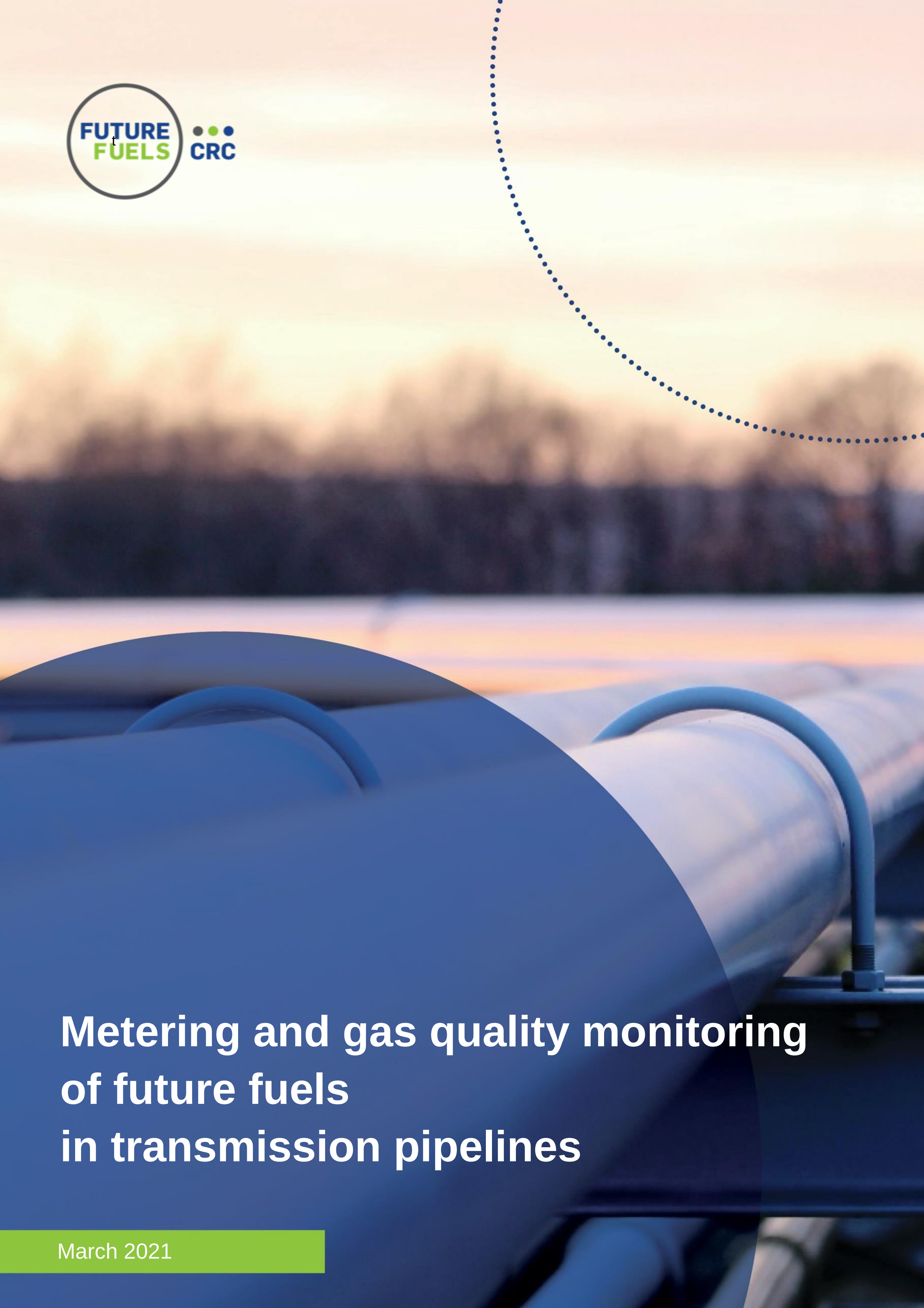

Metering and gas quality monitoring of future fuels in transmission pipelines

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Metering and gas quality monitoring of future fuels in transmission pipelines

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Executive Summary

Natural gas (NG) is a commodity that is subject to fiscal charges, typically billed according to the volume and calorific value (CV) of the gas supplied to the customer. These parameters are determined based on measured values obtained from system instrumentation; the volume is based upon measurements taken via gas meters and flow computers, and the calorific value is calculated from the measured gas composition. It is important that suppliers, consumers, importing/exporting countries and tax authorities can trust that the measurements of the amount of gas consumed are fair, consistent and reliable. It is thus necessary to ensure that the uncertainty associated with the measurement of gas quantity and gas composition be within acceptable limits.

The overall objective of the research described in this report is to assess the suitability of currently installed and new instrumentation for measurement of flow and composition for prospective gaseous 'future fuel' compositions within Australia's NG transmission network. Specifically, the research seeks to determine any additional technological limitations and/or measurement uncertainty for these applications in comparison to the existing criteria applied to NG alone. This will help assess whether existing metering facilities in Australia's transmission networks are capable of effectively managing future fuel applications, and indicate whether any modifications and/or additions are necessary.

Typically, the measurands (quantities that are measured/calculated) at a fiscal gas metering station are:

1. Actual volume flow (volumetric flow rate at line conditions);
2. Standard volume flow (volumetric flow rate at standard reference conditions);
3. Mass flow rate;
4. Gas composition;
5. Energy flow rate.

The volume and mass flow rates are measured using a variety of flow meters, with different types of flow meters designed to work on different physical principles.

The energy flow rate is determined in terms of the mass (or volume) flow rate and the higher heating value (HHV). In addition, the Wobbe Index ($\mathrm{WI} = \mathrm{HHV}/\sqrt{\text{Specific Gravity}}$) is used to ensure compatibility of fuel. The HHV and WI are functions of the gas composition, which can be measured using a gas chromatograph (GC).

Typically, flow and gas quality (composition) measurements are carried out continuously at many locations in the gas network and reviewed on a daily, weekly, monthly and annual basis. Gas custody transfer flow and energy flow measurement can take place anywhere along the process value chain from the wellhead to the delivery or sale location. However, to achieve the lowest uncertainty, measurements generally take place at stable, predictable single-phase locations or physically discrete hand-over points (e.g. platform/production exit location, pipeline entry/exit, terminal entry, etc.). These locations generally provide favourable conditions in which most measurement devices can operate with some degree of predictability and repeatability.

Neither the gas flow rate nor the gas composition/quality can be measured directly. Determination of flow rate and composition therefore relies upon measurement of physical parameters that can be readily observed by a sensor and processed via computational methods to give the desired result.

In natural gas transmission systems, gas quality measurement is mainly achieved by using permanently installed sampling systems which feed gas chromatographs (GCs). Natural gas in Australia contains minimal hydrogen. Therefore, current GCs do not measure hydrogen and do not have metrology approval for measurement of hydrogen. GC suppliers are already producing alternative strategies to be able to provide measurement of gas composition for hydrogen / natural gas blends. Models that are "hydrogen ready" for 10 mol% or 20 mol% hydrogen blends will be available for approval for custody transfer in the near future.

Flow computers measure, monitor, and may provide control of gas flow for all types of meters. They also act as record keepers for the date and time, and instantaneous, hourly and daily data. The flow computer receives volumetric flow measurement data from a positive displacement or inferential flow meter and calculates the flow rate. To calculate the energy flow, the flow computer also requires input reference data for the gas composition and density.

Future fuels considered in this study include hydrogen blends with lean natural gas (represented by methane, CH_4) — assuming typical compositions of 10, 20, 50 and 100 mol% H_2 — along with other gaseous fuels such as biogas, biomethane and synthetic methane.

For the non-hydrogen-based fuels presented (i.e. biogases), the impact of introducing these into existing natural gas systems is limited to an assessment of the potential impurities that may be introduced into the natural gas system. These impurities will vary depending on the source of the gas and any treatment systems that are proposed. Metering systems and their efficacy would remain largely unaffected as the biogas constituents (other than the impurities) are largely consistent with those that are found in the existing natural gas streams.

Upon review of the typical Standards and Regulations applicable to Australian transmission systems, no material deviations or concerns which may limit the ability to transition to future fuel applications were found within the scope of this assessment. Addition of hydrogen would likely require some wording changes in Regulations and the inclusion of hydrogen within the component list for the gas specification, given that hydrogen is not currently catered for in the specification for general-purpose natural gas, AS 4564. For 10 and 20 mol% blends, the slight reduction in Wobbe index and heating value of the fuel when hydrogen is added will normally be within existing limits.

An overall uncertainty analysis that compares a natural gas installation to that of a future fuel blend was conducted for an orifice meter, based on the general methodology recommended in the Guide to the expression of Uncertainty in Measurement (GUM). For orifice meters operating in typical conditions in Australian transmission systems, with pressures up to 15 MPa and velocities of up to 10 m/s, the situations with lower system pressures and lower velocities require the closest consideration when assessing whether the addition of hydrogen to natural gas will affect allowable overall uncertainty. Addition of 10 mol% hydrogen introduces no significant additional uncertainty for all cases tested. This conclusion can also apply to the addition of up to 20 mol% H_2, especially for larger pipe diameters and higher pressures and velocities above 4 m/s.

An overview of uncertainty is also presented for ultrasonic flow meters. The influence of hydrogen addition on measurement uncertainty is again more noticeable at low flow rates, however this quickly falls away as the flow rate increases. In addition, the influence of hydrogen on measurement uncertainty appears to be more significant on smaller metering systems and at lower system pressures.

Whilst the assessment here is focused on two types of meters only — these observations are considered representative of the maximum absolute uncertainty that can be expected from other meter selections requiring measurement of and compensation for physical flow conditions (e.g. pressure and temperature). On the other hand, Coriolis meters are potentially more accurate since they measure mass flow directly, but are less suitable for larger pipe sizes.

Overall uncertainty in gas composition measurements by GCs are due to the combined effects of uncertainty in repeatability, reproducibility, linearity (bias) and calibration gas. Existing ‘as-installed’ GC systems are not considered suitable for hydrogen / NG blends. However, the existing installations are expected to be able to readily accommodate hydrogen with minor modifications to existing GC componentry and/or alterations to calibration gas. This will need to be developed by the GC suppliers in response to market requirements.

For calculation of gas energy flow, measurements of pressure and temperature are required in addition to gas composition and flow rate. The uncertainties in all these measurements contribute to overall uncertainty in energy flow. Examples from literature indicate that flow measurement generally contributes most to overall uncertainty.

It was not possible to complete a detailed assessment on the performance of flow computing systems, gas accounting systems and performance monitoring systems with future fuel blends. However, on the basis that these systems will typically rely upon accurate modelling of the equations of state and measurement of flow rate, it is reasonable to infer that the overall uncertainty presented for flow metering is reasonably representative for these systems.

The study was not able to determine the implications that may be appropriate for high pressure calibration of custody transfer flow meters using hydrogen as the process fluid. This remains an area for potential further investigation.

1. INTRODUCTION

1.1 Background

In Australia and around the world, the idea of sustainability within the context of the energy revolution is coming into focus. Renewable energy sources such as wind and sunlight have an important role to play in the energy mix. Electricity generated from renewable energy sources cannot be transported or consumed in a way that allows for grid compensation. However, one possibility is to store the energy as gas in the existing natural gas (NG) network [1]. There have been developments towards converting electrical energy into storable gases, such as hydrogen (H_2) or synthetic methane. The use of these gases either directly or as a blend (e.g. NG + H_2), when produced from renewable electrical energy or biological processes with net zero carbon balance, also promises to reduce the proportion of carbon dioxide (CO_2) in the products of combustion, thus helping to reduce excessive CO_2 concentrations in the atmosphere.

Natural gas is a commodity that is subject to fiscal charges, typically billed according to the volume and calorific value (CV) of the gas supplied to the customer. These parameters are determined based upon measured values obtained from system instrumentation; the volume is based upon measurements taken via gas meters and flow computers, and the calorific value is calculated from the gas composition measured by gas analysers. It is important that suppliers, consumers, importing/exporting countries and tax authorities can trust that the measurements of the amount of gas consumed are fair, consistent and reliable [1]. It is thus necessary to ensure that the uncertainty associated with the measurement of gas quantity and gas composition be within acceptable limits.

The overall objective of the research described in this report is to assess the suitability of currently installed and new instrumentation for measurement of flow and composition for prospective gaseous “future fuel” compositions within Australia’s NG transmission network. Specifically, the research seeks to determine any additional technological limitations and/or measurement uncertainty for these applications in comparison to the existing criteria applied to NG alone. This will help assess whether existing metering facilities in Australia’s transmission networks are capable of effectively managing future fuel applications, and indicate whether any modifications and/or additions are necessary.

1.2 Scope

The defined scope for this research project is to elaborate on the current status of the following:

1. Measurement uncertainty levels of commonly used measurement instrumentation in the Australian transmission network, including changes and/or limitations that will apply as the gas blend changes;
2. Performance of the following when future fuel blends, specifically {NG + H_2}, are introduced:
    a. Flow computing systems;
    b. Gas accounting systems;
    c. Performance monitoring systems (such as capacity modelling software, efficiency monitoring software and leak detection software).
3. High pressure calibration of custody transfer flow meters using {NG + H_2} as the process fluid;
4. A technical review of Standards and Regulations such as the National Gas Rules (NGR), applicable to Australian gas transmission gas quality monitoring and metering facilities.
5. An ISO 5168 overall uncertainty analysis that compares NG to a {NG + H_2} blend in the aforementioned types of systems.

1.3 Other Studies

Projects such as the UK’s *Hy4Heat* are investigating the application of 100% H_2 in gas networks. The main aim of *Hy4Heat* is to “decarbonise heat”. Their overall objectives include developing suitable meters, and accounting for the combustion characteristics of H_2 that are very different from NG (predominately methane) [3]. However, overseas projects where only a small percentage of H_2 will be blended with NG, as is likely in Australia, do not appear to have investigated the issue of measurement uncertainty in custody transfer in depth. For example, PRCI has a “Measurement Library” of reports and other literature on the topic of H_2 as an emerging fuel [4]. However, measurement uncertainty does not appear to be one of the topics covered in that study.

2. MEASUREMENT SYSTEMS IN GAS TRANSMISSION NETWORKS

2.1 Measurement at a gas metering station

Typically, the measurands (quantities that are measured/calculated) at a fiscal gas metering station are [46] :

1. Actual volume flow (volumetric flow rate at line conditions);
2. Standard volume flow (volumetric flow rate at standard reference conditions);
3. Mass flow rate;
4. Gas composition;
5. Energy flow rate.

The volume and mass flow rates are measured using a variety of flow meters, with different types of flow meters designed to work on different physical principles.

The energy flow rate is determined in terms of the Higher Heating Value (HHV) and the Wobbe Index ($\text{HHV}/\sqrt{\text{Specific Gravity}}$), which, in turn, are determined by the composition of the gas. The gas composition can be measured using a gas chromatograph (GC).

Typically, flow and gas quality (composition) measurements are carried out continuously at many locations in the gas network and reviewed on a daily, weekly, monthly and annual basis [1]. Gas custody transfer flow and energy flow measurement can take place anywhere along the process value chain from the wellhead to the delivery or sale location. However, to achieve the lowest uncertainty, measurements generally take place at stable, predictable single-phase locations or physically discrete hand-over points (e.g. platform/production exit location, pipeline entry/exit, terminal entry, etc.). These locations generally provide favourable conditions in which most measurement devices can operate with some degree of predictability and repeatability [6].

2.2 Measurement parameters and data processing

Neither the gas flow rate nor the gas composition/quality can be measured directly. Determination of flow rate and composition therefore relies upon measurement of physical parameters that can be readily observed by a sensor and processed via computational methods to give the desired result.

A typical system for assigning a numerical value to any measured quantity associated with gas flow in a pipe is shown schematically in Figure 1.

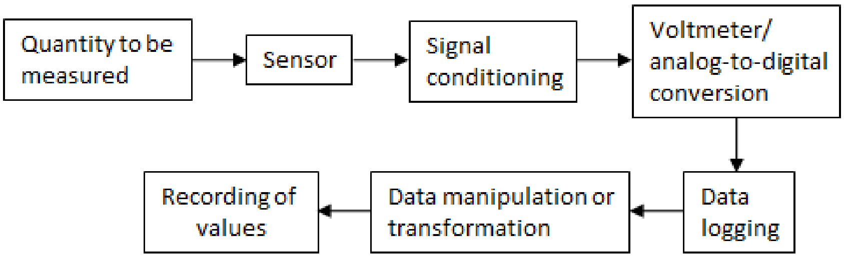


Figure 1 Typical measurement system for a quantity associated with gas flow rate or composition (adapted from [7])

The process for signal capture and processing is summarised below:

- The gas flowing in the pipe brings about a change in some physical attribute of the flow sensor.
- The output of the sensor generally takes the form of an electrical signal that may have to be conditioned (e.g. amplified or filtered to attenuate signal noise).
- The modified signal is read by a voltmeter or an analogue-to-digital converter on a data acquisition card in a computer. This is usually recorded by data-logging software.
- A *calibration curve* or *look-up table* is used to convert the voltage value to the value of the desired quantity. This value is recorded as an estimate of the quantity.

The overall flow measurement system consists of the flow sensor, the signal transmitter and the flow computer.

2.3 Gas flow measurement devices

In Australia, the following types of gas flow meters are typically used [8]:

1. Coriolis flow meter
2. Orifice flow meter
3. Turbine flow meter
4. Rotary flow meter
5. Diaphragm flow meter
6. Ultrasonic flow meter
7. Vortex flow meter

A small sample of gas flow meter types used in Australia is summarised in Figure 2. (It is noted that this sample population is not necessarily representative of all gas transmission infrastructure installed in Australia.)

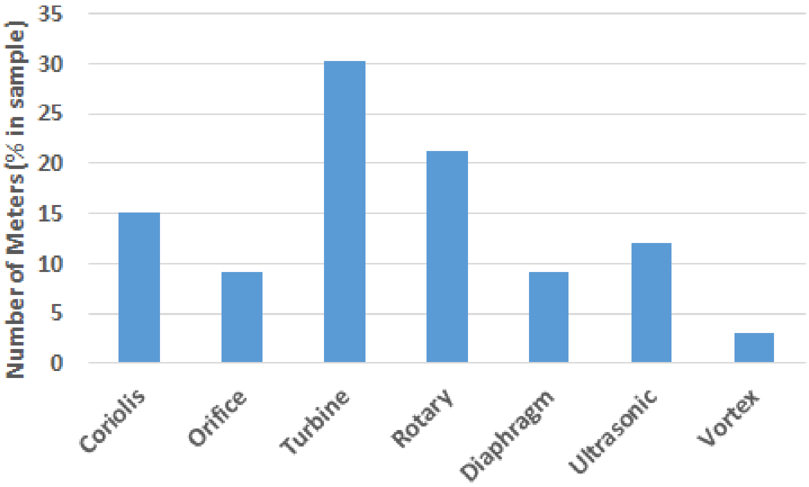


Figure 2 Breakdown of flow meter types used in Australia (sample of 33) [8]

Coriolis flow meters measure the flowing fluid inertia (mass flow rate) directly, and thus can be calibrated using water flow [9]. This is shown in Figure 3 [10]. The volumetric flow rate can be derived from the mass flow rate by estimating or measuring the gas density using a GC or a vibrating element densitometer.

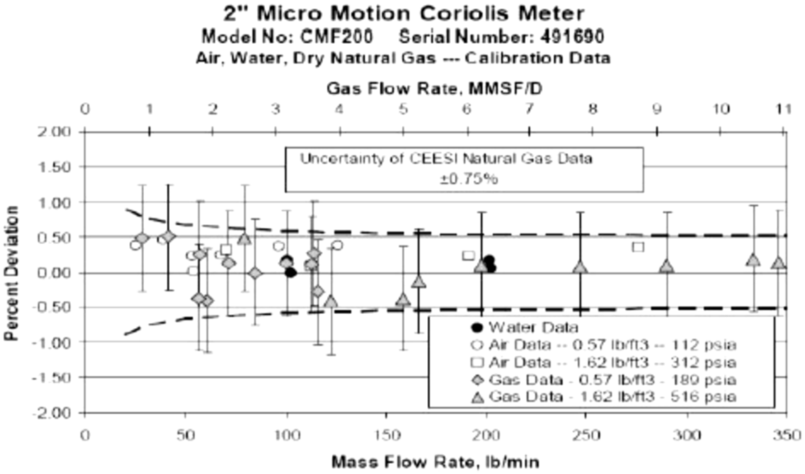


Figure 3 Water, air and gas transferability data [10]

With the other flow meters listed above, volumetric flow rate is reported as the primary output and these meters must be calibrated using gas flow. For example, the ultrasonic flow meter measures the average axial velocity of the gas in the pipe. The volumetric flow rate is derived by multiplying the average velocity by the pipe cross section area.

Diaphragm and rotary meters are termed *positive displacement* meters because they have well-defined measurement compartments that alternately fill and empty as the meter rotates. By knowing the volume displaced in each meter revolution and by applying the proper gear ratio, the meter reads ft^3 or m^3 [11].

Turbine, mass meter, ultrasonic, differential head and orifice meters have no measurement compartment to trap and then release the gas. They are classified as *inferential* because the volume passed through them is inferred by something else being observed or measured. In turbine meters (also called *velocity meters*), gas flowing through the meter impinges on a bladed rotor resulting in a rotational speed that is proportional to the flow rate. The volumetric flow is determined by counting the number of meter rotations [11]. The measurement tolerances achievable in turbine meters are shown in Figure 4.

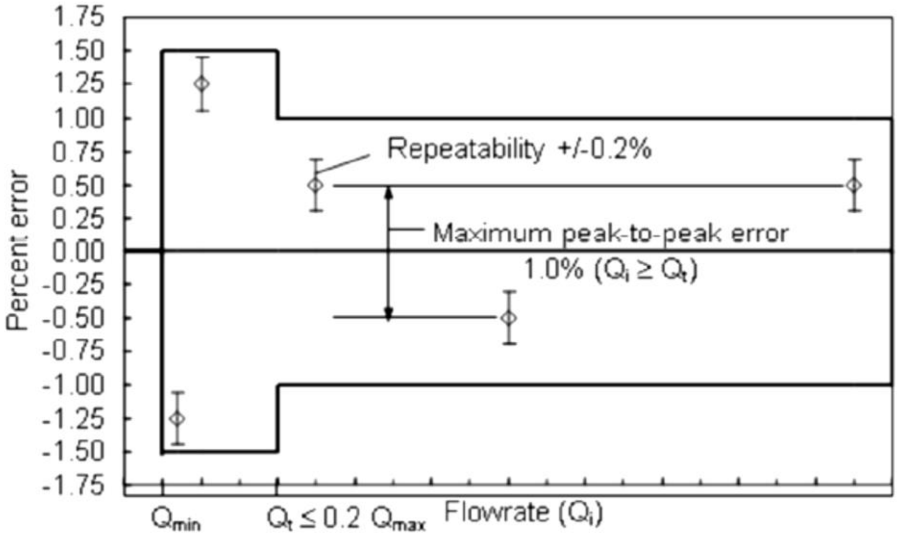


Figure 4 Turbine meter tolerances at atmospheric pressure [11].

2.4 Gas quality measurement devices

Table 1 [12] presents a summary of some of the types of gas quality/composition instruments currently used in Australia in the natural gas transmission network. More details about how some of these instruments can be adapted to future fuels is given in a later section of the report.

In natural gas transmission systems, gas quality measurement is mainly achieved by using permanently installed sampling systems which feed gas chromatographs (GCs). Measurements of gas composition in terms of hydrocarbons, inert components such as CO_2 and N_2, and contaminants such as O_2 and H_2S are performed with GCs. Hydrocarbon measurements are typically either in terms of C6+, or C9+. In particular, ‘C6+’ means that all hydrocarbons from methane (C1) to pentanes (C5s) are separated, detected and reported individually, and higher hydrocarbons are lumped together as C6+. Likewise, ‘C9+’ means that all hydrocarbons up to octanes (C8s) are measured and reported separately and any higher hydrocarbons are lumped together as C9+. Higher heating value and Wobbe Index are calculated from the composition and then the energy flow is calculated from the HHV and flow rate.

Natural gas in Australia contains minimal H_2. Therefore, current GCs do not measure H_2 and do not have metrology approval for measurement of H_2. GC suppliers are already producing alternative strategies to be able to measure H_2, as discussed in more detail later in this report.

Table 1 Gas quality/composition measurement equipment in use in Australia

Type	**Company**	**Model**	**Capability**	**Comments**
GC	Emerson	500X	C6+	
GC	Emerson	700XA	C6+	
GC	ABB	NGC8206	C6+	Current version uses the “BBF” measurement circuit
GC	ABB	8100 series		Obsolete but still in use in some areas
GC	ABB	8206		
GC	ABB	NGC8209	C9	
GC	Daniel	Danalyser 500		+ 2350A Controller
GC	Daniel	Danalyser 571	C6+	+ 2350A Controller
GC	Daniel	Danalyser 590	C9	+ 2350A Controller Installed where the Dew Point needs to be verified.
GC	Daniel	700		
GC	Daniel	700XA	S compounds	
Lead Acetate Tape	Galvanic	902 or 903	S compounds	
Tuneable Diode Laser (TDL)	Galvanic	Acculase-GPA	S compounds	
Tuneable Diode Laser (TDL)	Spectra Sensor	SS2000	Moisture	
Vibrating Crystal	Amatec	3050	Moisture	
Paramagnetic	Servomex	Oxy series	Oxygen	
Micro fuel cell	Teledyne	3000 series	Oxygen	
GC			Odorant level	Alternatively, based on measured gas flow rate and odorant injection rate
	Daniel	Danalyser 1000	H_2S	+ 2350A Controller
Electrochemical cell	Axel Semaru	Odor Easy	Mercaptan odorant concentration	

GCs operate by injecting the gas sample into a carrier gas, normally helium (He). The carrier gas conveys the sample to a heated stationary capillary column or packed column through which the different species move at different rates, resulting in the species getting separated. A valve sequencing procedure is used to isolate the species from each other before they are sent to detectors.

Thermal conductivity detectors (TCDs) are the most commonly used detector in natural gas GCs in Australia. In TCDs the thermal conductivity of the carrier gas alone is compared to that of the carrier gas with the sample added. Either helium or hydrogen can be used as carrier gases because their high thermal conductivity provides high resolution relative to the other species. The detectors send electrical signals to a computer, which are then converted to identify and quantify the different gas species.

Other types of detectors are sometimes used with GCs in other applications, but are not commonly used for natural gas, include flame ionisation detectors (FID), atomic emission detectors (AED), flame photometric detectors (FPD), electron capture detectors (ECD), mass spectrometry detectors (MS), chemiluminescence (CS) and photo ionisation detectors (PID).

2.5 Flow computers

Flow computers measure, monitor, and may provide control of gas flow for all types of meters. They also act as record keepers for the date and time, and instantaneous, hourly and daily data. The flow computer receives volumetric flow measurement data from a positive displacement or inferential flow meter and calculates the flow rate. To calculate the energy flow, the flow computer also requires input reference data for the gas composition and density.

Table 2 presents a sample of the flow computer makes and models in use in Australia.

Table 2 Sample of Flow computer makes and models [13]

Type	Company	Model
Flow computer	Daniel	2500
Flow computer	FlowBoss	FloBoss107
Flow computer	FlowBoss	FloBoss504
Flow computer	ROC	300 series
Flow computer	ROC	800 series
Flow computer	ROC	407 series
Flow computer	SLC	SLC5/05, SLC5/03
Flow computer	Bristol	CW micro series

Flow computers perform three main functions [14]:

- Computation of volume, mass, energy flow rate and supercompressibility;
- Calculation of flow accumulation registers;
- Data transfer.

Each flow meter is connected to a local flow computer, which receives and records the instantaneous values of all primary measurement inputs, i.e. flow measurement signals from the meter, physical parameters (pressure and temperature) from the transmitters, and gas composition and density from analysers (where applicable). From these inputs and along with the gas analysis, the flow computer continuously calculates the following quantities:

- Instantaneous uncorrected volumetric flow rate;
- Instantaneous corrected volumetric flow rate;
- Instantaneous energy flow rate;
- Cumulative uncorrected volumetric flow rate;
- Cumulative corrected volumetric flow rate;
- Cumulative energy flow rate;
- Supercompressibility factor.

If Coriolis meters are used, each Coriolis meter is connected to a local electronic flow computer, which receives a mass flow signal from the meter. Volume at standard conditions and energy flow rate through the meter are calculated from this signal and the specific gravity of the gas is provided by a GC. From these inputs and along with the gas analysis, the flow computer continuously calculates the following quantities:

- Instantaneous mass flow rate;
- Instantaneous corrected volumetric flow rate;
- Instantaneous energy flow rate;
- Cumulative mass flow rate;
- Cumulative corrected volumetric flow rate;
- Cumulative energy flow rate;
- Supercompressibility factor.

3. ADAPTABILITY TO 'FUTURE FUELS'

This section includes comments on the adaptability of the measurement systems summarised in Section 2 to cope with blends of natural gas and hydrogen and other future fuels.

3.1 Impurities

'Future fuels' is a broad term used to refer to potential alternatives to fossil fuels which may be adopted as part of a future decarbonised energy system. Depending on the types of future fuel currently envisaged, these may introduce different impurities into the gas transmission infrastructure which could adversely impact the system.

For the purpose of assessment, possible future fuel alternatives can be compared against the current Australian Standard for general purpose natural gas (AS 4564:2020) as an indication of tolerance levels for impurities that may need to be assessed and managed via gas quality analysis.

Table 3 provides some key examples in terms of the allowable maximum impurity levels in natural gas (AS 4564:2020) together with two examples of potential hydrogen specifications, a typical biogas composition, and the European standard for biomethane.

Table 3 Typical ranges of impurities for natural gas and some future fuels

	Natural Gas AS 4564 (2020) [15]	Hydrogen for dedicated hydrogen pipelines ISO 14687-2 (2012)	Potential least stringent hydrogen specification for blending (FFCRC RP1.2-02)	Biogas (raw), typical values (Baena-Morenao et al. [16])	Biomethane, European standard, EN 16723-1 [18]. Upper limits of minor species and contaminants
Methane	Not specified	2 µmol/mol	In balance	50 – 80 %	Methane Number >65
CO_2	Not specified	2 µmol/mol	3% (max.)	30 – 50 %	Not specified
N_2	Not specified	100 µmol/mol	3% (max.)	0 – 1 %	Not specified
H_2	Not specified	99.97%	70%	0 – 2%	2 mol%
Total inerts	7%	300 µmol/mol	3% (max.)	Not specified	Not specified
Water	Max. 112 mg/m^3	5 µmol/mol	73 mg/m^3 (max)	Saturation	Not specified
Oxygen	0.2 mol%	5 µmol/mol	0.2 mol%	0 – 1 %	1 mol%
CO		0.2 µmol/mol	Not specified	0 – 1 %	0.1 mol%
H_2S	5.7 mg/m^3	Not specified	Not specified	0.7 mol%	5 mg/m^3
Sulphur	Max.50 mg/m^3	0.004 µmol/mol	Not specified		30 mg/m^3
Ammonia	Not specified	0.1 µmol/mol	Not specified	Present but not quantified	10 mg/m3
Amines	Not specified	Not specified	Not specified		10 mg/m^3
Siloxanes	Not specified	Not specified	Not specified	Present but not quantified	0.3 mg volatile silicon per m^3
VOCs	Not specified	Not specified	Not specified	Present but not quantified	Not specified
Oil	20 mL/TJ	Not specified	Not specified	Not specified	Not specified

Other FFCRC projects are investigating hydrogen specifications in more detail, but it is to be noted that the impurity levels in the two examples given are compatible with AS 4564:2020 [15]. The current common method for producing H_2 at scale is steam methane reforming, and to a small but increasing extent, electrolysis of water. Many other production methods are also under investigation. Purification can be achieved with H_2 produced by any of the current methods. For example, in steam methane reforming, impurities can be removed with pressure swing absorption to produce high purity suitable for fuel cells.

Apart from blends of NG and H_2, other gaseous fuels such as biogas, biomethane and synthetic methane may also feature in the future energy mix. Some future fuels in their raw forms contain different contaminants compared to those typically found in natural gas. For example, biogas may contain ammonia, sometimes chlorides, siloxanes and volatile organic compounds (VOCs), in addition to a large amount of CO_2 and more oxygen than allowed in natural gas. The processing (conversion) of biogas to biomethane is likely before injection into pipelines. However, if biogas is used, the potential composition ranges of these impurities in the final blend would need to be understood and managed by controlling the blending rates. It would be necessary to understand all issues related to safety, health, corrosion, and pipeline integrity. The impurity levels need to be controlled at the point of manufacture or the point of delivery into the broader gas network. At the very least, biogas would be dried before being added to pipelines, in which case it would still have a low heating value due to the CO_2 content and would also have significant levels of other impurities such as H_2S. It is more likely to be cleaned to biomethane to produce a specification compatible with natural gas. The cleaning will likely include removal of most H_2S, VOCs and siloxanes [17]. The composition of biomethane varies depending on the gas cleaning technique used, but it is typically 96–99 vol% methane [19] with a Wobbe Index and HHV in the middle of the band specified for natural gas.

Europe has developed a standard for biomethane for injection into the natural gas grid (EN 16723-1) and another for supply to CNG vehicles (EN 16723-2) [18]. The pipeline standard for biomethane quality calls for a minimum methane number of 65, maximum hydrocarbon dew point of 2°C at up to 7 MPa, and maximum levels of contaminants as shown in Table 3. Further work is progressing on the impacts of contaminants on downstream equipment, e.g. of siloxanes on boilers, so it is possible that the European standard will be modified [20]. If a standard similar to the European one is adopted in Australia, the levels of contaminants and oxygen will still require consideration of impacts on downstream equipment and blending ratios may need to be controlled to reflect that.

Another possible future fuel is synthetic methane made by gasifying or pyrolyzing coal or biomass to initially produce raw syngas ($CO + H_2$) containing impurities such as tars, particulate matter and sulphur compounds. These impurities are typically removed by gas cleaning, and then the water gas shift reaction can be used to increase the H_2 to CO ratio before the syngas is fed to a methanation reactor where CH_4 is produced.

3.2 Sampling Systems

Gas sampling equipment includes heated regulators. Some issues that may need consideration are material compatibility and any impacts on hazardous area classification for electrically heated systems.

3.3 Gas flow meters

The inclusion of H_2 will affect the density of a blend, so that the characteristic curves of all instruments whose primary output is volume flow rate are likely to be affected by the presence of H_2 (e.g. [1]).

A Coriolis flow meter measures the mass flow and density directly, and thus does not need pressure and temperature compensation for fluid properties. The following considerations apply to a Coriolis meter:

- It can cope with wide turndown ratios and has no performance or calibration drift.
- It works where product density is not stable.
- Unlike differential pressure (DP) and ultrasonic (US) meters, it does not require flow conditioning.
- The onset of two-phase flow can be detected [6].

- The measurement accuracy of a Coriolis meter is design and fluid-specific. Most bending-mode Coriolis meters can measure gas mixtures at accuracies better than 1%. Some advanced designs can achieve accuracies better than ± 0.35% [10].

Because the meter responds directly to the inertia of the gas flowing through it, the injection of H_2 is not likely to introduce any *additional* measurement uncertainty.

A differential pressure (DP) flow meter measures only differential head. To determine either mass or volumetric flow, it must be corrected for density (mass) or temperature, pressure, and gas composition to obtain a standard reading. The following considerations apply to a DP meter:

- DP flow meters have low turndown and are subject to fouling.
- They are sensitive to the flow profile and require either a fairly long straight run or upstream flow conditioner and generate a medium-to-large pressure loss.
- In general, they are not as accurate as gas turbine, ultrasonic, or Coriolis meters [6].

Measurement of differential head will be affected by injection of H_2, because of the different density of the blend.

Ultrasonic meters (USM) measure volumetric flow rates by measuring the difference in the transit times of ultrasonic signals with and against the flow over one or more measurement path(s). A signal transmitted in the flow direction travels faster than one transmitted against the flow direction. Transit time measurements and transducer location information is used to calculate the average flow velocity. Advantages include standard volume flow accuracy of 0.35% to 0.5%, with 0.25% available. The following considerations apply to USMs:

- They have negligible pressure drop and high turndown [6].
- Limitations include need for sufficient straight run upstream or flow conditioner.
- Measurement accuracy depends on the accuracy with which the flow profile is known, so generally use a minimum of 4 measurement paths.
- Built-in diagnostics can detect the presence of liquids (two-phase flow), dirt buildup, blockage, etc.
- USMs continuously measure sonic speed in the gas, and thus can provide a cross check for other instruments such as GCs.

AGA Report 9 addresses minimum performance requirements that USMs must meet. It has three size ranges and accuracy limits [22]:

1. 10” Max error: ±0.7% $q_t \le q_i \le q_{max}$; ±1.4% for $q_{min} \le q_i \le q_t$ with linearity of ± 0.2% for $q_t \le q_i \le q_{max}$
2. 3’-8”: Max error: ±1.0% $q_t \le q_i \le q_{max}$; ±1.4% for $q_{min} \le q_i \le q_t$ with linearity of ± 0.2% for $q_t \le q_i \le q_{max}$
3. <3” : Max error: ±2.0% $q_t \le q_i \le q_{max}$; ±3.0% for $q_{min} \le q_i \le q_t$ with linearity of ± 0.2% for $q_t \le q_i \le q_{max}$

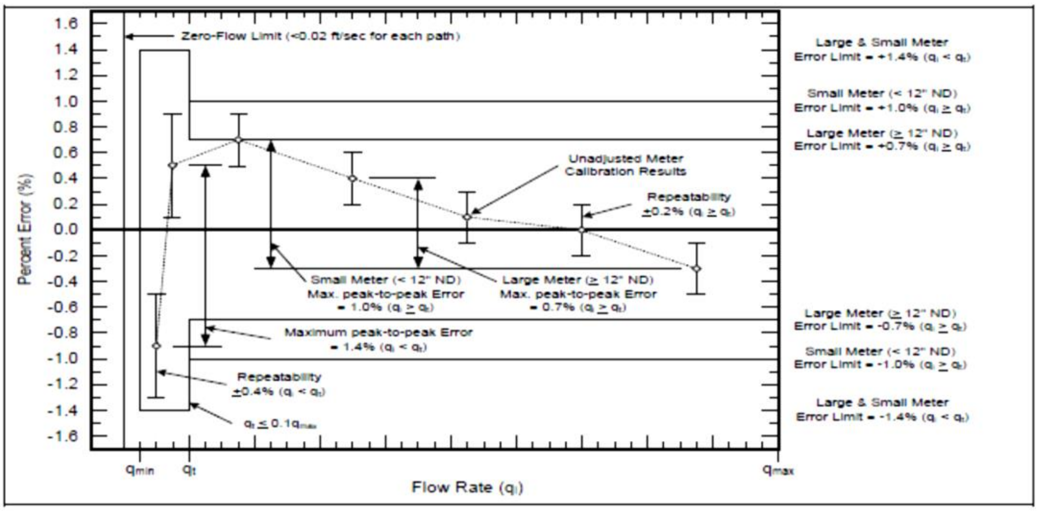


Figure 5 Performance specification summary for USM [22]

As described in Section 5.3, the presence of H_2 affects the measurement uncertainty of a USM.

An Orifice flow meter is one of three types of flow meters that work on the *Bernoulli obstruction theory*. The other two are the long radius nozzle flow meter and the venturi nozzle flow meter [24]. For orifice flow meters, major contributors to measurement uncertainty include predictability of flow profile, fluid properties at flowing condition, precision of empirical equation of discharge coefficient, manufacturing tolerances in meter applications, uncertainty associated with secondary devices monitoring the static line pressure, differential pressure across the orifice plate, flowing temperature, etc [23]. Accuracy in predicting the flow density is important for the precision of flow rate measurement.

As outlined in Section 5.2, the presence of H_2 changes the characteristic curve of the meter, and thus affects the measurement uncertainty.

A Turbine meter is sometimes called a “propeller meter”. The following considerations apply to a turbine meters:

- Flow straighteners are installed upstream of the rotor.
- Rotation is measured by electric/magnetic pickup of pulses caused by passage of a point on the rotor.
- Rotor rotation is approximately proportional to the volume flow rate in the pipe.
- Gas meters need many blades to produce sufficient torque and are accurate to ±1% [24].

Turbine meters are suitable for all non-corrosive gases such as natural gas, propane, butane, air, nitrogen, ethylene, hydrogen, etc. Possible measuring accuracy over the full range of flow rates (minimum to maximum) is estimated as ±1%, while that from 20% minimum to maximum is estimated as ±0.5% [25].

3.4 High-pressure calibration

One of the aims of this project was to investigate high pressure calibration of custody transfer flow meters using hydrogen and the process fluid. It was pointed out that while high-pressure calibration was typically arranged by the manufacturer, such calibration was completed at an independent laboratory [26]. Three such laboratories were contacted with requests for information: (1) Force Calibrations, Denmark, (2) TransCanada Calibrations, Canada, and (3) Euroloop, Netherlands. However, despite our best efforts, no responses have been forthcoming on this topic to date.

3.5 Flow computers and software

In the following paragraphs, the adaptability of flow computers and software to blends of natural gas and hydrogen only, are considered. This is because other likely future fuels are most likely to be predominantly composed of CH_4, as is natural gas, and so will not have a material effect on flow computers and software (other than possible effects related to any impurities present). Therefore, only hydrogen blends are discussed in further detail.

Flow computers take inputs of composition from a GC and also temperature, pressure, differential pressure and calculate energy flow. They use standard uncertainties, so the addition of H_2 does not change the uncertainty if the same method is used. There are only small differences in different standard methods. (However, if the measurement of flow is done without knowing the correct composition, then there would be large errors, because the low density of H_2 alters the differential pressure.)

If H_2 is added to natural gas, performance monitoring such as leak detection modelling software in SCADA and DCS systems that rely on measuring pipeline pressure and temperature, and hence calculation of flow through different sections of pipeline will be unaffected, although a calculation of leakage quantities and the composition of the leaking gas would change and may require changes to the software.

The scope also included consideration of gas accounting systems, Capacity modelling software and efficiency modelling software. All of these systems rely on the metering and GCs to determine the flow rate and the energy content, and hence the HHV and Wobbe Index in each section of the system. It may be necessary to introduce more GCs depending on the location and number of blending locations to ensure quality accuracy throughout the system.

3.6 Gas quality/composition

As for the previous section, the following discussion of gas quality and composition applies only to the addition of H_2 to NG, rather than other possible future fuels.

As described earlier, Gas Chromatographs measure gas composition after the gas species are physically separated using columns. Gas calorific or heating value is calculated from the composition. The term *superior heating value* or *gross heating value* are often used for the higher heating value (HHV). GCs take approximately five minutes to provide a full analysis of the sample.

The following table lists GCs for gas quality/composition measurement, with comments pertaining to adaptability for use with hydrogen blended into natural gas. Note that even when hydrogen is not used as the carrier gas, and if helium is used instead, there are some difficulties in measuring hydrogen because of the relatively similar thermal conductivities of hydrogen and the helium carrier gas.

Table 4 Adaptability of GCs to hydrogen blends

Company	Model	Capability	Comments
ABB	NGC8206 (Application BBF/BBK)	Current gas composition at fiscal metering stations	Can replace the BBF measurement circuit with BBC and use this model for up to 10 vol% H2, still using helium as the carrier gas. With this change, it becomes model PGC1000 Application BBC, but is not yet approved for custody transfer. TCD detector is used in GC for measuring H_2 after the gas is split by columns. If used alone, TCD is not accurate [27].
ABB	PGC1000 Application	0 – 100% H_2	Nitrogen carrier gas. This model is already available.
Emerson	Rosemount 770XA	Current gas composition at fiscal metering stations. C9+ H_2S	Can be adapted for up to 20% H_2 in natural gas. This use is being developed in Europe, so it is “hydrogen ready” for a change to blends with up to 20% H_2
Emerson	370XA	C6+	This model is simpler to install, use and maintain than other GCs, so doesn’t need specialist skills. It has been on the market for a few years. The model was adapted to measure hydrogen for the ATCO blending project. It was specifically designed to only analyse H_2 using N_2 as carrier gas instead of helium to avoid difficulties due to similar thermal conductivity of H_2 and helium.

A table listing comments on the adaptability to hydrogen blends of various other gas composition measurement instruments follows.

Table 5 Adaptability of a range of composition measuring instruments to hydrogen blends.

Type	**Company**	**Model**	**Capability**	**Comments**
FT-NIR	ABB	HP30	On-line process hydrogen analyser	Can be used when accuracy is not so important, and in process plants, not for custody transfer. Uses infra-red technology.
Moisture meters			Moisture	Latest models have no problems with H_2 – earlier ones sometimes did [28].
Sulphur analysers			S compounds	These are compatible with 10% H_2 [28].
Lead Acetate Tape	Galvanic		H_2S	Claimed to be the most accurate and cheapest method. It is based on an ASTM method utilising the fact that H_2S reacts with lead acetate to form a brown stain [30]. Fading of the lead acetate tape was noted as an issue in 1966 [31], but it was due to action of oxidants like SO_2 or O_2. No problems expected from hydrogen blending.
Tuneable diode laser (TDL)	Galvanic	AccuLase-GPA	H_2S	No mention of H_2 interference from hydrogen in the company brochure, but interference from benzene, methane, or CO_2 do occur.[32]
Tuneable diode laser (TDL)	Spectra Sensor	SS2000	Moisture	Can be used for either CO_2 or moisture and claim to provide fast (average of 4 measurements every second), accurate and reliable measurements. Non-intrusive. [33]
Tuneable diode laser (TDL) technique generally	Many, especially in process industries		In process industry applications. moisture, H_2S, CO, CO_2, CH_4, HCl, O_2, NH_3 [34].	TDLs can be tuned to measure many gases and water vapor (not H_2) [34]. Uncertainty in TDL measurement is claimed to be less than 3% [37]. New research is adapting the TDL technique [36] to H_2 measurement, so expect that TDL instruments will become available for H_2 in the future.
Vibrating quartz crystal	Amatek	3050	Moisture	Range 0.02 ppmv to 100 ppmv and highly accurate. No need for calibration. Useful for detecting trace amounts.
Micro-fuel cell	Teledyne	3000 series	O_2	Useful for low concentrations in the ppm range. Paramagnetic: Oxygen is influenced by magnetic fields, and this fact can be used to measure its concentration. Neither hydrogen nor methane are influenced and so do not interfere. CO_2 does and the known effect could be corrected for [38].
GasPT	Orbital Global Solutions			Based on transmission of an ultrasonic pulse followed by composition measurement using thermal conductivity. It has a fast response

(Gas Properties Transmitter)				(8 sec) hence for may be useful for blending or if fluctuations in composition occur. Accuracy would need to be proven over a period in the field with both natural gas and hydrogen blends before being considered for custody transfer [39].

3.7 Measurement locations

Mapping of locations where gas measurement occurs has not been possible in the current project, although it was a proposed part of the project scope. The provision of location information was explored, but for commercial confidentiality reasons it cannot be presented.

Injection of hydrogen in the gas network is likely to increase the number of locations where accurate measurement of flow, composition and energy flow are required for custody transfer. For blended gas it will be important to sample and measure far enough downstream from the injection point so that the gases are well mixed. A separate project may be required to determine this distance required depending on various factors such as injection design, pressures and diameter ratios. Similarly, it is assumed that the gases remain completely mixed throughout the network, though this issue may require further assessment in a future project.

The design of blending stations and operational considerations is beyond the scope of this project. The main focus is to ensure that requirements for gas flow, composition and energy flow are met. Examples of design and operational considerations for the future include:

1. decisions regarding whether to control the hydrogen injection flow rate by ratio control to an existing measure of natural gas flow rate (or energy flow rate), or to control hydrogen injection flow rate by measurement of post-mixing composition;
2. design of the blending station could include an isolatable section of pipeline (similar to Katherine power station) after the mixing point in case the mixture composition is outside of the specified range. This may suit the use of a fast-response composition measuring instrument rather than a GC. GCs would still be required for custody transfer calculations.

4. EXISTING STANDARDS AND REGULATIONS

The following standards and regulations have been investigated for elements that pertain to metering and gas quality monitoring in Australian natural gas transmission systems [40] :

1. National Gas Law
2. National Gas Rules
3. AS 4564 – Specifications for general purpose natural gas
4. AGA Report 3 – Orifice metering of natural gas
5. AGA Report 7 – Turbine metering of natural gas
6. AGA Report 8 – Compressibility factors of natural gas
7. AGA Report 9 – Ultrasonic metering of natural gas
8. AGA Report 11 – Coriolis metering of natural gas
9. National Greenhouse and Energy Reporting Act 2007 (NGER Act)
10. NGER Technical Guidelines

As noted in Chapter 3, the following observations apply to future fuels in the form of blends of natural gas and hydrogen. For bio-methane or other methane based future fuels, there may be differences in achievable levels of some impurities as noted in Table 3.

4.1 National Gas Law [41]

On review, there is nothing in the National Gas Law that is relevant and applicable to future fuels metering.

4.2 National Gas Rules [41]

The National Gas Rules deal with ensuring gas composition and metering compliance. For example, they specify that gas quality monitoring systems must include (unless agreed otherwise) a GC for heating value, relative density and Wobbe Index, an oxygen analyser, a sulphur analyser for H_2S and total sulphur, and a water analyser. These requirements will not change if H_2 is blended into natural gas.

Rule 296: Location of the metering point — may need to be reviewed for H_2 injection to ensure gas quality sampling and flow measurements are done where full mixing has occurred.

Rule 303: Connection points require energy metering. For small quantities of H_2 injection, it will need to be decided whether measurement of the H_2 flow and composition before the injection point is sufficient or if the resulting blend composition needs to be measured immediately downstream, or if the gas composition measurement at a downstream hub is sufficient. An uncertainty analysis may be useful to resolve this question.

4.3 AS 4564:2020 — Specifications for general-purpose natural gas

Defining a specification for H_2 is outside the scope of this project but is being undertaken in other FFCRC projects. In this section the focus is on what standards, regulations, conditions and infrastructure are now available for natural gas and how that may or may not suit the introduction of future fuels.

Natural gas is mainly methane, but also includes ethane, propane, very small amounts of higher hydrocarbons, nitrogen, carbon dioxide, other minor constituents, and odorizing agents. This definition of natural gas, found in the Australian Standard AS 4564:2020 [15], implies that H_2 does not fall into any existing categories of components of natural gas, since it will potentially be added at a much larger volume percentage than is typical for the ‘minor’ constituents of natural gas. Adding H_2 does not affect the existing inerts or other minor constituents apart from diluting them. An analysis of the effect of H_2 on hydrocarbon dew point is outside the scope of this project. The main impact of adding H_2 is on the thermal properties like Wobbe Index (WI) and higher heating value (HHV), and these are discussed below.

Addition of partially treated biogas would also reduce Wobbe Index and HHV due to the presence of CO_2. It also has other impurities, so blending would need to be carefully managed. In contrast, addition of biomethane and synthetic natural gas (SNG), both of which consist mainly of methane and have thermal properties similar to natural gas will present no issues for existing standards providing that impurities have been cleaned up to the required levels. It may be mentioned that the thermal conductivity of a {NG + H_2} blend appears to be significantly affected by the presence of H_2.

The Wobbe Index (WI, units MJ/m^3) has traditionally been used to assess the interchangeability of different gaseous fuels. Fuels with the same WI will deliver the same amount of energy through an orifice at a given supply pressure. Consequently, the energy input into the device is unchanged if the WI is constant. Wobbe Index is calculated from HHV and density relative to air, otherwise known as the specific gravity (s.g.):

$$\text{WI}=\frac{\text{HHV}}{\sqrt{\text{s.g.}}}$$

The Wobbe Index of natural gas is restricted to between 46 and 52 MJ/m^3 by AS 4564:2020.

Addition of H_2 reduces the volumetric HHV and WI of natural gas. Some examples of the reduction in WI with addition of hydrogen at two different partial pressure in a 15 MPa mixture with natural gas are given in Table 6 for a natural gas with WI of 49 MJ/m^3. It can be seen that a partial pressure of 0.2 MPa has little effect on WI, but a partial pressure of 3 MPa reduces it towards the 46 MJ/m^3 lower allowable limit. (Similarly, if the original natural gas WI was 48.3 MJ/m^3 instead of 49 MJ/m^3, then 3 MPa partial pressure of hydrogen would result in a mixture with WI = 46 MJ/m^3.)

Table 6 Effect of hydrogen blending on Wobbe Index, (mixture at 15 MPa with natural gas with WI = 49 MJ/m^3)

Hydrogen partial pressure, MPa	Hydrogen, vol %	WI
0.2	1.33	48.8
3	20	46.6

The density of H_2 is much lower than natural gas, so for a blend of hydrogen and natural gas it is always important to specify whether the blend composition is based on volume or mass.

In summary, AS 4564 caters well for addition of SNG and biomethane to natural gas. If any blending of biogas (containing substantial quantities of CO_2) into natural gas is to be performed it would need to be at low blending ratios so that the blend meets the specifications of AS 4564. Blending of H_2 into natural gas is not catered for in AS 4564, and a review of the standard could be considered to recommend some changes to wording and allowable composition ranges.

5. UNCERTAINTY ANALYSIS

Currently, the gas transmission networks in Australia convey 'natural Gas', either 'lean', consisting mainly of the lighter hydrocarbons, or 'rich', comprising greater fractions of heavier hydrocarbons. In this assessment for measurement uncertainty attributed to potential future fuel applications, it is assumed that the natural gas is 'lean', so that it can be adequately represented by pure methane (CH_4). It is also assumed that a 'future fuel' blend is represented by a {NG + H_2} blend, with a given (specified) mole fraction of H_2 [43].

Uncertainty analysis and considerations are presented below for flow meters (orifice meter and ultrasonic meter), gas chromatographs and other measurement parameters (pressure, temperature and energy flow).

5.1 Flow meter uncertainty

An aim of the present study is to "complete an ISO 5168 overall uncertainty analysis that compares a natural gas installation to that of a future fuel blend". Noting that ISO 5168 applies to differential pressure flow meters, an uncertainty analysis is presented here for an orifice meter. As noted in Section 3.3, an orifice flow meter is one of three types of flow meters whose working principle is the Bernoulli obstruction theory. It is also noted that any uncertainty analysis is based on the general methodology recommended in the Guide to the expression of Uncertainty in Measurement (GUM) [47].

In addition, for ultrasonic flow meters, an overview of uncertainty is presented based upon information published by SICK Engineering GMBH, a flow meter OEM.

5.1.1 Orifice flow meter: characteristic curve

Figure 6 shows a sketch of a typical orifice meter.

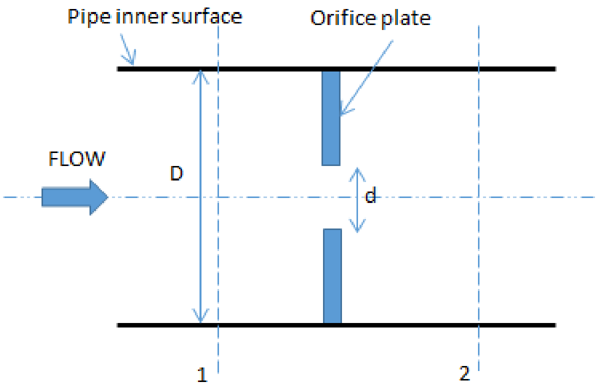


Figure 6 Schematic diagram of orifice flow meter geometry

<u>Functional Relationship [51]</u>

Using the terminology in **Error! Reference source not found.**, if the functional relationship between the input quantities X_1, … X_N and the output quantity Y in a flow measurement process is

$$Y = f(X_1, X_2, \dots, X_N),$$

then an *estimate* of the output quantity y in terms of the input estimates x_1, …x_N is given by:

$$y = f(x_1, x_2, \dots, x_N).$$

Provided the input quantities are uncorrelated, the total uncertainty of the measurement process is given by:

$$u_c(y) = \sqrt{\sum_{i=1}^{N}[c_i\, u(x_i)]^2} \quad \dots\dots (1)$$

Where c_i are the 'sensitivity coefficients' ($c_i = {}^{\partial f}/_{\partial x_i}$), and $u(x_i)$ is the standard uncertainty of each of input estimate x_i.

In case of an orifice flow meter, the functional relationship when a densitometer is not used [46] is:

$$\text{Mass flow rate, } \dot{m} \;= \frac{C_D}{\sqrt{1 - \beta^4}} \; C_E \; \frac{\pi d^2}{4} \; \sqrt{2 \, \rho_1 \, \Delta p}$$

$$= \frac{C_D}{\sqrt{1 - \beta^4}} \; C_E \; \frac{\pi d^2}{4} \; \sqrt{\frac{2 \, p_1 \, MW \, \Delta p}{Z_1 \, R_u \, T_1}} \quad \text{.......................................} (2)$$

In the equations above,

C_D = Discharge coefficient

C_E = Expansivity coefficient

D = pipe inner diameter

d = Orifice diameter

β = d/D

κ = ratio of gas specific heats

Δp = Pressure difference across orifice

MW = Molecular weight of gas

Z = Compressibility factor

T = Absolute temperature

R_u = Universal gas constant

Re_{D1} = Reynolds number based on station 1 parameters

'1', '2' : Stations upstream and downstream of orifice plate respectively.

Here,

$$C_E = 1 - \left(0.351 + 0.256 \, \beta^4 + 0.93 \, \beta^8\right) \left[1 \left(1 - \frac{\Delta p}{p}\right)^{1/\kappa}\right]$$

$$C_D = f(\beta) + 91.71 \, \beta^{2.5} \, Re_D^{-0.75} + \frac{0.09\beta^4}{1 - \beta^4} \, F_1 - 0.0337 \, \beta^3 \, F_2 \text{..} (3)$$

with

$$f(\beta) = 0.5959 + 0.0312 \, \beta^{2.1} - 0.184 \, \beta^8$$

Correlation factors F_1 and F_2 vary with tap position [24]: $F_1 = 0$; $F_2 = 0$ for corner taps

$F_1 = 0.4333$; $F_2 = 0.47$ for D:D/2 taps

It is seen that the molecular weight and compressibility factor of the gas feature in the functional relationship between the gas mass flow rate, $\dot{m}$, and the difference in pressure Δp across the orifice plate (Equation 2). It is therefore necessary to know how these properties (molecular weight and compressibility factor) of a {CH_4 + H_2} blend vary as a function of the fraction of H_2 in the blend. This investigation has recently been carried out as part of FFCRC research project RP3.2-01 [43].

PROPERTIES OF {CH_4 + H_2} BLENDS

Figures 7 and 8 show some of the basic properties of {CH_4 + H_2} blends (effective molecular weight, ‘reduced pressure’ and ‘reduced temperature’) that determine all other properties:

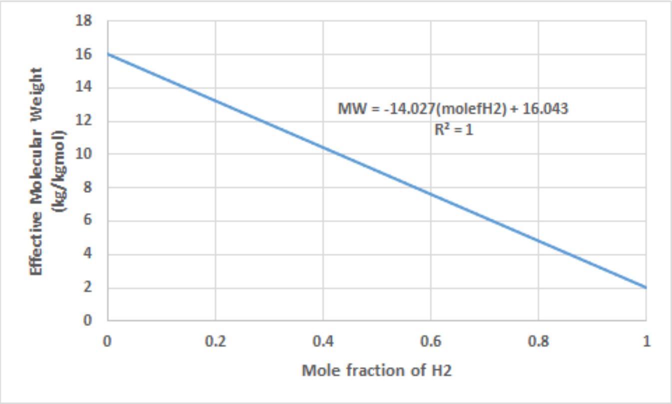


Figure 7 Effective molecular weight of {CH_4 + H_2} blends [43]

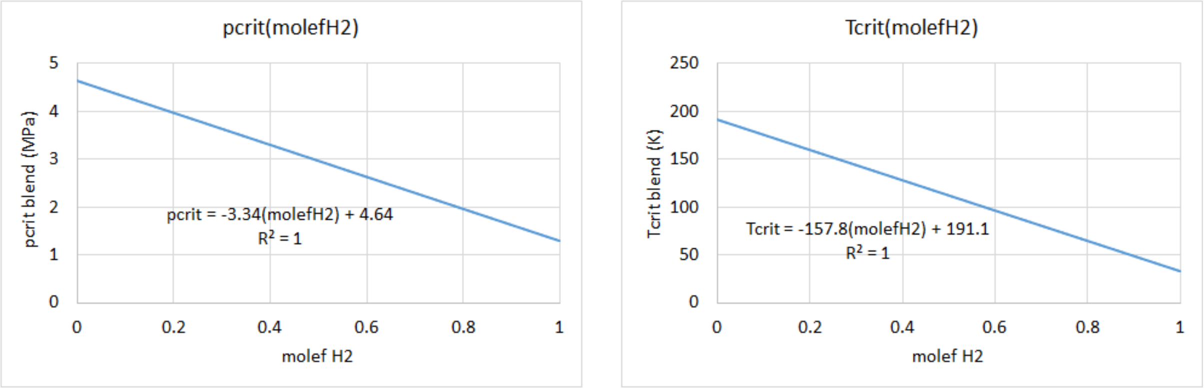


Figure 8 Critical pressure and temperature of {CH_4 + H_2} blends [43]

It is stated in [51] that the overall relative uncertainty in mass flow rate measurement ($u(\dot{m})/\dot{m}$) can be expressed as:

$$\left(\frac{u(\dot{m})}{\dot{m}}\right)^2 = \left(\frac{u(C_D)}{C_D}\right)^2 + \left(\frac{u(C_E)}{C_E}\right)^2 + \left(\frac{2\,\beta^4}{1-\beta^4}\right)^2 \left(\frac{u(D)}{D}\right)^2 + \left(\frac{2}{1-\beta^4}\right)^2 \left(\frac{u(d)}{d}\right)^2 + \left(\frac{1}{2}\right)^2 \left(\frac{u(\Delta p)}{\Delta p}\right)^2 + \left(\frac{1}{2}\right)^2 \left(\frac{u(p_1)}{p_1}\right)^2 + \left(\frac{1}{2}\right)^2 \left(\frac{u(MW/Z_1)}{MW/Z_1}\right)^2 + \left(\frac{1}{2}\right)^2 \left(\frac{u(T_1)}{T_1}\right)^2$$

The above equation shows that ($u(\dot{m})/\dot{m}$) has contributions from several terms. Of these, the first two terms on the right-hand side represent the relative uncertainties in the values of the discharge coefficient C_D and the expansivity coefficient C_E. Generally, the performance of an orifice plate is expressed in terms of its ‘characteristic curve’ (e.g. [24]):

$$C_D = f(geometry, flow\ condition) = f(\beta, Re_D)$$

Here Re_D is the Reynolds number of the flow based on the pipe diameter.

It is stated that “the addition of hydrogen has an effect on the characteristic curve behaviour and thus on the measuring uncertainty of the devices” **Error! Reference source not found.**. This claim can be tested as outlined in the following paragraphs.

SHIFT IN THE CHARACTERISTIC CURVE DUE TO ADDITION OF H_2

Definition of Reynolds number: $Re_D = \frac{\rho V D}{\mu}$, where ρ = fluid density, V = average fluid velocity, D = characteristic length scale, μ = dynamic viscosity of the fluid.

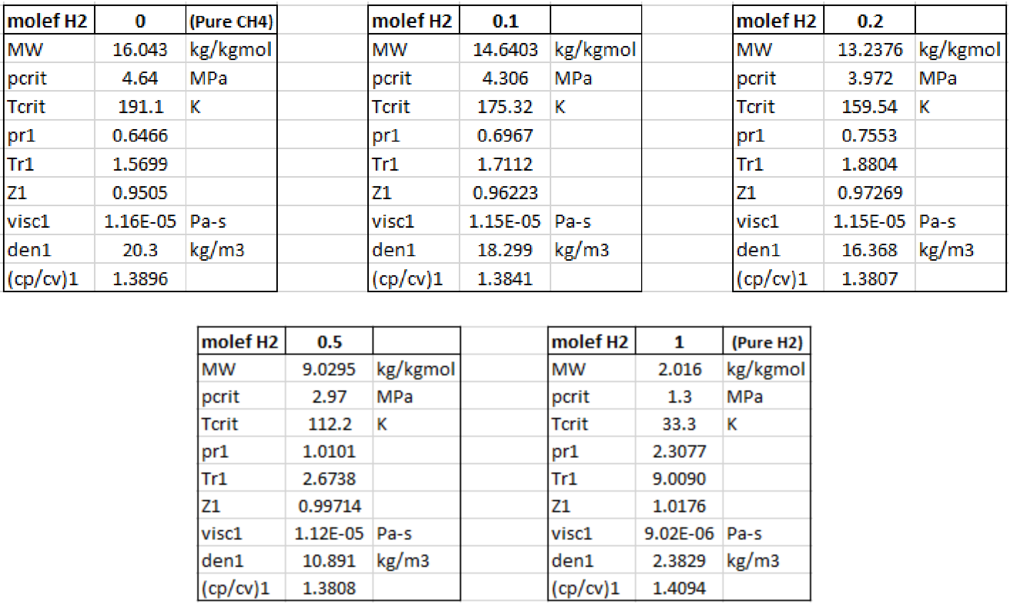
Definition of mass flow rate: $\dot{m} = \rho V A \;=\; \dot{m} = \rho V \frac{\pi D^2}{4}$ for a pipe with diameter D.

The above definitions of Re_D and $\dot{m}$ can be combined to give: $Re_D = \frac{4\dot{m}}{\mu \pi D}$ expressing the Reynolds number in terms of the mass flow rate.

The meter discharge coefficient (Equation 3) can now be expressed in terms of the mass flow rate:

$$C_D(\beta, \dot{m}) = f(\beta) + 91.71\,\beta^{2.5}\left(\frac{4\,\dot{m}}{\mu\,\pi\,D}\right)^{-0.75} + \frac{0.09\beta^4}{1-\beta^4}F_1 - 0.0337\,\beta^3 F_2$$

This function can be plotted for a fixed geometry (D, d, β) and for assumed specified upstream conditions (p_1 = 3 MPa; T_1 = 300 K, given mole fraction of H_2). The properties of the fluid are functions of the H_2 mole fraction as shown in Figure 9:



molef H2	0	(Pure CH4)
MW	16.043	kg/kgmol
pcrit	4.64	MPa
Tcrit	191.1	K
pr1	0.6466	
Tr1	1.5699	
Z1	0.9505	
visc1	1.16E-05	Pa-s
den1	20.3	kg/m3
(cp/cv)1	1.3896	

molef H2	0.1	
MW	14.6403	kg/kgmol
pcrit	4.306	MPa
Tcrit	175.32	K
pr1	0.6967	
Tr1	1.7112	
Z1	0.96223	
visc1	1.15E-05	Pa-s
den1	18.299	kg/m3
(cp/cv)1	1.3841	

molef H2	0.2	
MW	13.2376	kg/kgmol
pcrit	3.972	MPa
Tcrit	159.54	K
pr1	0.7553	
Tr1	1.8804	
Z1	0.97269	
visc1	1.15E-05	Pa-s
den1	16.368	kg/m3
(cp/cv)1	1.3807	

molef H2	0.5	
MW	9.0295	kg/kgmol
pcrit	2.97	MPa
Tcrit	112.2	K
pr1	1.0101	
Tr1	2.6738	
Z1	0.99714	
visc1	1.12E-05	Pa-s
den1	10.891	kg/m3
(cp/cv)1	1.3808	

molef H2	1	(Pure H2)
MW	2.016	kg/kgmol
pcrit	1.3	MPa
Tcrit	33.3	K
pr1	2.3077	
Tr1	9.0090	
Z1	1.0176	
visc1	9.02E-06	Pa-s
den1	2.3829	kg/m3
(cp/cv)1	1.4094	

Figure 9 Properties of pure CH_4 and {CH_4 H_2} blends for different H_2 mole fractions and for the same assumed upstream conditions (p_1 = 3 MPa, T_1 = 300K).

The characteristic curves for the five fluid compositions are shown in Figure 10.

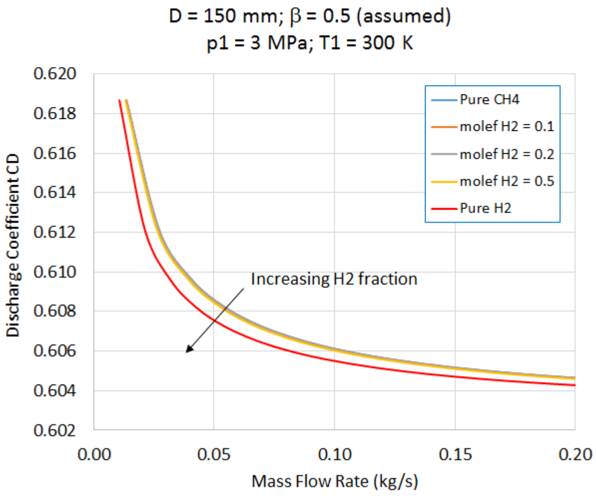


Figure 10 Effect of hydrogen addition on the characteristic curve of an orifice meter #1

These curves show trends that are very similar to the error trends in the analysis carried out by SICK GmBH, Germany. Figure 10 shows the variation of the discharge coefficient as a function of *mass* flow rate. In this case, the C_D curves for the {CH_4 + H_2} blends lie marginally *below* that for pure CH_4. The curves in Figure 10 are plotted for smaller ranges of the mass flow rate and discharge coefficient to show the small separations clearly. If, however, the discharge coefficient is plotted as a function of the *volume* flow rate the result is as shown in Figure 11. The curves for the {CH_4 + H_2} blends lie noticeably *above* that for pure CH_4, (as in the analysis by SICK GmBH [1]).

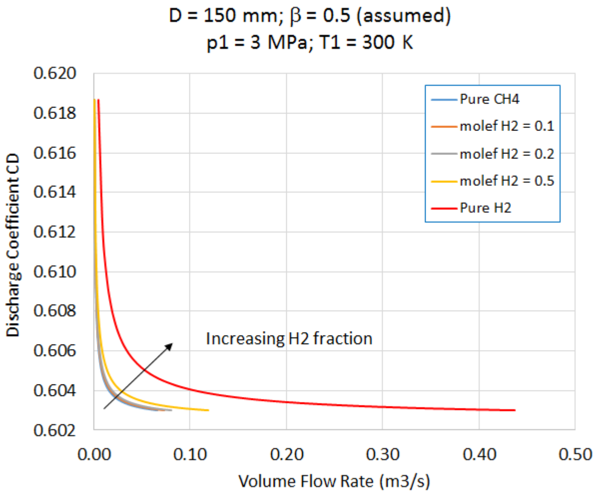


Figure 11 Effect of hydrogen addition on the characteristic curve of an orifice flow meter #2

NOTE: In ISO 5168, the characteristic curve [$C_D = f(\beta, Re_D)$] for a DP meter is given by the Reader-Harris/Gallagher equation [48]:

$$C_D=0.5961+0.0261{*}\beta^2 -0.216\,\beta^8 +0.000521\left(\frac{10^6\,\beta}{Re_{Dp}}\right)^{0.7} + \left(0.0188+0.0063\,F_{ReDp}\right){*}\beta^{3.5}\left(\frac{10^6}{Re_{Dp}}\right)^{0.3}$$

where $F_{ReDp} = \left(19000\,\beta/Re_{Dp}\right)^{0.8}$.

If these equations are used instead of Equation 3, very similar trends are obtained, as shown in Figure 12.

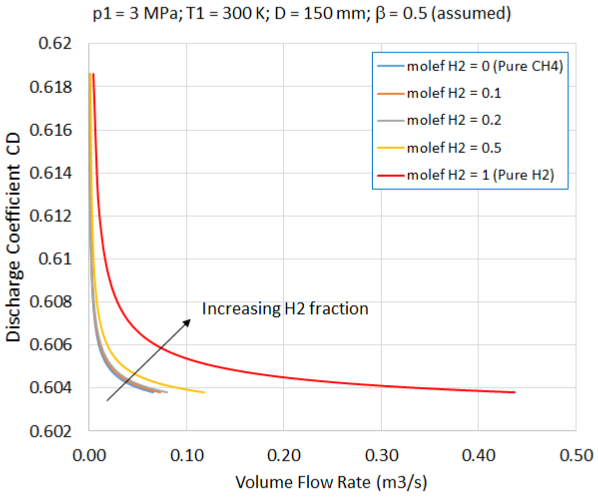


Figure 12 C_D vs Volume flow Rate Using Reader-Harris-Gallagher equation.

5.1.2 Orifice flow meter: uncertainty analysis

In the following paragraphs, a detailed evaluation of the measurement uncertainty as developed from first principles is presented. The aim is to theoretically compare the flow rate measurement uncertainty for a {CH_4 + H_2} blend with that for pure CH_4, using a differential pressure instrument (orifice meter) as the measuring device.

The overall steps are:

1. Sizing the orifice meter to measure the flow of pure CH_4, for given upstream conditions (pressure and temperature), and for a pipe of given inner diameter D. This involves determining the diameter d of the orifice bore, or equivalently, the ratio $\beta = d/D$, for a range of flow rates (based on the upstream flow velocity ranging from 2 m/s to 20 m/s), yielding a range of values for the differential pressure Δp across the orifice plate;
2. For the same orifice meter geometry (D, β), evaluating the range of differential pressures assuming that different {CH_4 + H_2} blends flow with the same upstream conditions across the orifice.

The analysis sequence summarized in Steps 1 and 2 above is shown in Figure 13:

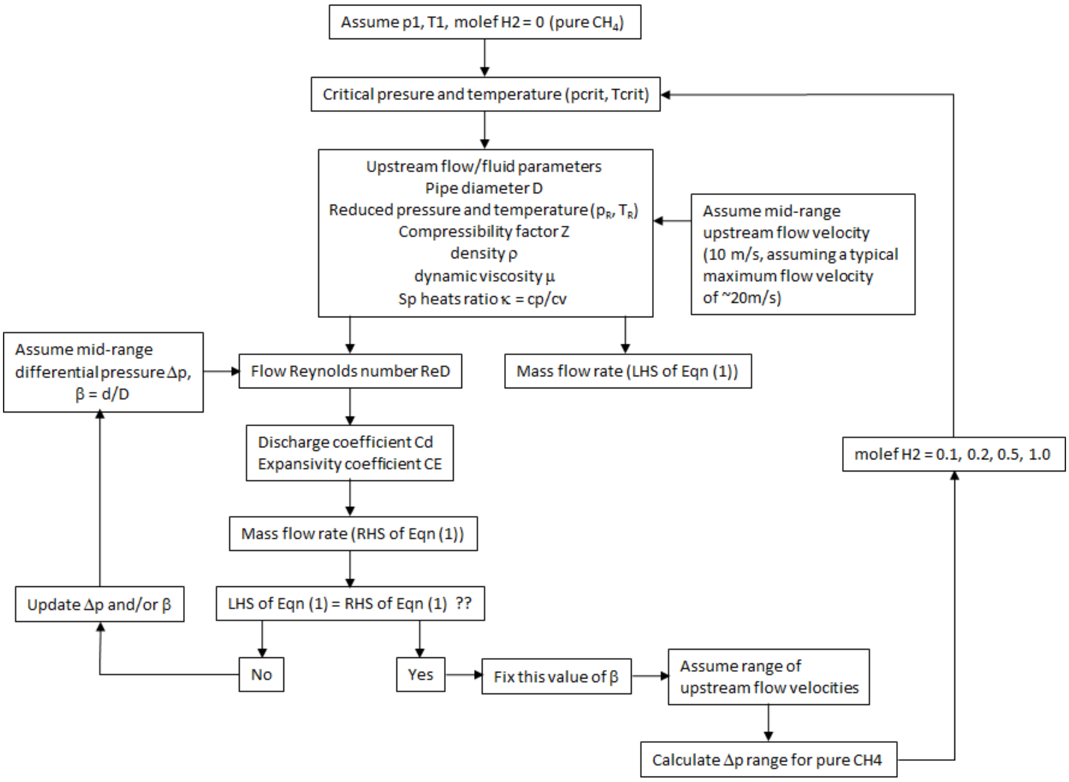


Figure 13 'Sizing' the orifice meter for pure CH_4 flow; using this to measure {CH_4 + H_2} blend flows

In the following paragraphs, uncertainty analysis is presented for four cases with assumed upstream conditions. These conditions and the corresponding results of the 'sizing' exercise are summarized in Table 7:

Table 7 Cases considered in uncertainty analysis

Case	Pipe diameter D1 (mm)	Upstream pressure p1 (Mpa)	Upstream temperature T1 (K)	β = d/D1
(a)	150	3	300	0.81
(b)	150	8	300	0.62
(c)	600	3	300	0.81
(d)	600	8	300	0.62

Assuming uncertainties in the input quantities [49], the following tables can be generated for the four cases:

Table 8 Orifice Sensitivity Coefficients; Sources of measurement error

Orifice Sensitivity Coefficients					
Error source					
Name	Symbol	Equation	ci	u(xi)/xi	[ci u*(xi)]^2
Pipe diameter	D	$2b^4/(1-\beta^4)$	1.4901	0.2	8.88E-06
Orifice diameter	d	$2/(1-\beta^4)$	3.4901	0.1	1.22E-05
Differential pressure	Δp		0.5		
density	ρ		-0.5	0.2	0.000001
Discharge Coefficient	Cd		0.5	0.375	3.52E-06
Expansivity Coefficient	CE		0.5	0.2	0.000001
MolWt/Comp Factor	MW/Z1		0.5	0.2	0.000001
Temperature	T1		0.5	0.5	6.25E-06

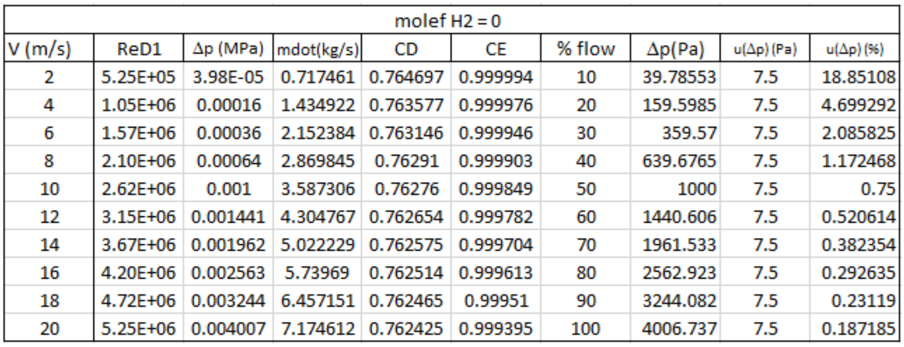
Orifice Sensitivity Coefficients					
Error source					
Name	Symbol	Equation	ci	u(xi)/xi	[ci u*(xi)]^2
Pipe diameter	D	$2\beta^4/(1-\beta^4)$	0.3484	0.2	4.85E-07
Orifice diameter	d	$2/(1-\beta^4)$	2.3484	0.1	5.51E-06
Differential pressure	Δp		0.5		
density	ρ		-0.5	0.2	0.000001
Discharge Coefficient	Cd		0.5	0.375	3.52E-06
Expansivity Coefficient	CE		0.5	0.2	0.000001
MolWt/Comp Factor	MW/Z1		0.5	0.2	0.000001
Temperature	T1		0.5	0.5	6.25E-06

(a) D1 = 150 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81
(c) D1 = 600 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81

(b) D1 = 150 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62
(d) D1 = 600 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62

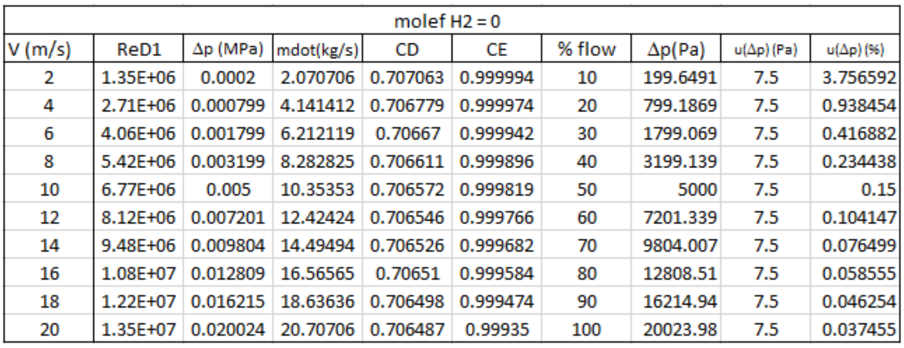
With the orifice meter geometry fixed for the four cases, the following tables can be generated, for a range of flow rates of pure CH_4 (mole fraction of H_2 = 0),

Table 9 Calculation of Δp, C_D, C_E for a range of flow rates (pure CH_4)



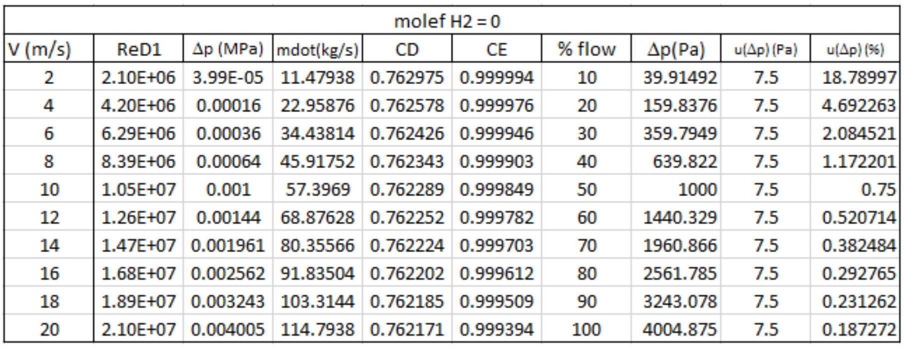
molef H2 = 0									
V (m/s)	ReD1	Δp (MPa)	mdot(kg/s)	CD	CE	% flow	Δp(Pa)	u(Δp) (Pa)	u(Δp) (%)
2	5.25E+05	3.98E-05	0.717461	0.764697	0.999994	10	39.78553	7.5	18.85108
4	1.05E+06	0.00016	1.434922	0.763577	0.999976	20	159.5985	7.5	4.699292
6	1.57E+06	0.00036	2.152384	0.763146	0.999946	30	359.57	7.5	2.085825
8	2.10E+06	0.00064	2.869845	0.76291	0.999903	40	639.6765	7.5	1.172468
10	2.62E+06	0.001	3.587306	0.76276	0.999849	50	1000	7.5	0.75
12	3.15E+06	0.001441	4.304767	0.762654	0.999782	60	1440.606	7.5	0.520614
14	3.67E+06	0.001962	5.022229	0.762575	0.999704	70	1961.533	7.5	0.382354
16	4.20E+06	0.002563	5.73969	0.762514	0.999613	80	2562.923	7.5	0.292635
18	4.72E+06	0.003244	6.457151	0.762465	0.99951	90	3244.082	7.5	0.23119
20	5.25E+06	0.004007	7.174612	0.762425	0.999395	100	4006.737	7.5	0.187185

(a) D1 = 150 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81



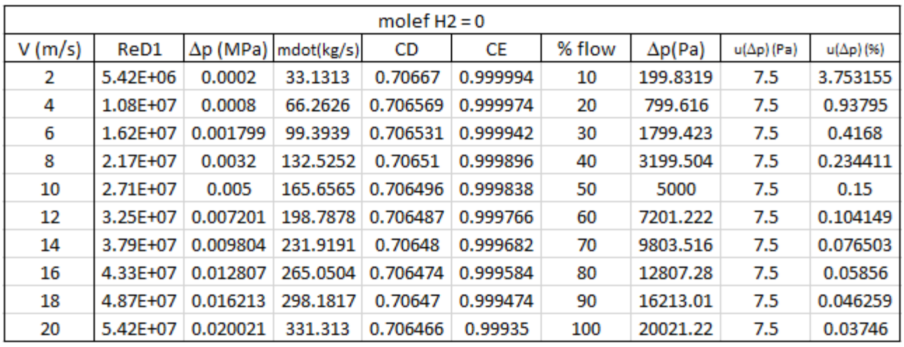
molef H2 = 0									
V (m/s)	ReD1	Δp (MPa)	mdot(kg/s)	CD	CE	% flow	Δp(Pa)	u(Δp) (Pa)	u(Δp) (%)
2	1.35E+06	0.0002	2.070706	0.707063	0.999994	10	199.6491	7.5	3.756592
4	2.71E+06	0.000799	4.141412	0.706779	0.999974	20	799.1869	7.5	0.938454
6	4.06E+06	0.001799	6.212119	0.70667	0.999942	30	1799.069	7.5	0.416882
8	5.42E+06	0.003199	8.282825	0.706611	0.999896	40	3199.139	7.5	0.234438
10	6.77E+06	0.005	10.35353	0.706572	0.999819	50	5000	7.5	0.15
12	8.12E+06	0.007201	12.42424	0.706546	0.999766	60	7201.339	7.5	0.104147
14	9.48E+06	0.009804	14.49494	0.706526	0.999682	70	9804.007	7.5	0.076499
16	1.08E+07	0.012809	16.56565	0.70651	0.999584	80	12808.51	7.5	0.058555
18	1.22E+07	0.016215	18.63636	0.706498	0.999474	90	16214.94	7.5	0.046254
20	1.35E+07	0.020024	20.70706	0.706487	0.99935	100	20023.98	7.5	0.037455

(b) D1 = 150 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62



molef H2 = 0									
V (m/s)	ReD1	Δp (MPa)	mdot(kg/s)	CD	CE	% flow	Δp(Pa)	u(Δp) (Pa)	u(Δp) (%)
2	2.10E+06	3.99E-05	11.47938	0.762975	0.999994	10	39.91492	7.5	18.78997
4	4.20E+06	0.00016	22.95876	0.762578	0.999976	20	159.8376	7.5	4.692263
6	6.29E+06	0.00036	34.43814	0.762426	0.999946	30	359.7949	7.5	2.084521
8	8.39E+06	0.00064	45.91752	0.762343	0.999903	40	639.822	7.5	1.172201
10	1.05E+07	0.001	57.3969	0.762289	0.999849	50	1000	7.5	0.75
12	1.26E+07	0.00144	68.87628	0.762252	0.999782	60	1440.329	7.5	0.520714
14	1.47E+07	0.001961	80.35566	0.762224	0.999703	70	1960.866	7.5	0.382484
16	1.68E+07	0.002562	91.83504	0.762202	0.999612	80	2561.785	7.5	0.292765
18	1.89E+07	0.003243	103.3144	0.762185	0.999509	90	3243.078	7.5	0.231262
20	2.10E+07	0.004005	114.7938	0.762171	0.999394	100	4004.875	7.5	0.187272

(c) D1 = 600 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81

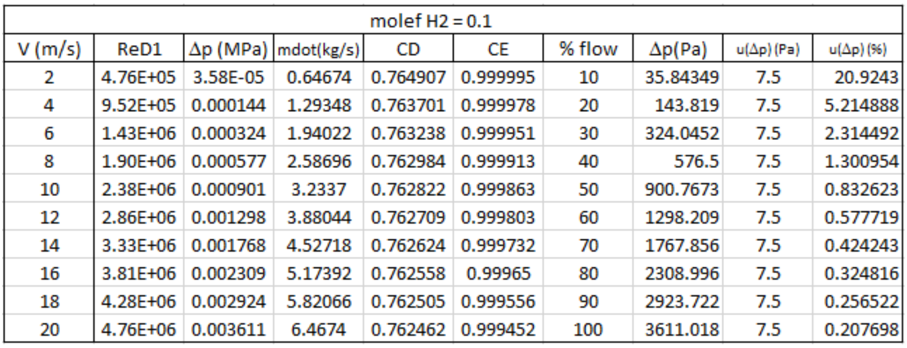


molef H2 = 0									
V (m/s)	ReD1	Δp (MPa)	mdot(kg/s)	CD	CE	% flow	Δp(Pa)	u(Δp) (Pa)	u(Δp) (%)
2	5.42E+06	0.0002	33.1313	0.70667	0.999994	10	199.8319	7.5	3.753155
4	1.08E+07	0.0008	66.2626	0.706569	0.999974	20	799.616	7.5	0.93795
6	1.62E+07	0.001799	99.3939	0.706531	0.999942	30	1799.423	7.5	0.4168
8	2.17E+07	0.0032	132.5252	0.70651	0.999896	40	3199.504	7.5	0.234411
10	2.71E+07	0.005	165.6565	0.706496	0.999838	50	5000	7.5	0.15
12	3.25E+07	0.007201	198.7878	0.706487	0.999766	60	7201.222	7.5	0.104149
14	3.79E+07	0.009804	231.9191	0.70648	0.999682	70	9803.516	7.5	0.076503
16	4.33E+07	0.012807	265.0504	0.706474	0.999584	80	12807.28	7.5	0.05856
18	4.87E+07	0.016213	298.1817	0.70647	0.999474	90	16213.01	7.5	0.046259
20	5.42E+07	0.020021	331.313	0.706466	0.99935	100	20021.22	7.5	0.03746

(d) D1 = 600 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62

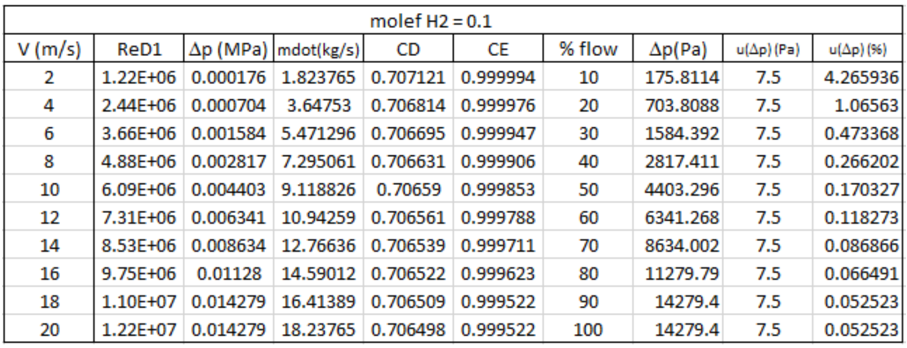
For the same values of *p1*, *T1*, *D1* and β, in each case, and for the same range of flow velocities, the following corresponding tables are generated for a range of flow rates of a blend consisting of 90% CH_4 and 10% H_2 (mole fractions):

Table 10 Calculation of Δp, C_D, C_E for a range of flow rates $\{0.9CH_4 + 0.1H_2\}$



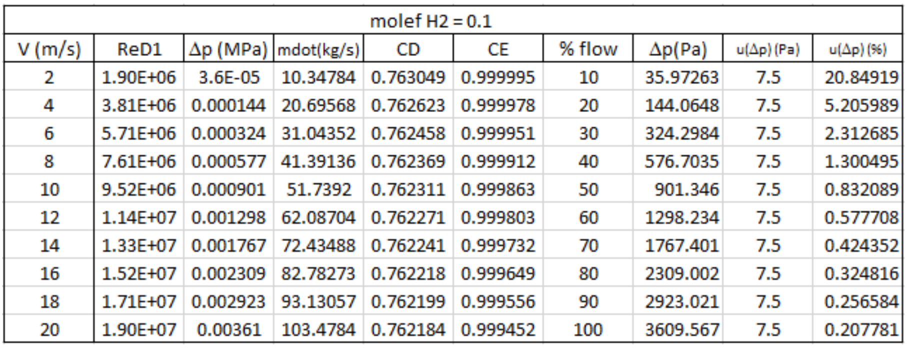
molef H2 = 0.1									
V (m/s)	ReD1	Δp (MPa)	mdot(kg/s)	CD	CE	% flow	Δp(Pa)	u(Δp) (Pa)	u(Δp) (%)
2	4.76E+05	3.58E-05	0.64674	0.764907	0.999995	10	35.84349	7.5	20.9243
4	9.52E+05	0.000144	1.29348	0.763701	0.999978	20	143.819	7.5	5.214888
6	1.43E+06	0.000324	1.94022	0.763238	0.999951	30	324.0452	7.5	2.314492
8	1.90E+06	0.000577	2.58696	0.762984	0.999913	40	576.5	7.5	1.300954
10	2.38E+06	0.000901	3.2337	0.762822	0.999863	50	900.7673	7.5	0.832623
12	2.86E+06	0.001298	3.88044	0.762709	0.999803	60	1298.209	7.5	0.577719
14	3.33E+06	0.001768	4.52718	0.762624	0.999732	70	1767.856	7.5	0.424243
16	3.81E+06	0.002309	5.17392	0.762558	0.99965	80	2308.996	7.5	0.324816
18	4.28E+06	0.002924	5.82066	0.762505	0.999556	90	2923.722	7.5	0.256522
20	4.76E+06	0.003611	6.4674	0.762462	0.999452	100	3611.018	7.5	0.207698

(a) D1 = 150 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81



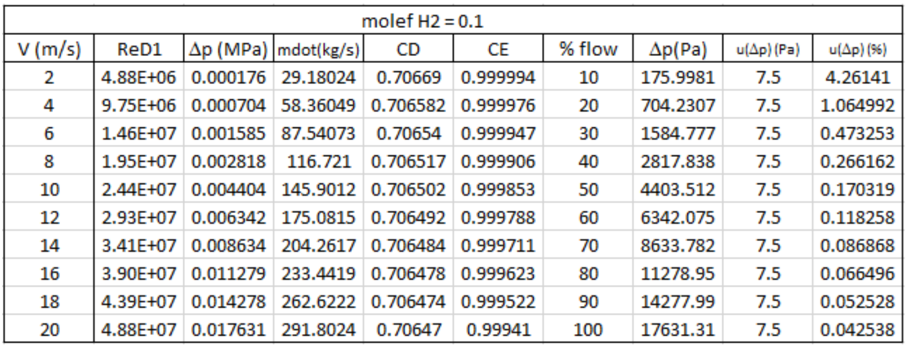
molef H2 = 0.1									
V (m/s)	ReD1	Δp (MPa)	mdot(kg/s)	CD	CE	% flow	Δp(Pa)	u(Δp) (Pa)	u(Δp) (%)
2	1.22E+06	0.000176	1.823765	0.707121	0.999994	10	175.8114	7.5	4.265936
4	2.44E+06	0.000704	3.64753	0.706814	0.999976	20	703.8088	7.5	1.06563
6	3.66E+06	0.001584	5.471296	0.706695	0.999947	30	1584.392	7.5	0.473368
8	4.88E+06	0.002817	7.295061	0.706631	0.999906	40	2817.411	7.5	0.266202
10	6.09E+06	0.004403	9.118826	0.70659	0.999853	50	4403.296	7.5	0.170327
12	7.31E+06	0.006341	10.94259	0.706561	0.999788	60	6341.268	7.5	0.118273
14	8.53E+06	0.008634	12.76636	0.706539	0.999711	70	8634.002	7.5	0.086866
16	9.75E+06	0.01128	14.59012	0.706522	0.999623	80	11279.79	7.5	0.066491
18	1.10E+07	0.014279	16.41389	0.706509	0.999522	90	14279.4	7.5	0.052523
20	1.22E+07	0.014279	18.23765	0.706498	0.999522	100	14279.4	7.5	0.052523

(b) D1 = 150 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62



molef H2 = 0.1									
V (m/s)	ReD1	Δp (MPa)	mdot(kg/s)	CD	CE	% flow	Δp(Pa)	u(Δp) (Pa)	u(Δp) (%)
2	1.90E+06	3.6E-05	10.34784	0.763049	0.999995	10	35.97263	7.5	20.84919
4	3.81E+06	0.000144	20.69568	0.762623	0.999978	20	144.0648	7.5	5.205989
6	5.71E+06	0.000324	31.04352	0.762458	0.999951	30	324.2984	7.5	2.312685
8	7.61E+06	0.000577	41.39136	0.762369	0.999912	40	576.7035	7.5	1.300495
10	9.52E+06	0.000901	51.7392	0.762311	0.999863	50	901.346	7.5	0.832089
12	1.14E+07	0.001298	62.08704	0.762271	0.999803	60	1298.234	7.5	0.577708
14	1.33E+07	0.001767	72.43488	0.762241	0.999732	70	1767.401	7.5	0.424352
16	1.52E+07	0.002309	82.78273	0.762218	0.999649	80	2309.002	7.5	0.324816
18	1.71E+07	0.002923	93.13057	0.762199	0.999556	90	2923.021	7.5	0.256584
20	1.90E+07	0.00361	103.4784	0.762184	0.999452	100	3609.567	7.5	0.207781

(c) D1 = 600 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81

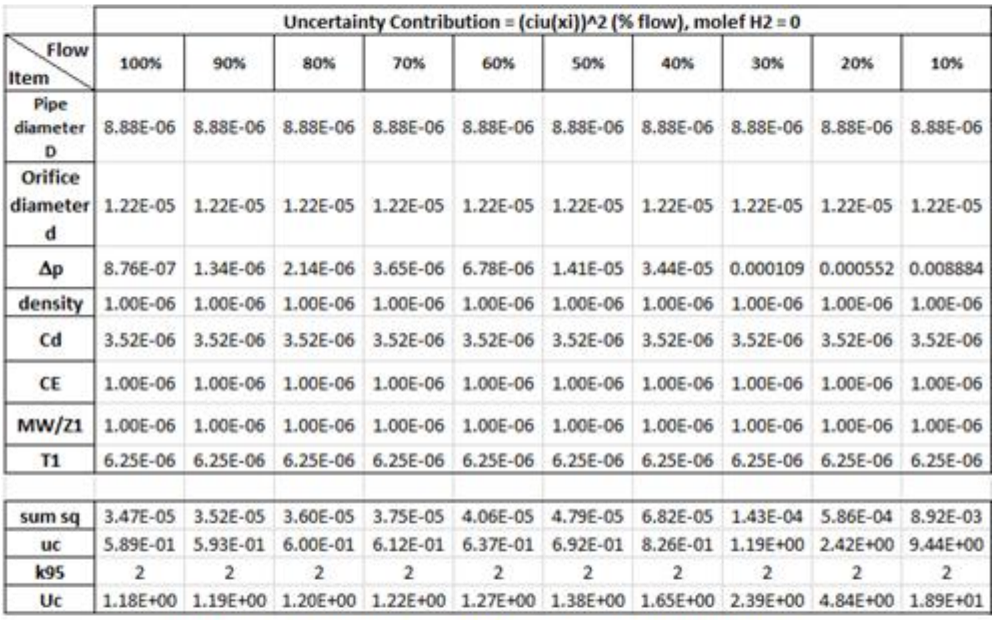


molef H2 = 0.1									
V (m/s)	ReD1	Δp (MPa)	mdot(kg/s)	CD	CE	% flow	Δp(Pa)	u(Δp) (Pa)	u(Δp) (%)
2	4.88E+06	0.000176	29.18024	0.70669	0.999994	10	175.9981	7.5	4.26141
4	9.75E+06	0.000704	58.36049	0.706582	0.999976	20	704.2307	7.5	1.064992
6	1.46E+07	0.001585	87.54073	0.70654	0.999947	30	1584.777	7.5	0.473253
8	1.95E+07	0.002818	116.721	0.706517	0.999906	40	2817.838	7.5	0.266162
10	2.44E+07	0.004404	145.9012	0.706502	0.999853	50	4403.512	7.5	0.170319
12	2.93E+07	0.006342	175.0815	0.706492	0.999788	60	6342.075	7.5	0.118258
14	3.41E+07	0.008634	204.2617	0.706484	0.999711	70	8633.782	7.5	0.086868
16	3.90E+07	0.011279	233.4419	0.706478	0.999623	80	11278.95	7.5	0.066496
18	4.39E+07	0.014278	262.6222	0.706474	0.999522	90	14277.99	7.5	0.052528
20	4.88E+07	0.017631	291.8024	0.70647	0.99941	100	17631.31	7.5	0.042538

(d) D1 = 600 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62

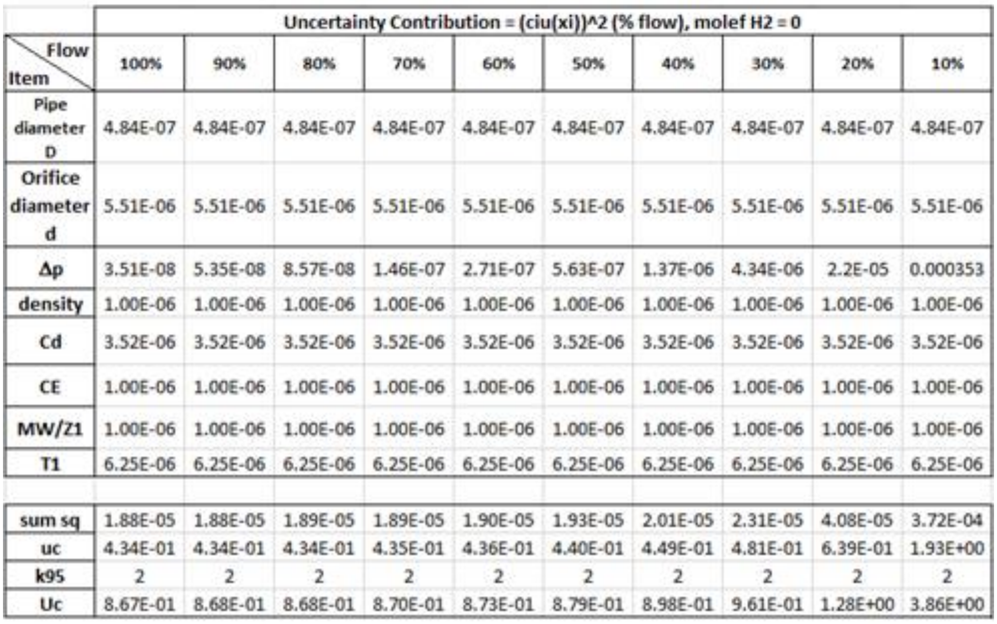
To express uncertainty contributions for a confidence interval of 95% (e.g [49]), a 'coverage factor' $k_{95} = 2$ can be applied (e.g. [7], [49], for the number of 'degrees of freedom >10). Accordingly, Tables 11 and 12 present the uncertainty contributions for pure CH_4 and a $\{0.9CH_4 + 0.1H_2\}$ blend respectively. Note that in Tables 11 and 12, the range from '10% Flow' to '100% Flow' corresponds to a range of flow velocities from 2 m/s to 20 m/s.

Table 11 Uncertainty Contributions (molef $H_2 = 0$; Pure CH_4)



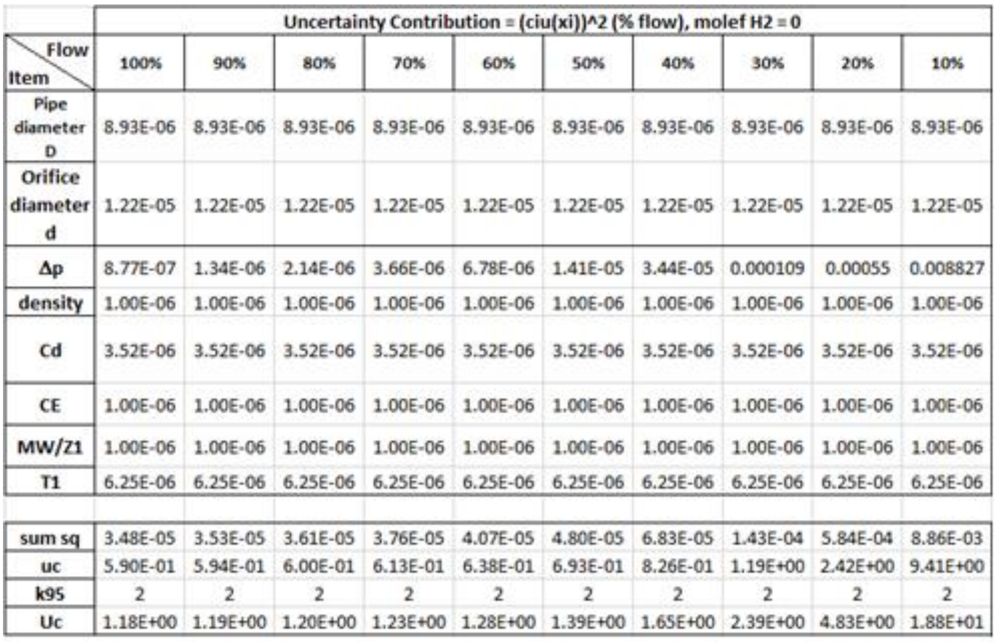
	Uncertainty Contribution = (ciu(xi))^2 (% flow), molef H2 = 0									
Flow Item	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
Pipe diameter D	8.88E-06	8.88E-06	8.88E-06	8.88E-06	8.88E-06	8.88E-06	8.88E-06	8.88E-06	8.88E-06	8.88E-06
Orifice diameter d	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05
Δp	8.76E-07	1.34E-06	2.14E-06	3.65E-06	6.78E-06	1.41E-05	3.44E-05	0.000109	0.000552	0.008884
density	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
Cd	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06
CE	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
MW/Z1	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
T1	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06
sum sq	3.47E-05	3.52E-05	3.60E-05	3.75E-05	4.06E-05	4.79E-05	6.82E-05	1.43E-04	5.86E-04	8.92E-03
uc	5.89E-01	5.93E-01	6.00E-01	6.12E-01	6.37E-01	6.92E-01	8.26E-01	1.19E+00	2.42E+00	9.44E+00
k95	2	2	2	2	2	2	2	2	2	2
Uc	1.18E+00	1.19E+00	1.20E+00	1.22E+00	1.27E+00	1.38E+00	1.65E+00	2.39E+00	4.84E+00	1.89E+01

(a) D1 = 150 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81



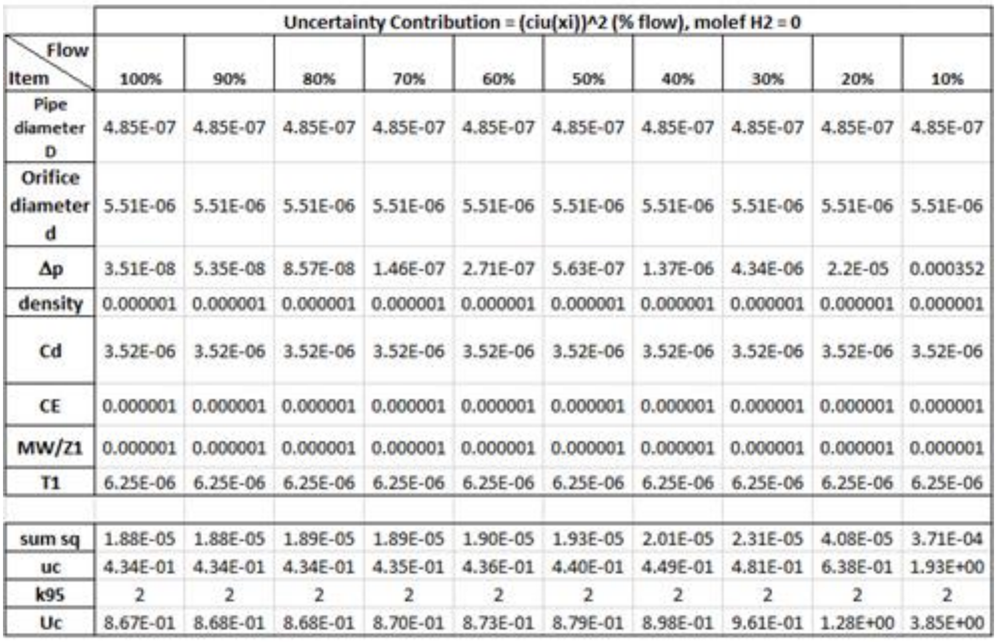
	Uncertainty Contribution = (ciu(xi))^2 (% flow), molef H2 = 0									
Flow Item	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
Pipe diameter D	4.84E-07	4.84E-07	4.84E-07	4.84E-07	4.84E-07	4.84E-07	4.84E-07	4.84E-07	4.84E-07	4.84E-07
Orifice diameter d	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06
Δp	3.51E-08	5.35E-08	8.57E-08	1.46E-07	2.71E-07	5.63E-07	1.37E-06	4.34E-06	2.2E-05	0.000353
density	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
Cd	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06
CE	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
MW/Z1	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
T1	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06
sum sq	1.88E-05	1.88E-05	1.89E-05	1.89E-05	1.90E-05	1.93E-05	2.01E-05	2.31E-05	4.08E-05	3.72E-04
uc	4.34E-01	4.34E-01	4.34E-01	4.35E-01	4.36E-01	4.40E-01	4.49E-01	4.81E-01	6.39E-01	1.93E+00
k95	2	2	2	2	2	2	2	2	2	2
Uc	8.67E-01	8.68E-01	8.68E-01	8.70E-01	8.73E-01	8.79E-01	8.98E-01	9.61E-01	1.28E+00	3.86E+00

(b) D1 = 150 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62



	Uncertainty Contribution = (ciu(xi))^2 (% flow), molef H2 = 0									
Flow / Item	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
Pipe diameter D	8.93E-06	8.93E-06	8.93E-06	8.93E-06	8.93E-06	8.93E-06	8.93E-06	8.93E-06	8.93E-06	8.93E-06
Orifice diameter d	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05
Δp	8.77E-07	1.34E-06	2.14E-06	3.66E-06	6.78E-06	1.41E-05	3.44E-05	0.000109	0.00055	0.008827
density	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
Cd	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06
CE	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
MW/Z1	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
T1	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06
sum sq	3.48E-05	3.53E-05	3.61E-05	3.76E-05	4.07E-05	4.80E-05	6.83E-05	1.43E-04	5.84E-04	8.86E-03
uc	5.90E-01	5.94E-01	6.00E-01	6.13E-01	6.38E-01	6.93E-01	8.26E-01	1.19E+00	2.42E+00	9.41E+00
k95	2	2	2	2	2	2	2	2	2	2
Uc	1.18E+00	1.19E+00	1.20E+00	1.23E+00	1.28E+00	1.39E+00	1.65E+00	2.39E+00	4.83E+00	1.88E+01

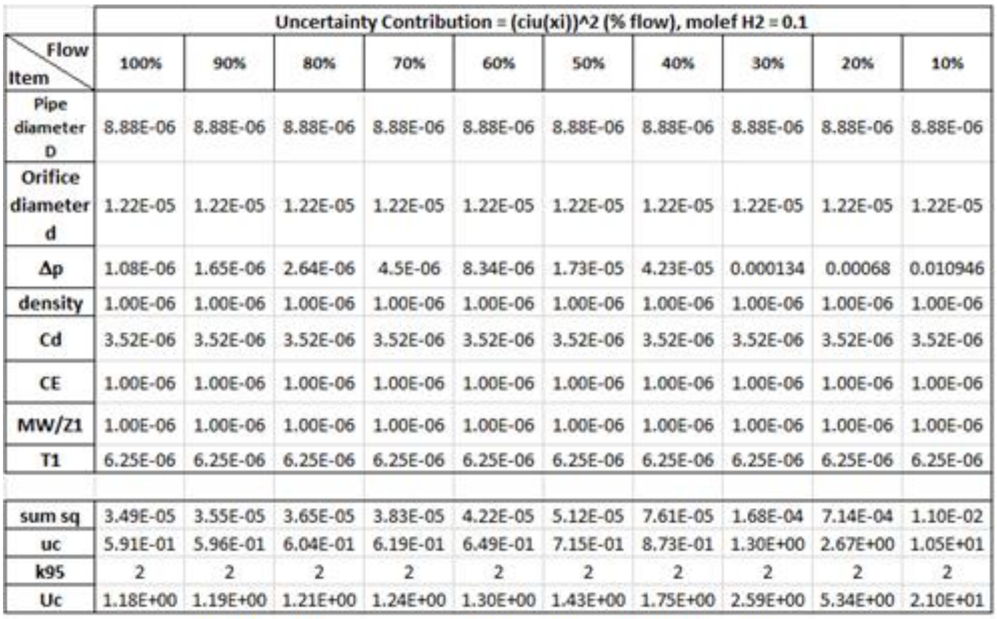
(c) D1 = 600 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81



	Uncertainty Contribution = (ciu(xi))^2 (% flow), molef H2 = 0									
Flow / Item	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
Pipe diameter D	4.85E-07	4.85E-07	4.85E-07	4.85E-07	4.85E-07	4.85E-07	4.85E-07	4.85E-07	4.85E-07	4.85E-07
Orifice diameter d	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06
Δp	3.51E-08	5.35E-08	8.57E-08	1.46E-07	2.71E-07	5.63E-07	1.37E-06	4.34E-06	2.2E-05	0.000352
density	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001
Cd	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06
CE	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001
MW/Z1	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001
T1	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06
sum sq	1.88E-05	1.88E-05	1.89E-05	1.89E-05	1.90E-05	1.93E-05	2.01E-05	2.31E-05	4.08E-05	3.71E-04
uc	4.34E-01	4.34E-01	4.34E-01	4.35E-01	4.36E-01	4.40E-01	4.49E-01	4.81E-01	6.38E-01	1.93E+00
k95	2	2	2	2	2	2	2	2	2	2
Uc	8.67E-01	8.68E-01	8.68E-01	8.70E-01	8.73E-01	8.79E-01	8.98E-01	9.61E-01	1.28E+00	3.85E+00

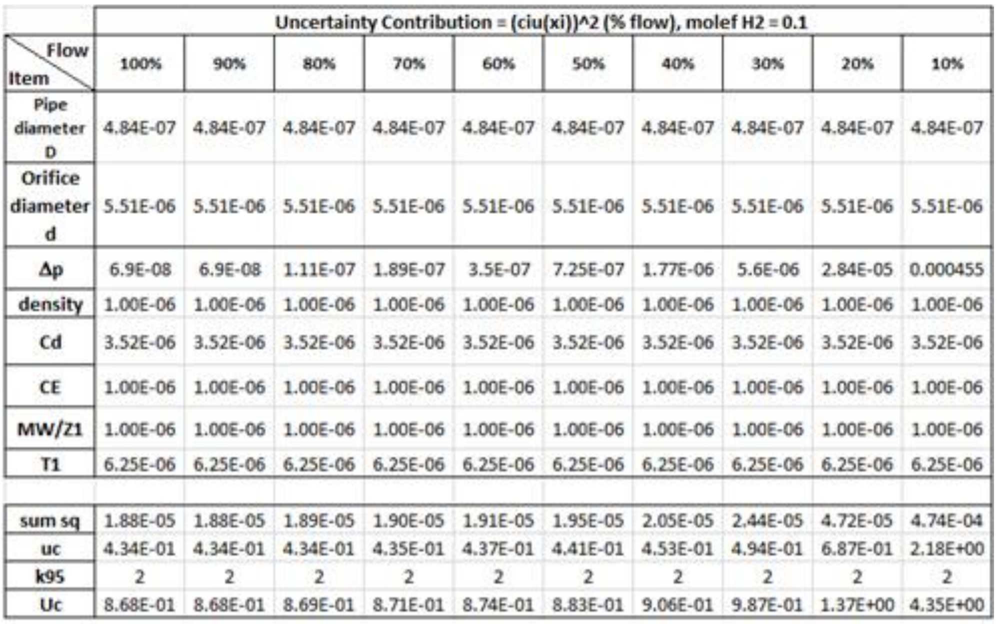
(d) D1 = 600 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62

Table 12 Uncertainty Contributions {$0.9CH_4 + 0.1H_2$}



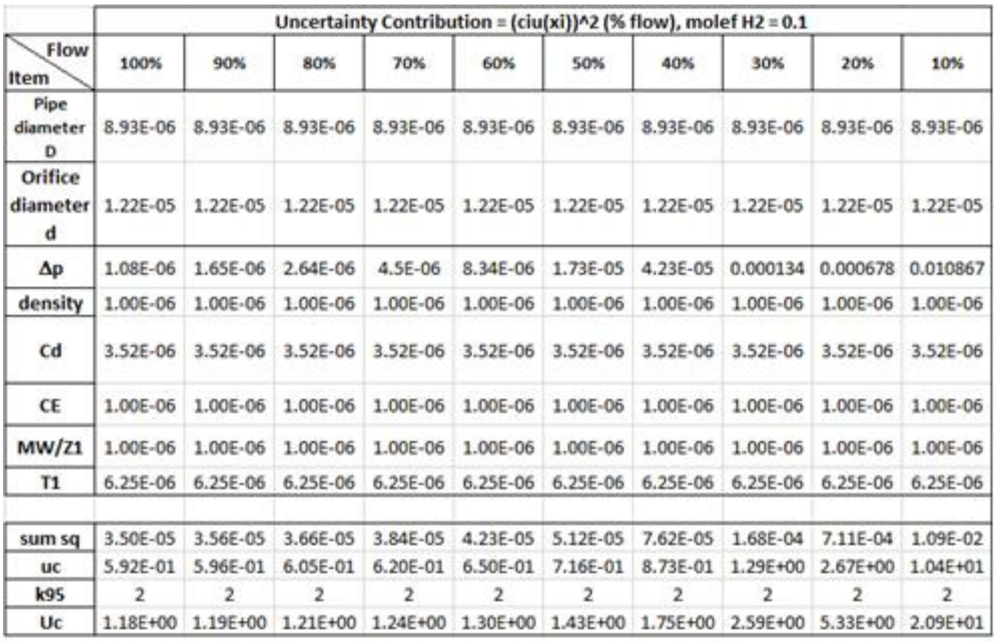
	Uncertainty Contribution = (ciu(xi))^2 (% flow), molef H2 = 0.1									
Flow Item	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
Pipe diameter D	8.88E-06	8.88E-06	8.88E-06	8.88E-06	8.88E-06	8.88E-06	8.88E-06	8.88E-06	8.88E-06	8.88E-06
Orifice diameter d	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05
Δp	1.08E-06	1.65E-06	2.64E-06	4.5E-06	8.34E-06	1.73E-05	4.23E-05	0.000134	0.00068	0.010946
density	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
Cd	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06
CE	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
MW/Z1	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
T1	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06
sum sq	3.49E-05	3.55E-05	3.65E-05	3.83E-05	4.22E-05	5.12E-05	7.61E-05	1.68E-04	7.14E-04	1.10E-02
uc	5.91E-01	5.96E-01	6.04E-01	6.19E-01	6.49E-01	7.15E-01	8.73E-01	1.30E+00	2.67E+00	1.05E+01
k95	2	2	2	2	2	2	2	2	2	2
Uc	1.18E+00	1.19E+00	1.21E+00	1.24E+00	1.30E+00	1.43E+00	1.75E+00	2.59E+00	5.34E+00	2.10E+01

(a) D1 = 150 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81



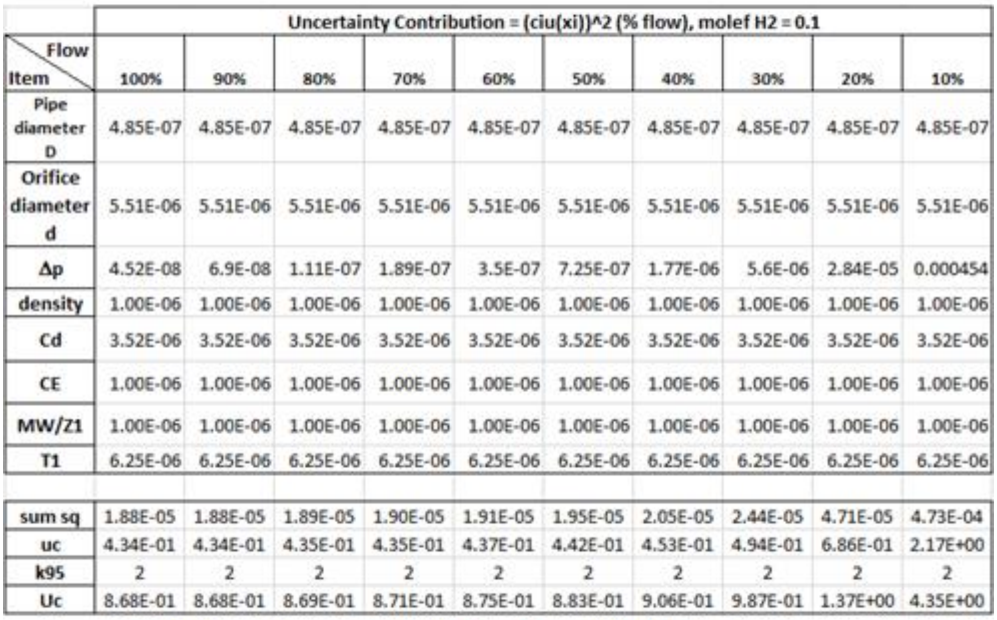
	Uncertainty Contribution = (ciu(xi))^2 (% flow), molef H2 = 0.1									
Flow Item	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
Pipe diameter D	4.84E-07	4.84E-07	4.84E-07	4.84E-07	4.84E-07	4.84E-07	4.84E-07	4.84E-07	4.84E-07	4.84E-07
Orifice diameter d	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06
Δp	6.9E-08	6.9E-08	1.11E-07	1.89E-07	3.5E-07	7.25E-07	1.77E-06	5.6E-06	2.84E-05	0.000455
density	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
Cd	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06
CE	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
MW/Z1	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
T1	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06
sum sq	1.88E-05	1.88E-05	1.89E-05	1.90E-05	1.91E-05	1.95E-05	2.05E-05	2.44E-05	4.72E-05	4.74E-04
uc	4.34E-01	4.34E-01	4.34E-01	4.35E-01	4.37E-01	4.41E-01	4.53E-01	4.94E-01	6.87E-01	2.18E+00
k95	2	2	2	2	2	2	2	2	2	2
Uc	8.68E-01	8.68E-01	8.69E-01	8.71E-01	8.74E-01	8.83E-01	9.06E-01	9.87E-01	1.37E+00	4.35E+00

(b) D1 = 150 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62



	Uncertainty Contribution = (ciu(xi))^2 (% flow), molef H2 = 0.1									
Flow Item	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
Pipe diameter D	8.93E-06	8.93E-06	8.93E-06	8.93E-06	8.93E-06	8.93E-06	8.93E-06	8.93E-06	8.93E-06	8.93E-06
Orifice diameter d	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05	1.22E-05
Δp	1.08E-06	1.65E-06	2.64E-06	4.5E-06	8.34E-06	1.73E-05	4.23E-05	0.000134	0.000678	0.010867
density	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
Cd	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06
CE	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
MW/Z1	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
T1	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06
sum sq	3.50E-05	3.56E-05	3.66E-05	3.84E-05	4.23E-05	5.12E-05	7.62E-05	1.68E-04	7.11E-04	1.09E-02
uc	5.92E-01	5.96E-01	6.05E-01	6.20E-01	6.50E-01	7.16E-01	8.73E-01	1.29E+00	2.67E+00	1.04E+01
k95	2	2	2	2	2	2	2	2	2	2
Uc	1.18E+00	1.19E+00	1.21E+00	1.24E+00	1.30E+00	1.43E+00	1.75E+00	2.59E+00	5.33E+00	2.09E+01

(c) D1 = 600 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81



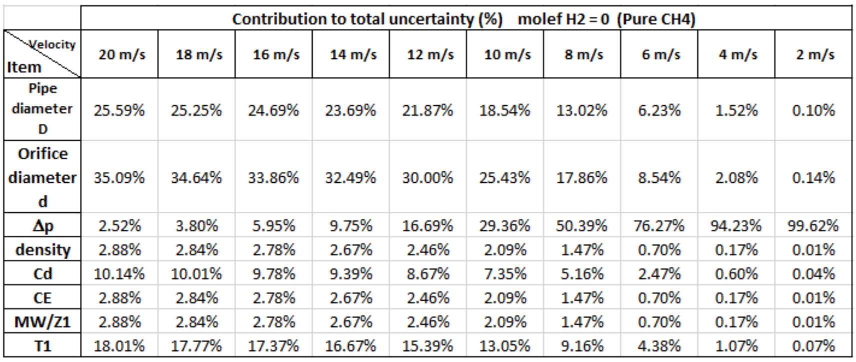
	Uncertainty Contribution = (ciu(xi))^2 (% flow), molef H2 = 0.1									
Flow Item	100%	90%	80%	70%	60%	50%	40%	30%	20%	10%
Pipe diameter D	4.85E-07	4.85E-07	4.85E-07	4.85E-07	4.85E-07	4.85E-07	4.85E-07	4.85E-07	4.85E-07	4.85E-07
Orifice diameter d	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06	5.51E-06
Δp	4.52E-08	6.9E-08	1.11E-07	1.89E-07	3.5E-07	7.25E-07	1.77E-06	5.6E-06	2.84E-05	0.000454
density	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
Cd	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06	3.52E-06
CE	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
MW/Z1	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
T1	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06	6.25E-06
sum sq	1.88E-05	1.88E-05	1.89E-05	1.90E-05	1.91E-05	1.95E-05	2.05E-05	2.44E-05	4.71E-05	4.73E-04
uc	4.34E-01	4.34E-01	4.35E-01	4.35E-01	4.37E-01	4.42E-01	4.53E-01	4.94E-01	6.86E-01	2.17E+00
k95	2	2	2	2	2	2	2	2	2	2
Uc	8.68E-01	8.68E-01	8.69E-01	8.71E-01	8.75E-01	8.83E-01	9.06E-01	9.87E-01	1.37E+00	4.35E+00

(d) D1 = 600 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62

Finally, the contribution of each to the total (overall) combined uncertainty can be calculated as in Tables 13 and 14 for pure CH_4 and a {$0.9CH_4 + 0.1H_2$} blend respectively.

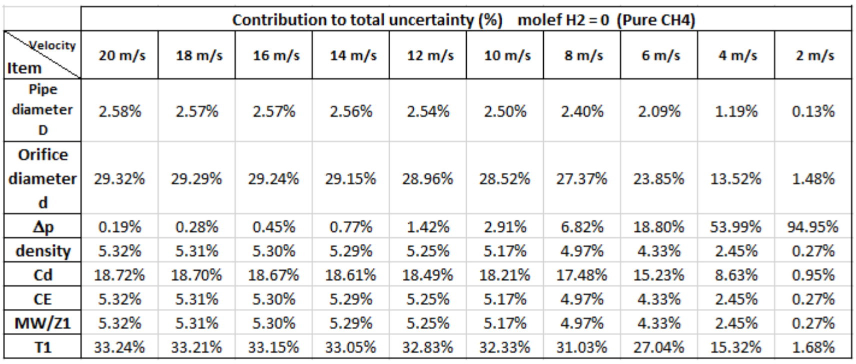
PURE METHANE (CH_4)

Table 13 Contributions to overall combined uncertainty (pure CH_4)



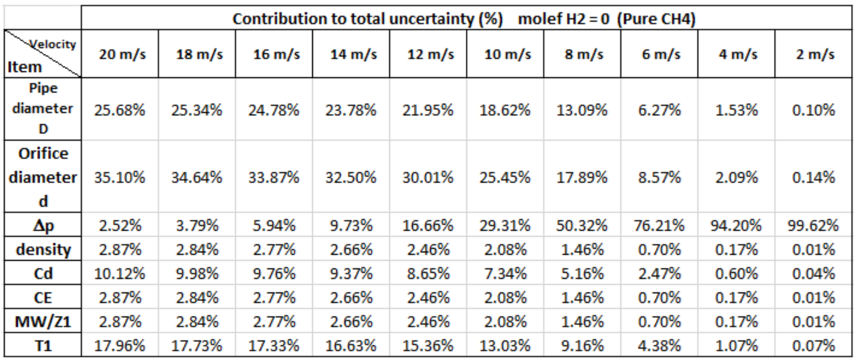
	Contribution to total uncertainty (%) molef H2 = 0 (Pure CH4)									
Velocity Item	20 m/s	18 m/s	16 m/s	14 m/s	12 m/s	10 m/s	8 m/s	6 m/s	4 m/s	2 m/s
Pipe diameter D	25.59%	25.25%	24.69%	23.69%	21.87%	18.54%	13.02%	6.23%	1.52%	0.10%
Orifice diameter d	35.09%	34.64%	33.86%	32.49%	30.00%	25.43%	17.86%	8.54%	2.08%	0.14%
Δp	2.52%	3.80%	5.95%	9.75%	16.69%	29.36%	50.39%	76.27%	94.23%	99.62%
density	2.88%	2.84%	2.78%	2.67%	2.46%	2.09%	1.47%	0.70%	0.17%	0.01%
Cd	10.14%	10.01%	9.78%	9.39%	8.67%	7.35%	5.16%	2.47%	0.60%	0.04%
CE	2.88%	2.84%	2.78%	2.67%	2.46%	2.09%	1.47%	0.70%	0.17%	0.01%
MW/Z1	2.88%	2.84%	2.78%	2.67%	2.46%	2.09%	1.47%	0.70%	0.17%	0.01%
T1	18.01%	17.77%	17.37%	16.67%	15.39%	13.05%	9.16%	4.38%	1.07%	0.07%

(a) D1 = 150 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81



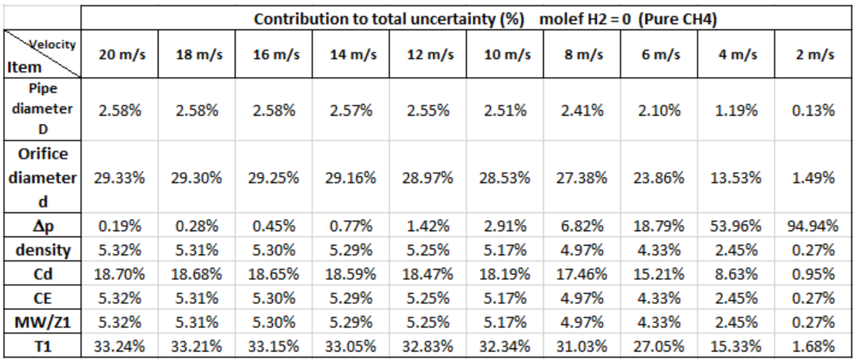
	Contribution to total uncertainty (%) molef H2 = 0 (Pure CH4)									
Velocity Item	20 m/s	18 m/s	16 m/s	14 m/s	12 m/s	10 m/s	8 m/s	6 m/s	4 m/s	2 m/s
Pipe diameter D	2.58%	2.57%	2.57%	2.56%	2.54%	2.50%	2.40%	2.09%	1.19%	0.13%
Orifice diameter d	29.32%	29.29%	29.24%	29.15%	28.96%	28.52%	27.37%	23.85%	13.52%	1.48%
Δp	0.19%	0.28%	0.45%	0.77%	1.42%	2.91%	6.82%	18.80%	53.99%	94.95%
density	5.32%	5.31%	5.30%	5.29%	5.25%	5.17%	4.97%	4.33%	2.45%	0.27%
Cd	18.72%	18.70%	18.67%	18.61%	18.49%	18.21%	17.48%	15.23%	8.63%	0.95%
CE	5.32%	5.31%	5.30%	5.29%	5.25%	5.17%	4.97%	4.33%	2.45%	0.27%
MW/Z1	5.32%	5.31%	5.30%	5.29%	5.25%	5.17%	4.97%	4.33%	2.45%	0.27%
T1	33.24%	33.21%	33.15%	33.05%	32.83%	32.33%	31.03%	27.04%	15.32%	1.68%

(b) D1 = 150 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62



	Contribution to total uncertainty (%) molef H2 = 0 (Pure CH4)									
Velocity Item	20 m/s	18 m/s	16 m/s	14 m/s	12 m/s	10 m/s	8 m/s	6 m/s	4 m/s	2 m/s
Pipe diameter D	25.68%	25.34%	24.78%	23.78%	21.95%	18.62%	13.09%	6.27%	1.53%	0.10%
Orifice diameter d	35.10%	34.64%	33.87%	32.50%	30.01%	25.45%	17.89%	8.57%	2.09%	0.14%
Δp	2.52%	3.79%	5.94%	9.73%	16.66%	29.31%	50.32%	76.21%	94.20%	99.62%
density	2.87%	2.84%	2.77%	2.66%	2.46%	2.08%	1.46%	0.70%	0.17%	0.01%
Cd	10.12%	9.98%	9.76%	9.37%	8.65%	7.34%	5.16%	2.47%	0.60%	0.04%
CE	2.87%	2.84%	2.77%	2.66%	2.46%	2.08%	1.46%	0.70%	0.17%	0.01%
MW/Z1	2.87%	2.84%	2.77%	2.66%	2.46%	2.08%	1.46%	0.70%	0.17%	0.01%
T1	17.96%	17.73%	17.33%	16.63%	15.36%	13.03%	9.16%	4.38%	1.07%	0.07%

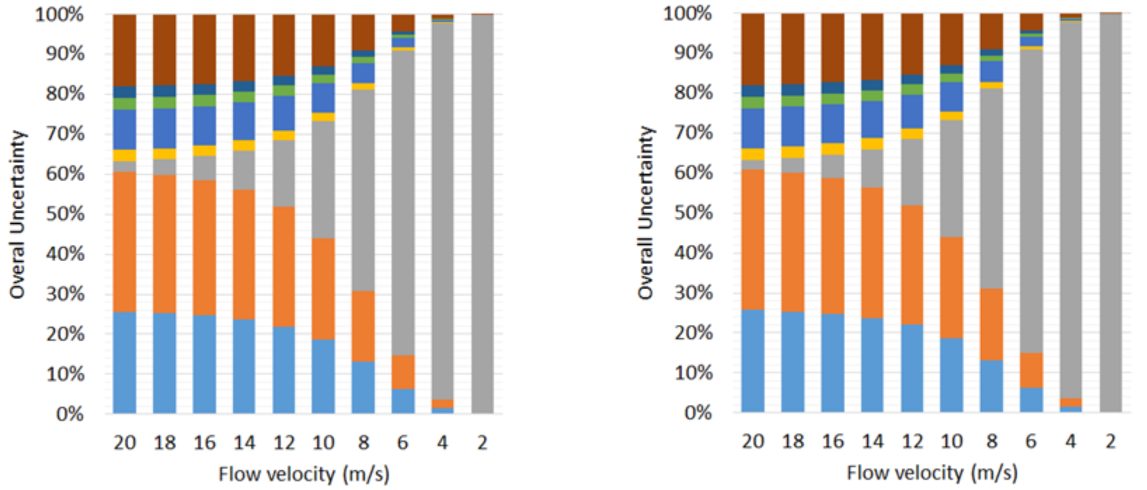
(c) D1 = 600 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81



	Contribution to total uncertainty (%) molef H2 = 0 (Pure CH4)									
Velocity Item	20 m/s	18 m/s	16 m/s	14 m/s	12 m/s	10 m/s	8 m/s	6 m/s	4 m/s	2 m/s
Pipe diameter D	2.58%	2.58%	2.58%	2.57%	2.55%	2.51%	2.41%	2.10%	1.19%	0.13%
Orifice diameter d	29.33%	29.30%	29.25%	29.16%	28.97%	28.53%	27.38%	23.86%	13.53%	1.49%
Δp	0.19%	0.28%	0.45%	0.77%	1.42%	2.91%	6.82%	18.79%	53.96%	94.94%
density	5.32%	5.31%	5.30%	5.29%	5.25%	5.17%	4.97%	4.33%	2.45%	0.27%
Cd	18.70%	18.68%	18.65%	18.59%	18.47%	18.19%	17.46%	15.21%	8.63%	0.95%
CE	5.32%	5.31%	5.30%	5.29%	5.25%	5.17%	4.97%	4.33%	2.45%	0.27%
MW/Z1	5.32%	5.31%	5.30%	5.29%	5.25%	5.17%	4.97%	4.33%	2.45%	0.27%
T1	33.24%	33.21%	33.15%	33.05%	32.83%	32.34%	31.03%	27.05%	15.33%	1.68%

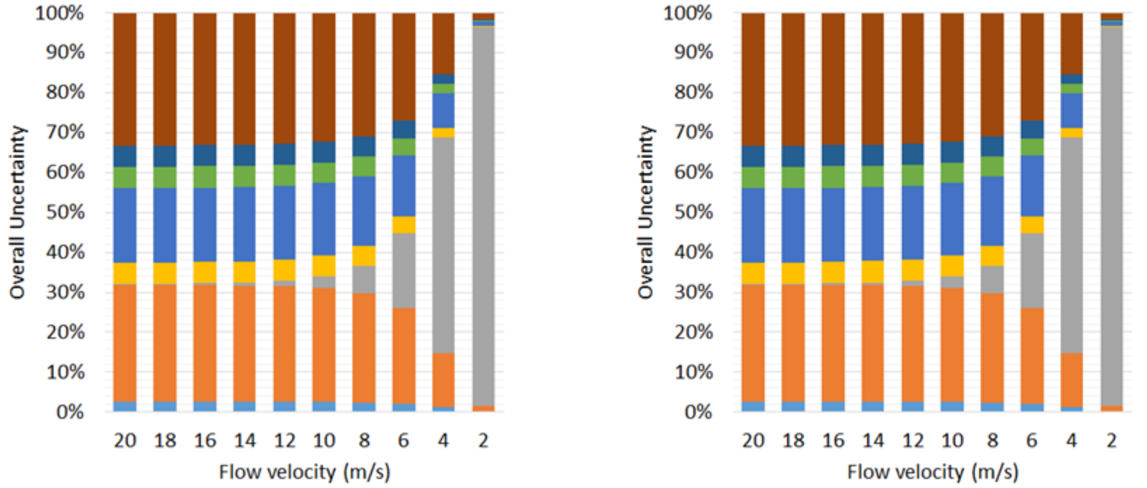
(d) D1 = 600 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62

The trends in the values in Tables 11 and 13 can be visualized as shown in Figures 14 and 15.



(a) D1 = 150 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81; Pure CH4

(c) D1 = 600 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81; Pure CH4



(b) D1 = 150 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62; Pure CH4

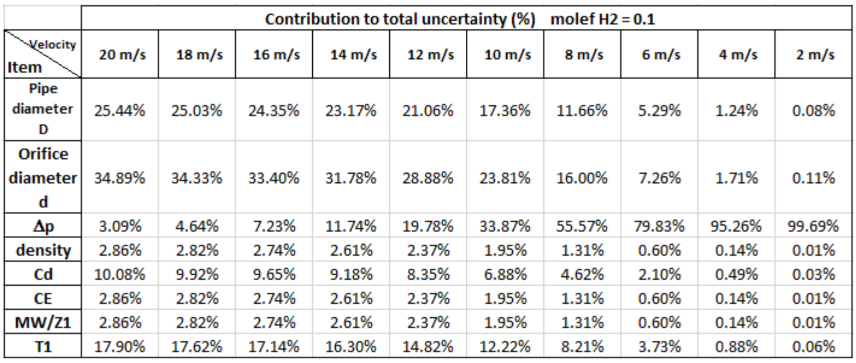
(d) D1 = 600 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62; Pure CH4

■ Pipe diameter D ■ Orifice diameter d ■ Dp ■ density ■ Cd ■ CE ■ MW/Z1 ■ T1

Figure 14 Contributions to overall uncertainty (pure CH4)

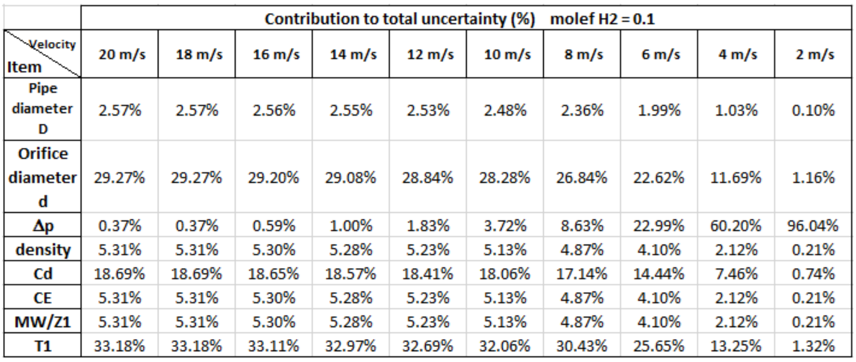
90% METHANE + 10% HYDROGEN

Table 14 Contributions to overall combined uncertainty {$0.9CH_4 + 0.1H_2$}



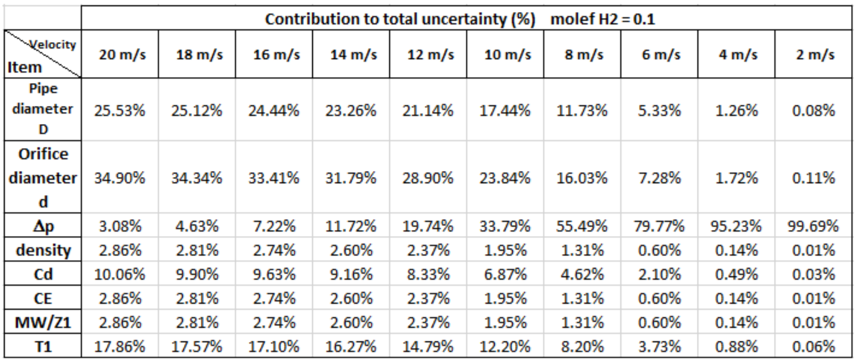
	Contribution to total uncertainty (%) molef H2 = 0.1									
Velocity Item	20 m/s	18 m/s	16 m/s	14 m/s	12 m/s	10 m/s	8 m/s	6 m/s	4 m/s	2 m/s
Pipe diameter D	25.44%	25.03%	24.35%	23.17%	21.06%	17.36%	11.66%	5.29%	1.24%	0.08%
Orifice diameter d	34.89%	34.33%	33.40%	31.78%	28.88%	23.81%	16.00%	7.26%	1.71%	0.11%
Δp	3.09%	4.64%	7.23%	11.74%	19.78%	33.87%	55.57%	79.83%	95.26%	99.69%
density	2.86%	2.82%	2.74%	2.61%	2.37%	1.95%	1.31%	0.60%	0.14%	0.01%
Cd	10.08%	9.92%	9.65%	9.18%	8.35%	6.88%	4.62%	2.10%	0.49%	0.03%
CE	2.86%	2.82%	2.74%	2.61%	2.37%	1.95%	1.31%	0.60%	0.14%	0.01%
MW/Z1	2.86%	2.82%	2.74%	2.61%	2.37%	1.95%	1.31%	0.60%	0.14%	0.01%
T1	17.90%	17.62%	17.14%	16.30%	14.82%	12.22%	8.21%	3.73%	0.88%	0.06%

(a) D1 = 150 mm; p1 = 3 MPa; T1 = 300 K; $\beta = 0.81$



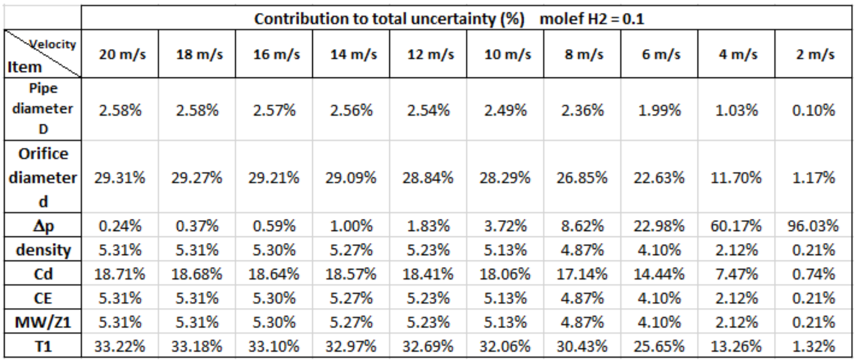
	Contribution to total uncertainty (%) molef H2 = 0.1									
Velocity Item	20 m/s	18 m/s	16 m/s	14 m/s	12 m/s	10 m/s	8 m/s	6 m/s	4 m/s	2 m/s
Pipe diameter D	2.57%	2.57%	2.56%	2.55%	2.53%	2.48%	2.36%	1.99%	1.03%	0.10%
Orifice diameter d	29.27%	29.27%	29.20%	29.08%	28.84%	28.28%	26.84%	22.62%	11.69%	1.16%
Δp	0.37%	0.37%	0.59%	1.00%	1.83%	3.72%	8.63%	22.99%	60.20%	96.04%
density	5.31%	5.31%	5.30%	5.28%	5.23%	5.13%	4.87%	4.10%	2.12%	0.21%
Cd	18.69%	18.69%	18.65%	18.57%	18.41%	18.06%	17.14%	14.44%	7.46%	0.74%
CE	5.31%	5.31%	5.30%	5.28%	5.23%	5.13%	4.87%	4.10%	2.12%	0.21%
MW/Z1	5.31%	5.31%	5.30%	5.28%	5.23%	5.13%	4.87%	4.10%	2.12%	0.21%
T1	33.18%	33.18%	33.11%	32.97%	32.69%	32.06%	30.43%	25.65%	13.25%	1.32%

(b) D1 = 150 mm; p1 = 8 MPa; T1 = 300 K; $\beta = 0.62$



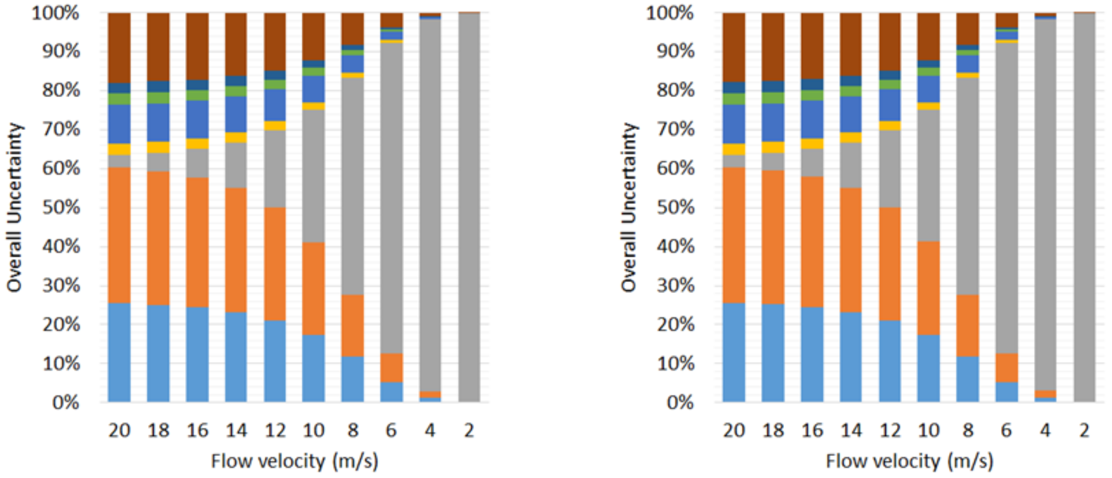
	Contribution to total uncertainty (%) molef H2 = 0.1									
Velocity Item	20 m/s	18 m/s	16 m/s	14 m/s	12 m/s	10 m/s	8 m/s	6 m/s	4 m/s	2 m/s
Pipe diameter D	25.53%	25.12%	24.44%	23.26%	21.14%	17.44%	11.73%	5.33%	1.26%	0.08%
Orifice diameter d	34.90%	34.34%	33.41%	31.79%	28.90%	23.84%	16.03%	7.28%	1.72%	0.11%
Δp	3.08%	4.63%	7.22%	11.72%	19.74%	33.79%	55.49%	79.77%	95.23%	99.69%
density	2.86%	2.81%	2.74%	2.60%	2.37%	1.95%	1.31%	0.60%	0.14%	0.01%
Cd	10.06%	9.90%	9.63%	9.16%	8.33%	6.87%	4.62%	2.10%	0.49%	0.03%
CE	2.86%	2.81%	2.74%	2.60%	2.37%	1.95%	1.31%	0.60%	0.14%	0.01%
MW/Z1	2.86%	2.81%	2.74%	2.60%	2.37%	1.95%	1.31%	0.60%	0.14%	0.01%
T1	17.86%	17.57%	17.10%	16.27%	14.79%	12.20%	8.20%	3.73%	0.88%	0.06%

(c) D1 = 600 mm; p1 = 3 MPa; T1 = 300 K; $\beta = 0.81$



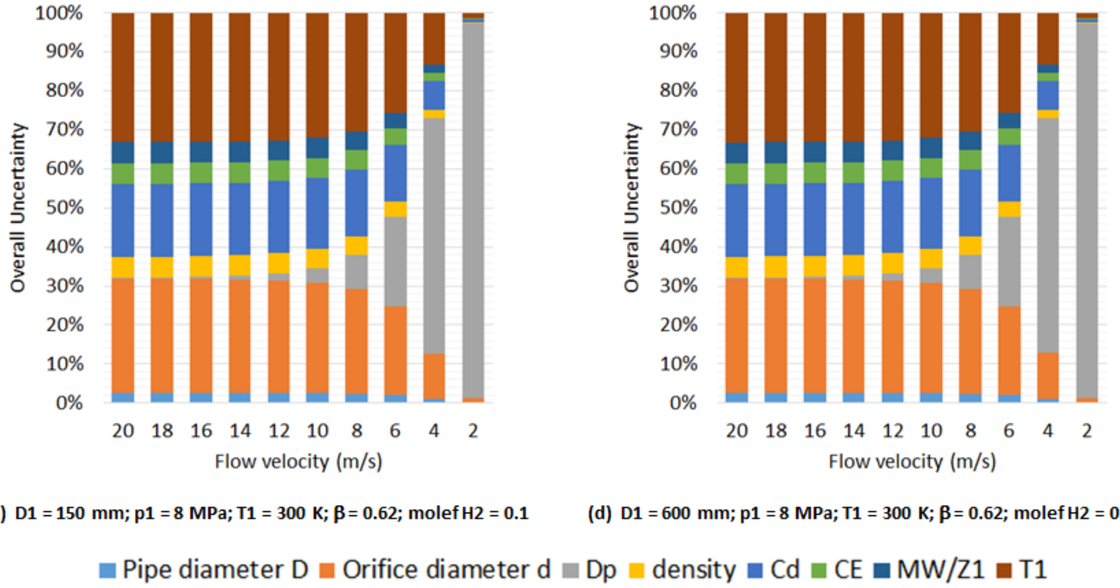
	Contribution to total uncertainty (%) molef H2 = 0.1									
Velocity Item	20 m/s	18 m/s	16 m/s	14 m/s	12 m/s	10 m/s	8 m/s	6 m/s	4 m/s	2 m/s
Pipe diameter D	2.58%	2.58%	2.57%	2.56%	2.54%	2.49%	2.36%	1.99%	1.03%	0.10%
Orifice diameter d	29.31%	29.27%	29.21%	29.09%	28.84%	28.29%	26.85%	22.63%	11.70%	1.17%
Δp	0.24%	0.37%	0.59%	1.00%	1.83%	3.72%	8.62%	22.98%	60.17%	96.03%
density	5.31%	5.31%	5.30%	5.27%	5.23%	5.13%	4.87%	4.10%	2.12%	0.21%
Cd	18.71%	18.68%	18.64%	18.57%	18.41%	18.06%	17.14%	14.44%	7.47%	0.74%
CE	5.31%	5.31%	5.30%	5.27%	5.23%	5.13%	4.87%	4.10%	2.12%	0.21%
MW/Z1	5.31%	5.31%	5.30%	5.27%	5.23%	5.13%	4.87%	4.10%	2.12%	0.21%
T1	33.22%	33.18%	33.10%	32.97%	32.69%	32.06%	30.43%	25.65%	13.26%	1.32%

(d) D1 = 600 mm; p1 = 8 MPa; T1 = 300 K; $\beta = 0.62$



(a) D1 = 150 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81; molef H2 = 0.1

(c) D1 = 600 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81; molef H2 = 0.1

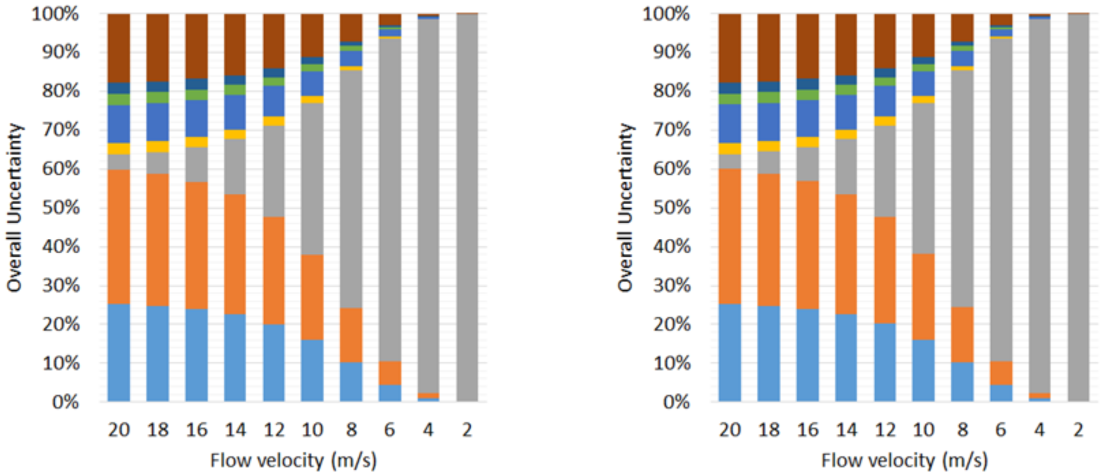


(b) D1 = 150 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62; molef H2 = 0.1

(d) D1 = 600 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62; molef H2 = 0.1

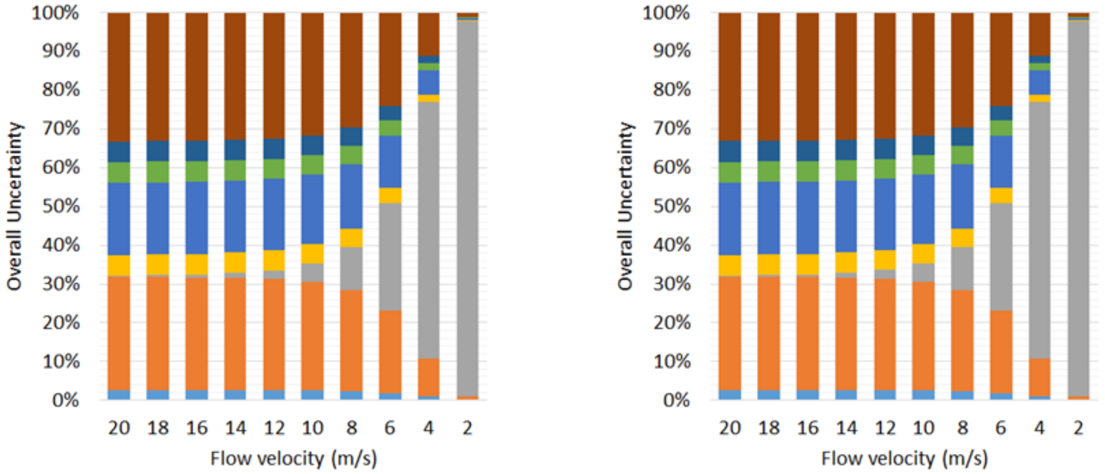
Figure 15 Contributions to overall uncertainty (0.9CH_4 + 0.1H_2)

As shown in the flowchart in Figure 13, the above procedure was applied to determine the overall uncertainty in the measurement of flow rates using an orifice meter for higher fractions of H_2 (mole fractions 0.2, 0.5 and 1) in the {CH_4 + H_2} blend, for the four sets of upstream conditions: (a) *D1*= 150 mm; *p1* = 3 MPa; *T1* = 300 K; (b) *D1* = 150 mm; *p1* = 8 MPa; *T1* = 300 K; (c) *D1* = 600 mm, *p1* = 3 MPa, *T1* = 300 K, and (d) *D1* = 600 mm, *p1* = 8 MPa, *T1* = 300 K. The charts showing the trends are shown in Figures 16 to 18.



(a) **D1 = 150 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81; molef H2 = 0.2**

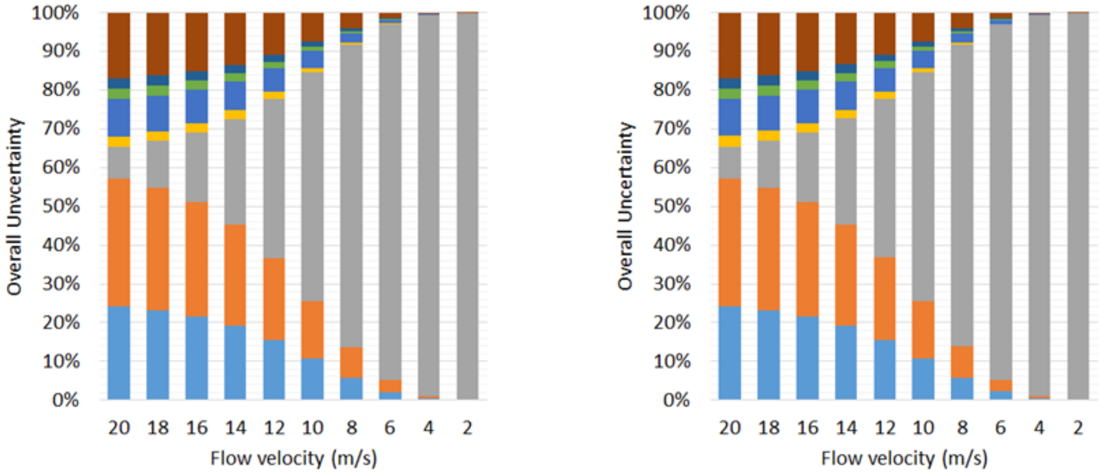
(c) **D1 = 600 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81; molef H2 = 0.2**



(b) **D1 = 150 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62; molef H2 = 0.2**

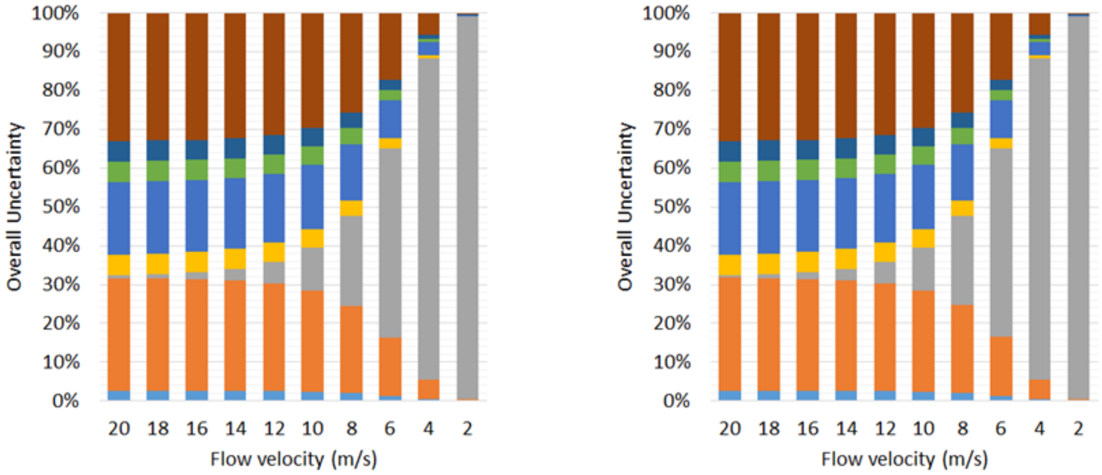
(d) **D1 = 600 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62; molef H2 = 0.2**

Figure 16 Contributions to overall uncertainty {$0.8CH_4 + 0.2H_2$}



(a) D1 = 150 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81; molef H2 = 0.5

(c) D1 = 600 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81; molef H2 = 0.5

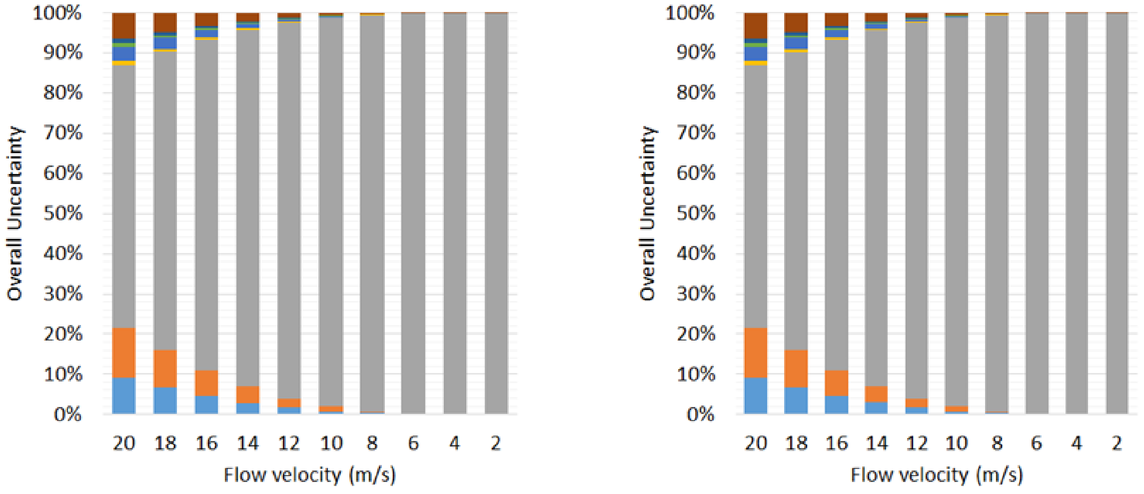


(b) D1 = 150 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62; molef H2 = 0.5

(d) D1 = 600 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62; molef H2 = 0.5

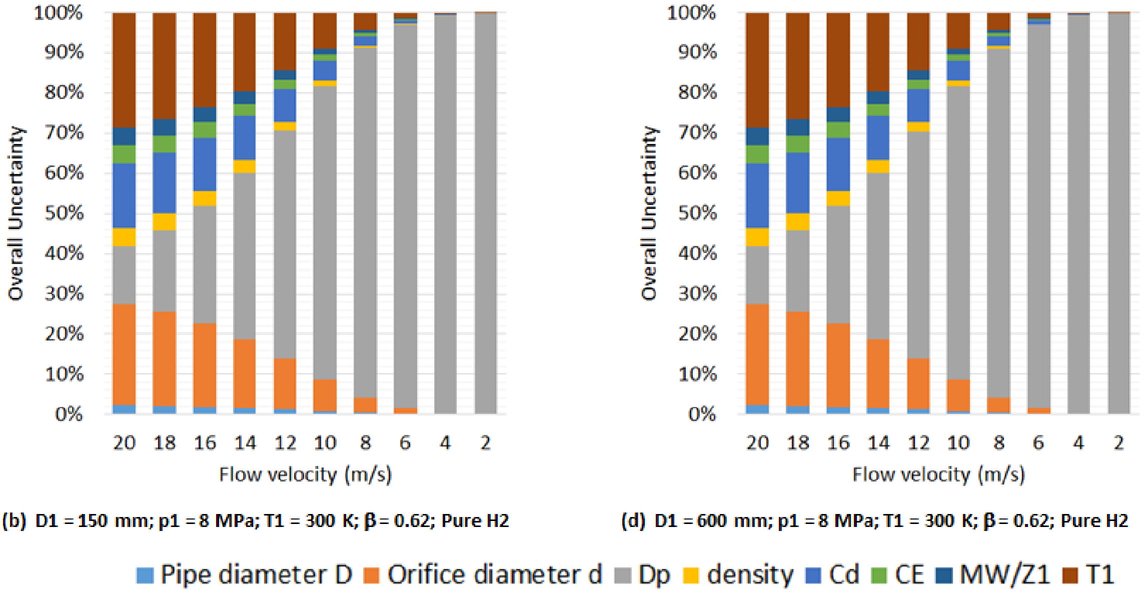
■ Pipe diameter D ■ Orifice diameter d ■ Dp ■ density ■ Cd ■ CE ■ MW/Z1 ■ T1

Figure 17 Contributions to overall uncertainty {0.5CH$_4$ + 0.5H$_2$}



(a) **D1 = 150 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81; Pure H2**

(c) **D1 = 600 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81; Pure H2**



(b) **D1 = 150 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62; Pure H2**

(d) **D1 = 600 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62; Pure H2**

Figure 18 Contributions to overall uncertainty (pure H_2)

It is seen that in all cases, the contribution of the differential pressure measurement to the overall uncertainty (grey bar) is maximum for low flow rates, and reduces progressively for higher flow rates. As the flow rate increases, the orifice diameter and temperature become increasingly dominant contributors to uncertainty to displace the effect of differential pressure.

Curves showing the comparative uncertainty trends are also provided in Figures 19 to 22. The graphs show the uncertainty contributions for blends {CH_4 + H_2} in comparison to the reference case with pure CH_4; i.e. the curves display the uncertainty introduced by the addition of H_2 when compared to the uncertainty for a stream comprising pure CH_4 only. The graphs on the left show H_2 mole fractions 0.1 and 0.2 along with the CH_4 reference, while the graphs on the right show the comparative trends for pure CH_4 vs {CH_4 + H_2} blends for all H_2 mole fractions tested: 0.1, 0.2, 0.5 and 1.0 (pure H_2).

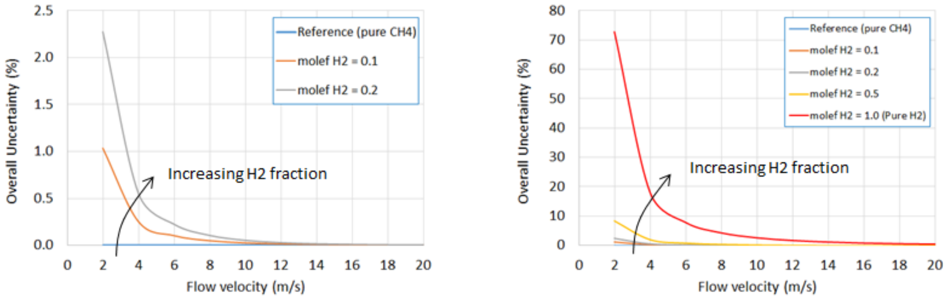
As demonstrated in Figures 19 to 22, increasing pipe diameter from 150 to 600 mm has a minimal effect (improvement) on uncertainty, whilst increasing pressure from 3 to 8 MPa provides a significant effect (improvement). At a flow velocity of 2 m/s the overall uncertainty in flow of a 10 mol% hydrogen blend increases from 0.25% to 1% as pressure reduces from 8 to 3 MPa. However, the effect of pressure is not as great as that of velocity, with an increase from 2 m/s to just 4 m/s reducing the uncertainties to 0.04% and 0.25% for 8 to 3 MPa respectively. Uncertainties are much lower at higher velocities.

These comparisons suggest that addition of 10 mol% H_2 introduces no significant additional uncertainty for all cases tested. This conclusion can also apply to the addition of up to 20 mol% H_2, especially for larger pipe diameters and higher pressures and velocities above 4 m/s. As expected, addition of 50 mol% H_2 to the blend introduces a higher uncertainty, while the uncertainty introduced by using pure H_2 for an orifice meter sized for pure CH_4 is much higher over the range of velocities (flow rates) tested.

For typical applications in Australian transmission systems, with pressures up to 15 MPa and velocities of up to 10 m/s, it is the situations with lower system pressures and lower velocities that require the closest consideration when assessing whether the addition of H_2 to natural gas will affect allowable overall uncertainty.

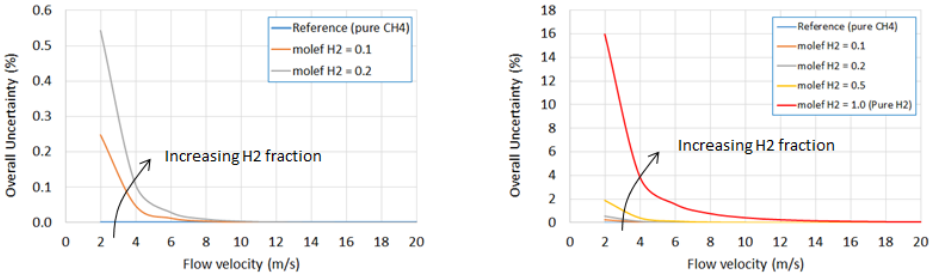
These comparisons and observations are summarised in the following overall trends:

1. at lower flow velocities, at lower pressures and for smaller pipe diameters, the additional uncertainty due to the addition of H_2 increases (with velocity and pressure being the dominating factors);
2. increasing the mole fraction of H_2 increases uncertainty, in comparison to pure CH_4;
3. for a given metering installation, understanding the minimum required operational flow velocity upstream of the meter is the key system parameter to determine whether the maximum additional uncertainty due to the introduction of H_2 is within acceptable limits.



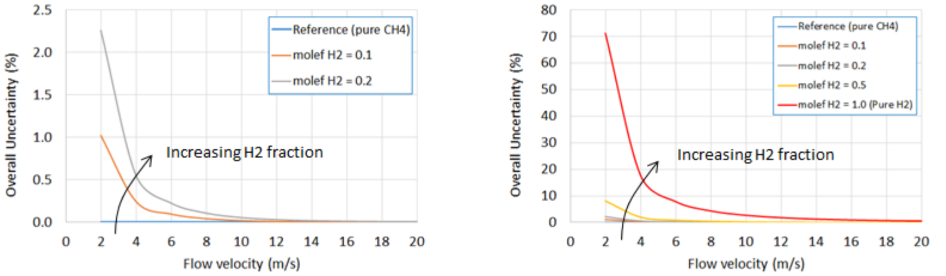
(a) D1 = 150 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81

Figure 19 Comparative uncertainty trends – pure CH_4 vs {CH_4 + H_2} blends – case (a)



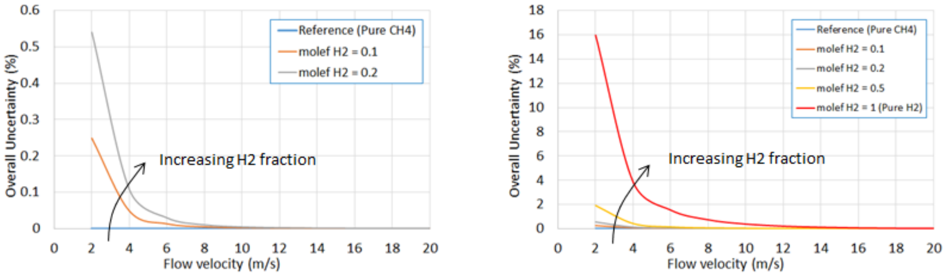
(b) D1 = 150 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62

Figure 20 Comparative uncertainty trends – pure CH_4 vs {CH_4 + H_2} blends – case (b)



(c) D1 = 600 mm; p1 = 3 MPa; T1 = 300 K; β = 0.81

Figure 21 Comparative uncertainty trends – pure CH_4 vs $\{CH_4 + H_2\}$ blends – case (c)



(d) D1 = 600 mm; p1 = 8 MPa; T1 = 300 K; β = 0.62

Figure 22 Comparative uncertainty trends – pure CH_4 vs $\{CH_4 + H_2\}$ blends – case (d)

5.1.3 Ultrasonic flow meter: uncertainty

A recent study on measurement uncertainties relevant to a sample ultrasonic flow meters is reported by SICK Engineering GMBH, Germany **Error! Reference source not found.**. This report refers to the Technical Guideline TR G 19, issued by the Physikalisch Technische Bundesanstalt (PTB) that regulates “Feeding hydrogen into the natural gas network” for “measuring instruments for gas”. The Guideline declares the use of gas measurement devices “of any technologies” shall be safe provided that the H_2 content of the gas is less than 5% by volume. The use of meters is permitted with natural gas containing between 5% and 10% by volume of H_2, provided the manufacturer explicitly permits this.

It is stated in **Error! Reference source not found.** that “the addition of hydrogen has an effect on the characteristic curve behaviour and thus on the measuring uncertainty of the devices. A measuring capability does not amount to the same thing as an unchanged measurement accuracy”.

The relative error is about 0.1% with a proportion of 10% hydrogen by volume in the natural gas in the lower flow rate range. This error lies well within the transport error limits for natural gas measurements subject to calibration.

Similar data was published in a technical report by gwf-Gas in May 2013. A FLOWSIC600 DN80 was used for these investigations. The report concludes that “up to 10% H_2 content by volume, no influence on the ultrasonic gas meter can be detected if the hydrogen is well-mixed with the natural gas”. This claim has been verified by SICK GmbH. In addition, they have also evaluated an admixture of 25% by volume of hydrogen. With the technology currently installed in the field (sensors and electronics), this has a slightly higher influence on the measurement accuracy (about 0.2%) especially in the lower flow range.

Figures 23 and 24 show the result of the *experimental* investigation [50] by SICK, Germany. It is seen that the additional relative error due to the presence of hydrogen in the $\{NG + H_2\}$ blend is noticeable for the smaller mass flow rates and tapers off to near-zero as the mass flow rate increases.

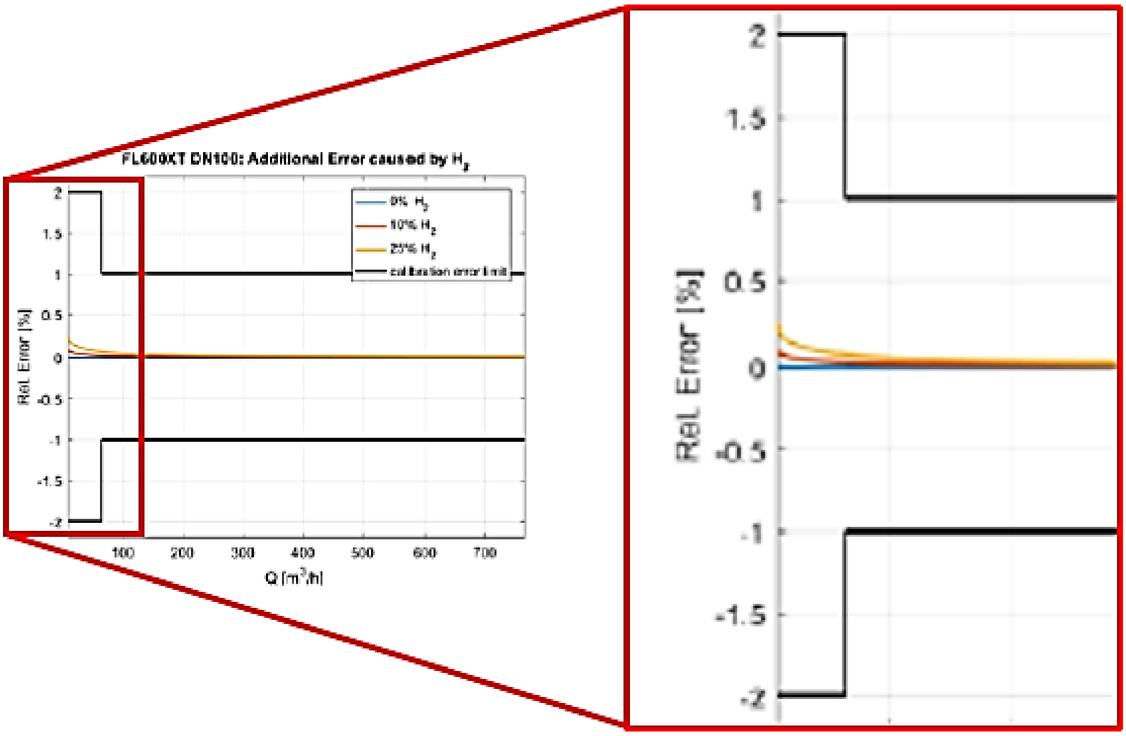


Figure 23 Influence of H_2 content on the measurement error of a DN100 FLOWSIC600-XT after application of linearization correction, on the basis of pure natural gas data ***Error! Reference source not found.***

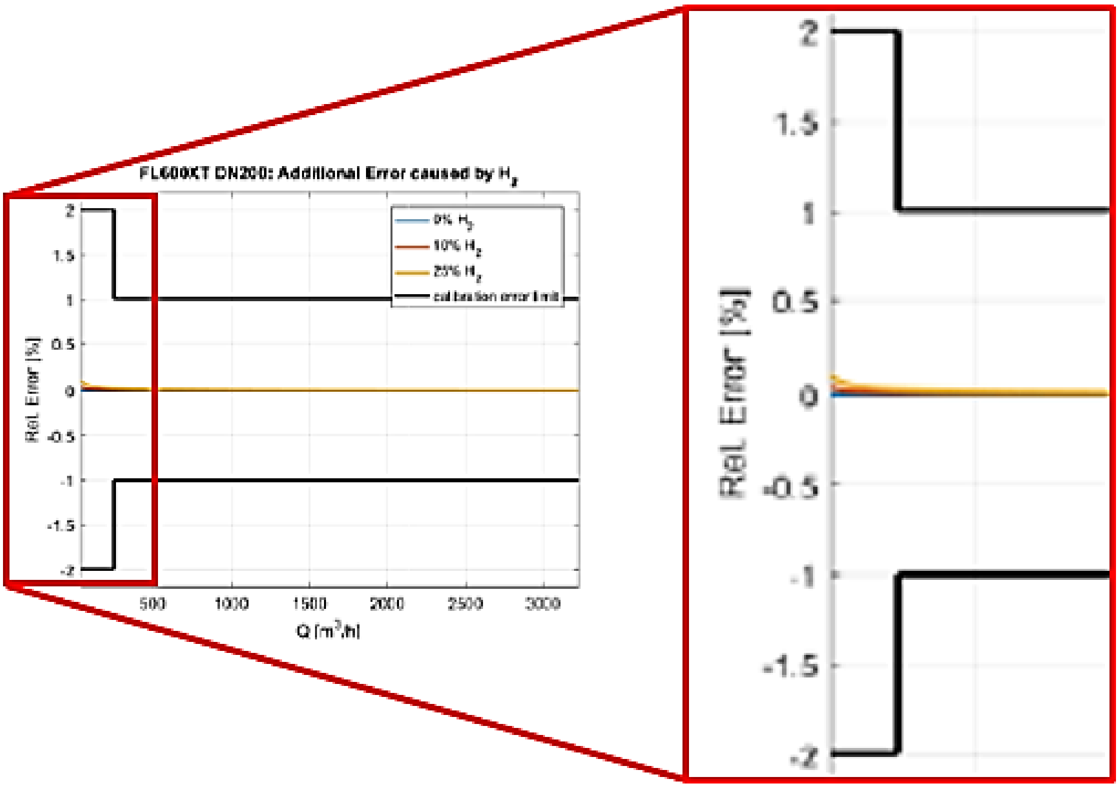


Figure 24 Influence of H_2 content on the measurement error of a DN200 FLOWSIC600-XT after application of linearization correction, on the basis of pure natural gas data [1].

5.1.4 Flow meters: uncertainty summary

As presented above, the influence of hydrogen on measurement uncertainty for both orifice meters and ultrasonic meters is dominated by the metering system flow rate. At low flow, the additional uncertainty due to hydrogen is noticeable, however, this quickly falls away as the flow rate increases.

In addition, the influence of hydrogen on measurement uncertainty appears to be more significant on smaller metering systems and at lower system pressures.

Whilst the assessment here is focused on two types of meters only—differential pressure (orifice) and ultrasonic—these observations are considered representative of the maximum absolute uncertainty that can be expected from other meter selections requiring measurement of and compensation for physical flow conditions (e.g. pressure and temperature), as do for example positive displacement meters. On the other hand, Coriolis meters are potentially more accurate since they measure mass flow directly, but are less suitable for larger pipe sizes.

5.2 Gas Chromatographs: uncertainty in gas composition and heating value

This section provides an overview of the uncertainty applicable for gas chromatograph applications in natural gas service, followed by considerations that are applicable for future fuel (H_2) service.

5.2.1 GC uncertainty: NG application

An uncertainty analysis for gas compositional measurement using gas chromatographs is applied following the method outlined for the orifice meter in Section 5.1.2. There the standard uncertainties, $u(x_i)$ of each measurement, x_i, contributing to the overall uncertainty in flow were multiplied by a sensitivity coefficient, c_i. Then the combined standard uncertainty was calculated from Equation (1), repeated here:

$$u_c(y) = \sqrt{\sum_{i=1}^{N} [c_i\, u(x_i)]^2} \quad \text{...} \; (1)$$

The expanded combined uncertainty, U_c, is then obtained by multiplying u_c by a coverage factor, k, which is 2 for a 95% confidence interval. Examples of the application of this method are given in the sections to follow, in particular in Table 16 and Table 17.

GC uncertainties are normally described in terms of repeatability, linearity (bias) and calibration gas composition. Sensitivity coefficients, c_i, are rarely used. Some relevant information about standard uncertainties $u(x_i)$ are discussed below.

5.2.2 Repeatability

Uncertainty in GC repeatability (i.e. how closely successive measurements correspond) can be introduced by many factors. These include variability in sample injection time and rate, carrier gas flow rate, sample temperature, column temperature, detector temperature, oven temperature [52]. Columns can degrade over time due to contamination, which requires retuning of valve timings to collect the required amount of sample.

Well set-up sampling systems — including a combination of sample conditioning and tuning — can reduce the impact of uncertainties. GCs in service are connected to a calibration gas cylinder and typically perform an automatic calibration check daily. Hence, it is important to account for the repeatability of GC measurements of component compositions (C1 to C6 hydrocarbons, carbon dioxide and nitrogen) for both the sample gas and for the calibration gas. Typical values for each component are given in Norwegian Standards[1]. For components that make up 0–25 mol% of the mixture a standard uncertainty of 0.01% is used. For components that make up >25% of the mixture (i.e. methane), a standard uncertainty of 0.025% is used. Measurements by others (e.g. [56]) have produced different results for repeatability, which are compared with the standard assumptions in Table 15. The measured data appears higher, but when sensitivity coefficients are also considered the overall uncertainty is low — as detailed further in Section 5.2.5. The same paper [56] also has standard uncertainty data for reproducibility, which is distinct from repeatability, in that it relates to measurement using a different condition or method. Numerically, the values are similar to those for repeatability for each component.

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[1] Norsok I-104:2005, or its later version Norsok I:106:2014

Table 15 GC Repeatability standard uncertainties of natural gas components.

	NORSOK	Sutan and Daniel [57]
Component	$u(x_i)$, %	$u(x_i)$, %
CH4	0.025	0.019006
C2H6	0.01	0.07121
C3H8	0.01	0.098314
C4H10	0.01	0.115847
C5H12	0.01	0.343006
C6H14	0.01	1.16812
N2	0.01	0.077837
CO2	0.01	0.131377
H2	0.01	0.01

5.2.3 Linearity

Linearity (bias) relates to the fact that the response of the instrument may not be linear with respect to gas composition. So, using a single calibration gas can introduce bias. As one example of accounting for linearity, GC supplier Emerson typically applies a linearity standard uncertainty of 0.015%. However, there are ways to reduce bias errors to near zero.

ISO 10723:2012 (Natural gas — Performance evaluation for analytical systems) provides a method for calculating the errors in measurements made by GCs. In this method, 3, 5 or 7 calibration gases with different mixtures of components are measured by the instrument. The range of compositions of the different calibration gases are chosen to cover a relevant range for the target gas. By using this array of many different calibration gases with different compositions, a polynomial ("analysis function") can be fitted to the response and used to correct for non-linearity. The analysis function can then be programmed into those GCs that have the capability, to reduce linearity errors, whilst still only using one calibration gas [57]. Likewise, [56] suggests that bias can be reduced to near zero.

5.2.4 Calibration Gas

GCs compare their analyses to that of a calibration gas, so any uncertainty in the calibration gas composition is directly transferred to the GC analysis. In-service GCs are connected to a calibration gas cylinder and perform automatic calibration checks. However, the cylinder is typically changed infrequently and certified calibrations of the instrument are also typically performed very infrequently. Consequently, there is a reliance on the accuracy of the calibration gas in the cylinder remaining stable over a period of time, meaning that the cylinder gas composition uncertainty is normally the most significant source of uncertainty and hence in the calorific value calculated by GCs. For best accuracy, accredited calibration gas suppliers fill each component in turn into the cylinder gravimetrically with the aid of a precision balance. The accredited laboratory supplying the gas may also check the compositions using on-site GCs with appropriate columns. (Filling by pressure can also be done but is not practiced for calibration gas mixtures.)

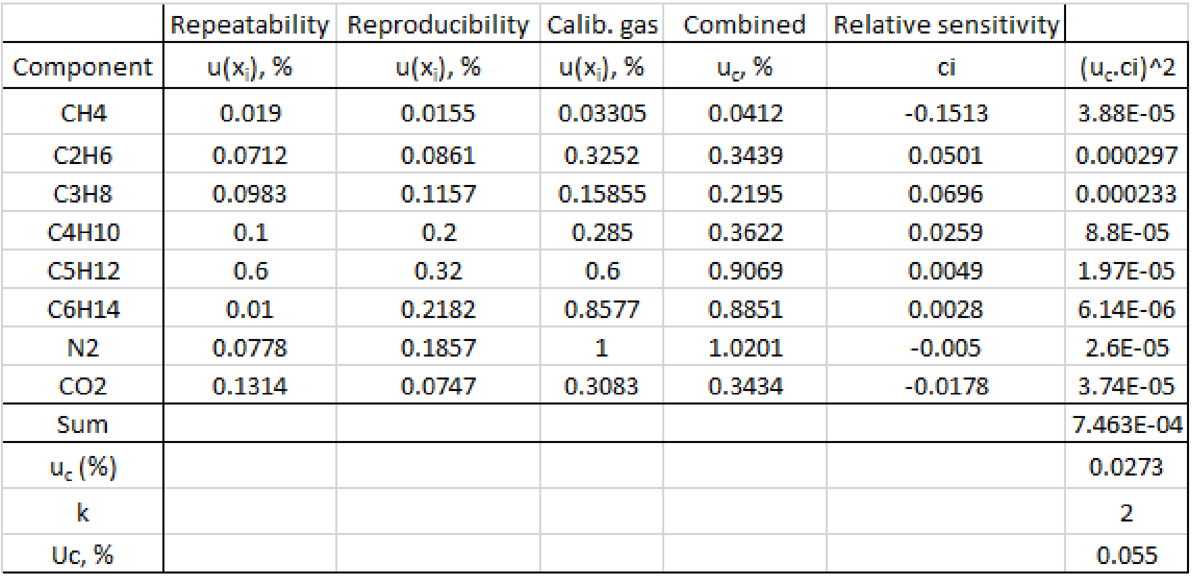
Various values for uncertainty in the calorific value of the calibration gas are available. In all these cases, the uncertainty in compositions of individual components, i.e. C1 to C6 hydrocarbons, carbon dioxide and nitrogen are combined to give an overall uncertainty in calorific value. (Hydrogen is not included in typical natural gas compositions.)

ABB provided a calibration study [54] for its GC model NGC8206 (Application BBF/BBK) used for hydrocarbon composition at fiscal metering stations. It was noted that the uncertainty in the gross heating value is mainly a function of the uncertainty in calibration gas composition, and this varies with the calibration gas supplier. The calibration gas can be supplied with a certificate from a laboratory accredited to a suitable international standard (e.g. ISO 17025, General requirements for the competence of testing and calibration laboratories) which results in a marked improvement in overall uncertainty. The ABB study used 7 reference gases with different compositions, all supplied with accredited certification. Their compositions were measured 6 times each with the GC, resulting in a mean uncertainty in calorific value of 0.038% attributed to both calibration gas uncertainty and repeatability (and excluding bias). When bias was included, the mean overall uncertainty in calorific value increased to 0.091%.

5.2.5 Combined effects

The combined effects of uncertainty in repeatability, reproducibility, linearity (bias) and calibration gas can be calculated in a table like that in [56], to produce a combined standard uncertainty in gas composition of 0.0273% as shown below in Table 16. This is then multiplied by the coverage factor of 2 to give the combined expanded uncertainty, U_c, in gas composition. In this case the sensitivity coefficients come from the reference.

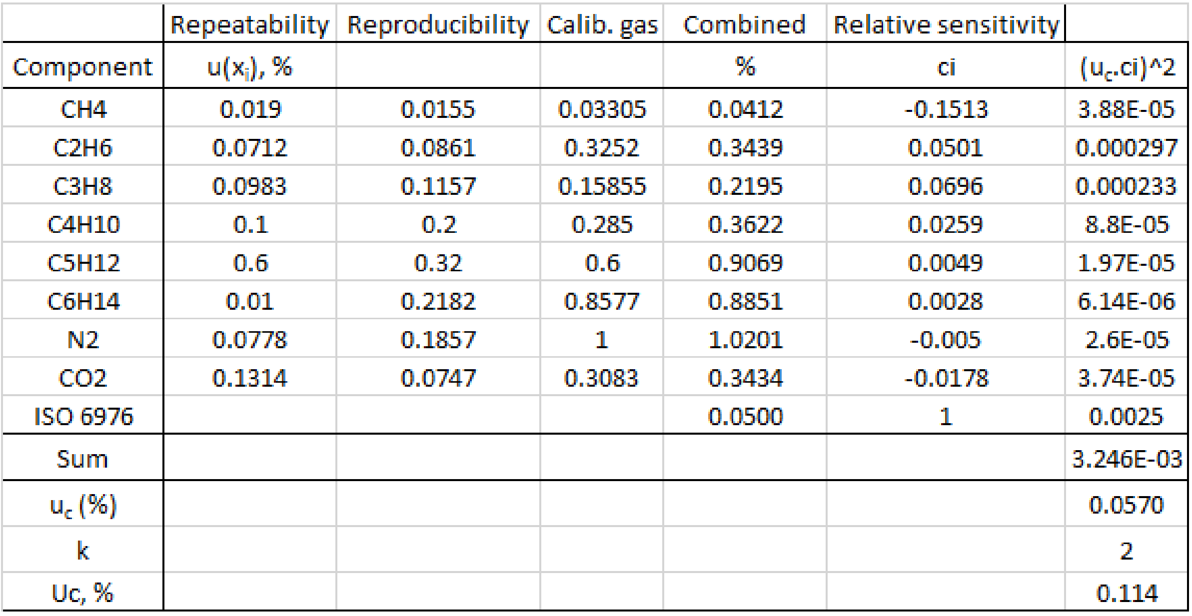
Table 16 Uncertainty example for gas composition



	Repeatability	Reproducibility	Calib. gas	Combined	Relative sensitivity	
Component	$u(x_i)$, %	$u(x_i)$, %	$u(x_i)$, %	u_c, %	ci	$(u_c \cdot ci)$^2
CH4	0.019	0.0155	0.03305	0.0412	-0.1513	3.88E-05
C2H6	0.0712	0.0861	0.3252	0.3439	0.0501	0.000297
C3H8	0.0983	0.1157	0.15855	0.2195	0.0696	0.000233
C4H10	0.1	0.2	0.285	0.3622	0.0259	8.8E-05
C5H12	0.6	0.32	0.6	0.9069	0.0049	1.97E-05
C6H14	0.01	0.2182	0.8577	0.8851	0.0028	6.14E-06
N2	0.0778	0.1857	1	1.0201	-0.005	2.6E-05
CO2	0.1314	0.0747	0.3083	0.3434	-0.0178	3.74E-05
Sum						7.463E-04
u_c (%)						0.0273
k						2
Uc, %						0.055

If the calculation method for calorific value is also included in the assessment with an uncertainty of 0.05%, this increases the combined standard uncertainty up to 0.057%, and the combined expanded uncertainty in CV up to 0.114%. For natural gas with a CV of 38 MJ/Sm^3, this would provide a CV uncertainty of 0.00114 × 38 = 0.043 MJ/m^3. This is shown in Table 17.

Table 17 Uncertainty example for gas calorific value



	Repeatability	Reproducibility	Calib. gas	Combined	Relative sensitivity	
Component	$u(x_i)$, %			%	ci	$(u_c.ci)$^2
CH4	0.019	0.0155	0.03305	0.0412	-0.1513	3.88E-05
C2H6	0.0712	0.0861	0.3252	0.3439	0.0501	0.000297
C3H8	0.0983	0.1157	0.15855	0.2195	0.0696	0.000233
C4H10	0.1	0.2	0.285	0.3622	0.0259	8.8E-05
C5H12	0.6	0.32	0.6	0.9069	0.0049	1.97E-05
C6H14	0.01	0.2182	0.8577	0.8851	0.0028	6.14E-06
N2	0.0778	0.1857	1	1.0201	-0.005	2.6E-05
CO2	0.1314	0.0747	0.3083	0.3434	-0.0178	3.74E-05
ISO 6976				0.0500	1	0.0025
Sum						3.246E-03
u_c (%)						0.0570
k						2
Uc, %						0.114

Others report different overall uncertainties in GC composition and CV. Typical figures for total expanded uncertainty in calorific value from GCs have also been reported to be approximately 0.06% [53]. Emerson [55] provided an example with the calibration gas composition contributing a standard uncertainty of 0.15% to the calorific value of a sample gas, with repeatability of component measurement of both the sample gas and the calibration gas being 0.015% each, with bias tending to zero. This makes a combined standard uncertainty of 0.1515%, with almost all of it attributable to uncertainty in calibration gas composition.

In comparison, the previously mentioned ABB study calculated an expanded uncertainty in calorific value, excluding bias, of on average 0.038%. This fits well with the specified ABB GC model NGC8206 (Application BBF/BBK) which has an indoor uncertainty on gross heating value and Wobbe index of 0.025% and an outdoor uncertainty of 0.05% [27]. Analysis in accordance with ISO 10723:2012 (Natural gas — Performance evaluation for analytical systems) can be repeated multiple times so that drift with time can also be measured. Drift corrections can then be programmed into GCs.

5.2.6 GC uncertainty: influence of hydrogen

The effect of adding hydrogen to natural gas on uncertainty in gas calorific value has not yet been established. GCs currently installed in the NG transmission network do not measure H_2, but suppliers are working to modify GCs to meet either 10 vol% H_2 or 20 vol% H_2 targets. Calibration gases for GCs can be supplied with any proportion of H_2 in them.

GCs or other instruments to calculate the heating value of a hydrogen blend in natural gas are not currently available from suppliers. However, it can be assumed that if the market develops for such instruments, suppliers will develop the necessary solutions to achieve similar uncertainty to current instruments applied in natural gas service by adapting the GC components. Instruments have been developed, but the testing uncertainty has not yet been done.

Emerson factory feedback on uncertainty calculations with hydrogen blended into natural gas is that they will be treated like any other component in the gas [55]. The current procedure for uncertainties of each component of the gas are based on the Norwegian standard, NORSOK I-104. Importantly the Standard methods can be applied whether or not H_2 is in the blend. Likewise, other standards, such as ISO 6976 (Natural gas — Calculation of calorific values, density, relative density and Wobbe indices from composition) and ISO 10723 (Natural gas — Performance evaluation for analytical systems) can accommodate hydrogen as another component of the gas and treat uncertainties in the same way as for other components. Hence the crucial next step is for testing to provide uncertainty measurements for GCs equipped with hydrogen capability over various ranges of blends. Current work undertaken by various GC instrument OEMs (including ABB and Emerson) is focussed on 10 vol% and 20 vol% hydrogen blends and 100% hydrogen.

In summary, the implications of adding hydrogen on the uncertainty in gas composition and calorific value have not yet been determined. However, it is expected that existing instrumentation applied in natural gas service will be adapted to achieve similar performance with the addition of hydrogen in the gas stream. Instrument measurement uncertainty is expected to be far less significant than the contribution to uncertainty of calibration gas composition, and less than the variation in uncertainty reported from a range of different references.

5.3 Uncertainty in other measurement parameters: pressure, temperature and gas energy flow

Gas energy flow is given by the product of the volume flow rate at standard conditions, V_o, and the higher heating value of the gas calculated at standard conditions, H_o:

$$E = V_0 \; H_0$$

The gas volumetric flow rate, V_m, along with gas temperature, T_m, and pressure, P_m are all determined at the metering station. Likewise, the gas composition is determined by the GC at the metering station (or an alternative representative location within the pipeline system) and is then used to calculate the higher heating value of the gas. The conversion from measurements at actual gas conditions to standard conditions requires use of a real gas law incorporating the gas compressibility factor, Z. This factor accounts for departure from ideal behaviour. So, the energy flow can be expressed in terms of the measured variables, and the standard temperature, T_o, and pressure, P_o, as follows:

$$E = V_0 \; H_0 = \frac{P_0 \; T_m}{P_m \; T_0} \cdot \frac{1}{Z} \cdot V_m \; H_0$$

Gas companies currently perform accuracy verification testing of in-service pressure and temperature meters (against another meter or within a specified range) to check if it is within defined OEM guidelines. Manufacturers include an accuracy range, which includes fluctuations that may occur with time in service. Meters in series are cross-checked against each other, e.g. over a 24-hour period to discover anomalies in the flow-rate. Pressure and temperature meters and GCs are calibrated regularly using online calibration gas from an on-site cylinder (although with infrequent certified calibration), providing uncertainty considerations as described above. Some meters need to be taken out every 5 to 10 years depending on regulations (and own arrangements of each business) to get re-certified. It should follow that where the addition of H_2 does not alter the level of uncertainty of a meter, in-situ calibrations should also be unaffected. Physical testing may be required to verify if this holds true. Further study could be performed in this area.

In Australia, AEMO [58] specifies the use of the “Detail Characterisation Method” in AGA 8 for determining the gas compressibility factor but allows for other methods if they produce “acceptable results”. The AEMO document refers to Rule 303 of the NGR for calculation of energy flow through metering stations in Australia. To ensure consistency, they require use of higher heating value, expressed in MJ/Sm^3, where the standard conditions are 15°C and 101.325 kPa.

An example of the calculation of overall uncertainty of the energy flow based on the inputs described above is provided by [46] using an ultrasonic flowmeter (USM) coupled with a GC, with some of the data reproduced in Table 18. The uncertainty in temperature, pressure, flow rate and heating value are all required to calculate the overall uncertainty in energy flow. It is worth noting that there are multiple components to uncertainty in all the inputs, i.e. in measured flow, pressure, temperature, gas composition and calculated compressibility factor.

Details of how the components of uncertainty and the overall uncertainty were calculated are summarised below to provide an insight into the rigour involved, and to illustrate that the dominant factors influencing energy flow uncertainty are related to flow calibration rather than gas composition.

For temperature measurement the factors considered and quantitatively assessed in the calculation were transmitter element stability, radio frequency interference (RFI), ambient temperature effects and stability. Other factors that were assumed negligible were vibration, power supply effects, and lead resistance. Each of these factors has a standard uncertainty which can be obtained from the equipment vendor’s documented uncertainty statements. The combined standard uncertainty in temperature measurement was in this case 0.0765°C. The expanded uncertainty with a confidence interval of 95%, requires multiplication by k=2, so U_c = 0.15°C. The temperature was 50°C = 323K, so the relative expanded uncertainty is 0.15/323 = 0.047% (see Table 18).

For pressure, a similar analysis produced a combined standard uncertainty of 0.08 bar. The expanded uncertainty with a confidence interval of 95%, was, with $k = 2$, $U_c = 0.16$ bar. The operating pressure was 100 bar(a), so the relative expanded uncertainty is 0.16/100 = 0.16% (see Table 18). For the gas compressibility factor, the analysis depends on the accuracy of the model used and the accuracy of performing the calculation of compressibility. In this case, the authors used a combined standard uncertainty of 0.1695% and hence an expanded uncertainty with a confidence interval of 95%, $U_c = 0.339\%$ (see Table 18). For the gas calorific value, the authors used an expanded uncertainty with a confidence interval of 95%, $U_c = 0.15\%$ (see Table 18), based on legislated requirements rather than going through a technical reasoning. This is very similar to an example from Emerson but is much higher than the value of 0.114% from different calculations in Table 17, illustrating that it is a conservative estimate. Any changes that H_2 might introduce are likely to be negligible, but this awaits demonstration.

The USM flow meter used in the example has an internal diameter of 308mm [46]. The maximum flow rate, q_{max}, corresponded to a velocity of 10 m/s (much lower than maximum flow rate in the orifice plate example in Section 5.2). Two examples of uncertainty calculations were provided with flow rates of $0.1q_{max}$ and $0.7q_{max}$, i.e. at 1 m/s and at 7 m/s respectively. Table 18 brings together all the inputs for calculating uncertainty in energy flow for a natural gas. It shows that the contribution of flow calibration and flow repeatability is much higher than the contribution from CV. GC manufacturers do not yet have data on changes to uncertainty in gas composition and CV that addition of H_2 to natural gas might introduce, but they are aiming to produce instruments for hydrogen applications that match current levels of uncertainty. Hence it is most likely that gas composition will continue to have only a small contribution to uncertainty in energy flow. It is also worth noting that the uncertainties in flow measurements are also lower than those for the orifice meter discussed in Section 5.2.

Table 18 Contributions to uncertainty in Energy Flow for a USM / GC measuring station for two velocities [46]

	Relative expanded uncertainty, %	
	at 1m/s	at 7m/s
Pressure	0.1598	0.1598
Temperature	0.0473	0.0473
Compressibility factor	0.3393	0.3393
Calorific Value	0.15	0.15
Flow calibration in laboratory	0.3	0.3
Flow calibration deviation	0.7901	0.072
USM repeatability in lab	0.2	0.2
USM field repeatability	0.2	0.2
field flow calibration	0.461	0.461
Energy Flow, Uc (%)	1.08	0.74

5.4 Uncertainty in flow computing, gas accounting and performance monitoring systems

The original scope of this study included the objective to assess the performance of flow computing systems, gas accounting systems and performance monitoring systems with future fuel blends, specifically hydrogen + natural gas. Through the course of the study, it was apparent that these assessments could not be meaningfully performed as specific details of such systems are retained as proprietary information by the asset owner (gas transmission company).

Some subjective comments can be offered, however, on the basis that these systems will typically rely upon accurate modelling of the equations of state and measurement of flow rate and energy flow rate. Consequently, the uncertainty analyses discussed for flow metering and determination of energy flow rates can be considered representative for flow computing, gas accounting and performance monitoring systems that may be maintained by the asset owners, therefore providing a good basis for confidence in these systems up to 10–20 mol% hydrogen blends.

6. CONCLUSIONS

This study provides an overview of the existing equipment typically deployed within Australia's natural gas transmission systems for metering and gas quality monitoring of natural gas. Assessments have then been performed to indicate the suitability of these instruments for measurement of flow and composition for prospective future fuel gas compositions, with a particular focus on how prospective future fuel blends can influence overall measurement uncertainty.

Future fuels considered in this study include hydrogen blends with lean natural gas (represented by methane CH_4) — assuming typical compositions of 10, 20, 50 and 100 mol% H_2 — along with other gaseous fuels such as biogas, biomethane and synthetic methane.

For the non-hydrogen based fuels presented (i.e. biogases), the impact of introducing these into existing natural gas systems is considered to be limited to an assessment of the potential impurities that may be introduced into the natural gas system. These impurities will vary depending on the source of the gas and any treatment systems that are proposed. These assessments can be performed on a case-by-case basis for any prospective connection into the existing natural gas transmission system to ensure that this provides an acceptable and manageable outcome for the pipeline system and for the end consumers. Quality monitoring systems could then be provided at the source (gas production facility and or at the point of connection) as appropriate. Metering systems and their efficacy would remain largely unaffected as the biogas constituents (other than the impurities) are largely consistent with those that are found in the existing natural gas streams.

For blends of hydrogen, a detailed analysis is presented for orifice meter uncertainty, which has been extended to assess overall uncertainty for systems containing a differential pressure (orifice) flow meter, an ultrasonic meter and gas chromatograph analysers. Overall uncertainty analyses were completed using a methodology according to the Guide to the expression of Uncertainty in Measurement (GUM) [47]. This methodology is generally consistent with the study objective to complete an ISO 5168 overall uncertainty analysis, noting that ISO 5186 is applicable to differential flow meters and defers to the GUM as the authoritative document where ISO 5168 does not provide enough depth or detail. An example of uncertainty in total energy flow illustrated that uncertainty in flow-rate dominates over the uncertainty in gas composition. Future work may seek to extend the applicability of this assessment.

From the flow meter uncertainty assessments completed in this study, the following conclusions are considered applicable when introducing hydrogen blends into the Australian transmission network:

1. at **lower flow velocities**, at **lower pressures** and for **smaller pipe diameters**, the **additional uncertainty** due to the addition of H_2 **increases** (with velocity and pressure being the dominating factors);
2. increasing the mole fraction of H_2 increases uncertainty, in comparison to pure CH_4;
3. for a given metering installation, **understanding the minimum required operational flow velocity** upstream of the meter is the **key system parameter** to determine whether the maximum **additional uncertainty** due to the introduction of H_2 is **within acceptable limits**.

The comparisons suggest that addition of 10 mol% hydrogen introduces no significant additional uncertainty for the cases presented. This conclusion can also apply to the addition of up to 20 mol% H_2, especially for larger pipe diameters and higher pressures and velocities above 4 m/s. As expected, addition of 50% H_2 to the blend introduces a higher uncertainty which would provide a limitation to system suitability.

For typical applications in Australian transmission systems, with pressures up to 15 MPa and velocities of up to 10 m/s, it is the situations with lower system pressures and lower velocities that require the closest consideration when assessing whether the addition of hydrogen to natural gas will affect allowable overall uncertainty.

Whilst the detailed assessments presented focuses on differential pressure (orifice) and ultrasonic meters, these observations are considered representative of the maximum absolute uncertainty that can be expected from other meter selections requiring measurement of and compensation for physical flow conditions (e.g. pressure and temperature), as do for example positive displacement meters. On the other hand, Coriolis meters are potentially more accurate since they measure mass flow directly, but are less suitable for larger pipe sizes.

In relation to gas chromatographs (GCs), the 'as-installed' GC systems are not considered suitable for hydrogen blends, however, the existing installations are expected to be able to readily accommodate hydrogen with minor modifications to existing GC componentry and/or alterations to calibration gas. This will need to be developed by the GC suppliers in response to market requirements. Instrument measurement uncertainty is expected to be far less significant than the contribution to uncertainty of calibration gas composition, and less than the variation in uncertainty reported from a range of different references.

Through the scope of this study, it was not possible to complete a detailed assessment on the performance of flow computing systems, gas accounting systems and performance monitoring systems with future fuel blends. However, on the basis that these systems will typically rely upon accurate modelling of the equations of state and measurement of flow rate, it is reasonable to infer that the overall uncertainty presented for flow metering is reasonably representative for these systems.

Upon review of the typical Standards and Regulations applicable to Australian transmission systems, no material deviations or concerns which may limit the ability to transition to future fuel applications were found within the scope of this assessment. Addition of hydrogen would likely require some wording changes in Regulations and the inclusion of hydrogen within the component list for the gas specification, given that hydrogen is not currently catered for in the specification for general-purpose natural gas, AS 4564.

The study was not able to determine the implications that may be appropriate for high pressure calibration of custody transfer flow meters using hydrogen as the process fluid. This remains an area for potential further investigation.

These conclusions can be related to some nominal priorities and timeframes for future fuel transitions, as defined below:

1. Short-term – partial pressure of hydrogen up to 0.2 MPa = 1.3 vol% hydrogen in natural gas at 15 MPa
2. Medium term – partial pressure up to 3 MPa = 20 vol% hydrogen in natural gas at 15 MPa
3. Long term – partial pressure up to 15 MPa = 100% hydrogen

The investigations presented in this report focussed on either natural gas or H_2 mole fractions of 10%, 20%, 50% in natural gas, and 100% H_2, which is well beyond the medium-term priority category. The study presents that for typical system conditions expected in the transmission network, little change is observed in flow uncertainty of the 10 mol% hydrogen blend relative to natural gas. Other measurement parameters are expected to be smaller contributors to the overall uncertainty. Hence, there are no significant concerns to make existing metering and gas quality systems suitable for the short-term proposal of 0.2 MPa partial pressure of hydrogen, noting that some minor adaptation would be appropriate for GC installations (e.g. modified calibration gas composition).

For the medium term, blends up to 20 vol% hydrogen should also be capable of being accommodated. However, this would be subject to more specific assessment on a case-by-case basis to validate the given system conditions.

Beyond the medium term, it is likely that additional equipment and/or more significant system modifications would be required to accommodate higher percentage blends within the metering and gas quality monitoring installations.

In all cases, owners would need to consult with equipment manufacturers to validate and certify equipment suitability (uncertainty) for the specific system conditions.

7. IMPLICATIONS AND RECOMMENDATIONS FOR INDUSTRY

Equipment suppliers already have or are developing instruments that perform the required duties if hydrogen is blended into natural gas at up to 20 mol%. This may be through updating uncertainty statements and/or through developing changes to instruments (e.g. GCs). The implications of this study are that equipment suppliers are highly aware of issues related to custody transfer requirements, and aim to provide solutions, ahead of commencement of blending. This is particularly the case in Australia, where blending may occur later than in some other countries.

In the short to medium term, existing metering and gas quality monitoring systems within the transmission network are considered to be readily capable of adapting to future fuel applications with minimal modification. Industry (owners) would need to complete its own assessments for each asset and installation, and consult with the existing instrument suppliers to re-certify and/or adapt existing equipment as required.

It is noted that this study has focused on equipment functionality (measurement uncertainty) only. Other factors such as material selection and mechanical integrity would also need to be investigated by owners on a case-by-case basis for each equipment installation.

A recommendation is that Industry decides on which blends or ranges of blends to select and ask for the relevant uncertainty statements from equipment suppliers. This will provide a signal for equipment suppliers to perform the required development and analysis in cases where it has not already been done.

In addition to the above, industry will need to address the following for each asset:

1. Existing pipeline systems, monitoring locations, operating regimes and pipeline management tools within each operating company would need to be assessed by the operating company internally as part of a management of change process.
2. Software for gas accounting and performance modelling software will need to be updated by the owners / software providers.
3. Asset owners will need to validate flow and gas composition measurements and all software outputs after changes are made.

8. NEXT STEPS AND FUTURE WORK

It is recommended that industry maintains close contact with equipment suppliers, as outlined above, to enable these suppliers to readily support potential upcoming applications with future fuel blends. This may range from a readiness to respond to minor modifications and recertification of existing equipment, through to development and testing of new products to suit potential medium-to-long term needs.

In addition, industry may wish to engage with metering calibration laboratories to assess any possible implications for high-pressure calibration of flow meters with hydrogen gas. As noted in Section 3.4 of this report, no progress was able to be made during the course of this study despite contact with several overseas laboratories.

It is conceivable that an experimental program can be developed in Australia to validate the claim made by SICK, Germany that “up to 10% H2 content by volume, no influence on the ultrasonic gas meter can be detected if the hydrogen is well-mixed with the natural gas”. They also have suggested an increase in uncertainty of 0.2% for a 25 vol% hydrogen blend.

FFCRC or gas transmission companies could assemble a listing of equipment suppliers’ validated uncertainty statements for different future fuels including varying blend ratios. If digitised appropriately, this could then be used to readily calculate overall uncertainty for any combination of instruments in a gas metering station.

Whilst beyond the scope of this study, further work is recommended to assess instrumentation and measuring requirements outside of the transmission networks, i.e. in distribution networks.

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