IEA GREENHOUSE GAS R&D PROGRAMME

REDUCTION OF CO_2 EMISSIONS BY ADDING HYDROGEN TO NATURAL GAS

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Background to the Study

The IEA GHG R&D programme has issued reports on a range of technologies which reduce or eliminate CO_2 emissions from large power plants and major industrial processes by capturing the CO_2 for geological sequestration. The costs of reducing greenhouse gas emissions in this way have been estimated on a consistent basis. Studies have also been made to characterise the costs of CO_2 emission abatement through use of renewable technologies with the same economic evaluation parameters. The results show that centralised capture and storage options are quite costly but have the potential to allow deep cuts in global emissions from fossil fuel consumption. In contrast, the cost of mitigation by switching to renewables is generally higher but has potential for cost reductions. There is considerable interest in technologies which could create a bridge between the renewable options and CO_2 capture and storage.

A central theme in many future energy systems is the use of hydrogen as an energy carrier. Several of the CO_2 capture technologies use hydrogen as an intermediate product and renewable energy systems can use hydrogen as an energy carrier and storage medium.

One approach, which has been put forward as possible means of making a transition to a carbon-free energy system, is to blend into natural gas, hydrogen made from fossil fuels with CO_2 captured for storage. This would have the advantage that a wide range of energy consumers could be reached and benefit from greenhouse gas emissions reduction. It is worth bearing in mind that the original towns gas systems were almost 50% hydrogen by volume. Ultimately, it might be possible to effect a complete conversion from natural gas to hydrogen.

Approach adopted

The overall scope for introduction of hydrogen into natural gas systems is wide: up to addition of 100% hydrogen, variation of the hydrogen content in the system, use of different sources of hydrogen, and many variants on the possible timescale for conversion. The scope is further widened by the significant differences which exist between the gas systems in different countries and regions. It was thus decided that this study should concentrate on the early stages of hydrogen introduction. From previous work, it was determined that the combustion properties of hydrogen/natural gas blends would not show great differences until concentrations of 20%-30% vol are reached. Therefore this study explores the effects of addition up to a maximum of 25%vol should not require radical new burner technology to be developed. Later studies could examine greater proportions of H_2 addition.

Today almost all hydrogen produced on a commercial scale is derived from fossil fuel reforming processes of which steam reforming of natural gas is by far the most common. IEAGHG has already issued a report on the costs of hydrogen manufacture with CO_2 sequestration using this technology (PH2/2). The current study builds on this work, concentrating on the costs of distribution and on end-user systems. Before commissioning the study it was also noted that transient effects of hydrogen plant shutdowns and gas load variations could greatly complicate the blending operation. This opens up an important area of study but one which it was considered would be best addressed once the basics of hydrogen addition had been understood. Accordingly the consultant was asked to base the work on supply of constant quantities of hydrogen for blending and to note where disruptions in supply might have significant consequences.

There are significant differences in the structure of gas distribution systems around the world, mostly for historical reasons. The consultant was asked to develop a number of scenarios based on converting part or all of a country or regional gas system, selected so that the main systems in place around the world were represented. This resulted in the choice of three countries:

- The UK, which has a large component of older piping with low pressure final distribution,
- The Netherlands, with a modern network and low pressure final distribution,
- France, with a modern network and a high pressure final distribution system.

These three systems incorporate most of the features which will be found in any gas system around the world. The Consultant was asked to recommend a practical conversion programme with appropriate steps of adding hydrogen up to the study limit of 25% by volume.

It did not appear to be economical or practical to provide gas with a constant hydrogen content – for example, this would require plants in northern temperate climates to operate at about 50% annual utilization with turndown to as low as 25% in the summer months to achieve this. This study is thus based on producing hydrogen at constant rate and allowing the gas composition to vary. This requires domestic appliances and industrial equipment to be capable of adjusting to the composition variations, which is a significant but not insurmountable problem. The minimum cost of CO_2 abatement will occur when there is some turndown of hydrogen capacity in summer months but this optimum is dependent on the shape of the annual consumption profile. The information generated in this report is sufficient for this optimum to be investigated further. Because the hydrogen plant investment is centralized, whereas that in the network and appliances is dispersed, commercial pressures will tend to favour full utilization of the hydrogen plants rather than the network.

The major issues and costs were expected to be associated with the final distribution and end user appliances. Gastec of the Netherlands was selected to carry out the technical study. Gastec has considerable experience with the testing of appliances including those burning hydrogen/natural gas blends.

Results and Discussion

Safety
The report includes a detailed review of all the effects that hydrogen addition would have on safety. It concludes that safety will not be compromised as a result of blending of up to 25% hydrogen by volume into the natural gas grid. The physical property changes in the gas blend have a range of minor, safety-related effects but, in aggregate, cause no additional risk.

Conversion scenarios
Small amounts of hydrogen could be blended into the grid at almost no cost apart from that of generating the hydrogen from natural gas (about 20$/ton CO_2 abated with 73.3% energy conversion efficiency). A threshold occurs at around 3% vol. To go to higher levels requires significant investment in the network and checks and changes to end-user appliances.

The combination of hydrogen production and alterations to the gas system makes blending to higher levels more costly. The consultant recommended a two stage approach for proceeding to higher levels. Domestic customers would first be supplied with gas containing up to 12% hydrogen, which would require some older apparatus to be retired but allowing the current generation of appliances to be adapted. Some elements of the network capacity would have to be upgraded in one step. Once the network had been upgraded, a second increase to a maximum of 25% hydrogen would be implemented. The timescale chosen would be such that the bulk of appliance replacements would occur through the natural cycle of retirement and replacement. This study was limited to hydrogen additions up to 25% vol beyond which level additional adaptations may be necessary.

Various specific aspects of network operation and end-user equipment had to be considered:

Network upgrade
The effective energy-carrying capacity of the gas system is slightly reduced when hydrogen is added. Because systems are designed for peak demand and use pressure reducers to control distribution, most systems should be capable of distributing hydrogen-blended gas without changes to piping, valves and fittings. Controlled pressure levels would need to be adjusted upwards in the distribution network. Some industrial consumers may need to have their supply lines debottlenecked as they have constant energy off-take patterns and do not have the same capacity margins. The peak capacities of trunk lines will be slightly reduced, which could limit supplies on the coldest winter days. This can be overcome by switching off the hydrogen for those days. Nevertheless no insurmountable problems were identified.

Engines and turbines
Industrial gas engines are expected to need modified control systems to control knocking. Existing gas turbines will need to modification which will be machine and application specific. Compressed natural gas vehicles (CNG) will suffer a severe reduction in range which could be partly compensated by moving to the higher pressure tanks which are already envisaged for use in hydrogen powered vehicles.

Metering
A small investment in centrally provided gas analysers will be required in order to be able to continue to measure the relevant properties of the gas being supplied to customers for fiscal purposes. The effects on consumers' gas meters will be within allowable ranges of accuracy and repeatability and thus no costs for meter upgrades are expected.

CO_2 abatement costs
Estimation of the costs for a project of this nature is complicated by the difference in timescales for the various parts of the project and the fact that some costs are incurred only once, whilst others continue indefinitely. The timescale on which the conversion is carried out has a large impact on the overall cost.

The long term costs of proceeding to 25% hydrogen were found to lie between $12 and $23/ton CO_2-avoided for the three countries investigated. Thus the overall cost of CO_2 abatement including hydrogen production lies between $32 and $43/ton CO_2.

Table 1. Overall CO_2 abatement costs for three country scenarios with constant rate hydrogen addition to natural gas to max 25% vol.

UK	Netherlands	France
43 $/ton CO_2	**32 $/ton CO_2**	**39 $/ton CO_2**

The above costs are based on the operation of the hydrogen plant at full capacity which does not make optimum use of the network. The optimum design for the complete system would be with some spare hydrogen capacity installed. Simple estimates of where this optimum lies show that for the Netherlands overall abatement costs might be 5% lower requiring hydrogen plants to operate at down to 75% capacity during periods of minimum summer demand. For France and the UK overall costs might be 10% lower but hydrogen plants would have to operate at down to 55% of capacity in the summer.

CO_2 abatement potential
The magnitude of CO_2 abatement achievable by introduction of a peak of 25% hydrogen derived from fossil fuel with CO_2 sequestration is only some 4%. In absolute terms this is about 3 million tons per annum for each of the three countries evaluated. The main reasons for this counter-intuitive result are that average concentrations would only be half the peak, hydrogen has only one third the heating value on a volumetric basis and hydrogen production (even from renewable sources) will be accompanied by some greenhouse gas emissions. This figure should be compared with what might be achieved by investment in energy efficiency improvements. The amount of abatement could be increased to 5 or 6% by installing spare hydrogen capacity as mentioned above and, in principle, this reduces overall abatement costs by making better use of the investments in the network and end user devices.

Resistance to change
The consultant concluded that early and extensive consultation would be essential if hydrogen introduction into the gas network was to be successfully implemented. This is especially so as the case for such a change is not compelling even on commercial grounds. Codes and standards would also need to be altered before such a change could be started. Because of the long term nature of gas infrastructure investment it would also be essential to have clear long term plans on which the industry could base its decision making. There are lingering concerns about the possible effects of hydrogen on the integrity of pipeline materials in the high pressure grid. This could lead to calls for precautionary reduction of operating pressures and hence capacity which might be strongly resisted by the transmission companies. Trunk lines are used in some countries for cross-border gas trade and the introduction of hydrogen may be unacceptable in lines which are used for this purpose. The alternative is to construct separate high pressure hydrogen transmission lines where needed, which would incur additional expense.

Expert Reviewers' Comments

Expert reviewers found the report contained much valuable information. One expert considered that steel material problems associated with even small hydrogen additions to the high pressure gas grid were understated. Experts also questioned the use of a single figure for cost and capacity of the hydrogen plant. As the main objective was to identify the costs associated with the distribution network, in practice the first introduction of hydrogen would require a limited number of state-of-the-art production plants in any one country and it is not expected that the technology, and hence cost, of these massive plants would change significantly if firm plans on the timescale indicated in the study were actually set in motion.

Some experts felt the report was biased towards use of hydrogen produced from fossil sources as a result of the simplifying assumption made on the hydrogen source. A practical scenario for introduction of hydrogen from renewable sources would have a more gradual capacity build up and, because of the much higher costs for hydrogen from this source, might not be achievable in the same timescale. The main results of this study are applicable to utilization of hydrogen from any source and could be adapted to consider different profiles for building up production capacity.

There was concern at the severe effects of the change on the range of CNG vehicles but experts pointed out that tank pressures could be increased to offset this effect. Much higher pressures are contemplated for pure hydrogen storage in vehicles and this would be one way to overcome this problem. One expert expected that the efficiency of CNG vehicles would also improve slightly as a result of the hydrogen addition.

One expert felt that the value of hydrogen addition to assist in the transition to a hydrogen economy based on renewable resources should have had much more emphasis. However, this was outside the scope of this initial study.

Experts felt that more should be done to present the costs of alternative CO_2 abatement options. However it is in the nature of the IEAGHG's detailed technical studies that such comparisons will be made in summary reports or overview papers rather than in those covering a particular technology.

Major Conclusions

Small amounts of hydrogen could be added to the natural gas grid with almost no expense, apart from that of producing the hydrogen, although there are several technical and organizational barriers which would have to be overcome. This could provide a small but significant outlet for hydrogen generated from surplus renewable resources.

The cost effectiveness of adding larger quantities of hydrogen is poor compared to some other options for greenhouse gas abatement. The magnitude of CO_2 abatement achievable by introduction of up to 25% hydrogen derived from fossil fuel with CO_2 sequestration is comparatively small.

Even if higher levels were introduced it is likely that users would have to accept wide variations in gas properties because it is difficult and expensive to modulate the production of hydrogen in step with gas demand. This is possibly the greatest obstacle to introduction of higher levels of hydrogen into the gas network.

Recommendations

Although the economics of the scenarios examined in this study are not compelling, further work in this area is recommended because of the widespread interest in the hydrogen economy and the belief that it might provide the bridge from a fossil fuel to a renewable energy system.

Areas which should be considered for further study are:

- Costs and technical implications of proceeding to higher levels of hydrogen in natural gas, up to 100%

- Cost effective technical solutions for reducing or eliminating concentration variations in hydrogen-blended natural gas. The use of buffer storage, line pack and variable capacity hydrogen production facilities should be considered. Also the possible advantageous interplay between renewable and fossil fuel hydrogen production profiles should be examined. The use of "swing" consumers able to accept larger composition variations should also be investigated.

- Optimisation of hydrogen plant location for minimum hydrogen line, gas line, CO_2 line and other system conversion costs (this could be done using IEAGHG's cost calculator).

- Alternative development strategies to attain 100% hydrogen distribution, including how parallel H_2 and gas networks should develop to minimise overall transition costs, and comparing blended hydrogen with use of separate networks for gas and H_2.

- Technical solutions for utilising gas with variable quantities of added hydrogen.

Reduction of CO_2 emissions by adding hydrogen to natural gas

GASTEC TECHNOLOGY BV

Erik Polman

16th September 2003

Reduction of CO2 emissions by adding hydrogen to natural gas

Commissioned by	**: IEA Greenhouse R&D Programme**
Project number	**:**
Project manager	**: Erik Polman**
Project team	**: Hans de Laat, Jan Stappenbelt, Paul Peereboom, Wim Bouwman, Bram de Bruin, Cees Pulles, Martin Hagen**
Report no.	**: IE/020726/Pln**

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COMPANY PROFILE

Gastec is a company with an international reputation in the field of energy related technology. Gastec is engaged in research and development, consultancy, engineering, certification and training. Its customers base comprises the industry in the energy supply chain from well head to burnertip. The mission of Gastec is to provide technology to energy companies as strategic assets.

The Gastec Group consists of companies in the Netherlands, Germany, Italy, UK and USA. A network of agencies around the world supports the commercial operations.

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CONTENTS

EXECUTIVE SUMMARY

The principle objective of this study is to examine the environmental benefits and costs for adding up to 25% v/v hydrogen into existing natural gas transport and distribution systems as an early way of decarbonising energy systems. The second objective is to discuss the numerous technical and societal issues involved, according to the following plan:

- A review of existing or planned projects concerning hydrogen addition to natural gas
- The consequences of hydrogen addition on the performance and safety of a typical gas network
- The consequences of hydrogen addition on end user devices and the options for upgrade or replacement
- An analysis of likely causes of resistance to change and proposals for overcoming them

The size and costs of bulk hydrogen production facilities from natural gas and CO_2 capture technologies have been taken from a previous IEA study (PH2/2) on decarbonisation of fossil fuels. The typical size of a (single) production train was 280 MW thermal equivalent, supplying 94.000 Nm^3/h. Costs for hydrogen production and underground CO_2 storage are not analysed further in this study. The price for hydrogen from this earlier study was \$7/GJ based on a "centre price" of \$3/GJ for natural gas and a 10% discount rate.

Three IEA countries, U.K., France and The Netherlands were taken as base cases for the technical and financial analysis. The gas systems in these three countries are considered to be representative of the global gas infrastructure.

We could not identify any practical demonstrations on mixed natural gas/hydrogen distribution through existing natural gas networks, although considerable experience exists on pure hydrogen distribution to industrial customers and the distribution of town gas to residential customers. Studies and laboratory experiments on components have been performed in Germany, Denmark and the Netherlands.

Hydrogen production facilities are expensive therefore for economic reasons a constant production rate (~8500 hrs/yr) is highly desirable. The consequence of this is that (at least ideally) the hydrogen content in natural gas should be permitted to vary over the year as the energy demand is subject to seasonal variations. The result is that the hydrogen content would vary by a factor of about 4 between winter and summer and the average addition can only amount to half the upper specification limit.

There are a number of other important factors that need to be considered. The performance of the gas infrastructure will change, of which the following are probably the most important:

- The energy transport capacity of the grid will decrease, especially for the high pressure grid. This is because of the lower CV of hydrogen (on a volumetric basis)
- For peak energy demand days the hydrogen addition may have to be restricted in order to use the full energy carrying capacity of the network.
- For industrial clients with a non temperature dependent off-take pattern, additional transport capacity might need to be installed to cater for summer peaks of hydrogen content when the volumetric CV of the gas is at its lowest.

- The varying gas quality needs a more sophisticated system of fiscal transfer than conventional natural gas and in consequence would require an upgrading of the gas chromatograph currently used for gas quality measurement.
- The risks for hydrogen embrittlement are unknown. There are indications that high pressure grids (>40 bars) made of high strength steel under tensile stress would be more vulnerable to crack growth. There is currently not a consensus between experts and the technical and economic consequences cannot yet be estimated.
- A large fraction of the current gas engines (stationary and mobile applications) need a λ-control system and anti-knocking system.
- In order to accommodate 3 to 12 % hydrogen mixtures, domestic boilers will need to be of a quality equivalent to the EU standard of 1998 or later.
- For blends up to and above 25 % hydrogen, new burner concepts for domestic appliances leading to a broad band gas appliance will certainly be necessary, although the percentage at which these new concepts needs to be introduced is unclear.
- The seasonal variations in gas quality with hydrogen addition will affect the accuracy with which boilers can be adjusted. Special instructions for installers/service operatives will be necessary.
- At 25% hydrogen content, the vehicle range may be half the normal CNG vehicle range. This could limit the commercial development of hydrogen/natural gas blend vehicles to niche markets.
- The consultants could not identify any gas turbine having been adapted to operate on hydrogen/natural gas blends. However, considering the experiences with dual fuel turbines, these modifications seem feasible and affordable.

Agreement should be reached in advance, between all stakeholders regarding the new requirements and specifications of appliances and devices. It is, therefore, of primary importance to develop and write amendments to the existing Standards extending them to hydrogen blended gas.

A reasonable scenario for the introduction of hydrogen would be the use of three sequential phases:

- Introduction phase up to 3 %, when hardly any radical adaptations are needed
- Intermediate phase up to 12 %, when adaptations are needed but Wobbe variations are within acceptable range corresponding to the various standards for quality of natural gas as far as utilisation is concerned. Significant adaptations needed for the other links of the supply chain.
- Target level of up to 25 %: feasible but very significant changes needed all along the gas supply chain.

The economic benefits and the business case for hydrogen addition have to be clear before industrial partners will participate. It must be said that the costs summarised below are relatively high and do not indicate a good case at present compared to other options. This will make it difficult to attract subsidies.

The total specific abatement cost of a project is the sum of the hydrogen plant costs and the costs for upgrading the network and appliances per ton of CO_2 saved (discount rate 10 %).

Country	NL	UK	FR
	\$/ton CO_2	\$/ton CO_2	\$/ton CO_2
Hydrogen plants with CO_2-capture*	20.7	20.7	20.7
Gas chain upgrade to supply 25% H_2	12	19	23
All in cost to supply 25% H_2	**32.7**	**39.7**	**43.7**
Incremental costs gas chain to supply 3 % H_2	*0.1*	*0.1*	*0.1*
Incremental costs gas chain to further increase to 12% H_2	*38*	*76*	*83*
Incremental costs gas chain to further increase to 25% H_2	*5*	*14*	*8*

*Foster Wheeler study for IEA GHG report PH2/2, primary energy price at 3\$/GJ, 10 % discount rate. The costs of hydrogen plants with CO_2 capture comprise the hydrogen production plant, capture and compression and allowance for operation of CO_2 disposal line, well heads and wells.

Table: Specific abatement costs in \$/tonne CO_2

Some of the incremental costs are high because the full expense of replacing/upgrading the infra-structure (pipelines and appliances) has all been assigned to the hydrogen addition project. For the long term the replacement costs are not considered anymore as extra costs and the overall costs fall dramatically. Using this economic evaluation technique long term costs for adapting the infrastructure to hydrogen addition to natural gas vary between 12 and 23 \$/ton CO_2 (exclusive of H_2 production costs and based on 25 % H_2 addition[1]). It is worth repeating that the latter are marginal costs of making the conversion in a reasonable time scale, the details of which are contained in the main-text. These costs also exclude the beneficial effects of newer more efficient appliances that could be created by the market that would be encouraged by the transition to the new hydrogen rich gas.

Unfortunately the costs of addition of hydrogen to natural gas over a long period of time (in this instance ~15years) are much less transparent than the cost of (for example) adding flue gas scrubbing to a power station. If the decision were made to convert a large country to 25% hydrogen over (for example) 2 years the cost would be both astronomic and the task physically impossible (in the UK ~\$75 billion). As this task is spread over a longer period of time, the cost reduces as it is possible to take advantage of the appliance regular replacement cycle, imposed by its durability and perform the upgrade to hydrogen tolerant appliances at very modest incremental prices. It is likely that the cost of an appliance to burn a hydrogen/natural mixture will (in mass production) be similar to the cost of an appliance to burn natural gas.

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[1] *Note*

Whilst this scoping study is very sensibly based upon 25% v/v hydrogen; the consultants would like to remind readers this is not an optimised figure. A cost benefit analysis would be necessary, this will inevitably require trade-offs as appliance manufacturer's operating on a world scale will wish to see certain uniformity of hydrogen addition values. These may not be financially optimised for particular countries.

Boilers, cookers etc only have a life of only 15 to 20 years so imposing appropriate hydrogen compliant standards now would result in substantial reductions in transitional costs. The use of a 30 year transition (thought unreasonably long by the authors) could result in a much more modest set of additional costs.

The complexity of these issues means the introduction of hydrogen addition to natural gas requires a very careful and open communication and decision making plan agreed with all stakeholders, and probably legislatively driven. The costs calculated are relatively high beyond the 3% addition level, although as said above, these are dependant upon the time frame considered for the transition. Other reasons why the addition of hydrogen may not be enthusiastically embraced are:

- A long term commitment is necessary before investments will be made
- Hydrogen addition costs have to be competitive with other CO_2 reduction options
- The economic benefits and business case for hydrogen addition to natural gas are not clear at present, largely because of the usual wide uncertainty attached to the economic evaluation of environmental damages.

However, it must be stressed that ALL of the current projects that investigate hydrogen addition see it NOT as an end in itself but as one of the few ways of making a transition to the “hydrogen economy”, especially if the hydrogen is produced from renewable sources. There are other significant side benefits such as the creation of an “instant” market for hydrogen, which would increase the possibilities of:

- developing low-cost hydrogen production , and
- creating a new medium pressure distribution network for pure hydrogen. This could provide pure hydrogen for fuel cells, with “surplus” hydrogen being sold into the existing local low pressure gas network.

1. INTRODUCTION

Hydrogen is widely considered to have great potential as one of the principal sustainable energy carriers of the future. Future supplies of hydrogen that do not affect the global climate could be obtained from sustainable primary sources, such as wind, solar and geothermal energy. Hydrogen could also be generated by nuclear power without significant CO_2 production.

In the present situation however, society depends largely on fossil fuels, and the contribution of sustainable energy to the global energy demand is limited. A sudden change to the hydrogen economy described above is most unlikely to happen, but a controlled transition from the current energy system to a fully sustainable, hydrogen based energy supply is far more realistic, if governments provide the necessary framework.

The gradual conversion of natural gas systems to hydrogen systems is therefore a possible long-term option. Blending existing supplies of natural gas with hydrogen generated either from fossil fuels with CO_2 capture or from economically viable sustainable sources, might then be an excellent step forward.

The present study is aimed at understanding the costs and benefits of adding up to 25% hydrogen into existing natural gas distribution systems. Technical consequences for the gas chain –transmission, distribution, storage utilizations- will be analysed and incorporated into realistic implementation scenarios.

The technical issues of hydrogen addition to the gas chain are outlined in chapter 3 and the considerations for the operation of a hydrogen production unit are given in chapter 6. The resistances to change and lessons learnt from previous large infrastructural projects are also described. Chapter 8 describes a realistic practical time scheme for hydrogen addition to natural gas and the necessary technical measures for the gas systems of the UK, France and the Netherlands. The environmental benefits and costs expressed in $/tons of CO_2 avoided are evaluated in chapter 9.

2. RATIONALE FOR THE ADDITION OF HYDROGEN TO NATURAL GAS

Although natural gas has the lowest carbon emissions of all fossil fuels, it does have a significant carbon content. Hydrogen gas has no carbon content so the replacement of some of the natural gas burnt in homes and industry with hydrogen would reduce carbon emissions at point of use. However, in practice not all the CO_2 produced during the manufacture of hydrogen from fossil fuel would be captured thus reducing the overall reduction which is achievable. Typical CO_2 emission reduction potential is shown in the table below:

Gas	High calorific gas	Rel. CO_2 emission
H_2-content [vol%]	Relative Wobbe [%]	[%]
0	100	100
5	98.7	98.6
10	97.4	97.1
15	96.0	95.4
20	94.7	93.7
25	93.4	91.7
30	92.0	89.6
40	89,3	85,5
60	84,2	73,0
80	80,4	52,6
100	85,0	13,3

Table 2.1 Variation of the Wobbe[2] index and the CO_2 savings with hydrogen content. The hydrogen is presumed to be made by large scale steam reforming and CO_2 capture with a recovery rate of 86.7 % for CO_2.

Possible CO_2 emission reduction savings will be discussed in greater detail in chapter 9. The hydrogen is presumed to be made by large scale steam reforming and CO_2 capture with a recovery rate of 86.7 % for CO_2 .

The above table highlights the substantial effect that arises from the low calorific value of hydrogen on a volumetric basis; thus replacing 30% by volume of the gas supplied to a customer only reduces carbon emissions by ~10%. To reduce the CO_2 emission by 50% requires a gas of about 80% v/v hydrogen.

For future options, the hydrogen can be produced by renewable sources. In that case there is no CO_2 emission and no need for storage. The relative CO_2 emissions would then also be lower.

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[2] The Wobbe-index is The ratio of the gross calorific value (H_s) to the square root of the relative density d of a gas. $W = H_s / \sqrt{d}$. The Wobbe index is a measure of the amount of energy delivered to a burner via an injector.

3. OVERVIEW OF TECHNICAL ISSUES

The addition of hydrogen to natural gas networks is expected to have implications across the whole supply chain ranging from:

- Overall safety of hydrogen/natural gas mixtures
- Gas compression
- High Pressure (HP) transmission
- Pressure reduction
- Intermediate and low pressure distribution
- Metering
- End use
- Maintenance of gas quality

The following sections will address each of these items in turn from a technical perspective using references taken from various Appendices included later in the report. It will then return to the total picture and offer recommendations for different scenarios.

The two main technical issues that have to be considered here and that are actually linked are the volumetric capacity of any gas system and the calorific value of the gas on a volumetric basis. The first problem is that natural gas has a high calorific value (typically ~38 to 40 MJ/m^3), the addition of hydrogen reduces this value (to ~30 MJ/m^3 at 30% H_2 v/v); this effectively reduces the energy carrying capability of the system. This means that (particularly for those few "peak load" days in the depths of winter) any particular system may not meet demand without substantial reinforcement (ie without installing additional distribution pipe work). The second problem is that hydrogen production plant is expensive to build and operate, slow to start up and the large scale storage of hydrogen (sufficient for summer/ winter load swings) is currently considered almost prohibitively difficult and expensive. This means that hydrogen, unlike natural gas (which is easy to store), is best produced at a steady rate and blended continuously.

3.1 Safety

The generic potential hazards in using flammable gases are: explosion, fire, suffocation and poisoning. These hazards phenomena may have different origins. This section applies mainly to domestic and smaller commercial consumer hazards, because industrial consumers have different safety considerations and a professional ability to handle any hazards. All aspects in relationship to hydrogen blended with natural gas are discussed in brief in this chapter.

3.1.1 Hazard phenomena and their origins

A gas related hazard can be caused by:

- the high pressure of the supplied gas
- the chemical properties of the supplied gas
- the presence of the unburned gas itself in the air due to leaks or rupture
- by the use of a gas in a heating appliance or other consuming device

- by the appliance
- by the flue gas from the appliance
- by the heated media,

If good practices are in place these phenomena are well controlled and accidents are not common. However lapses in application of good practice can still occur, leading to development of immediate or latent hazards.

There is a general perception (the so-called Hindenburg effect, named after the infamous airship) that H_2 is dangerous. Therefore a careful analysis of how all the hazards associated with the use of gas are affected by the addition of hydrogen is needed in order to obtain an objective view of its effect on overall safety.

The hazards may cause a gas related accident which usually involves at least one of the following phenomena with damage to constructions and or injuries:

- Rupture of pressurised parts and harmful chemical effects on materials
- Explosion of flammable mixtures
- Fire
- Burns
- Suffocation
- Poisoning

Table 3.1 gives an overview of those phenomena which are considered important and the hazards which cause them in relationship to appliances burning a hydrogen/natural gas blend. The symbols indicate whether the risks are altered by introduction of hydrogen.

	Main hazardous phenomena					
Causes	Rupture*	Explosion	Fire	Burns	Suffocation	Poisoning
High pressure of the gas (or heated medium) and chemical properties of gas	x					
Unburned gas in air		- -	+ +		- -	
Use of gas & open fire in a device or heating appliance	x	x	x	+ +		
The appliance itself outside				x		
Flue gas system			x	x	- -	- -
Heated media	x	x	x			

* Rupture is inclusive of harmful chemical effects on materials used
x Hazard exists but unchanged by presence of hydrogen up to 15%
+ + Hazard increased by presence of hydrogen
+ - Hazard both increased and decreased
- - Hazard reduced by presence of hydrogen

Table 3.1 Hazardous phenomena and their causes

Each of the phenomena as they apply in the domestic situation is reviewed in Appendix H. Table 3.2 gives more specific details.

3.1.2 Gas Properties

The effects of adding hydrogen to natural gas depend on the physical and chemical aspects of both hydrogen and natural gas. The effects of adding up to 25% hydrogen to natural gas have been analysed, relative to the use of standard natural gases and an assessment of whether the particular property results in a safer or less safe situation with respect to each phenomenon has been made. This is a purely qualtitative assessment and in practice may be greatly dependent on a particular situation.
“Less safe” can also be due to lowered operational safety. For example: while increasing the amount of hydrogen, the visibility of the flame decreases. In the case of flue-less cooking appliances it will be more difficult for the user to notice a burning cooking burner. The flame may also be less visible to a flame detector like a UV cell. This means that the chance of a safety lock out by safeguard failure will increase.

Properties and Phenomena	Effect of hydrogen addition	Main hazardous phenomena					
		rupture	explosion	fire	burns	suffocation	poisoning
Physical/chemical properties							
Density	Lower					x	
Viscosity	Lower					x	
Velocity of dispersion	About the same [1)]		x	x		x	
hydrogen component	Higher	x					x [2)]
Household gas pipe system							
Leak rate	Higher		x	+		x	
Ignition/ Burning Process In General							
Lower flammability limit	about the same level		x	x			
Higher flammability limit	Higher		+				
Flammability range	Wider		x				
Detonability range	Wider		x				
Explosive energy/volume	Lower		x	x			
Explosive energy/mass	Higher		x	x			
Minimum energy for ignition	Lower		x	x			
Auto ignition temperature	Lower		x	+			
Ignition/Burning Effects							
Uncontrolled ignition	Easier		x	x			
Severity of explosive damage	Lower		x				
Explosion risk in confined room	Higher		+				
Explosion risk in unconfined room	Lower		-				
Effects particularly for heating appliances							
Nominal power in appliance	lower; proport. to Wobbe		x	x			
Visibility of flames	Lower				+		
Flame lift off	Lower		-	-			
Incomplete combustion	Lower						-
Flame light back	Higher			+			
Electrical conductivity of the flame	In general lower			x	x		
Flame detection by conductivity	In general lower		x	x			
Sooting	Lower		x	x			
Crosslighting	Better		-	-			
Temperature of burner area inside	for metal plate: higher for ceramics: lower						
Efficiency	About the same or higher						
Combustion gases and flue system							
CO emission	In general lower						- [3)]
NO_x emission	In general lower						
Condensation of H_2O in appliance or flue system	Higher						
Temperature of flue gas or outside wall of flue pipe	about the same			x	x		

Table 3.2: Gas properties and phenomena[Lit. SG2-1]

1) *The velocity of dispersion of hydrogen is higher than natural gas, but up to 25% the main part of the mixture is natural gas and its properties and behaviour dominate.*

2) *Hydrogen like natural gas is not a poisonous gas.*

3) *There are two effects: the first one is a lower CO content in the flue gas because of a better burning process in general; the second effect is a more stable flame. The safety of modern gas appliances is monitored with a so-called Oxy-pilot. This device reacts to a reduction in oxygen content in the combustion air (or an increase in CO_2) by allowing a pilot flame to lift off a thermocouple. The presence of hydrogen counteracts this; so the addition of hydrogen will tend to reduce the safety limit of the appliance).*

3.1.3 Overall effects on safety

When we relate the main hazard phenomena of table 3.1 to the properties and phenomena of table 3.2, the following conclusions can be drawn for a natural gas blended with up to 25 v/v% hydrogen.

The risk of the presence of unburned gas in an explosive amount will hardly increase, while those risks dependant upon equipment failure are considered independent of the small change in composition of the gas.

In the past, town gas was distributed with hydrogen as one of its principal components (frequently up to 50 %). Such gas had a modest (even poor) safety record, but this was primarily due the presence of CO as a toxic and deadly component of that town gas, it was not due to its hydrogen content. Poisoning by gas or flue gas was the main cause of fatal accidents, and not accidents involving explosions.

In the Netherlands there was a significant decrease in the average number of accidents per million connections after converting to natural gas, thus the number of deadly accidents for gas distribution in the Netherlands dropped from 25 to below 5 per million gas connections after the conversion from town gas (50% hydrogen and 10% CO) to natural gas. Most realistically this can be attributed to the advances in safety rules and rigorous inspection by the gas companies at that time [Wolt].

To consider the possible risks from explosion, deadly accidents caused by explosions or fire of any gas distribution network tend to be low. In the Netherlands they have been at a rate of less than 1 per million gas connections for years and these numbers were not been affected by the conversion form town gas to natural gas. Fatalities from gas explosions in the UK are currently <0.5 per million gas connections per year. These currently arise primarily from major rupture of low pressure gas mains and because of this are unlikely to be affected by addition of hydrogen. In the unlikely event of an explosion, a natural gas/hydrogen mixture is considered to be less destructive than a pure natural gas explosion of the same volume.

It could be argued that as the hydrogen blended gas ignites more easily and as it has a lower ignition limit, in the event of a leakage the flow of gas will ignite earlier (nearly similar ignition temperature but much lower energy threshold) and in this way may avoid an explosion, but this is unlikely to be statistically significant. The higher explosion limit offered by hydrogen is not considered significant.

Overall the use of H_2 blended gas under well regulated circumstances should not increase the risks of explosions in comparison to those with unblended natural gas.

3.2 Gas compression

The capacity of compressors is defined by the power input required to drive the turbines and the efficiency and number of turbine stages given a specified mass (or energy) flow through the compressor. Compressors are only used in high-pressure transport lines. The effect of hydrogen addition has been evaluated on the assumption that such mixtures behave as ideal gases and the results are presented in Table 3.3. At the detailed level the effect of differences in compressibility would need to be accounted for. As the compressibility factor of hydrogen/methane mixtures is larger than unity (Z>1), the capacity of the compressor (on an energy basis) will be decreased.
The compression of hydrogen/natural gas mixtures by the large axial compressors originally designed for transport of natural gas will result in lower head pressures and lower capacities. Compensation by the installation of extra capacity or additional gas compressing stations may be necessary. This is a complex issue, but is not regarded as a significant short-term impediment to hydrogen addition. The problem is avoided if it is assumed that most hydrogen would be compressed at the hydrogen plant using its own compressors and then fed into the gas grid; the gas mixture would therefore only pass through modest booster compressors.

H_2-content [vol%]	Relative required power [%]
0	100
5	99.0
10	98.0
15	96.8
20	95.6
25	94.3
30	92.9

Table 3.3. The effect of hydrogen addition on the required power for the compressors in the gas transport system (Only the effects from calorific value and specific density are taken into account, the effect of compressibility is neglected)

3.3 High pressure transmission

Two issues are at the stake for this domain; one is system integrity, the other one is system capacity.

The transport of gas over long distances is the cheapest by high pressure lines. When hydrogen is produced for a large part of a country, such as analysed in this report, blending natural gas with hydrogen will be most cost effective when performed at entry points in the high pressure transportation grid. The hydrogen production and hydrogen blending process will be relatively cost effective because of economies of scale and the transportation can be carried out effectively via existing lines.

Extra investments for prevention of hydrogen embrittlement or extra capacity can be made simultaneously with autonomous growth or replacement of the existing pipeline system.

The use of dedicated high pressure hydrogen lines from a centralized hydrogen factory to small local blending facilities will almost always add more costs, compared to using the existing high pressure transportation grid.

3.3.1 System integrity

Material degradation and lifetime

The reason for this discussion of suitability of steel for hydrogen transport is that hydrogen will weaken many steel grades at elevated temperature. The most common cause is the attack of carbon atoms within the steel to form methane molecules which in turn cause delamination of the steel. In normal refinery or other industrial service the suitability of steel for hydrogen service is derived from ASME Nelson curves; these curves define the likely durability's of various steel grades in hydrogen service at elevated temperature and pressure. Until the 1960s this hydrogen attack was not thought to occur at room temperature (as demonstrated by the steel bottles used to handle compressed hydrogen) but extensive academic studies have shown a risk.

Hydrogen Embrittlement Failures

Tensile stresses, susceptible material, and the presence of hydrogen are necessary to cause hydrogen embrittlement. Residual stresses or externally applied loads resulting in stresses significantly below yield stresses can cause cracking. Thus, failure can occur without significant deformation or obvious deterioration of the component.

Small amounts of hydrogen can cause hydrogen embrittlement in high strength steels. Common causes of hydrogen embrittlement are pickling, electroplating and welding, however hydrogen embrittlement is not limited to these processes.

Experiences

There is a long history of the successful transportation of "pure" hydrogen at medium pressures (<20 bar) across the world, with steel (ferritic) pipelines running several hundred kilometres and no operational problems occurring over many decades.

Town gas has also been manufactured and transported at pressures below 20 bar without specific incidents. Commercial grades of hydrogen have been transported for many years in steel cylinders. Problems with hydrogen embrittlement occurred early in refineries and chemical plant but until the 1960s these were only believed to occur above about 200°C. Conversely there are also known examples of ferritic steels (particularly high strength steels) failing when subjected to extremely high operating pressures (>100bar) with extremely high purity hydrogen. This arises from penetration of hydrogen atoms within the steel. Academic papers [Cialone] have shown that hydrogen degrades the physical properties of pipeline steels, but then usually avoid making specific recommendations. This loss of fracture toughness or increased tendency to fatigue crack growth or crack propagation is clearly very dependant upon the incidence of hard spots in the pipe which themselves will be dependant upon the specifics of the fabrication technique. Results from the above paper showed a 30% reduction in the pressure at which time-dependant crack growth initiated failure. The risks from hydrogen cracking increase as the absolute stress within the pipe wall increases and the absolute pressure swings increase. Lower pressure lines tend to have greater proportional corrosion allowance, and are made from lower grade steel, so all of the problems decrease.

A few authors {Pottier] have claimed that as long as the hydrogen purity is not greater than 99,5%, the steel grades and welds generally used for natural gas transmission are not adversely affected,. This is contrary to the data of Kaske [Kaske]. Whilst the presence of impurities is important, quantifying their effect (even to the extent if they are beneficial or detrimental) is very difficult. In view of the conflicting and incomplete open literature information on the topic, we decided to consult a specialized institute whose conclusions are reported below.

Expert opinion

The Dutch Corrosion Centre (NCC) was consulted to give their opinion on the vulnerability of natural gas pipelines for hydrogen embrittlement. They stated that for carbon containing steel, hydrogen embrittlement will not take place for a hydrogen partial pressure of 75 MPa and temperatures below 220 degrees Celsius. For alloyed steels such as 1.25Cr - 0.5 Mo and 2.25Cr-Mo, the allowable temperature range is even higher.

In light of this statement, the operating regimes (hydrogen pressures and temperatures) for natural gas/hydrogen mixtures will not be a problem at all.

Gasunie [the Gas Transport Services in the Netherlands], have taken a more cautious approach and is currently investigating the influence of hydrogen addition to natural gas on pipeline material used in the Dutch main transmission network "HTL"(working pressure 67 bar). There are three reasons for this investigation:

- The pipeline material is of high strength steel which is reported to be more susceptible to hydrogen enhanced crack growth than low strength steels.
- The operating pressure swing experienced in the HTL network may enhance the above mentioned crack growth
- The older parts of the HTL pipeline material may contain more hidden defects (so called sleeping defects) than the newer HTL pipelines and the older welds are of a type that may be more susceptible to hydrogen enhanced crack growth

According to Gasunie Transport Services, the RTL (Regional Transmission System) pipeline material is currently not under examination, as it is expected that these pipelines will be far less susceptible to hydrogen enhanced crack growth, mainly due to the relatively low operating tensile strength compared to the design strength. A significant part of the RTL still stems from the coke gas era where hydrogen was present too, and did not give any problem in this respect. However, the coke gas contained, among other components, some oxygen which is known to prevent hydrogen enhanced crack growth.

These two contrary opinions make clear that the opinion on the risks on hydrogen embrittlement and crack growth in steel pipelines are diverse and that this topic is very relevant to the gas industry, especially because of the security of supply and the financial consequences.

The recommendation of this report is that before the addition of hydrogen to natural gas is made, to any welded steel line a risk assessment should be carried as to its design factor. However at low and medium pressures this risk for hydrogen embrittlement is likely to be extremely low and no allowance has been factored into the economic analysis to allow for upgrading of such pipelines.

In summary, the absence of detrimental effects of the addition of hydrogen to medium and low pressure systems is well proven (as demonstrated by town gas experience); In contrast, whilst the addition of hydrogen to high pressure systems would be unlikely to cause failure, it could produce marginal decreases in steel strength and hence decrease safety margins. The risk associated with the latter is however associated with a very large economic dis-benefit. Taking the example of the UK, the system was originally designed to operate at 69 bar but over the past 5 years has been up-rated to as much as 85 bar. This has been carried out following a very detailed engineering review but nevertheless does result in greater stresses within the steel.

3.4 System capacity

3.4.1 Effects on capacity

In this chapter the relevant parameters and their dependence on the hydrogen content are presented and discussed. In general it is assumed that the design pressure levels are kept the same, regardless of the hydrogen content of the gas. Those pressure levels are usually derived by general considerations of

- risk,
- standardisation or
- by law

and it is not appropriate for this report to recommend their alteration.

When not explicitly mentioned otherwise, all comparisons are made to high calorific gas (G20, pure methane). The pressures mentioned are gauge pressures. The most important parameters, related to the use of gas, are Calorific Value (CV) and Wobbe Number; the following table shows the alteration of these values with hydrogen content in G20.

hydrogen content	methane content	CV (MJ/m^3)	Rel. Wobbe index (SI)
0	100	35,8	100
5	95	34,6	98,6
10	90	33,3	98,1
15	85	32,1	97,1
20	80	30,8	96,2
25	75	29,6	95,3

Table 3.4 calorific data for HC gas

The formulas used in this chapter are outlined in Appendix A.

3.4.2 Transport capacity of the lines

The important parameter describing the transport capacity of a line is the pressure loss per transported amount of energy. The density, viscosity and calorific value of the gas determine this parameter. All these parameters are influenced by the addition of hydrogen. To first order approximation the line capacity is proportional to the square of the calorific value of the gas and inversely proportional to the density and compressibility factor (see Appendix A).

The effect on transport capacity is calculated for several pressures and the results are presented in table 3.5 . G20 is a High calorific (HC) gas and G25 a Low Calorific (LC) gas.

Pressure	50 mbar **(low)**	5 bar **(intermediate)**	50 bar **(high)**
H_2-content [vol%]	Relative capacity G20 (G25) [%]		
0	100 (100)	100	100 (100)
5	97.4 (98.1)	97.3	94.0 (95.2)
10	94.8 (96.2)	94.5	87.7 (89.8)
15	92.2 (94.4)	91.8	81.1 (84.2)
20	89.7 (92.6)	89.1	74.7 (78.5)
25	87.2 (90.9)	86.4	68.6 (73.0)
30	84.7 (89.2)	83.7	63.0 (67.8)

Table 3.5. The effect of hydrogen addition on the capacity of gas transport and distribution lines

The main conclusion is that the higher the pressure, the more pronounced the detrimental effect of hydrogen addition on capacity because it is far less compressible than methane.

3.4.3 Capacity of pressure regulators

The capacity of pressure regulators depends on the upstream pressure, the speed of sound and the density of the gas. The upstream pressure is here taken as a fixed design parameter. When the expansion is less than critical (P_u/P_d < ca 1.5), the capacity also depends on the downstream pressure.

The relative capacity of the pressure regulators as a function of the hydrogen content of the fuel and some typical transport and distribution pressures, assuming critical expansion and assuming approximately ideal behaviour, is shown in table 3.6

Pressure	
H_2-content [vol%]	Relative capacity of pressure regulator [%]
0	100
5	98.6
10	97.1
15	95.7
20	94.2
25	92.8

Table 3.6. The effect of hydrogen addition on the capacity of pressure regulators.

3.4.4 Noise and velocity

Additional limits may be imposed because of noise emission and forces on line bends. The noise of a line will slightly increase as the flow velocity must be increased in proportion to the speed of sound in the mixture to maintain the same energy transport. This increase in Mach number and corresponding increase in noise emission will be less than 20% (1dB). The forces on bends are proportional to the pressure drop of the line and will remain unaffected if the same pressure budget is used operating a line with hydrogen.

3.5 Intermediate and low pressure distribution

There are major differences in the operation of intermediate and low pressure gas systems around the world.

3.5.1 Global coverage

In 2000 the International Gas Union (IGU) published the outcome of a study regarding “Service Pipes”. Based on the questionnaire of this study it is possible to give an overview of the distribution of pipeline length used for the distribution gas grid at different pressure levels. In the table below the results for a selection of countries are presented.

The main distinction in distribution systems can be made by the classification in medium pressure systems - Type A (supply to the boundary of individual customers at a pressure between 2 to 5 bar) and a low pressure distribution grid - Type B (distribution grids of 100 mbar or lower). Type A (France) as well as Type B (Netherlands and UK) are represented in this study.

Country	D	USA	Japan	Arg	Can.	UK	F	I	NL
response of grid owners in % of national grid length	100%	8% (est.)	67%	36%	31%	95%	100%	35%	29%
Total grid length considered in questionnaire (km)	293,200	70,740	147,170	35,080	26,090	270,000	143,510	43,452	24,238
P< 100 mbar			69%	2%	7%	93%	16%	61%	78%
100mbar<P<2 bar			28%	80%	0%	0	0%	14%	9%
2 bar<P< 5 bar	74% < 4 bar	97 % < 5 bar	0	10%	80%	0	79%	24%	5%
P> 5 bar	26 % > 4 bar	3%	3%	8%	13%	7%	4%	1%	8%
Type	A	A	B	B	A	B	A	B	B

Table 3.7: Classification of pressure regime for various national distribution systems

3.5.2 Leakage

Intermediate and low pressure natural gas grids have many joints. All of these joints are potential leakage points, but the actual extent of this leakage depends very much upon the detail of its engineering. Thus in old steel, ductile systems many of these joints leaked either by passage along the threads (screwed fittings) or through the packing (traditional mechanical joints). GTI, the Gas Technology Institute, formerly IGT in the USA has carried out leakage measurements on gas distribution systems. It was found that the leakage rate by volume for hydrogen was about a factor of three higher than for natural gas. This is in marked contrast to PE systems composed of butt or electrofusion welded joints. These are effectively sealed systems except for the occasional valve stem or end-cap. In neither case is the rate of leakage expected to significantly increase the risk of explosion over natural gas lines. The leakage loss of a grid is estimated to be 0.4 +/ 0.2 % and occurs essentially in the low pressure grid. The use of hydrogen as an energy carrier would avoid the leakage of methane and thus contribute to GHG reduction since methane has a high Global Warming Potential.

3.5.3 Permeation

In contrast to metallic systems it is frequently thought that hydrogen would diffuse unacceptably rapidly through plastic materials such as HDPE (high-density polyethylene), MDPE (medium density poly ethylene), PE100, PEX, PVC (poly-vinyl-chloride) and ductile PVC. Diffusion coefficients were taken from various literature sources and were also determined by means of laboratory measurements [Polman].

The measured permeation coefficients and literature values are listed in Table 3.8. The measured values are generally consistent with literature data. Since the materials used for this experimental research are representative of materials in the Dutch grid, these experimental permeation coefficients were taken as a base for further calculations. The total loss of permeation due to the addition of 17% hydrogen was estimated to be 26 x 10^3 m^3 per year for the Dutch gas distribution grid. This represents is only 0.0005 % of the hydrogen transported and is therefore considered insignificant.

In summary whilst hydrogen will diffuse much faster than methane, the overall level of permeation can still be regarded as negligible. Possibly more importantly the permeation of hydrogen through plastic materials is not considered a significant problem.

Material	Permeation coefficient ($ml.mm/mm^2/day/bar$)	
	Measured	Literature
PE 80 HDPE	17.1 X 10^{-5}	22.7 X 10^{-5}
MDPE	18.5 X 10^{-5}	12.5 – 23.8 X10^{-5}
PE100	16.6 X 10^{-5}	N/A
PEXa	38.3 X 10^{-5}	N/A
PVC	10.3 X 10^{-5}	7.81 X 10^{-5}
Ductile PVC	11.0 X 10^{-5}	N/A

Table 3.8 : Permeation coefficient of hydrogen gas for plastic pipe materials at 20 °C

3.6 Gas metering

Gas meters will record volumetric quantities of either methane or methane/hydrogen mixtures with almost equal accuracy. The influence of hydrogen addition was measured for leather and plastic diaphragm gas meters. Deviations in gas metering were determined at five different flows from 0.013 to 5 m^3/h. The deviation was measured first for natural gas and then for a mixture of natural gas and 17 % hydrogen and then again for natural gas.

For both leather and plastic diaphragm gas meters, the deviations observed were lower than 0.1%. This deviation can be regarded as negligible considering the calibration standards stating a maximum deviation of 4% for recalibration and a repeatability within 0.2%. It is noted that by adding hydrogen to natural gas, the required capacity of the meters will be affected. For mixtures up to 17 %, this effect is limited. In this study, the gas meters are expected to run at part load when all appliances are in operation. There are no data available on the load, but accuracy of the meters is best at part load, considering metering error curves[3]. No costs for meter exchange are expected.

3.6.1 Gas metering and control equipment

The value of the delivered or transported amount of gas is primarily based on the amount of energy it contains. The metering process usually consists of three steps:

- Measuring the amount of transported gas usually by volume
- Correcting the volume measured for temperature and pressure effects, effectively calculating the mass flow
- Calculating the energy flow based on discontinuous sampling of the composition of the gas (a continuous measurement of some physical property is sometimes used as an indication of the composition or calorific value of the gas).

The metering error when no correction is made for the hydrogen content of the gas is given in table 3.9 for various types of idealised meters. Actual errors of specific instruments can be slightly different because of residual effects.

Meter type	Ideal volume meter (bellows, turbine)	Ideal mass flow meter	Ideal orifice meter
H_2-content [vol%]	Relative error on delivered energy		
0	100	100	100
5	96.5	100.9	98.7
10	93.0	101.9	97.4
15	89.5	103.0	96.0
20	86.0	104.3	94.7
25	82.5	105.6	93.4

Table 3.9. The effect of hydrogen addition on the metering error.

Depending on the manufacturers details of the design of the meter the correction for temperature and pressure is usually based on the ideal gas law. Occasionally, depending on the details of the customers' contract, the compressibility factor is also taken into account. Such compressibility factor deviations from the ideal gas are only significant for pressures above 10 bar.

The corrections for temperature and pressure based on the ideal gas law are independent of the composition of the gas and are therefore not influenced by the hydrogen content. The correction for the compressibility depends on pressure and hydrogen content. The relative change in compressibility due to the presence of hydrogen is given in table 3.10. For volume meters corrected according to the ideal gas law this additional correction factor must be fully applied.

For ideal orifice meters the change in density is important too. The volume flow is derived from the dynamic pressure using a calibration factor which assumes a certain density, therefore an unrecognised relative change of +1% in density will create a 0.5 % error in volume measurement.

[3] A rough estimation by Schlumberger accounted for a 70% part load average.

Principle of mass flow metering

The mass flow meter principle is based on determining the force which a fluid exerts on measuring bodies within a semi-circular flow channel. The deflection and the temperature of the bodies (which affects their flexibility) are used to calculate the force and finally the fluid's mass flow [source: Yokogawa].

The mass flow is used directly to bill the customer for the purchased quantity of fuel from a CNG refueling station. The quantity of gas is measured in kg, and the unit price ($/kg) is, among others, dependent on the gas composition.

Materials used in the high pressure parts of the mass flow meter are selected for measuring flows containing hydrogen [Source: Fisher Rosemount]. No extra costs for the metering of hydrogen in CNG refueling stations are expected.

Pressure	50 mbar	5 bar	50 bar
H_2-content [vol%]	Relative change in compressibility factor [%] G20 (G25)		
0	100	100	100 (100)
5	100.0	100.1	103.6
10	100.0	100.3	10.8.1
15	100.1	100.5	113.7
20	100.1	100.7	120.0
25	100.1	100.9	127.0

Table 3.10 The effect of hydrogen addition on the metering error due to compressibility effects.

In the final step the calorific value of the fuel is determined and the presence of hydrogen must of course be taken into account. Standard techniques are available and can be applied without significant cost increase or loss of accuracy.
Not all on line sensors that are used to monitor the gas quality and correct the meter readings would operate correctly in the presence of hydrogen. This would require careful attention.

3.6.2 Gas quality and calorific reconciliation

In the Netherlands, the gas composition is monitored on-line by Gasunie Transport Services, and billed to the customer by consumed energy. [Source: Gasunie Transport Services]. The amount of energy used by large consumers is determined by metering at one hour interval.

Daily average gas composition is used in combination with degree-days to determine the daily energy consumption of clients whose gas consumption is recorded once per year, through return of the gas meter indicator reading by mail. Clients concerned are households and small commercials, which make up more than 95% of all connections. Every year, the annual gas consumption in cubic metres per customer is corrected for the calculated energy consumption and reconciled in the annual gas bill by the local gas supply company.

In Holland such a billing system would be considered adequate for the major changes in gas composition, which will occur when hydrogen is blended in gas flows with seasonal swing [Source: Gasunie Transport Services]. The only necessary technical upgrade is the use of extra gas chromatographs because the present monitoring system cannot detect hydrogen.

A total of 33 gas chromatographs [Source: Gastec] are connected to the Gasunie main transmission network at blending stations and in the regional network, in zero-flow regions around peripheral interconnections. Upgrading costs are estimated to $15,000 - per chromatograph.

This type of system is typical of that in other countries. As the percentage of H_2 increases, the acceptability of the approximations inherent in this system by the weights and measures may become an issue. If this were to occur, technology is available in the UK to continuously monitor the calorific value (CV); this is dependant upon historical correlations between CV and thermal conductivity of the gas. In mass production, it is claimed the equipment is priced suitably for the domestic market.

3.7 End use

3.7.1 Combustion properties

Usually the rating of an appliance is proportional to the Wobbe-index of the gas. This is the case when the delivery pressure is kept constant and gas flow is regulated by a kind of orifice (i.e. injector).

Occasionally other control systems are used; ie modulated appliances where the heat release itself is used as parameter to control the gas flow. Nevertheless, even in that case the available maximum rating is proportional to the Wobbe-index since the maximum flow of fuel is always limited by the resistance of the wide open regulator and gas nozzles of the appliance.

Gas	High calorific gas	Rel. CO_2 emission	Low calorific gas	Rel. CO_2
H_2-content [vol%]	Rel. Wobbe index [%]	[%]	Rel. Wobbe index [%]	[%]
0	100	100	100	100
5	98.7	98.6	99.0	98.3
10	97.4	97.1	98.1	96.5
15	96.0	95.4	97.1	94.5
20	94.7	93.7	96.2	92.5
25	93.4	91.7	95.3	90.2

Table 3.11: The effect of hydrogen addition on the rating of an appliance (Wobbe-index).

It should be noted that the net calorific value (Lower heating value) is used in table 3.11. Modern high efficiency appliances are frequently of a condensing design and therefore the effective rating is more proportional to the gross calorific value (Higher heating value). As the difference between the nett and gross value is particularly large for hydrogen, the addition of hydrogen to the gas will increase the efficiency of the condensing appliances. The effect is maximum (ca. 3% efficiency increase) at 15% H_2-addition. The calculation for the CO_2-emission is based on the assumption of a CO_2-capture of 86.7% (this equates to 0.0282 m^3CO_2/m^3H_2).

Alternatively the Wobbe-index of the gas could be kept constant, by adding propane or butane to the gas/hydrogen-mixture. An advantage of this approach would be that the capacity of the lines (which also depends on the Wobbe index) remains unaffected. The great disadvantage would be that the CO_2-reduction is severely compromised.

3.7.2 Flame speed, Flame stability, Flame detection, Ignition and burner deck temperature

For internal combustion engines, the ignition temperature of the air-fuel mixture is an important parameter determining the quality of operation. The addition of hydrogen lowers the ignition temperature and, up to a certain concentration, generally improves the combustion. This effect is discussed in more detail elsewhere in the report.

Gas	s_ad (n=1)
H_2-content [vol%]	[cm/s]
0	0.39
5	0.42
10	0.46
15	0.50
20	0.54
25	0.59

Table 3.12. The effect of hydrogen addition on the adiabatic flame speed of G20/H2-mixtures under stoichiometric conditions.

The addition of hydrogen also increases the flame speed. The effect is most readily measured in laminar premixed flames. The consequences of increased flame speed are threefold:

1. For radiant burners, the burner surface temperature increases for the same specific rating (rating per unit surface area), which can lower the life time of the burner
2. The critical velocity gradient for light back increases. This is the case for premixed and non-premixed laminar flame burners as well as for radiant burners.
3. The critical velocity gradient for blow off increases. This is the case for premixed and non-premixed laminar flame burners.

Measurements have shown that these effects are negligible up to hydrogen addition of 20 vol%. The effect of change of flame speed in turbulent flames, as occurs in the larger industrial burners, is negligible.

In many appliances a flame detector is present. This device detects the presence of a flame and closes the gas valve when the absence of a flame is noted. Two systems are common:

1. Flame ionisation detection
2. Thermocouple detection

The ionisation current depends very much on the presence of free electrons in the flame. It is known that the combustion of pure hydrogen does not create free electrons in significant amounts. Measurements have shown that the addition of up to 20 vol% hydrogen to natural gas mixtures causes no significant decrease in ionisation current [Srelow]. This type of safety device will perform nominally up to this level.

A thermocouple detector registers the flame temperature. Adding hydrogen tends to increase the flame temperature (for premixed flames also the effect of a change of air-fuel ratio should be taken into account). This effect depends on the construction of the appliance. Generally the air ratio increases. For fully premixed flames this implies a temperature decrease, for partially premixed flames this implies a temperature increase. Despite these changes this type of device will still perform properly.

A final type of safety device, often used in non room-sealed appliances is the critical pilot flame or oxy-pilot. Its operation is based on the principle that as the oxygen content of the ambient air decreases the flame speed of the pilot decreases too and the pilot flame will lift off the tip of a thermocouple. Theoretically the addition of hydrogen could affect the performance of this safety device delaying the point at which it lifts off. No field data are available, but as the effect on flame speed is moderate and comparable to the effects of the normal range of gas quality, experts estimate that the effect is negligible up to a hydrogen content of 20%vol.

3.7.3 Practical experiments: Cooking devices and boilers

In the Netherlands, research was carried out on gas cooking devices and domestic boilers [Polman] up to a hydrogen percentage of 17 %. The devices tested were state of the art devices for the year 1998.
Three modern cooking devices (two modulating devices) and six different boilers (differing burner materials, five modulating) were selected. The appliances were chosen to represent a cross section of the current appliance population in the Netherlands and a variety of burner types and burner principles. The gas composition for the experiments varied from 0 to 17% hydrogen.
Measurements included (results shown in table 3.13) flame stability, burner temperature, CO and NO_x emissions, load power and efficiency, burner pressure, flame detection and condensation.

Phenomenon	Boilers	Cooking device	Remarks
Flame stability	No deviations observed	No deviations observed	---
Burner temperature	At low load an increase of maximum + 38 C	At low load a maximum of + 30 C	--- *
Emissions of CO, NO_x,	Equal or less for CO and NO_x	CO and NO_x emissions are lower	Cancelling out of effects **
Load, power and efficiency	Load and power decrease between 1 and 6 %, efficiency equal	Load and power decrease with 3 %	---
Burner pressure	No changes	---	---
Flame detection	No failure, ionisation current decreases by 1 to 10 %	---	---
Condensation	No influence	---	Cancelling out of effects

Table 3.13: Phenomena observed for modern gas appliances up to 17% hydrogen

* Two effects control the burner temperature. Cooling, due to an increased air factor and cooling at the bottom of the burner. The increased flame velocity leads to a flame burning closer to the burner surface and therefore a higher temperature. For metal plate burners, the second effect dominates due to high thermal conductivity. For ceramic burner stones, the temperature at the bottom of the burner material decreases due to poor heat conduction.

**The CO formation is slightly lower due to the higher concentration of water and therefore the higher concentration of hydroxy radicals.
The reaction:
$OH^{\bullet} + CO \rightarrow CO_2 + H^{\bullet}$
is promoted, leading to lower CO concentrations.
The NO_x formation is influenced in two ways. The increase of the adiabatic flame temperature causes an increase in NO_x formation while the increased air factor leads to a decrease. For the experimental conditions, the latter effect appears to dominate.
The ionisation current is influenced since the amount of carbon decreases. This did not lead to flame detection failures during the experiments.

The main conclusion from the research is that no technical barriers for the use of L-gas (low calorific gas see Appendix B) mixed with 17% hydrogen were observed. The ionisation current is not greatly influenced by the added hydrogen percentage.

When the percentage is further increased to 25%, calculations show that the occurrence of flame light back due to increased burner temperature is a main concern, although in laboratory experiments no light back was seen and most burners showed no increased burner temperatures up to a percentage of 17%. A proper choice of materials seems therefore sufficient to avoid flame light back. This is not surprising as the limit gas used for light back tests across most of Europe (G222), contains 23% hydrogen.

When the hydrogen percentage is further increased to percentages higher than 25%, special burner concepts will be needed. One ceramic foam burner manufacturer already claims the safe use of mixtures up to 75% hydrogen [Ecoceramics].

Some aspects of adding hydrogen to natural gas does not apparently influence the performance of an appliance, but may affect its safety. For example, the temperature of the flue gases will change. A combustion products discharge safety device in the draught diverter detects the temperature of the flue gas in case of blockage or reduce capacity of the flue system. The change in volume and temperature of the flue gas remain small and can be safely neglected in comparison to the ambient (temperature and wind) effect for hydrogen additions up to 25 vol% in the fuel.

3.7.4 Adjusting and maintenance by an installer

Manufacturer's instructions are given for an appliance for specified types of gas. The main impact of hydrogen addition (lowering the Wobbe-index) is a proportionally lower energy input to the appliance. Unless the installer knows the CV of the gas on which he is commissioning/servicing the appliance, measuring the energy input (thermal rating) by a gas meter may give a wrong indication and can thus lead to a wrong adjustment of the rating of the appliance. Adjusting the air ratio of the appliance on basis of the CO_2 content in the flue gas can also lead to a wrong setting because the CO_2 content of the flue gas will be lower than expected. Analysers used by installers often depend on measuring O_2 and a calculation of the CO_2 content on the basis of a known gas. This method will also be affected by introduction of hydrogen into natural gas.

Questions that will need to be answered include:

- How does the installer or inspector know what kind of gas is being distributed to the appliance at the moment?
- How accurate are the measurements for adjusting the load and air ratio of the appliance in the presence of an uncertain or unknown amount of hydrogen in the fuel?

3.7.5 Variability in hydrogen content

In case the hydrogen content in the gas is not steady but fluctuates, the above mentioned effects will be even worse. If the gas supply has a low Wobbe index and the installer performs the adjustments accordingly, it is possible that when a higher Wobbe index is supplied the appliance will be overloaded or maladjusted with the consequent associated risks.

3.8 Natural gas vehicles

A detailed analysis of the effect of hydrogen addition on the storage ability of cylinders for compressed natural gas for vehicle use is presented in Appendix F. In summary, addition of hydrogen to natural gas will lead to a substantial reduction of the range. This reduction will be 10% for 3% vol addition, 30% for 10% vol addition and 50% for 25% vol addition mainly because of compressibility effects at high pressure. The small range is one of the main drawbacks of NGVs, so this effect is significant. A further decrease of the range seems therefore unacceptable. In order to compensate for the decreased range, the design standards for HCNG (DOE's designation of H2/natural gas vehicle fuel blends) storage tanks could be upgraded to those for hydrogen storage (300 bar) This would lead to decrease in range for 25 % hydrogen of only 25 %. The engine will have the same problems as those described for gas engines (paragraph 3.9).

3.9 Gas engines

Even today knocking problems occur with gas engines. Vehicle engines do not suffer same knock problems since they are not tuned to optimum efficiency.

For stationary gas engines this is often a combination of poor adjustment of the λ (air factor), in combination with a high intercooler temperature. Decreasing the Methane Number (MN) of the gas by adding hydrogen would lead to more failures of gas engines, especially for gas engines with lambda control systems and stoichiometric running engines.

These problems can be overcome but at significant costs. For example in Denmark, 450 gas engines have been modified at a total costs of $ 3.100.000,- (1999 price see 5.2). equivalent to $ 6.900,- per engine.

Gastec asked Jenbacher, a major European gas engine manufacturer, to comment on problems that could arise in the operation of Jenbacher gas engines on transition from natural gas to a mixture of natural gas with hydrogen. Assuming that the H_2 gas is reasonably pure and the mixture ratio is stable, the engine output depends just on the methane number (MN).

The following scenarios were outlined by Jenbacher:

- A gas mixture of 97% natural gas and 3 % hydrogen; this gas has usually no negative influence on the engine (output & efficiency), as long as MN of the mixture is above 70.
- A gas mixture of 88% natural gas and 12 % hydrogen; this gas will probably decrease the MN significantly and has an influence on the knocking margin.
- Gas mixtures, fluctuating within the range of 5% and 25% hydrogen. The composition may fluctuate within half an hour. A fluctuating mixture of up to 25% H_2 has to be checked in detail. The detonation detection system can be used as a hydrogen sensor. The main drawback is that it would become more difficult to optimize the efficiency since optimal performance is close to the knocking boundary.

3.10 Gas turbines

Gas turbines are currently the most important prime movers for power production and large scale gas transport. Gas turbines are available for all commercial fuel gases, including natural gas, syngas, and any blends of these fuels. Gas turbines are designed to agreed specifications between manufacturer and user. The turbine guaranteed performance is conditional to gas quality specifications.

Technology

All gas turbines have three components: the air compressor, the burner and the turbine. The air compressor and the turbine are mounted on a single shaft. In the design all components are tuned to the power output and the fuel to be used. The fuel is characterised by its combustion properties: stoichiometric air requirement, calorific value, combustion velocity, combustion limits, ignition temperature and energy. Usually the contractual operating limits are very tight, especially for large electric power generating machines.

All natural gases have, apart from their calorific value, rather similar combustion properties. Adding hydrogen, even low percentages, will however change the combustion properties significantly, thereby moving the fuel quality outside the agreed design limits.

Four modes of hydrogen addition to natural gas are to be distinguished for this study: Mixing in low amounts of hydrogen (e.g. up to 3 %), mixing in hydrogen in a fixed ratio (e.g. somewhere in the range between 3 and 25 %), mixing in hydrogen in a flexible ratio moving between 5 and 25 % and a dual fuel operational mode (one fuel natural gas, the other fuel a fixed ratio natural gas /hydrogen mixture. The following annotations reflect discussions with experts and manufacturers:

Mixing in low but variable amount of hydrogen (<3%vol)

Some experts expect serious combustion problems in natural gas fuelled gas turbines even at a few percents of hydrogen. Upon introducing even low amounts of hydrogen in natural gas dangerous combustion instabilities may occur. One expert at a leading knowledge centre observed these problems in a test rig.

Mixing in to a fixed hydrogen to methane ratio (3- 25 %vol)

There is no problem in adapting a specific gas turbine to any fixed ratio mixture of hydrogen and natural gas. Several large scale projects successfully use hydrogen rich fuel gas, even in modified existing machines.

Experience shows that there is a considerable tolerance (in the order of some percents) in the mixing ratio. Exact values for these tolerances are not available.

Dual fuel operation

There is a good experience in the use of dual fuel gas turbines. Mostly the turbine operates on a fixed quality of hydrogen rich gas (e.g. syngas or blast furnace gas, often available as an off gas or fuel gas in large plants) and natural gas. Occasionally, the turbine is switched to natural gas when the hydrogen rich gas becomes unavailable.

Mixing in to a flexible hydrogen to methane ratio

The use of natural gases with a high and flexible ratio of hydrogen in gas turbines (e.g. hydrogen concentrations fluctuating between 5 and 25 %) is currently impossible.

Summarising “gas turbines”
Natural gas driven gas turbines are used for:

- Compressing natural gas in the production and transport of natural gas.
- Power production.

Gas turbines can be designed for any fixed natural gas – hydrogen mixture. There is a long lasting, wide spread, experience of use of gas turbines for power production from, coal or biomass derived, syngasses and blast furnace gasses. Adaptation of a gas turbine to the use of a fixed ratio natural gas – hydrogen mixture requires the assistance of the manufacturer and may be performed at low cost.
Dual fuel gas turbines are commercially available. These may be suited to use natural gas as the one fuel, and a fixed ratio natural gas – hydrogen mixture as the other fuel.

Adaptation of a gas turbine to use natural gas with fluctuating hydrogen concentrations is more difficult. It will require significant modifications, particularly if the turbines are to meet the very tight contractual specifications of the power industry, rather than the simple operational specifications of other users. The technology for this redesign has still to be developed. A solution may be adjustment of the pressure dependent on the hydrogen content of the inlet gas. The development is estimated to be feasible so that natural replacement of existing gas turbines should be possible within a reasonable time scale.

3.11 Natural gas as a chemical feedstock

Syngas is the building block of chemicals made from natural gas. Supply of extra hydrogen in natural gas is therefore beneficial for the production of those chemicals such as ammonia derived from high hydrogen content syngas.

In contrast, the production of chemicals derived from lower H_2 content syngas (methanol, oxochemicals) or directly from methane such as HCN (Andrussov process) will not benefit, at best, from the presence of hydrogen in natural gas. However, the chemical industry should be able to cope with the hydrogen enriched natural gas as long as the hydrogen content does not fluctuate beyond certain specifications without their knowledge so that they have sufficient time to adjust their process parameters.

4. STANDARDIZATION ISSUES

4.1 Appliance standards

In the European Community and in some other countries the gas appliances in use [other than in industrial circumstances] are covered by the Gas Appliance Directive; some heating appliances must also meet the requirements of the Boiler Efficiency Directive. The precise nature of the fuel gas is not defined in those Directives but in the mandated European Standards (EN) to those Directives, different kinds of gases are defined and divided into three so-called “families”.

These families are based upon the Wobbe index and the composition of the gases. For the natural gases (gas of the second family), hydrogen blended gas is only in use as a light-back limit gas (a test gas for testing the light back effect i.e. the flame is going through or around the burner surface to the nozzle) for the group H and group E within a given family. The composition of that type G222 gas is 77% volume CH_4 and 23% volume H_2. The reference gas in those groups is G20, pure methane. There is no hydrogen blended limit gas for the L group in which G25 is the reference gas with a composition of 86% volume CH_4 and 14% volume N_2.

It might therefore appear that the group H and E type appliances are more suitable for burning hydrogen blended gas than the group L appliances. In reality this may not be the case. So, before hydrogen blended gas is officially introduced, the standards will have to be modified and probably all the existing appliances will need to be re-tested by type in the laboratory of the manufacturer or Notified Body. The new appliances will have to satisfy the new standards in all aspects, the most important of which will relate to product safety.

New limit gases, with perhaps to 30 or even 35 % hydrogen will be necessary if commercial supplies were to be blended with up to 25% hydrogen. Agreement would have to be reached between all participants about the new requirements and specifications of appliances, devices and gas pipe systems. It is, therefore, of primary importance to develop amendments to all existing Standards which encompass natural gas to cover hydrogen blended gas.

4.1.1 The choice of 25% v/v hydrogen

It must be said that there is no obvious reason to choose 25% addition as the base line figure for hydrogen addition; whilst a convenient reference point for this IEA Greenhouse Gas study it is important to appreciate this is NOT an optimised value. There could be very valid technical reasons for making this value higher; a full cost benefit analysis should be carried out.

4.2 Introduction of hydrogen; conversion of appliances

As discussed above, appliance modification is likely to be the largest cost in any hydrogen addition program. This is very significant in the UK where there are a substantial number of appliances per household. If adding hydrogen blended gas is phased over many years, it is possible to schedule increases in hydrogen beyond critical amounts until most appliances are new and thus prepared for the wide variations in Wobbe index and the higher burning speed of the supplied gas. Substantial change through natural replacement will take at least 15 to 20 years.

Other standards, like installation standards, and equipment standards will also require partial rewriting for hydrogen blended gas. The estimated costs of the conversions depend in fact on the impact of hydrogen blended gas on the appliances and other devices and the new requirements. Presuming that most gas appliances will need to be converted in a major programme, the average time spent for conversion of one appliance is estimated to be half an hour.

4.3 Some specific measures

Specific measures to be taken for the introduction of up to say 10 to 15 volume % hydrogen use are:

- The use of modern boiler types (state of the art 1998 or newer)
- Control and adjustment of the flame supervision device, like ionisation pen, and settings
- Adjustment of the certification standards

Beyond 15 % hydrogen addition, special attention to the burner types has to be made. Probably a new generation of devices will have to be developed.

5. OVERVIEW OF TRIALS AND STUDIES ON HYDROGEN ADDITION

In order to learn from previous experiences, a literature study was performed on expertise on hydrogen and hydrogen-natural gas mixtures. This is used to assess the credibility (or otherwise) of the various problems thought to be associated with the addition of hydrogen to natural gas.

5.1 Germany

In 1994 Ludwig-Bőlkow-Systemtechnik and the municipality of Munich (Germany) performed a study on the interest and feasibility of the distribution of hydrogen in the Munich gas grid [Bolkow]. The area selected contained 24 terraced houses, 350 apartments, shops and a swimming pool.

The study involved 3 stages:

- Up to 5 % addition with limited effort
- Up to 60 % within the conventional techniques
- Up to 100 % with new technologies

It was anticipated many of the new appliances were to lead to higher energy efficiencies and it was this efficiency that would offer a major proportion of the payback. The study never led to implementation. The main reason was that the city of Munich expected much more from the development of fuel cells with their implementation in the short term; this did not materialise. Investments in hydrogen/natural gas mixtures were therefore considered as not useful. This emphasis upon improved thermal efficiency of new equipment is considered important.

5.1.1 The Netherlands

The influence of hydrogen addition up to 17% to natural gas (L-quality) was investigated by Gastec by means of case studies and laboratory experiments [Polman].

Highlights of this study were:

- Potential risks were identified for cooking devices and gas boilers when operating these appliances on mixtures of natural gas and hydrogen. These potential risks include an increased propensity for light back, a possible reduction in lifetime of premix burners at low loads and failures caused by the flame ionisation detection systems.
- Three modern cooking devices (two modulating devices) and six different boilers (differing burner materials, five modulating) were selected. The appliances were chosen to represent a cross section of the current appliance population in the Netherlands and a variety in burner types and burner principles. The gas composition for the experiments varied from 0 to 17% hydrogen.
- No technical barriers were observed for the use of 17% hydrogen added to natural gas. It must be emphasised however that the views of manufacturers were not sought.

5.2 Denmark

Around 1999 a Danish consortium of DGC, DONG and HNG performed experiments on the addition of hydrogen to natural gas for gas engines [DGC]. The aim of this investigation was to outline the possibilities and restrictions for adding hydrogen to the existing distribution and transmission grid. The report outlines areas where it is necessary to be careful when adding hydrogen to natural gas.

The report explored international experiences and describes the consequences for gas quality, and the transmission and distribution grid when adding hydrogen to natural gas. With its basis in Danish natural gas (mean values for 1998) and the Danish Gas Regulation it was found that the upper limit for hydrogen addition is 17% based on the requirements for the relative density and 25% based on the requirements for the Wobbe index.

The investigation showed that hydrogen addition to the Danish natural gas grid above 1-2% can cause operational problems or losses in output for the many gas engine based combined heat and power stations.

The study also showed that admixture of 10% hydrogen will not give material problems or significant operational limitations using the existing practice for transporting natural gas in Denmark. If the admixture is larger, the report pointed out several areas that needed to be looked into, such as lubricants, meters, regulators, odorisation and mechanical strength of piping and welds.

Another Danish consortium studied different total energy scenarios for introducing hydrogen as an energy carrier, as an energy storage medium and as a fuel in the future Danish energy system and completed this study in 2002 [RISO]. System-wide aspects of the choice of hydrogen production technologies, distribution methods, infrastructure requirements and conversion technologies were studied, in particularly, the possibility of using in the future the existing Danish natural gas distribution grid for carrying hydrogen. The outcome of the analysis will be used to identify the components in an implementation strategy, for the most interesting scenarios, including a time sequence of necessary decisions and technology readiness.

5.3 Norway

In the year 2000 a Norwegian consortium started a study sponsored by the Norwegian Government. Project Description: A national feasibility study with the aim of making an elucidation of possibilities and challenges within the area of "hydrogen as an energy carrier". Some recommendations have been given with respect to research on three main issues:

- How can society be prepared for the change of an energy system based on hydrogen from fossil fuels to a system based on renewable energy sources together with hydrogen?
- In which areas should the research effort be strengthened in order to develop new technology for hydrogen for the Norwegian industry (from technology push to market pull)?
- How do we meet the different demands within education, research and development, when the different markets start requiring special knowledge within the area of hydrogen?

Required material for the study will be collected from national and international contacts and network and also by arranging two workshops. The project will be completed in the year 2003.

5.4 Others

In the years 2003 & 2004, DGC will perform experiments on components of the existing gas grid at laboratory conditions using pure hydrogen. Components: gas pipes, steel pipes, welds and gas meters.

In the year 2002 a large European consortium called “NATURALHY” has been formed under supervision of Gasunie and GERG in order to investigate all transmission, distribution and user aspects of the introduction of hydrogen into the existing natural gas grid as a mean to introduce smoothly the idea of hydrogen as an energy carrier. The consortium has applied for a substantial grant for this research programme including demonstrations in the Framework Programme 6 of the European Commission.

It is interesting to note that all of these projects see the addition of hydrogen to natural gas as a stepping stone to the hydrogen economy NOT as an end in itself. This is considered an extremely important point. Most gas transportation companies have business plans with 10, 20 & 30 year horizons. If hydrogen is going to play an important role by 2030, it is vital that the implications of this (at least at the largest scale) are included into these business plans as soon as possible.

On the URL: http://www.hydrogen.org/pro/index.html, [hydrogen] to date, 491 hydrogen projects, mainly fuel cells projects, are listed.

6. DESCRIPTION OF BASE CASES AND CONSIDERATIONS

In this chapter the gas infrastructure is reviewed for three countries: France, the UK and the Netherlands. More details for each country are given in Appendix D.

The Netherlands has an extensive HP network with 700 off-takes to relatively small IP and LP systems (up to 75mbars to the property). The ownership of the HP network is separate to that of the LP networks.

The UK has a less extensive HP network, but a much larger IP and LP network. There are only about 100 off-takes across the whole country. The country is divided into geographical areas (historically known as Local Distribution Zones); a typical rural zone might have ~I million connections, and be fed by only a handful of HP supplies. Pressure to the property is up to 75mbars. Most of the UK's distribution system is owned by one company. This does not trade in gas but only provides a transportation service to gas companies (who buy gas in the North Sea, Russia or elsewhere, and sell it to UK households and industry) for a government-controlled fee.

France has an extensive HP network. Pressure to the property is 4 bars.

The three infrastructures described are representative for gas distribution systems on a global scale, see paragraph 3.6.

Considerations relating to the size of the hydrogen production units and consequently the scale for introduction of hydrogen and the variation in hydrogen content are outlined in this chapter.

6.1 Technical considerations

When hydrogen is added to natural gas, the Wobbe-number decreases – up to 85 % vol hydrogen (see Fig A2). The Wobbe-number could be kept constant by significant amounts of gaseous alkanes with a higher calorific value, such as propane. This will lead to logistic problems because of the large amounts of propane needed and a disturbance of the market for propane. More importantly, the addition of the necessary alkanes almost completely negates the CO_2 emissions savings since they have higher CO_2 emissions per unit energy than methane (CH_4). This is not considered a viable option (see paragraph 3.11).

There is the possibility of mixing L-gas of constant Wobbe (by blending H-gas, hydrogen and L-gas), but this would achieve little on a global scale, since L-gas is distributed only in a few countries.

This study will thus concentrate upon the addition of up to 25% hydrogen to natural gas, leading to a decrease in Wobbe-number. The loss in capacity for the gas should be compensated by increase of the grid capacity, by adjustments to the pressure or increasing the line diameter. This will result in additional costs.

6.2 The hydrogen production unit

There are various hydrogen sources available or emerging. Carbon neutral production technologies include the production of hydrogen from biomass by gasification, biological hydrogen production or electrolysis by means of “green” electricity such as wind power or photo-voltaics. For biomass gasification a price of 10 to 15 \$/GJ seems possible. However, the local availability and transport of biomass to central plants seems a limiting factor.

Hydrogen production by wind power will cost between 10 and 20 \$/GJ.

These production methods are capital intensive hence the very high price for hydrogen.

The production of hydrogen from fossil fuels is possible (although currently unproven) by means of the CBH (Carbon Black and Hydrogen) process. In this process hydrogen and carbon black are produced by means of high temperature plasma pyrolysis of the methane. The carbon is captured in the form of carbon black and can be used as a feedstock. Since the market price of carbon black is of major influence on the economic viability, this process can only be economic when applied on a limited scale. For local initiatives this process may be worth considering.

For a large scale introduction of hydrogen, the steam methane reforming (SMR) of natural gas, together with CO_2 storage seems most appropriate. Foster Wheeler performed a study on this, jointly funded by the IEA Greenhouse Gas R&D Programme and Statoil [Foster Wheeler, ref Report PH2/2 May 1996].

The study showed hydrogen prices of \$6.08/GJ (5% discount rate) \$6.97/GJ (10% discount rate) with a centre price for natural gas of \$3/GJ. The equivalent CO_2 capture and disposal costs were \$15.13/ton 5% discount rate) and \$20.73/ton (10% discount rate).

Key parameters from this study are:-

- The capacity of a single train is about 280MW of thermal equivalent (LHV
- basis). For larger capacities multiple trains are assumed.
- Capture percentage is 86.7%.
- The level of hydrogen production will be 278,000 Nm^3/h. The plant will be divided into three equal streams of 94.000 Nm^3/h.
- The investments for the SMR unit are 262 Million US\$.
- The investments for the SMR plus CO_2 capture are 453 Million US\$.
- Centre price for gas \$3/GJ
- Discount rate 10 %

Since the capital costs are a substantial component of the hydrogen price, it is assumed that the SMR unit is operating on full load all over the year, except for a maintenance period of two weeks and shut off for cold days. Partial load behaviour will lead to much higher (and probably unacceptable) costs of the hydrogen.

Downscaling of the hydrogen production unit is thus possible to a minimum size of 90 MW (94,000 Nm^3/h).

Whilst trying to stimulate the demand for hydrogen to kick-start the “Hydrogen Economy”, the possibility of hydrogen supplies from non-standard sources should not be overlooked; these include “surplus” hydrogen from:

- ammonium nitrate fertiliser plants,
- from refineries that have seen a down-turn in throughput, or
- from a coal gasification plant subsidised under a “clean coal” technology program.

If the plant already exists, some of these options could deliver demonstration scale quantities of hydrogen (<~2tonnes/hr) at very competitive prices.

6.3 Seasonal variations of the hydrogen supply

The Dutch distribution grid is taken as an example in order to consider the effects of hydrogen addition on a large scale. The presence of a continuously operating hydrogen production unit in a gas grid with variable off take results in changing levels of hydrogen in the blend. Since space heating is the main purpose of natural gas, a high level of hydrogen can be expected in summer, conversely a low hydrogen level would be expected during days with extremely low ambient temperature.

The individual gas line capacity is sized for the maximum off take expected. When consumers with a temperature-related offtake pattern are connected to a line, the line capacity will be only slightly affected by adding hydrogen, because peak gas demands coincide with low hydrogen content.

When consumers with an offtake pattern from an industrial process (ie continuous) are connected, the relation with ambient temperature may be less present or hardly present at all. In the extreme case of a flat-rate offtake, the maximum (summer) hydrogen content will be present at the time the design line capacity is needed.

With the seasonal swing defined as:

<u>Swing = Maximum winter off take/ minimum summer off take</u>

a flat-rate off take will have a swing of 1. All ambient temperature related heating systems will have a swing larger than 1.

In the Netherlands about 45 x 10^9 Nm^3 of natural gas are distributed every year. The average gas offtake is 1.3 x 10^6 Nm^3/h. For peak days this offtake is 2.9 x 10^6 Nm^3/h and for low offtake during summer this number is 7.3 x 10^5 Nm^3/h. So the variation between low and high offtake, at national scale, is a factor of 4 for the transmission grid. The ratio of seasonal values in the UK is similar.

For the low pressure distribution grid, the seasonal swing can be more than 10. Because of the large scale of hydrogen plants, there are attractions to injecting the gas into the transmission grid. Mixing of hydrogen in the distribution grid would require substantial investments of a parallel grid of high pressure hydrogen lines. The seasonal variation will be around 4.

There are two approaches to overcome this problem neither of which seem attractive:

- The storage of large volumes of hydrogen or natural gas/hydrogen mixture. This is not considered viable.
- The construction of a sufficiently large and flexible hydrogen plant to follow demand. This is unattractive on grounds of capital cost (ie it would operate for most the year at substantially reduced output), and thermal efficiency would certainly suffer during transient changes of capacity.

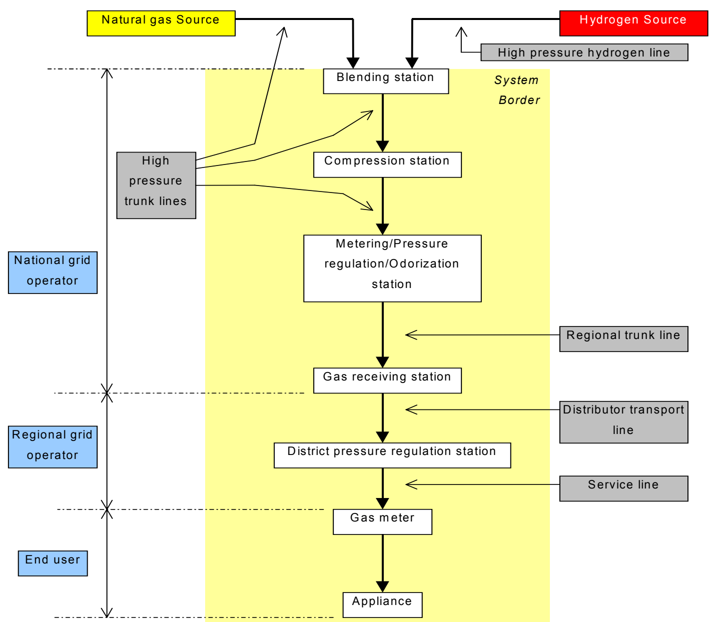
The construction of one or more large plants which continuously feed hydrogen into the gas grid and acceptance of major compositions swings is thus taken as the only viable option. This has advantages at the production scale, but will produce significant variations in the hydrogen content of the gas being provided to customers. For example the scenario

for conversion in France shows peak levels of 23.6 % in summer dropping to only 4.2% in winter and attaining an average of only 13.1% hydrogen over a full year.
For further details on the hydrogen levels see Appendix C.

6.4 General outline of the transmission and distribution system

In figure 6.1 a general description of the gas supply chain is given. The hydrogen production unit and the CO_2 capture are not objects of this study. The gas grid consists of a national grid, a regional grid and the end user. All components outlined in figure 6.1 will be evaluated.

Figure 6.1 Outline of the gas chain



7. RESISTANCE TO CHANGE

This chapter mainly deals with the non-technical barriers, such as economical and psychological/emotional barriers, hindering the introduction of hydrogen as a substantial energy carrier. The information in this chapter has been obtained in the main, from interviews with specialists in their field.

7.1 Social resistances

The psychologist Jan Gutteling from the Twente University in the Netherlands is an expert in the field of social processes concerning the introduction of new technologies.

According to Gutteling the Dutch government is very cautious with regard to the introduction of hydrogen as an energy carrier. The reasons for this are the lessons learnt from previous large infrastructural projects such as the extension of Schiphol Airport and a new rail connection for cargo transport that both have lead to large opposition in society. The bad reputation of hydrogen, which originates from a single incident, the Hindenburg accident in 1937, makes the government even more reluctant.

Gutteling stresses that often mistakes are made at the very start of the process. All stakeholders should be approached in very open minded way at the start in order to determine their attitude towards change.
An insight into the opinions of all the various stakeholders is very important. One group embraces a change while the other will reject it. An example is the acceptance of mobile phones by young people and employed people since they appreciate their usefulness. Elderly people on the other hand are relatively unfamiliar with new technologies and tend to stress the potential dangers such as radiation.
Lessons learnt from large infrastructural projects show that adherents emphasize the economic benefits while opponents stress the environmental effects.
Fake-participation is very detrimental for the decision making process. Gutteling mentions the "decide, announce, defend" model. In this model governmental bodies make a decision with only a few stakeholders. The announcement of this decision leads to large opposition and the government is forced to adopt a very defensive role. Other stakeholders may give their opinion but are not capable of changing policy. This leads to a cynical attitude and needless resistance.
Environmental bodies are very important stakeholders. They should be approached actively and convinced of the benefits of addition of hydrogen to natural gas.
Environmental bodies oppose the storage of CO_2, associated with the concept of hydrogen production by large scale steam reforming. According to Gutteling, for this reason, Greenpeace is not participating anymore in GHG reduction initiatives, involving the storage of CO_2.

7.2 Manufacturers

A potential manufacturer and supplier of hydrogen said that the only real boundary condition for starting up the production of hydrogen is that this should be economically profitable. As soon as a market develops, they will participate. At this moment the company is monitoring developments. The business case is weak. The extra costs for a hydrogen/natural gas mixture will be at least 10 % and the CO_2 savings are relatively small. The party that benefits most is

the government. They should invest in order to make the business profitable, according to this manufacturer.
Other manufacturers see a hindrance in the current absence of a long term commitment to changes towards a hydrogen economy. Investments should be done according to a long term programme, initiated by governmental bodies. They want a guaranteed long term programme before they will invest.

7.3 Energy utilities

Energy utilities have a need for new products that appeal strongly to the customer desires and that give a differentiation from their competitors. The utilities are not convinced that the addition of hydrogen is of common interest.
The network divisions of energy companies are faced with the need to make large cost reductions and restrictions by the regulator. The network companies are certainly not interested in developments with high risks and which increase costs.
At this moment there is no strong support from the utilities for a top-down approach with central hydrogen injection. There is a need for concepts where the benefits for individual clients are clear.

7.4 Governmental bodies

The Dutch Ministry of Environment and Country Planning (VROM) is interested in environmental effects. The Ministry of Economic Affairs is involved with the new Gas Law and is therefore involved in all other aspects related to gas infrastructure.

VROM considers the addition of hydrogen attractive because of the CO_2 reduction, but the main priority is given to the reduction of methane emission. Methane has a high GWP (Global Warming Potential) factor and the reduction of methane emission by means of flaring and other options are considered to be very important.

The government will give subsidies for investments related to the amount of tonnes of CO_2 reduction. For this reason the addition of hydrogen has to be competitive with other CO_2 reduction options and techniques.

The costs for the option of hydrogen addition to natural gas are considered to be high by the Ministry. They currently estimate these costs to be between 100 and 200 \$/ton of CO_2 avoided and these costs are therefore not lower than that of PV or wind power.

For the installations or replacement of pipelines, VROM stimulates installation of pipelines that are capable of carrying fuels of varying quality. In this respect VROM tries to take into account the transport and distribution of future energy carriers.

7.5 Conclusions

The introduction of hydrogen added to natural gas needs very careful and open communications and decision making plan which includes all stakeholders.
The economic benefits and the business case for hydrogen addition have to be clear before industrial partners will participate, at present they are not.
Although the potential for CO_2 reduction is very large, investments subsidies will only be supplied when the specific costs are competitive with other options.

8. SCENARIOS FOR THE INTRODUCTION OF HYDROGEN

In line with the objective of this study - find out the technical and economic consequences of the introduction of hydrogen up to a percentage of 25 % - and considering the scale of the hydrogen production unit, the following H_2 addition scenarios are proposed

- **Introduction:** the addition of maximum 3% H_2 during the summer period. This addition is an introduction to hydrogen and will hardly influence the capacity of the gas grid and the performance of the appliances. Furthermore, this amount of H_2 can be added to L-gas within the existing narrow Wobbe-band in the Netherlands[4].
- **Intermediate:** 12 % hydrogen addition is the maximum allowable addition to H-gas within the DVGW 260 standard and can be seen as an intermediate level (see Appendix 10.3).
- **Target level:** The long term scenario is the addition of maximum 25% hydrogen.

In appendix C, the main attributes of these scenarios have been calculated for The Netherlands, The United Kingdom and France. Starting points and assumptions for the calculations are:

- Appliance distribution in the grid is evenly across the country. The energy consumption is distributed evenly as well.

- Hydrogen units with a capacity of 92,000 m^3/h per train (ref Report PH2/2) are used for hydrogen production. The area supplied by the units is kept as small as possible. The area size depends on the maximum allowed hydrogen percentage in summer in the introduction phase, the gas swing and the gas offtake in the network. One train is used in the introduction.

This leads to a scale factor that indicates 1/(part of a country covered). Scale factors are given in table 8.1

Country	NL	UK	FR
Scale factor	1.1	2.1	1

Table 8.1 Scale factors for three countries considered

In the Netherlands almost the whole country will be covered in the introduction, about half of the United Kingdom and the whole of France.

8.1 Technical measures

The technical consequences for hydrogen addition, described in chapter 3, form the basis for the technical measures described below.

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[4] Gasunie Transport Services stated that hydrogen blending has been investigated, but only up to a percentage that will keep the gas quality within the specified Wobbe bandwith.

8.1.1 Distribution and transmission aspects

The loss of line capacity as indicated in 3.4.2, can be compensated for by adjusting the inlet pressure in low pressure grids and by allowing more pressure drop in intermediate pressure grids. The potential of both measures is given in table 8.2.

hydrogen content (G25)	10%	25%
intermediate pressure		
standard pressure drop=100%		
allowed pressure drop	110%	110%
line capacity at allowed pressure drop	107%	103%
necessary pressure drop	102%	107%
low pressure (up to 150 mbar)		
standard inlet pressure (gauge)	100%	100%
allowed inlet pressure (gauge)	140%	140%
line capacity at allowed inlet pressure	135%	130%
necessary inlet pressure (gauge)	103%	108%

Table 8.2 the potential of variations in pressure for low and intermediate pressure grids, for two hydrogen percentages in low-calorific gas.

Table 8.2 shows that less than 10% extra pressure drop is sufficient to transport the hydrogen through intermediate pressure grids. The low pressure grid has enough flexibility for the inlet pressure to transport a gas with up to 25% hydrogen. Both measures can be implemented by adjusting pressure levels.

For the transmission grid, the capacity problem is serious. The high pressure grid is fully occupied during certain winter periods. The installation of extra grid capacity (additional lines or increase of diameter) will lead to very large investments, a long transition period in order to increase the capacity and probably infrastructural hindrances. The best possibility to overcome the capacity problems is to interrupt the hydrogen production and addition during peak days occurring in wintertime.

The costs due to a decrease of the capacity of the hydrogen plant, by shut down of the plant for some days, are considered smaller than those for the installation of extra transmission grid capacity. An exception is made for the regional transmission lines to industrial clients. These lines are in some cases fully utilised and the offtake patterns are mostly not temperature dependent. Also in summer time, the existing capacity may be fully utilised, and therefore the addition of 25% hydrogen, leading to 30% loss of capacity, can be undesirable in some cases. For this reason the capacity of a part of these lines needs to be increased.

The necessity for replacement of pipe segments due to the potential hazards of cracking, induced by hydrogen embrittlement and tensile stresses is unknown. As indicated above, expert opinion on this topic varies too much to estimate the necessary measurements and the costs involved. As a result costs and measures for pipeline replacement are not considered in this analysis. An additional complexity is that of transit gas. A country such as the UK uses its *national transmission system to transport gas to third party countries such as Eire and Belgium. Clearly the addition of hydrogen would affect this gas quality; this must raise substantial contractual issues.*

8.1.2 Compressors and turbines

Gas turbines can be designed for any natural gas/hydrogen mixture. Some experts expect that up to 3% hydrogen may be used without adaptation of the gas turbine. Experiments in a test rig showed however serious instability problems.

Adaptation of a gas turbine to the use of a specific natural gas/hydrogen mixture requires the assistance of the manufacturer. The costs for these modifications to turbines are in the same order as the costs for a scheduled maintenance.

Adaptation of a gas turbine to use natural gas with fluctuating hydrogen concentrations requires redesign of the gas turbine based on new technology. Hydrogen rich gasses need a higher inlet pressure. An adjustment of the inlet pressure according to the actual hydrogen content may be the key to a solution.

Over the 15 year time period allowed for domestic device change out it is anticipated that much of the stock of gas turbines will become suitable through introduction of a new generation of machines or incorporation of routine upgrades during servicing.

The compression of hydrogen/natural gas mixtures by compressors originally designed for transport of natural gas will result in lower head pressures and lower capacities. Compensation by the installation of extra capacity or additional gas compressing stations may be necessary.

8.1.3 Gas engines

Nowadays knocking problems with stationary gas engines occur. This is often a combination of bad adjustment of the λ (lambda), in combination of a high intercooler temperature. Decreasing the Methane number (MN) of the gas will lead to more failures of gas engines, especially in gas engines with lambda control systems and in stoichiometric running engines. In order to prevent problems, the engine will have to be modified. The price is about $8,400 per engine (price level 2003). In a time period of three years, the required number of gas engines will be converted.

8.1.4 Boilers and cookers

For domestic boilers, the modern gas appliances, installed since 1998, can be utilized when an installer adjusts the boiler settings upon the introduction of hydrogen for the intermediate scenario. This holds for the Netherlands with their small Wobbe number. For other countries, with a broader Wobbe band, the adjustments will be equal or less. For the introduction scenario, no extra costs are involved. For the long term scenario, the boiler has to be designed so that light back is avoided and the boiler is flexible to operate between 0 and 25 vol% of hydrogen. Costs for such features in new devices are low and are expected to be incorporated in the ongoing improvements on these appliances. Costs for conversion or early replacement of existing devices are accounted for.

8.1.5 Metering / Gas quality monitoring

A total of 33 gas chromatographs {Source: Gastec} are connected to the Gasunie main transmission network at blending stations and in the regional network, in zero-flow regions around peripheral interconnections. Upgrading costs are estimated at $15,000 per chromatograph. Data on gas chromatographs were only available for the Netherlands. For other countries, the number of gas chromatographs is factored (based on NL) by the amount annual gas consumption.

8.1.6 Industrial processes

For ammonia production, natural gas is used as a feedstock. For this process the addition of hydrogen is not detrimental.

8.1.7 Natural gas vehicles

The numbers and costs of these appliances are limited in the three countries so that the total costs of the measures have not been calculated. A commercial breakthrough of CNG however, is a possible scenario. Figures for NGVs and CNG vehicle refueling stations are stated in table 8.3. [source: IANGV]. Please note that these figures, gathered at different dates, are subject to rapid change.

country	NL	UK	FR
CNG refueling stations	15	105	18
NGVs	300	4550	835

Table 8.3 Numbers of NGV's and CNG refueling stations

More storage space on board is not likely to be available in most vehicles. The solution for the diminished range of the vehicles can be pursued by applying a higher storage pressure, such as already is done with prototype vehicles running on compressed hydrogen. Pressure is up to 70 Mpa [Source: Daimler-Chrysler]. Commercial prices for these storage systems are not available yet.
CNG refueling stations differ greatly in design (both compressor and storage tanks). Costs for upgrading to hydrogen cannot be given.

8.1.8 Standards and regulations

For L-gas the test gases for certification and testing of appliances have to be changed in order to test for light back even for percentages up to 3%.

For additions up to 12%, the Wobbe range for L-gas has to be extended.

For percentages exceeding 12%, Norms and Standards for H-gas as well as L-gas have to be changed.

8.2 Timing of the hydrogen programme

The following global actions are foreseen in a time perspective. The economic and environmental analysis is based on this timing. It has been chosen to avoid major change out of domestic devices and is based on a realistic allowance of 15 years for ageing devices to be replaced. This is considerably longer than allowed for the Towns gas to Natural gas conversion which was propelled by much larger economic incentives.

MEASURES AND ACTIONS	YEAR
Decision making on initial budgets	2003-2005
Construction of the hydrogen production plant	2005-2008
Adjustment gas chromatographs	2005-2008
Introduction of hydrogen (3% max)	**2008**
Development of broad band"" boiler (25% max)	2008-2012
Sales of "broadband" boiler	2012
Set up of standards and norms	2008-2015
Building of new hydrogen factories	2015-2020
Boiler replacement programme (all boilers sold before 1998)	2018-2020
"Broad band" gas turbine development & sales	2010-2020
Gas engines adaptation	2018-2020
Adaptation of high and medium pressure grid	2010-2020
Check of boilers by installer	2019-2020
Introduction of intermediate level hydrogen (12%max)	**2020**
Low and high pressure control adjustment	2020-2025
Building of new hydrogen factories	2020-2025
Boiler replacement programme (Part of the boilers sold before 2012)	2023-2025
Introduction of target level (25% max)	**2025**

Table 8.4 timeschedule

The investments for each measure are given in table 9.1

For each country, the actions and the investment level will be different because of the local situation. In the France, for example, the number of gas engines is much lower than for the UK and The Netherlands. This leads to much lower additional investments. Regional differences are outlined in Chapter 9.

8.3 Summary of measures per country

The scenarios are all based on starting to make pre-emptive measures in 2005 and on introduction in 2008. Additional replacement costs and stranded investments up to the introduction year 2008 will be calculated as capital costs. Increased O&M costs will also be calculated.

Measures	NL1	NL2	NL3
gas chromatographs	X		
gas engines		X	
low pressure control adjustment			X
medium pressure control adjustment			X
high pressure control adjustment		X	
medium pressure transmission upgrade		X	
domestic appliances: check for light-back		X	
gas turbines		X	X
domestic appliances: conversion			X
H2 train shutoff at cold days		X	X

Table 8.5 Measures in the Netherlands (NL1 means addition up to 3 %, 2 means up to 12 % and 3 up to 25 %)

Measures	UK1	UK2	UK3
gas chromatographs	X		
gas engines		X	
low pressure control adjustment			X
medium pressure control adjustment			X
high pressure control adjustment		X	
medium pressure transmission upgrade		X	
domestic appliances: check for light-back		X	
gas turbines		X	X
domestic appliances: conversion			X
H2 train shutoff at cold days		X	X

Table 8.6 Measures in the UK

measures	FR1	FR2	FR3
gas chromatographs	X		
gas engines			n.a.
low pressure control adjustment			n.a.
medium pressure control adjustment			X
high pressure control adjustment		X	
medium pressure transmission upgrade		X	
domestic appliances: check for light-back		X	
gas turbines		X	X
domestic appliances: conversion			X
H2 train shutoff at cold days		X	X

Table 8.7 Measures in France

9. ENVIRONMENTAL AND FINANCIAL ANALYSIS

9.1 Environmental analysis

The annual CO_2 reduction is dependent on the number of trains that can deliver the hydrogen to the network. The annual CO_2 reduction for each country is shown in figure 9.1.

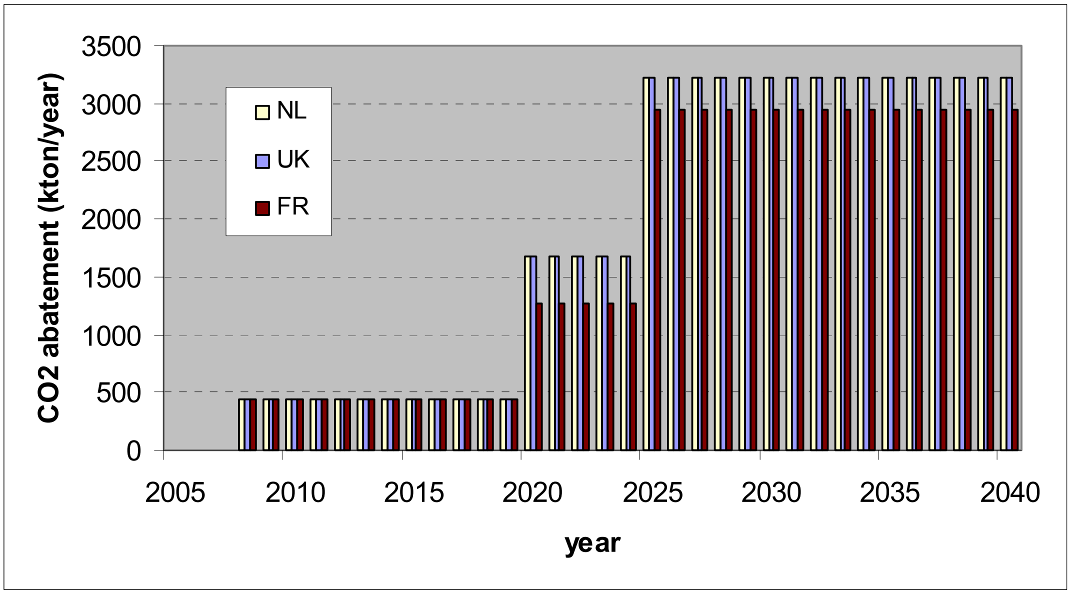


Figure 9.1 The annual CO_2 abatement for three countries, as a function of time, based on 100% plant use (Assumptions see Appendix C)

The amount of reduced CO_2 is limited by the maximum allowed amount of hydrogen in summer.

9.2 Economic analysis

Calculation of the costs are outlined in Appendix H.

measure	unit	NL	UK	FR
gas chromatographs	$	450,000	470,000	430,000
gas engines	$	30,450,000	5,640,000	0
low pressure control adjustment	$	651,074	0	0
medium pressure control adjustment	$	1,286,033	1,418,571	2,457,186
high pressure control adjustment	$	75.099	0	0
medium pressure transmission upgrade*	$/year	19,680,845	32,911,850	28,597,645
domestic appliances: check for light-back	$	174,068,182	461,845,238	295,050,000
natural gas vehicles		Low	Low	Low
natural gas refueling stations		Low	Low	Low
gas turbines	$	**	**	**
domestic appliances: conversion	$	62,664,545	166,264,286	106,218,000
H2 train shutoff on cold days		Dependent on	duration	

*For a period of 30 years these costs will repeat every year !! ** Covered by the development of a broad band turbine

Table 9.1 Measures and costs per country

The enforced shutdown of the hydrogen plant would lead to a higher hydrogen cost of several percent. This effect is not calculated. The costs of the building of the hydrogen plant are not included as such but are as an additional unit cost per ton CO_2 abatement.

A check and replacement program for boilers is assumed to be limited to 5% of the current population of appliances.

Some costs are negligible in relation to the investment costs. These costs are decision making, sales of boilers, and development of standards and norms. They are only mentioned as necessary milestones.

The annual cash flow for upgrading the network and the appliances is shown in figure 9.2

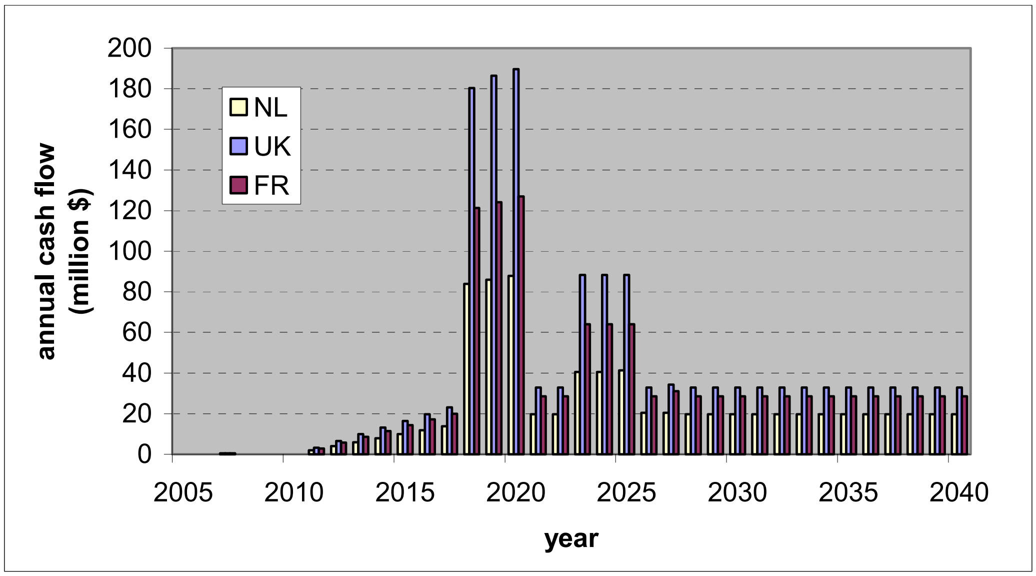


Figure 9.2 The annual cash flow (costs) for upgrading the gas network and the appliances

The initial costs for the 3% hydrogen content introduction are limited to the investments in new gas chromatographs. When the 3 % is introduced, upgrading of infrastructure for industrial consumers is started and completed in ten years.
Three years before the introduction of 12% hydrogen a boiler replacement programme is carried out. A second replacement programme is necessary prior to the introduction of the target hydrogen level of 25%. Both programmes are visible as cost peaks.
The extra medium pressure infrastructure has an expected life of 30 years. Annual costs are therefore calculated for this time period. For long term planning reasons the scope of this upgrade is assumed to be that needed to accommodate the final target of 25% hydrogen.

9.2.1 Cumulative abatement costs

The cumulative abatement costs in year x are equal to the cumulative cash flow up to year x divided by the cumulative CO_2 abatement up to year x. The cumulative abatement costs are depicted in figure 9.3.

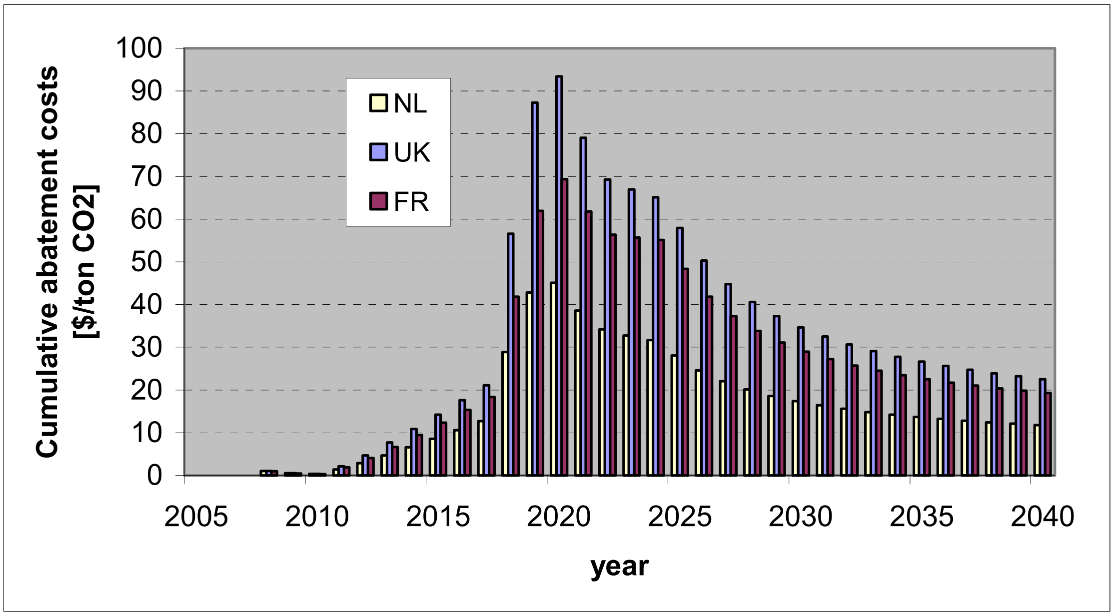


Figure 9.3 The cumulative abatement costs as a function of time

Until the first hydrogen train is operative, the scenarios do not add significant additional costs. When the scenarios are frozen at this stage, the low cost level will remain. The abatement costs are relatively low until the first measures for adding up to 12% hydrogen are initiated in 2011.

Costs rise relatively quickly until 2020 when newly installed hydrogen plants start to operate. The extra costs between 2010 and 2020 are determined mainly by the increase of line capacity. It is assumed, that the extra line capacity installed is based on 25% hydrogen content.

After 2020 the cumulative unit abatement costs drop as cumulative hydrogen production rises. A second drop occurs again in 2025 when all remaining unconverted boilers are replaced and more new plants are started up allowing the full benefits of the investments to accrue..

Abatement costs per blending step

The investment costs per abatement step divided by the annual CO2 abatement for each step result in specific abatement costs per step. Costs are annual costs and abatements are yearly extra abatements relatively to the preceding step. The basic assumptions for the annual cost calculation are 10% interest, a 10 year design life for investments in appliances and 30 years for investments in infrastructure. The specific costs are given in figure 9.4

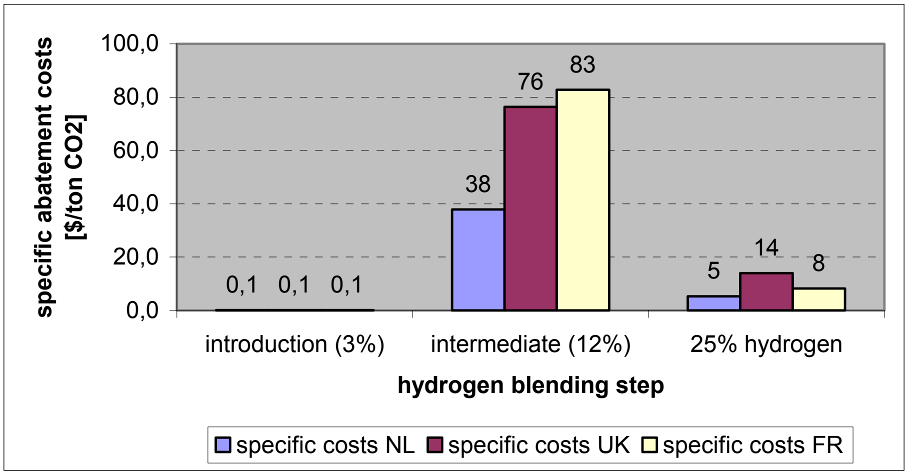


Figure 9.4. Abatement costs per blending step

The abatement costs for the activities per step are shown in figure 9.5.

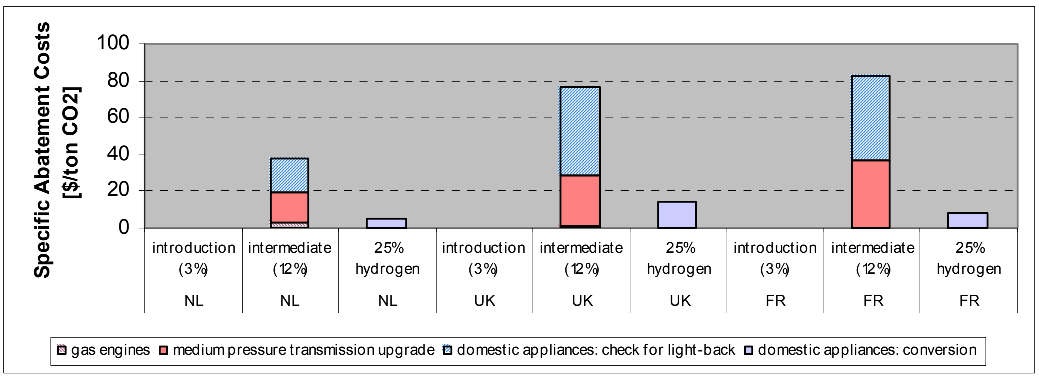


Figure 9.5. Abatement costs, specified per activity

The introduction scenario is relatively cheap. Costs for the intermediate scenario are mainly formed by the inspection at home of all devices installed and the upgrade of the medium pressure transmission system. Costs for the 25 % scenario involve mainly the replacement of boilers by broadband appliances. The remaining value of the old boilers is reimbursed.

9.2.2 Regional differences

The costs for the United Kingdom are relatively high because of the high number of appliances per household. Costs in the Netherlands are low because of the large number of low pressure lines in the grid which will not need upgrading.

9.2.3 Costs for upgrading in relation to the costs of hydrogen production

The total specific abatement costs are the sum of the hydrogen plant costs and the costs for upgrading the network and appliances.
The total specific CO_2 abatement costs are the costs of 1 ton of CO_2 not produced in the combustion process, including the production costs plus the costs for upgrading the network and appliances, taking into account the CO_2 capture percentage of 87%.
In table 9.6, the yearly costs for CO_2 abatement for each phase are indicated.

Country	NL	UK	FR
	\$/ton CO_2	\$/ton CO_2	\$/ton CO_2
Hydrogen plants with CO_2-capture*	20.7	20.7	20.7
Gas chain upgrade to supply 25% H_2	12	19	23
All in cost to supply 25% H_2	**32.7**	**39.7**	**43.7**
Incremental costs gas chain to supply 3 % H_2	*0.1*	*0.1*	*0.1*
Incremental costs gas chain to further increase to 12% H_2	*38*	*76*	*83*
Incremental costs gas chain to further increase to 25% H_2	*5*	*14*	*8*

*Foster Wheeler study for IEA GHG report PH2/2, primary energy price at 3\$/GJ, 10 % discount rate. The costs of hydrogen plants with CO_2 capture comprise the hydrogen production plant, capture and compression and allowance for operation of CO_2 disposal line, well heads and wells.

Table 9.2 Specific abatement costs in \$/tonne CO_2

10. FINAL CONCLUSIONS AND RECOMMENDATIONS

Conclusions

As may be seen the costs of CO_2 reduction by hydrogen addition are quite high, but it must be pointed out that the long term operational costs are much lower. Thus the long term costs for adapting the infrastructure to hydrogen addition to natural gas vary between 12 and 23 $/ton CO_2 (exclusive of H_2 production costs and based on max. 25 % addition). They are marginal costs of making the conversion in a reasonable time scale. The marginal nature of these costs and their time dependency makes them much less transparent than (for example) an exercise to calculate the costs of sequestration. They do not include costs for replacement of appliances to higher specifications. Whilst these specifications will include those necessary to accommodate hydrogen they are usually accompanied by a host of other advantages, especially increased energy efficiency. Unfortunately at this time it is impossible to quantify these, developments in the future (especially fuel cells) would greatly benefit the move to hydrogen.

Allowance is made for the residual value (not the replacement value) of those appliances which have not been changed out after 15 years. Whilst this allowance is small this still represents a significant proportion of the total cost.

A gradual introduction of hydrogen, taking into account the depreciation and technical life time of components, may lead to a 25 % hydrogen addition in the year 2025.

In order to achieve this, in the intermediate time the costs will peak around 2020.

The costs for adaptations and early replacement of components will be carried until the year 2040.

The costs for converting appliances in the field are high and contribute largely to the costs of a hydrogen blending scenario. Nowadays there is only limited experience with large conversion programmes since the switch from town gas to natural gas occurred 40 years ago.

The storage capacity of CNG vehicles (i.e. NGVs) needs to be increased when natural gas/hydrogen is used as a vehicle fuel, otherwise the commercial breakthrough may never take place.

Gas lines that link industrial consumers to the network tend to lack capacity for the transport of gas with high percentages of hydrogen. Costs for upgrading these lines are expected to be high, since existing capacity is assumed to be insufficient.

The liberalisation of the gas markets has invoked benchmarks for grid operators and efficiency cuts imposed by regulators. As a result, the average grid load will rise and space for hydrogen blending will decrease.

The financial aspects of this study are based on the assumption that the high pressure transmission systems are suitable for hydrogen addition. In the Netherlands this may well be a technically and politically feasible option; in the UK with its use of this system to transit gas to storage, Eire and mainland Europe this is not considered a realistic option. Local or regional hydrogen plants producing the gas from a variety of sources are considered more feasible. This would be transported via a new infrastructure of high and medium pressure pipes to new injection/blending stations. The cost of this is beyond the scope of this study, but is unlikely to be so high as to prohibit the concept of hydrogen addition; it tends to be the low pressure distribution pipe work and service connections that dominate the asset value of gas distribution

companies. In the UK the asset value of the high pressure natural gas network is only 15% of the whole.
These new medium pressure hydrogen mains could be the new arteries of a hydrogen economy.

Recommendations

Carry out a widespread review of the optimum “break points” for the introduction of hydrogen into natural gas. This should pay close attention to the 25% value, and a “best guess” of the appliance stock in 20 years. This may be considerably different from that of today.

Perform a detailed review of the real practicalities of central vs. regional/local hydrogen production from a range of sources, involving politically/economically realistic decisions. This should involve:

- some consideration of the geographical realities of sequestration and hydrogen production
- further consideration of the use of HP Transmission systems for transporting hydrogen rich gas.

Consider a range of options involving combined hydrogen production for power generation and for injection into the gas grid.

Against this background, the development of standards for hydrogen presence in natural gas should be initiated before any attempt of large scale introduction of hydrogen in gas networks.

Local circumstances could indicate preferable areas for practice trials on large scale hydrogen addition. These circumstances could be one, or a combination of several of the following:

- a clear view on available extra capacity in the gas network
- a readily available H_2 source (e.g. from an industrial process)
- a single upstream connection to a high pressure gas grid
- a well defined population of appliances connected
- a well defined breakdown of gas lines and grid components in use
- a distribution scale at least the size of a town

When searching for areas for practical trials, efforts to investigate locations which meet with such favourable circumstances should be made.

Carry out further studies to clarify possible problems of hydrogen embrittlement. The susceptibility of commonly used steels in natural gas grids can be quantified by simulations of long-time exposure of these materials to an environment resembling the transmission of hydrogen enriched natural gases. This should however be against the background of the reality of the introduction of hydrogen at this pressure.

Review the reality of whether such hydrogen addition really is a gateway to the hydrogen economy, or a false trail likely to result in mis-allocation of funds. This should (for example) include assessment of the likely effect of fuel cells, which can benefit enormously from pure hydrogen feedstock. Such a study is considered important as (in essence) the current report considers the effect of adding hydrogen to natural gas in “today’s world”. There is real likelihood that in 20 years time both appliances and load patterns may have changed. This more futuristic study should least attempt to estimate these and then view possible routes to the hydrogen or mixed gas economy in this new light.

APPENDIX A: FORMULAS USED

Conversion from volume-fraction to mole-fraction.

$n_i = x_i/V_i \,/\, \Sigma\, x_i/V_i$

n_i mole fraction of component i in mixture
V_i molar volume of component i [m^3/kmol]
x_i volume fraction of component i in mixture

Dynamic viscosity of mixture

$\mu = \Sigma\, n_i\, \mu_i \sqrt{M_i} \,/\, \Sigma\, n_i \sqrt{M_i}$

n_i mole fraction of component i in mixture
μ_i dynamic viscosity of component i [Pa s]
M_i molar mass of component i in mixture

Flammability limits

$UFL = 100 \,/\, \Sigma\, x_i/UFL_i$
$LFL = 100 \,/\, \Sigma\, x_i/LFL_i$

Compressibility

Definition $z = p\,V / (n\, R_a\, T) = p / (\rho\, R_a\, T)$
according to BWR-method (lit. Phys Prop of Nat. Gases, N.V. Ned. Gasunie, 1980,1988)

Speed of sound

$c = \sqrt{k\, P / \rho}$
with

$$k = \frac{1}{\left(1 - \frac{P}{z}\left(\frac{\partial P}{\partial z}\right)_T\right) - \frac{R_a z}{c_p}\left(1 + \frac{T}{z}\left(\frac{\partial z}{\partial T}\right)_P\right)^2}$$

Pressure loss, line capacity

$$Cap \equiv (M\, H_i/\rho_0) / (dP/dx)$$

with (small pressure range):

$$dP/dx = \tfrac{1}{2}\, \rho\, (Q/\tfrac{1}{4}\pi D^2)^2\, \lambda/D$$
$$M = Q\, \rho$$
$$\rho = \rho_0\, (P/P_0)\, (z_0/z)$$

where:

Cap: specific capacity (unit power per unit pressure gradient)
M: mass flow
Q: volume flow (at actual conditions),

H_i: volume net calorific value (at standard conditions)
D: diameter
ρ: density
P: pressure (absolute, at actual conditions)
z: compressibility factor
λ: pipe friction coefficient

with:

λ assumed constant (Re > 100000)
D assumed constant
$M\ H_i/\rho_0$ assumed constant
P assumed constant

and

H_i, ρ_0, z_0, z: depend on composition

but z_0 can be assumed to be approximately equal to 1, independent on composition, so

$\rho \equiv \rho_0 / z$
$dP/dx \equiv \rho\ Q^2 \equiv \rho_0^2 / (\rho\ H_i^2) = z\ \rho_0 / H_i^2$

$Cap \equiv 1/(dP/dx) \equiv H_i^2 / (\rho_0\ z) \equiv W_i^2 / z$

Mass flow meter

$Q_{assumed} = M_{actual} / \rho_{assumed}$
$Q_{actual} = M_{actual} / \rho_{actual}$
$1/Error = (Q_{assumed}\ H_{assumed}) / (Q_{actual}\ H_{actual}) = (H_{assumed} / H_{actual})\ (\rho_{actual} / \rho_{assumed})$

Volume flow meter

$Q_{assumed} = Q_{actual}$
$1/Error = (Q_{assumed}\ H_{assumed}) / (Q_{actual}\ H_{actual}) = H_{assumed} / H_{actual}$

Orifice Meter.

$Q_{assumed} = (\Delta P_{actual} / \rho_{assumed})^{1/2}$
$Q_{actual} = (\Delta P_{actual} / \rho_{actual})^{1/2}$
$1/Error = (Q_{assumed}\ H_{assumed}) / (Q_{actual}\ H_{actual}) = (H_{assumed} / H_{actual})\ (\rho_{actual} / \rho_{assumed})^{1/2}$

Capacity of regulators

Maximum mass flow by critical expansion:

$$M = \left(\frac{2}{\gamma+1}\right)^{\frac{\gamma+1}{2(\gamma-1)}} \sqrt{\gamma \cdot P_u \cdot \rho_u}\, A$$

where
M: mass flow through regulator
A: effective cross sectional area of nozzle
P_u: upstream pressure
ρ_u: upstream density
γ: c_p/c_v

c_p in kJ/(kmol K)

Maximum capacity:

$W_{rs} = M\ H_i/\rho_0$

Capacity of compressor

Required power, isentropic compression of ideal gas:

$$W_c = \frac{MRT_u\gamma}{\gamma-1}\left(1-\left(\frac{P_d}{P_u}\right)^{(\gamma-1)/\gamma}\right)$$

Where

W_c:	power required
M	molair flow [kmol/s]
R	gas constant [J/(kmol K)]
T_u	upstream temperature [K]
P_d	downstream pressure [K]
P_u	upstream pressure [Pa]
γ	C_v/C_p

Valid under the assumption of ideal behaviour

$\gamma = n_{H2}\ 1.3 + n_{CH4}\ 1.4$

Specific power required: $W_{cs} = W_c\ /\ (M\ H_i/\rho_0)$

Figures

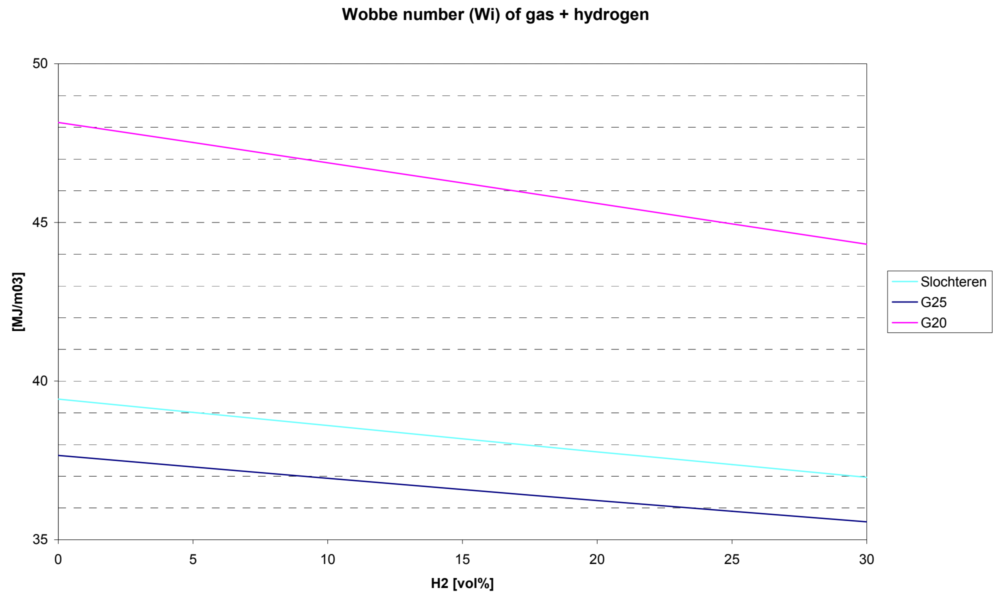


Figure A.1 Wobbe number of mixture over range considered in this report

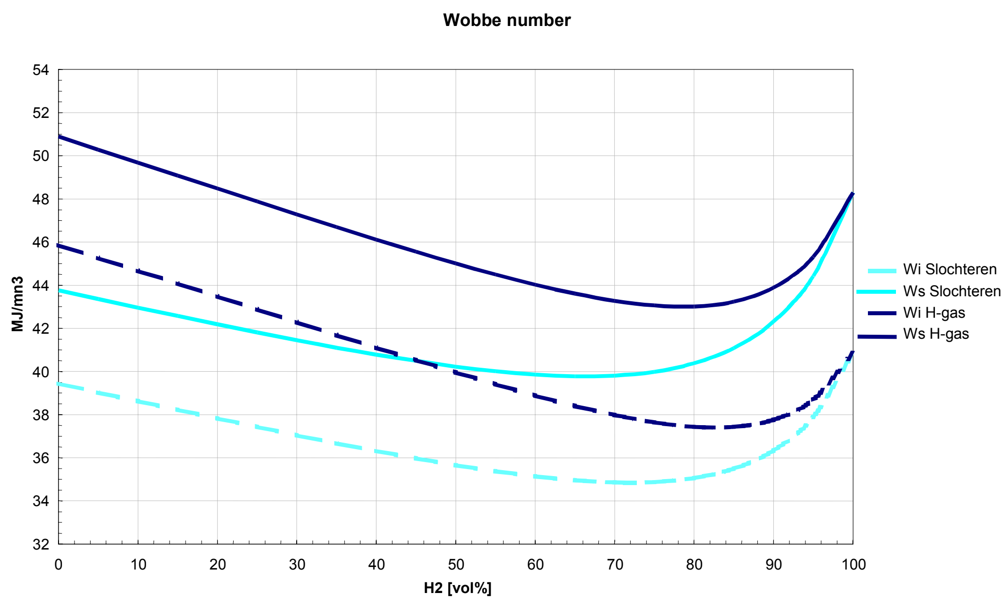


Figure A.2 Wobbe number over whole mixture range, and based on net and gross calorific value.

APPENDIX B: GAS QUALITY BANDS

The gas qualities that are delivered to end-users in Europe vary between different countries and sometimes even within individual countries. The quality specifications are normally not incorporated in the legislation but are defined in national and international standards and regulations. The most common standards and regulations in Europe are based on the European standard EN 437 and the DVGW 260.
All fuel gases that are distributed in Europe are categorised in three ‘families’. The first comprises fuel gases with high hydrogen content, e.g. town gases. The second family comprises methane gases with, for example, natural gas and biogas. The third family comprises Lquified Petroleum Gases, LPGs e.g. propane/butane mixtures. The second gas family is divided into two groups L and H according to Wobbe index.
The standards EN 437 [EN 437] and DVGW 260 [DVGW260] are compared to the national regulations for L and H gas.

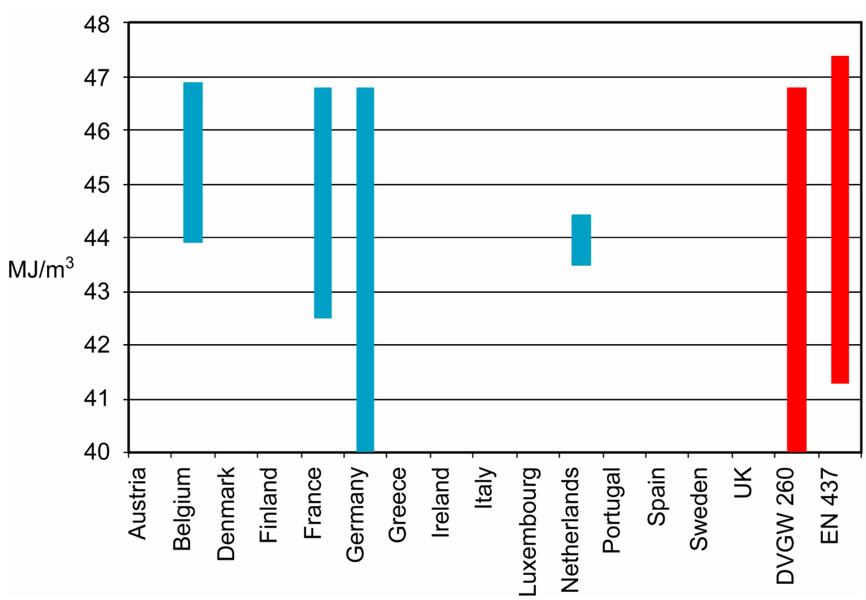


Figure B.1: Maximum range of permitted Wobbe index in Europe, L gas

From the figure above it can be concluded that the permitted Wobbe values for L gas in European countries all are within the limits stated in EN 437. Only the German L gas may vary outside the limits set by EN 437. Purified biogas therefore could be used directly in the L gas grid in the Netherlands, providing other purity demands are fulfilled.

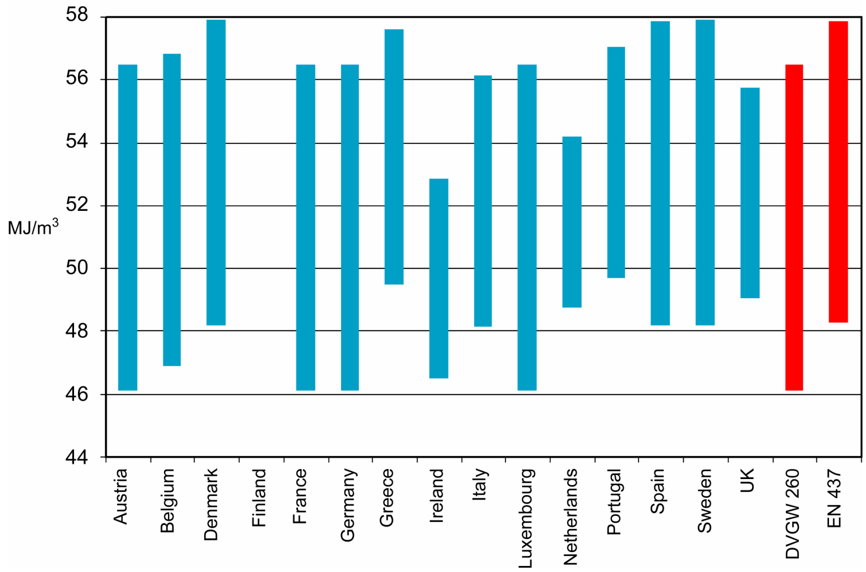


Figure B.2: Maximum range of permitted Wobbe index in Europe, H gas

The allowed H gas compositions vary between different countries, some countries follow the recommendations in DVGW 260 and some the EN 437 (with minor variations).
The actual gas compositions in the European countries, compared to EN 437 and DVGW 260 are presented in figures B.3 and B.4.

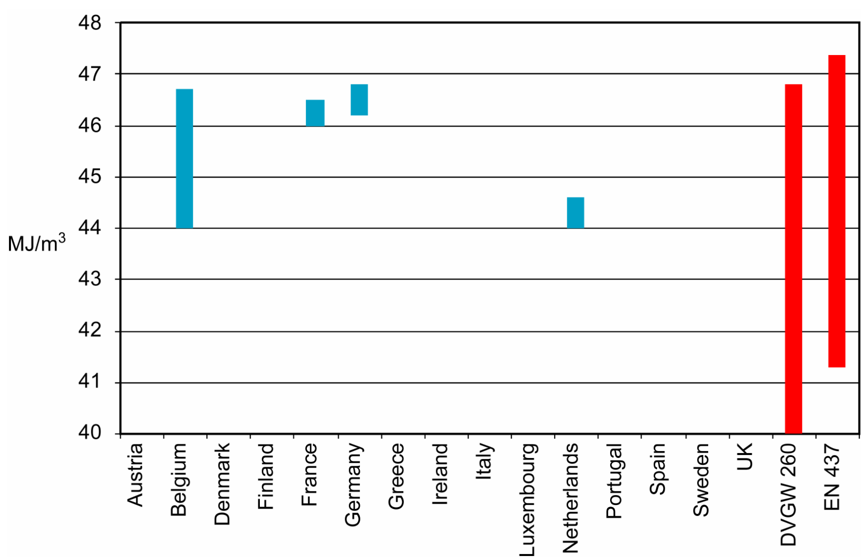


Figure B.3: Maximum range of delivered Wobbe index in Europe, L gas

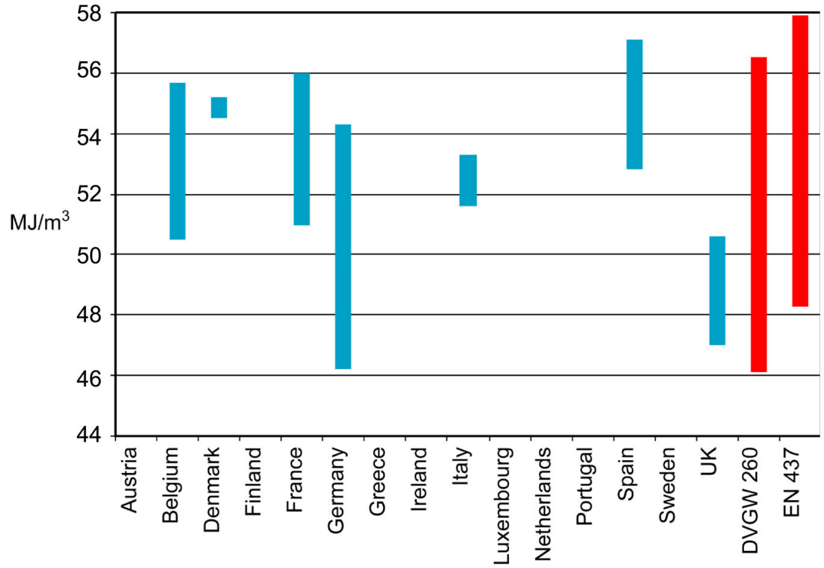


Figure B.4: Maximum range of delivered Wobbe index in Europe, H gas

From these figures it can be concluded that the gas that actually is delivered to the customer shows much smaller variations than is allowed in the national regulations. Biogas has to be purified to > 92% methane in order to fit into the Wobbe index demands stated in DVGW 260.

In conformance with DVGW 260 it is important that the variations in gas quality in a specific distribution grid do not vary too much. Large variations will cause problems in the combustion equipment. Variations between + 0.6 / -1.4 kWh/m^3 are allowed for L gas and + 0.7 / -1.4 kWh/m^3 for H gas. Some national regulations are even stricter.

APPENDIX C: MEASURES PER COUNTRY

base cases	country			NL base	NL1	NL2	NL3
energy demand appliance		energy demand	TJ	1,275,683	1,275,683	1,275,683	1,275,683
		average appliance yield	total	90%	90%	90%	90%
		gas demand	TJ	1,417,426	1,417,426	1,417,426	1,417,426
energy production	hydrogen plant	capacity per train	m3/h H2		92,667	92,667	92,667
		shutdown	weeks		2	4	6
		full load	h		8,424	8,088	7,752
		number of trains	[-]		1	4	8
		thermal efficiency	[-]		72,8%	72,8%	72,8%
		energy production	TJ	0	8,431	32,378	62,066
specific emissions	natural gas	CO_2 emission (methane)	ton/TJ	56	56	56	56
	hydrogen plant	CO_2 production	ton/h		27	107	213
		CO_2 capture	ton/h		23	91	181
		CO_2 emission	ton/h		4	16	32
emissions	natural gas	CO_2 emission	kton	79,376	78,904	77,563	75,900
	hydrogen plant	CO_2 emission	kton		34	129	248
	total	CO_2 emission	kton	79,376	78,937	77,692	76.148
	reduction	CO_2 emission	kton		438	1,684	3,228
					0.6%	2.1%	4.1%
primary energy	consumption	natural gas	TJ	1,417,426	1,408,995	1,385,048	1,355,360
		hydrogen production	TJ		11,581	44,475	85,255
	total		TJ	1,417,426	1,420,576	1,429,523	1,440,615
	reduction				-0.2%	-0.9%	-1.6%
gas	consumption	low, summer	TJ/day		2164	2164	2164
		peak, winter	TJ/day		6131	6131	6131
		average	TJ/day		3883	3883	3883
hydrogen content		peak, summer	[v/v]		2.9%	11.6%	23.1%
		low, winter			1.0%	4.0%	7.7%
		average			1.8%	7.1%	13.9%

Table C.1 CO_2 reduction, primary energy use and hydrogen content in the gas for The Netherlands

base cases	country			UK base	UK1	UK2	UK3
energy demand		energy demand		1,551.292	1,551.292	1,551.292	1,551.292
appliance		average appliance yield	total	90%	90%	90%	90%
		gas demand		1,723,657	1,723,657	1,723,657	1,723,657
energy production	hydrogen plant	capacity per train	m3/h H2		92,667	92,667	92,667
		shutdown	weeks		2	4	6
		full load	h		8,424	8,088	7,752
		number of trains	[-]		1	4	8
		thermal efficiency	[-]		72.8%	72.8%	72.8%
		energy production	TJ	0	8,431	32,378	62,066
specific emissions	natural gas	CO_2 emission (methane)	ton/TJ	56	56	56	56
	hydrogen plant	CO_2 production	ton/h		27	107	213
		CO_2 capture	ton/h		23	91	181
		CO_2 emission	ton/h		4	16	32
emissions	natural gas	CO_2 emission	kton	96,525	96,053	94,712	93,049
	hydrogen plant	CO_2 emission	kton		34	129	248
	total	CO_2 emission	kton	96,525	96,086	94,841	93,297
	reduction		kton		438	1,684	3,228
					0.5%	1.7%	3.3%
primary energy	consumption	natural gas		1,723,657	1,715,227	1,691,279	1,661,592
		hydrogen production	TJ		11,581	44,475	85,255
	total		TJ	1,723,657	1,726,807	1,735,755	1,746,847
	reduction				-0.2%0	-0.7%	-1.3%
gas	consumption	low, summer	TJ/day		2438	2438	2438
		peak, winter	TJ/day		12847	12847	12847
		average	TJ/day		4722	4722	4722
hydrogen content		peak, summer	[v/v]		3.0%	11.9%	23.6%
		low, winter			0.6%	2.2%	4.2%
		average			1.7%	6.7%	13.1%

Table C.2 CO_2 reduction, primary energy use and hydrogen content in the gas for The United Kingdom

base cases	country			FR base	FR1	FR2	FR3
energy demand		energy demand		1,427,687	1,427,687	1,427,687	1,427,687
appliance		average appliance yield	total	90%	90%	90%	90%
		gas demand		1,586,319	1,586,319	1,586,319	1,586,319
energy production	hydrogen plant	capacity per train	m3/h H2		92,667	92,667	92,667
		shutdown	weeks		2	4	4
		full load	h		8,424	8,088	8,088
		number of trains	[-]		1	3	7
		thermal efficiency	[-]		72.8%	72.8%	72.8%
		energy production	TJ		8,431	24,283	56,661
specific emissions	natural gas	CO_2 emission (methane)	ton/TJ	56	56	56	56
	hydrogen plant	CO_2 production	ton/h		27	80	187
		CO_2 capture	ton/h		23	68	159
		CO_2 emission	ton/h		4	12	28
emissions	natural gas	CO_2 emission	kton	88,834	88,362	87,474	85,661
	hydrogen plant	CO_2 emission	kton		34	97	226
	total	CO_2 emission	kton	88.834	88,395	87,571	85,887
	reduction		kton		438	1.263	2.947
					0.5%	1.4%	3.3%
primary energy	consumption	natural gas		1,586,319	1,577,888	1,562,035	1,529,657
		hydrogen production	TJ		11,581	33,356	77,831
	total		TJ	1,586,319	1,589,469	1,595,392	1,607,489
	reduction				-0.2%	-0.6%	-1.3%
gas	consumption	low, summer	TJ/day		2173	2173	2173
		peak, winter	TJ/day		15211	15211	15211
		average	TJ/day		4346	4346	4346
hydrogen content		peak, summer	[v/v]		3.4%	9.9%	24.2%
		low, winter			0.5%	1.4%	3.2%
		average			1.9%	5.5%	13.0%

Table C.3 CO_2 reduction, primary energy use and hydrogen content in the gas for France

APPENDIX D: DESCRIPTION OF GAS SYSTEMS IN UK, F AND NL

The Netherlands

Transmission

The principle of the transmission of gas in the Netherlands is shown in figure D.1. The total length of the transmission pipeline system is more than 11,000 km; the distribution gas grid has a length of 105,300 km. The materials used are shown in table D.2. This system delivers natural gas to electrical power plants, industry, market gardening and about 6 million households.

In the early years(~1960), natural gas was extracted out of the huge gas field "Slochteren" in the northern part of the Netherlands. This gas has a medium calorific value. Nowadays, gas is extracted from several locations both on and off shore. The use of the gas from the small and medium sized gas fields required considerable system modification, as gas of both high calorific value (H-gas) and low calorific value (L-gas) became available. For industrial consumers whose appliances could be converted for the use of H-gas, a special main transmission system was constructed.

H-gas and L-gas is mixed into a gas with medium calorific quality, and delivered to the consumers using the existing transmission and distribution systems.

H-gas is mixed with nitrogen and transformed into M-gas and subsequently injected into the transmission gas system.

The "Nederlandse Aardolie Maatschappij" (NAM) is in charge of the extraction of Natural Gas. Sand, water, condensate and other pollutants are removed at the extraction site. NAM delivers the gas at a pressure of about 67bar to the "Nederlandse Gas Unie" (NGU). One of the departments of this company, named "Gastransport Services" is responsible for the transmission of gas throughout the Netherlands.

As showed in figure D1, gas is delivered to the gas distribution companies via:-

- compressor stations,
- measuring and
- regulating stations and
- city gate stations

Compression is only required when the gas flow, and therefore the pressure drop is high, which is the case in wintertime.

At the measuring and regulating stations gas is transferred from the High-pressure Transmission grid (HTL; pressure range 67 – 46 bar) into the Regional Transmission grid (RTL; pressure range 40 – 16 bar). At this stage gas receives its characteristic smell by adding odorant. More than 700 city gate stations are supplied by the RTL. At the city gate station the gas pressure is again reduced, usually to 8 bar and the gas flow is metered (before it is transferred into the gas grid of the distribution company. There are another 400 direct take-off points to supply industries and power plants. A few of the largest consumers are supplied directly from the HTL.

Preferably the H-gas is delivered to the major industries and power plants, as well as to export consumers.

To make two gas qualities out of the large variety of gas qualities that are offered by NAM, Gastransport Services operates several mixing (or blending) stations. In these stations the M-gas can be mixed with H-gas (a limited amount), so that the calorific value is slightly increased. Gastransport Services also have equipment available to mix H-gas with nitrogen, so H-gas can be converted into M-gas quality. It must be said that this level of sophistication of gas mixing is unique to the Dutch situation.

Figure D.1 Schematic set-up of the Dutch gas transmission system

Pressure	Material	Length
67 bar	Steel	5.000 km
40 bar	steel	6.100 km
TOTAL		11.100 km

Table D.1: Pipeline materials of the Dutch transmission system

Distribution

The transmission pipeline system and the city gate stations supply the gas to the distribution system of the gas-distribution companies. The outlet pressure of the city gate stations is usually 8 bar, this is the pressure of the gas grid that is feeding the local district stations. In this station the pressure is reduced to 100 mbar or 30 mbar, this is the pressure in the low-pressure gas grid. The low-pressure gas grid is usually a meshed gas grid to increase reliability. The small consumers like households and small companies are connected to the low-pressure distribution system. Consumers with higher gas consumption receive their gas from a special delivery station, which is connected to the high-pressure distribution pipelines. The principle of the distribution system is shown in Figure D.2. For historical reasons many of the gas companies use slightly different pressures.

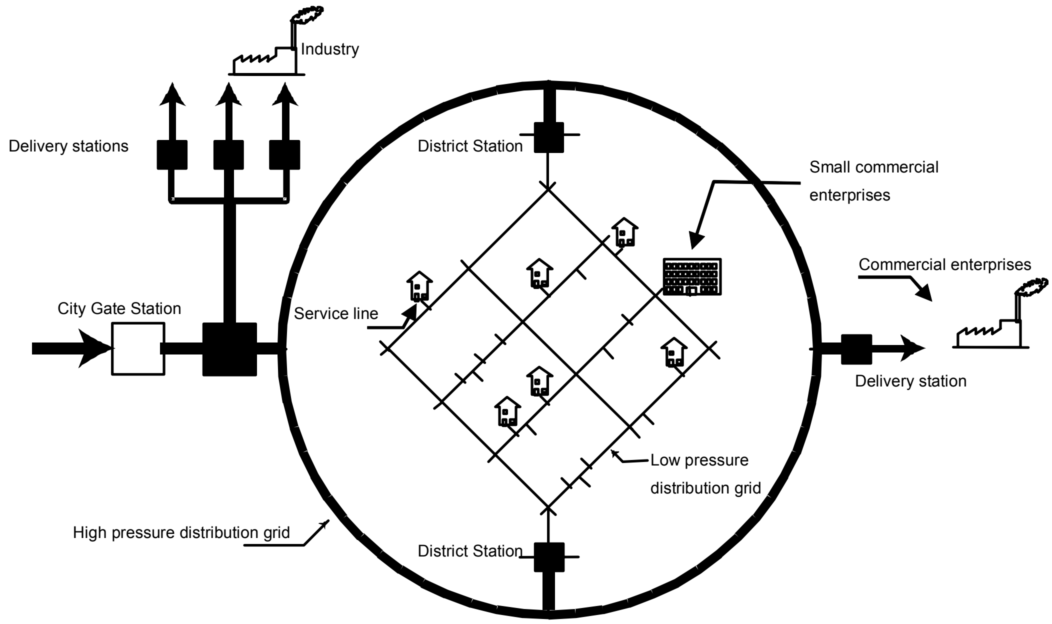


Figure D.2 Schematic set up of the Dutch gas distribution system

Steel	Ductile Cast Iron	Grey Cast Iron	Asbestos	U PVC (unplastized)	PVC Ductile	PE	Total
19.000	3.200	5.100	1.500	16.500	45.000	15.000	105.300
18 %	3%	5%	1%	16%	43%	14%	100%

Table D.2: Pipeline materials of the Dutch gas distribution system

High pressure Distribution (8,4,1 bar)	*Low Pressure Distribution (100,30 mbar)*	*Total*
20.453 km	84.847 km	105.300 km
19,4 %	80,6 %	100 %

Table D.3: Pipeline length of the Dutch gas distribution system

UK

The UK has a conventional gas distribution system consisting of the National Transmission System, NTS, (a spine of high pressure steel mains operating up to 85 bar), feeding the Local Transmission system, LTS, which in turn feeds large sites such as power stations and the Distribution system, the latter operating at Intermediate (IP), Medium (MP), and Low Pressure (LP). Over 98% (by length) of the UK gas network is owned by Transco PLC (now National Grid Transco PLC) and for simplicity we consider the UK & Transco network to be synonymous.

The UK has a very old gas distribution network, much of the cast iron low-pressure mains dating from the early 20th or even 19th century. Gas at that time was produced at local gas works and distributed over areas that rarely exceeded 80km in radius, and frequently were closer. Most of the low-pressure systems operated on towns gas (typically 47% hydrogen, 14% Carbon Monoxide, 23% Methane, the balance nitrogen & carbon dioxide). These systems were converted to natural gas in the late 1960s and early 1970s. The natural gas was transported from the North Sea using the newly built national transmission system. The conversion allowed the transportation of much greater quantities of energy through the local distribution systems because of the increased calorific value (up from ~19 to ~39 MJ/m^3), and because the pressure in the local distribution systems was increased from typically 5mbar to 22mbar. Many of the joints in the old ferrous systems are still "lead and yarn", and quantities of wetting agent have to be added to maintain these seals in a swollen (and thus effective) condition. Such a network will be similar to that in many parts of the world where an extensive gas network has existed from the 19th Century, eg New York, Chicago, and even parts of Amsterdam.

In many ways the addition of hydrogen to natural gas is a return to UK Towns gas (Wobbe No ~27 MJ/m^3), except that Wobbe No of hydrogen/natural gas mixtures (40 to 50 MJ/m^3) is a better match to Natural gas (~50 MJ/m^3).

More details of each element of the various grids are given below.

National Transmission System (NTS)

The NTS transports nearly half of Britain's primary energy. Operating at pressures of between 38 and 85 bar it is used to transport gas on behalf of approximately 60 gas shippers from coastal terminals to local transmission and distribution systems, or direct to consumers and third party pipeline systems. The NTS is connected to terminals that export and receive gas from Continental Europe and transport gas to Northern Ireland and the Republic of Ireland. At the end of 2000 the NTS comprised approximately 6,400 km of pipeline (ie about half the length of the Dutch transmission system despite being a much larger country) and 24 compressor stations incorporating 63 compressor units. Operating costs in 2000 were £254m. Typical pipe diameter is 600 to 1000mm.

Local Transmission System (LTS)

The LTS system, operating between 7 and 70 bar, transports gas from the NTS to the lower pressure distribution tiers and also feeds a small number of directly connected large loads. At the end of 2000 the total length of the LTS was 2,200km.

<u>The Distribution System</u>

At the end of 2000 the Distribution system comprised 258,000 km of pipeline split into three pressure tiers: Intermediate (IP), Medium (MP), and Low Pressure (LP). The material composition is shown below.

'000s km [31/12/2000]	*Low pressure* (up to 75 mbar)	*Medium pressure* (75mbar to 2bar)	Intermediate pressure (2bar to 7bar)	Total
Polyethylene	102.6	16.7	1.1	120
Cast/Spun iron	92.7	6.0	-	99
Ductile iron	16.3	3.6	-	20
Steel	9.3	4.4	4.7	18
Total	**221**	**31**	**6**	**258**

Table D.4 Composition of the UK distribution grid

Intermediate/Medium-pressure Distribution Systems (IP/MP)
The IP/MP systems are made up of 36,000 km of pipeline operating at pressures between 75mbar and 7bar. 2000 saw an acceleration of the replacement programme on the IP/MP systems. The number of pressure reduction governors, which feed gas into/from these systems, is approximately 33,100.

Low-pressure Distribution System (LP)
At the end of 2000 the LP system comprised 222,000km of pipeline operating at pressures not exceeding 75mbar. During 2000, Transco's mains renewal programme continued to replace iron pipe with polyethylene (PE) in the LP Distribution system.

Service Pipes
Service pipes connect individual gas consumers' premises to the distribution mains.. There are approximately 20million of these.

Depreciation charges
The depreciation charges for the various parts of the UK gas network (£m) for 2000 and 1999 were:-

	2000	%	1999	%
NTS	83	17.3	76	16.7
LTS	56	11.6	60	13.2
IP	50	10.4	60	13.2
LP	164	34.1	149	32.7
Services	128	26.6	111	24.3
	481		456	

Table D.5: Depreciation charges for the UK gas grid

This indicates that the National distribution System, although extremely important has an asset value of <20% as compared to the whole system.

Operating costs

It is also interesting to compare the relative operating costs of the various parts of the UK system.

By Service: 2000	£m
Storage	N/A
NTS	257
LTS	124
Distribution IP/MP	149
Distribution LP	533
Customer/ Metering	787
Unaccounted for Gas	46
Excluded Services	4
Total Transco Cost Base	1900

Table D.6 Operating costs (£m) for the UK gas grid

This shows that the costs for NTS are only ~14% of total operating costs, and the costs for LTS ~6%. This supports the proposition made elsewhere in this report that any addition of hydrogen should be (if anywhere) at the NTS/ Distribution system interface. Such an approach would maximise the use of the ~80% of the system already in place.

France

Natural gas has a rather low share in the country's primary energy consumption at about 13%. Reasons for this low share are the large share of electricity in the residential heating market and the priority given to nuclear power in power generation. Furthermore the relatively sparse population of France and the relatively high costs of connecting remote communities form a limiting factor.

However, a large growth is expected by the French government [IEA], bringing natural gas to over 19% of the country's primary energy consumption in 2010 and reaching almost 25% in 2020 (table D.7).

Sector	**1998**	**2010**	**2015**
Residential	9.4	17.1	18.8
Commercial and other	8.9	8.3	10.5
Industrial	14.0	15.1	16.5
Power generation and CHP	1.6	17.4	33.9
Own use	0.5	1.7	2.7
Total	**34.4**	**59.7**	**82.4**

Table D.7 Present and Forecasted Natural Gas Demand in Mtoe

<u>Description of the transmission and distribution system</u>

For the residential sector, only 10 million of the 22.8 million households are connected to the gas grid. The total natural gas supply amounts 38 x 10^9 cubic metres of which 4% is produced in France and the rest is imported based on long term contracts with Norway (31%), Russia (28%), Algeria (24%) and the Netherlands (12%).

France receives pipeline gas from Russia at Medelsheim (French-German border), from the Netherlands, Norway and the UK at Blaregnies at the French-Belgian border and at Dunkirk from Norway. Furthermore LNG is transported by bulk carriers from Algeria.

The French transmission (high pressure grid) extends about 32,000 km and the distribution grid about 140,000 km in the year 1999. The distribution grid will extend substantially in the next decade. The main distribution and transmission company is Gaz de France (GdF) supplying 88% of the French gas consumption. Furthermore GdF is a substantial shareholder in the companies CFM and GSO (see table D.8).

	Transmission (km)	Distribution (km)
GDF	21,658	134,525
CFM	6,352	
GSO	3,930	
SEAR	72	
17 LDCs		6,031
Total	32,012	140,556

(LDC is Local Distribution Company)

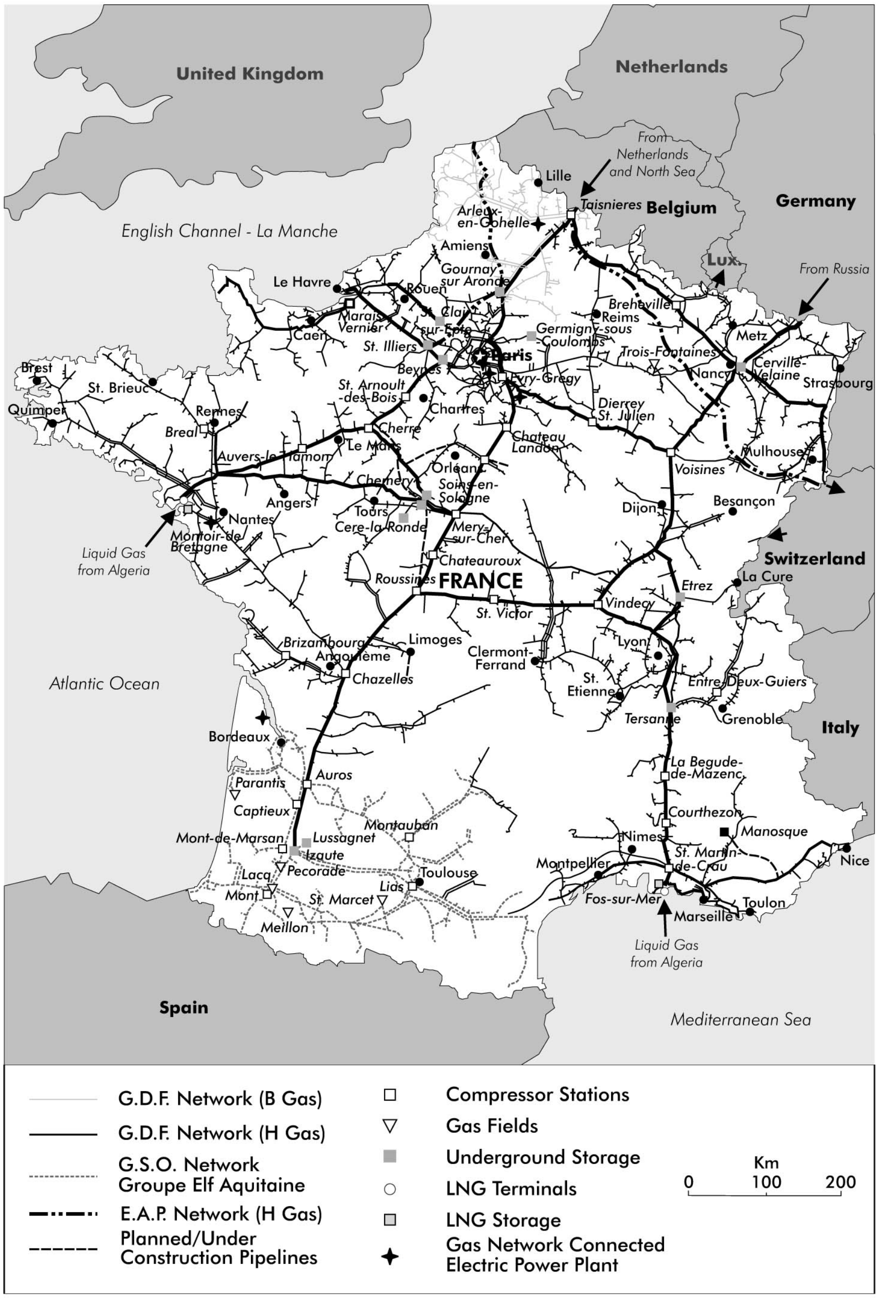
Table D.8: Transport Infrastructure Owners in France

An overview of the French Gas pipelines and Facilities is outlined in figure D.3.

Pipeline materials:
In the 141.000 km French distribution gas grid, Polyethylene is used mainly. According to the replacement programmes, the number of PE pipelines will further increase.

The composition in the year 1997 was:
70.000 km PE
54.000 km steel
15000 km cast iron
2000 km others

Natural Gas Pipelines and Facilities Map, France, 1999



Source: *Natural Gas Information 1998*, IEA/OECD Paris 1999.

Figure D.3 Outline of the French gas grid

APPENDIX E: EFFECT OF HYDROGEN ADDITION ON INTERNAL COMBUSTION ENGINES

Problem definition
When hydrogen is mixed in the natural gas grid, then gas engines are critical end users. The effects of a hydrogen-enriched gas on a gas engine are strong, because the burning takes place under high pressure and detonation can easily occur.

In 1999 Gastec has done experiments with hydrogen enriched gas in gas engines. The influence on knocking behaviour, air factor (λ), $NO_{x,}$ CH_4-emissions, shaft efficiency, λ-control systems in relation to mixing hydrogen with the distributed natural gas was established.

Detonation

Gas engines for cogeneration units are designed and adjusted to perform optimally, in relation to efficiency and emissions. The margin to the detonation and /or misfiring limit has therefore become very small. If the composition of the natural gas does not change, then the gas engine can operate with a small setting margin and has a larger margin to the misfiring and detonation limit. The detonation area can grow or shrink with the knocking properties of the fuel. The knocking properties of a fuel are expressed in a Research Octane Number (RON), the Motor Octane Number (MON) and Methane Number (MN). The Methane Number is used for natural gases. Table 1 shows the methane number of different pure gases. Pure hydrogen has a bad resistance to knocking. However added in small fractions (<40 % in methane) its knocking behaviour is better than that of other fuel components (see figure E.2).

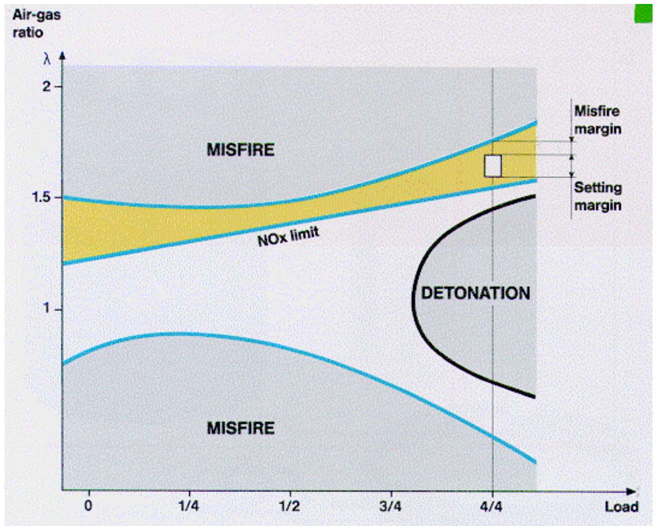


Figure E.1: Detonation- misfiring and NOx-limits in relation to the engine load and air-gas ratio (source: brochure Wärtsilä SACM).

Gas		Methane Number
CH_4	(methane)	100
C_2H_6	(ethane)	44
C_3H_6	(propane)	19
C_3H_8	(propane)	34
$n\text{-}C_4H_{10}$	(n-butane)	10
H_2	(hydrogen)	0

Table E.1: Methane Number of pure gases.

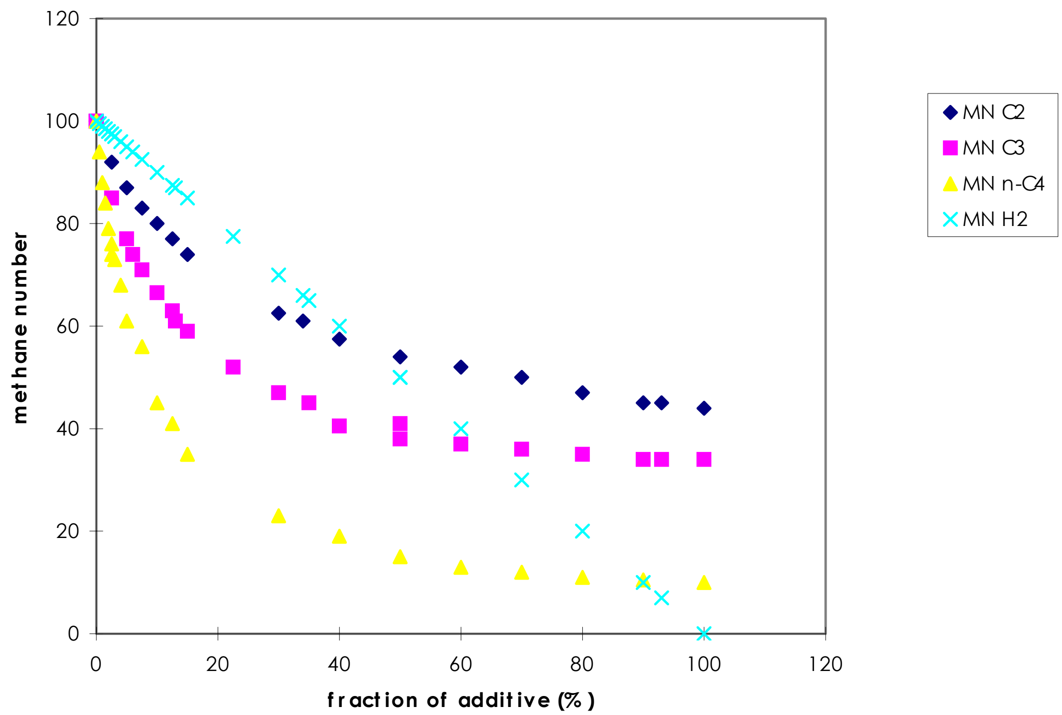


Figure E.2: Influence of additions on the Methane Number of different compounds to methane.

To obtain the maximum amount of energy from natural gas, the compressed fuel-air mixture inside the combustion chamber needs to burn evenly, propagating out from the spark plug until all the fuel is consumed. This would deliver an optimum power stroke. A series of pre-flame reactions occur in the unburned “end gases” in the combustion chamber before the flame front arrives. If these reactions between molecules can auto ignite before the flame front arrives, knocking occurs. If auto-ignition occurs, it results in an extremely rapid pressure rise, as both the desired spark-initiated flame front, and the undesired auto-ignited end gas flames are expanding. The combined pressure peak arrives slightly ahead of the normal operating pressure peak. The end gas pressure waves are superimposed on the main pressure wave, leading to a saw tooth pattern of pressure oscillations that create the “knocking sound” The combination of intense pressure waves and overheating can induce piston failure in a few minutes.

Knocking behaviour of different natural gases

Situation in Holland

The distributed natural gas in the Netherlands has a small bandwidth of Wobbe-Index (between 43,46 – 44,41 MJ/m^3). Remarkable is the high content of nitrogen in the natural gas distributed. The “quality” is kept constant by mixing H-gas, G-gas, N_2 and CO_2. The knocking resistance of the gas is good considering the high concentration of inert gases. The Methane Number (MN) is 89 (table E.2).

Description	Value
CH_4 (vol. %)	81.62
C_2H_6 (vol. %)	3.14
C_3H_8 (vol. %)	0.57
C_4H_{10} (vol. %)	0.2
N_2 (vol. %)	12.79
CO_2 (vol. %)	1.33
H_2 (vol. %)	**0**
Others (vol. %)	0.13
Cal. V. (MJ/m^3)(Gross)	35.73
WI (MJ/m^3) (Gross)	44.4
Rel. density	.675
MN	**89**

Table E.2: Composition and properties of distributed natural gas in the Netherlands.

Consequences of mixing hydrogen in the distributed gas grid for gas engines.

The main consequence of mixing hydrogen in the natural gas grid is that the knocking resistance of the gas and the Wobbe-Index decreases. The main effect is that gas engines without air/fuel (λ) control system will have to be operated with a leaner mixture (higher air excess).

The consequence of mixing 25 vol.% H_2 of hydrogen in the natural gas is that a gas engine running with a λ=1.6 will run with a new λ = 1.05 x 1.6 = 1.68.

$$\lambda_{new} = \frac{W_{old}}{W_{new}} x \lambda_{old} = \frac{44.4}{42.27} * \lambda_{old} = 1.05\ \lambda_{old}$$

In order to deliver the same gas engine power output, the air supply has to be increased by 5%. The throttle valve has to be open wider, leading to a lower shaft efficiency. Hydrogen supply to the natural gas will give lower throttle losses and therefore a higher shaft efficiency. The sum of these effects is positive for the shaft efficiency (0–1% point).

A lower Methane Number means that the detonation area is greater. Operating at the same λ can induce detonation. A lower Wobbe-Index and a constant λ mean a higher NO_x-production (figure E.3). A varying λ with addition of hydrogen (no λ control system) will hardly give any change of NO_x, CH_4 and CO-production of the flue gases.

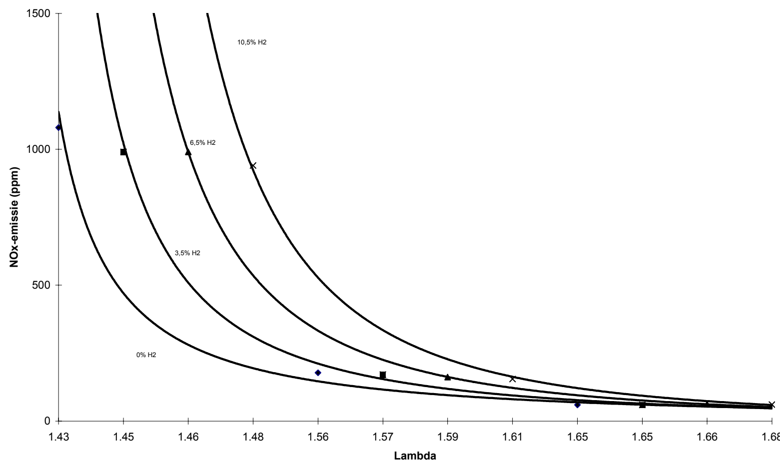


Figure E.3: NO_x-emission of a MAN 2842 LE gas engine, in relation to the air/fuel ratio (λ) and the hydrogen concentration (vol. H2%) in the natural gas (Groningen gas).

Situation in England

The natural gases from England have a relatively high content of ethane and propane. This implicates that the methane numbers of the gases are relatively low (table E.4).

Natural gas	Methane Number
Bacton	84
Burrow	78
Easington	86
St. Fergus	74
Teeside	70
Theddlethorpe	82

Table E.3: Methane number of different natural gases from England.

The MN of Bacton gas mixed up to 25 vol.% H_2 gives a MN of 69 and Teeside gas with 25 vol.% H_2 gives a MN of 63.
A gas engine can be designed for a MN of 63 (restricted compression ratio, engine load and adjusting ignition timing), however without any readjustment the engine will run with a lower shaft efficiency if the MN increases.

Situation in France

In France large differences exist in the MN of the distributed gases. The Russian gas has a high MN in comparison to Nigerian or Algerian natural gas. A gas engine on Russian natural gas can run with a higher shaft efficiency than on Algerian gas. Changing from Russian gas to Algerian gas can initiate knocking problems of the gas engine.
Mixing Russian natural gas up to 25 vol.% H_2 will decrease the MN from 90 to 73. The methane number of Algerian gas will decrease from 72 to 63.

Natural gas	Methane Number
Russian	90
Netherlands	86
Nigerian	63
Abu Dhabi	67
Algerian	72
Norway	81

Table E.4: Methane number of different natural gases in France.

Considerations of a rapidly change of hydrogen supply

The influence on hydrogen on lean burn engines without λ-control systems is little. If the hydrogen supply stops, then the λ decreases at the same moment and the shaft (power) output will increase suddenly. The power control systems of the cogeneration unit have to be fast enough to prevent overloading of the unit.

Anti knocking control systems have also been fast enough to re-adjust the load and ignition timing of the gas engine. Experiments (measurements in practice) on gas engines will be required to confirm this.

Prevention measures

Lean burn engines with λ-control systems have to be set in the open loop mode. If a lean burn engine (without λ-control system) is adjusted to a low NO_x level, then the engine has enough margin to the knocking limit to prevent detonation.

To prevent detonation and to have optimum performance of the engine, a detonation detection system in combination with a motor management system can be applied.

The detonation detection system detects detonation with sensors and adjusts the ignition timing. If the maximum adjustment is reached then the engine load is decreased.

Another (cheaper) option is the use of a methane sensor. This infrared sensor (figure E.4) detects components (figure E.5) and the quantity of these components in the natural gas and calculates the methane number. With this information the ignition timing and the load of engines can be adjusted. The system has been developed to detect natural gas components, like methane, ethane, propane and butane. The sensor has to be made suitable for detection of hydrogen.

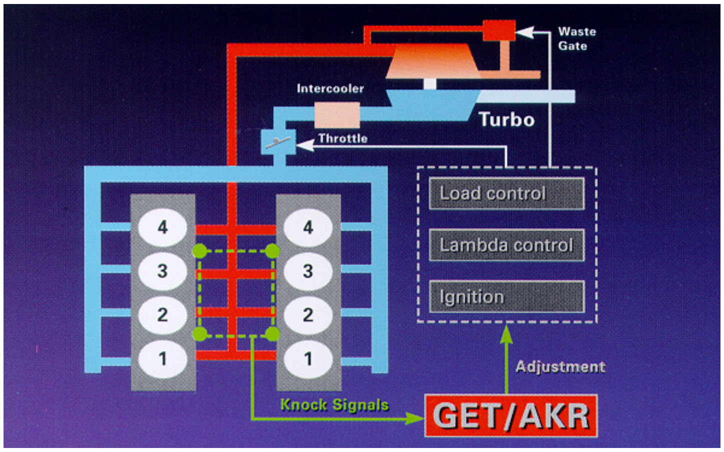


Figure E.4 Schematic diagram of the function of an anti knocking system from GET(Gas Engine Technology)

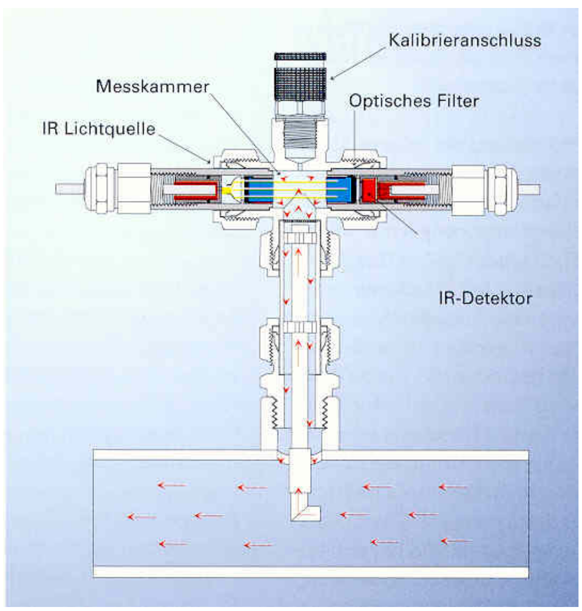


Figure E.5: Methane sensor developed by Ruhrgas

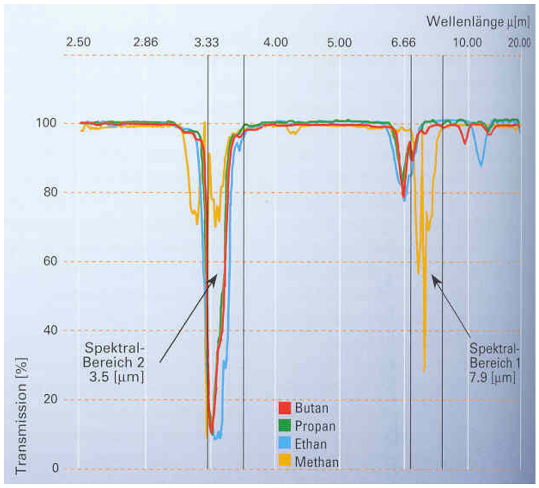


Figure E.6 Example of an infra red absorption spectrum of methane, ethane, propane and butane, depending of the wavelength.

APPENDIX F: EFFECT OF HYDROGEN ON THE USE OF CNG FOR TRACTION

The pressure in the natural gas refuelling station and the vehicle storage cylinders varies from zero to well over 20 MPa during the process of fuelling. At this pressure level, the non-linear behaviour of gases has a significant influence on the characteristics of CNG systems.

Gas storage

The main difference between a traditional vehicle and a CNG vehicle is the low storage density of energy on board, since methane remains gaseous at high pressure. In Europe, the natural gas is usually stored at 20 MPa pressure in gas cylinders. The amount of energy stored in the cylinders determines the vehicle's range. At present, some OEM CNG vehicles have 50% to 75% of the range of a standard gasoline vehicle.

When hydrogen is blended with natural gas, the energy content of one m^3 gas will decrease because of the relatively low energy content of hydrogen (hydrogen contains about 30% of the energy of methane). Blending therefore will decrease the amount of energy stored.

The non-linear behaviour at high pressure of both hydrogen and methane will influence the storage capacity as well. Methane becomes easier to compress at high pressures. Depending on the temperature, up to 20% more methane will be present in a 20 MPa pressurized cylinder than would be predicted by Boyle's law [ref Bkr, Gastec]. On the contrary, hydrogen becomes more difficult to compress at high pressures.

Both effects act negatively to the stored energy amount and amplify each other. This is shown in figure F.1, for three natural gas compositions, as a function of the hydrogen content. The stored energy is set to 100% in the case of natural gas without hydrogen blending. The blend temperature is 288K, and compressibility factors of the gases and blends are calculated according to the BWR-method.

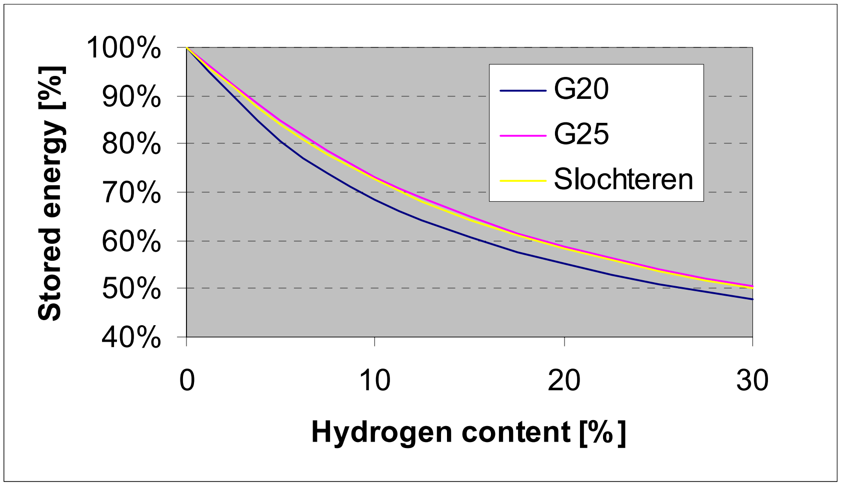


Figure F.1:The effect on the stored amount of energy on board of a natural gas vehicle, as a function of hydrogen content of the natural gas, for three natural gas compositions, with the gas blend stored at 20 MPa and 288K.

The negative effect on the stored energy is clearly worse in case of gases with high methane content (which is G20). Generally, at 25% hydrogen addition, about 50% to 55% of the usually stored energy remains. This will affect the vehicle's range significantly in the summer months since the maximum hydrogen percentage will occur in the summer months (see paragraph 6.3).

Gas metering

To eliminate the effect of the pressure fluctuation, a mass flow meter can be used. In the Netherlands, a mass flow meter is the only type of device approved by the national institute of Metrology for use in the high pressure line of a public CNG station. This type of meter is expected to become standard in CNG stations in Europe.

The accuracy of the coriolis meter is not affected by the gas composition, since mass flow is metered. No adjustment of any kind is necessary in case of a gas composition change.

Hydrogen embrittlement

Parts in the gas channel under tension load are made of 316L stainless steel, a material which has a very low susceptibility to hydrogen embrittlement.

CNG cylinders are made of steel or a composition of steel and carbon fibre wrapping. The newest are either type 3 or type 4 (Aluminium liner with carbon wrap or polymer liner with carbon wrap).

All steel cylinders are x-rayed in the production process to locate possible cracks. Products with cracks are rejected. Another step in the steel cylinder manufacturing process is the simultaneous internal and external shot blasting.

Hard pellets are shot against the exterior and interior of the cylinder and cause the typical dimpled surface. The deformation of the surface results in a three dimensional compression stress in the surface layer when the steel cylinder is empty (not loaded).

When the cylinder is loaded with gas tensile stress will occur in the cylinder wall. At the surface layer, the tensile stress will be compensated by the already present compression stress. In practice, the cylinder surface will only be subject to compression stress, which minimises the chance of crack growth or hydrogen embrittlement.

APPENDIX G: PURE HYDROGEN DISTRIBUTION

Hydrogen is transported in steel pipelines to industrial clients. Data about the composition and functioning of the various pipelines are available [Pottier].

In the USA there is 720 km of hydrogen pipeline network and in Europe about 1,500 km. Over great distances, pipeline transport of hydrogen could be an effective way of transporting energy. The energy loss in an electric power grid can be up to 7.5-8% of the energy it is transferring. This is about double that needed to feed gas through a pipeline of the same length.

Hydrogen pipes that are in use today are constructed of regular pipe steel, and operate under pressure at 10-20 bar, with a diameter of 25-30 cm. The oldest existing system is found in the Ruhr area. It is 210 km long and distributes hydrogen between 18 producers and consumers. This network has been in use for 50 years without any accidents. It is now owned by Air Liquide. The longest single hydrogen pipeline is 400 km and runs between France and Belgium.

With few or no changes, the majority of existing steel natural gas lines can be used to transport mixtures of natural gas and hydrogen. It is also possible, with certain modifications, to use pure hydrogen in certain existing natural gas lines. This depends on the carbon levels in the pipe metal. Newer gas pipelines such as those in the North Sea, have low carbon content and are therefore suitable for transporting hydrogen. If the flow rate is increased by a factor of 2.8 to compensate for hydrogen having 2.8 times lower energy density per volume than natural gas, the same amount of energy can be moved. The fact is that by using efficient hydrogen technology such as fuel cells, etc., the same amount of transported energy will yield increased output at final consumption.

Air Liquide has pipelines of a total length of 1300 km, consisting of 100 mm and 300 mm pipelines. No failures were observed for 15 years of operation. The hydrogen transported is of a high purity (99,995 %), impurities of oxygen and water may lead to failure. Special attention has to be paid to the microstructure. The operating pressure is 25 bars [Kaske].

As long as the hydrogen purity is not greater than 99,5 %, the steel grades and welds generally used for natural gas transmission are not adversely affected. When subjected to cyclic stresses the steels are vulnerable to embrittlement. Therefore the steel should have low sulphur content and a heat treatment should be applied.
This may lead to increased pipe prices of 30% to 50% [Pottier].
For weldings a high-energy process, preventing hardening of the metal around the weld, should be used. Oney et al. give a theoretical approach on the compression costs and pipeline costs as a function of the volumetric fraction of hydrogen and the transmission distance. Costs for hydrogen and hydrogen natural gas mixtures are slightly higher than for natural gas [Oney].

APPENDIX H: ECONOMIC DATA SHEETS

domestic appliances country	NL	UK	FR
domestic CH boilers (space heating)	6,296,000	14,500,000	3,644,000
domestic cookers	1,363,000	4,795,000	8,158,000
fires		17,000,000	
gas wall heaters		2,500,000	
Clients connected to the gas	6,491.000	19,897.000	9,590,000
Number of appliances/ household	1.2	1.9	1.2
CNG refueling stations	15	105	18
gas engines	4000	1414	
NGV's	300	4550	835

TableH.1 Gas appliances per country

gas chromatographs	NL	UK	FR
number	33	66	29
number to convert	30	31	29
conversion per unit	15.000	15.000	15.000

Table H.2 Estimation of the number of gas chromatographs

costs gas engines	(Denmark)	
in $		*year*
project price	3,100,000	
units	450	
per unit	6889	*1999*
inflation	1.05	
expected life	10	
investment per unit	8373	*2003*

Table H.3 Price estimation of gas engine adaptation

costs pressure regulator adjustments $	NL	UK	FR
working hours/regular adaptation	1,0	1,0	1
travel hours/regular adapatation	0,3	0,5	0,5
low pressure stations	10,100		27,302
medium pressure stations	19,950	33,100	
high pressure stations	1,165		
scale factor	1.1	2.1	1
total working hours			
low pressure stations	11,936	0	
medium pressure stations	23,577	49,650	40,953
high pressure stations	1,377	0	0
total labour costs			
low pressure stations	651,074	0	0
medium pressure stations	1,286,033	1,418,571	2,457,186
high pressure stations	75,099	0	0
total	2,010,000	1,420,000	2,460,000

TableH.4 Costs of adjusting gas pressure regulators ($)

domestic appliances			
ionisation safeguard check			
price per million boilers	25,000,000		
conversion			
specific labour costs per million conn.	80,000,000		
hardware costs per million conn.	100,000,000		
country	NL	UK	FR
scale factor	1.1	2.1	1
appliances per household (average)	1.2	1.9	1.2
number of households	6,491,000	19,897,000	9,590,000
measures up to 12 % H2 blending			
ionisation safeguard check	174,068,182	461,845,238	295,050,000
percentage to convert	5%		
labour costs, appliance upgrade	27,850,909		
hardware costs, appliance upgrade	34,813,636		
measures from 12% H2 to 25% H2			
percentage to convert		5%	5%
labour costs, appliance upgrade		73,895,238	47,208,000
hardware costs, appliance upgrade		92,369,048	59,010,000
total	236,732,727	628,109,524	401,268,000

Table H.5 Cost calculation of boiler conversion ($)

country		NL		UK		FR	
pressure control stations	interface	number	gas rows	number	gas rows	number	gas rows
	67 to 40 bar	65	130				
	40 to 8 bar (residential)	700	1,400				
	40 to 8 bar (industrial)	400	800				
	8 to 4 bar	750	1,250				
	delivery (industrial, distribution)	19,200	32,000				
	8, 4, or 1 to 0,1 bar (residential)	10,100	16,833				
	7 to 2 bar			[-]	33,100		
total		31,215	52,413		33,100		
low pressure		10,100	16,833				
medium pressure		19,950	33,250		33,100	27,302	
high pressure		1,165	2,330				
compression stations		8		24			
compressor units		12		83			

Table H.6 Estimation of gas rows in the grid

Medium transmission pressure grid upgrade

The configuration of the medium pressure transmission grid is not known in detail. Upgrading costs cannot be estimated without this basis. The costs for extra capacity in lines for industrial customers are estimated equal to the next-best option in relation to diameter increase. This option is installing a compressor to make up for lost capacity. The compression costs are the capital costs for the compressor, the electricity costs and maintenance.

In table H.7 . The costs for a compressor are compared with the costs for diameter upgrade.

compression costs		NL1	NL2	UK	FR
hydrogen content (summer)		3%	25%	25%	25%
base load	m3/h	729,000	729,000	1,555,855	1,286,244
industrial extensions	-	400	400	400	400
average per client	m3/h	1823	1823	3890	3216
summer flow increase	-	0.02	0.37	0.37	0.37
summer flow	m3/h	1859	2497	5329	4405
specific electricity requirement	kWh/m3	0.1	0.1	0.1	0.1
summer gas throughput (4 months)	m3/j	5,428,134	7,290,729	15,560,107	12,863,729
specific electricity costs	$/MWh	40	40	40	40
required energy	MWh	543	729	1556	1286
compression costs	$/j	21,713	29,163	62,240	51,455
compressor investments	$	200,000	200,000	200,000	200,000
lifespan	j	15	15	15	15
capital costs	$/j	19,268	19,268	19,268	19,268
maintenance		4%	4%	4%	4%
maintenance costs	$/j	771	771	771	771
total per extension	$/j	41,752	49,202	82,280	71,494
all industrial extensions	$/j	16,700,693	19,680,845	32,911,850	28,597,645
power generation efficiency		40%	40%	40%	nuclear
extra primary energy demand	TJ	1,954	2,625	5,602	-
power generation emissions	ton CO_2/TJ	73	73	73	-
extra CO_2 emissions	kton/j	143	192	409	-
costs for extra diameter (full length)					
line construction	$/m	350	350	350	350
length per extension	m	10571	10571	5500	25000
investment per extension	$	3,700,000	3,700,000	1,925,000	8,750,000
interest		5%	5%	5%	5%
lifespan	j	30	30	30	30
capital costs/extentsion	$/j	229,229	229,229	119,261	542,095
all industrial extensions	$/j	91,691,547	91,691,547	47,704,386	216,838.117
max. length extra diameter mark		18%	21%	69%	13%

Table H.7 Estimation of compression costs and comparison to line diameter upgrade ($)

Installing a compressor is generally cheaper than upgrading the diameter along the full length of the line. A problem with electrical compression however is the extra primary energy demand and extra CO_2 emission. The part of the line that can be upgraded with the same costs as compression is calculated. For the Netherlands and the UK this is sufficient. The emissions of France are set to zero due to it’s nuclear power plants.

APPENDIX I: DESCRIPTION OF HAZARDEOUS PHENOMENA (SEE CHAPTER 3)

Rupture

A rupture may be the result of overpressure in a gas pipe system, or is the result of over pressure of heated media, like water or steam. A rupture in the gas pipe system can be followed up by a gas explosion and or fire. Chemical harmful effects may be the result of components of the gas and the influence they have on materials used in the gas system and appliances, like swelling or hardening of rubbers.

Explosion

An explosion is the result of the presence of an amount of gas mixed with air between the explosion limits in an unconfined or confined situation, ignited by a source. The suddenly energy release may cause malfunctions to appliances, damage to buildings and flying fragments can harm or kill people. An explosion is often followed by a fire, which can greatly exacerbate the consequences. Explosions in the domestic situation rarely occur as a result of small leaks but rather due to total rupture of a supply pipe or hose.

Fire

A fire can, like an explosion, be the result of the release of an amount of gas. However, the amount can be small especially when it is ignited before an explosion can occur. A fire can also be started by hot areas of the cover of the appliance, burner, or the surface of a flue pipe. This can occur by radiation to nearby materials or by direct contact. A third cause of fire can be the result of an excessively explosive ignition of a burner resulting in large flames coming through holes in the cover of the appliance.

A further cause is a very particular one in which the open fire or pilot flame ignites an explosive mixture from other sources in the ambient air. The presence of such a mixture is not normal and has nothing to do with the immediate gas supply or appliance. Explosive mixtures in buildings can occur if petrol (gasoline), thinner, sewage gas and even natural gas are leaking or are being used for other purposes.

Burns

Burns are generally caused by inadvertent contact with open flames or hot surfaces. Visibility of flame can play an important role in avoiding this type of accident.

Suffocation

Suffocation results from the absence of air caused by displacement of the air by gas in unconfined or confined situations. Without an odorant added to the gas, people tend not to notice the absence of oxygen.

Poisoning

Poisoning is mostly caused by the CO content in the flue gas arising as a result of an inadequate burning process; the presence of flue gas in the air is mostly a result of failures in the flue system and ventilating or combustion air system, or is caused by design faults.

APPENDIX J: LITERATURE REFERENCES

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APPENDIX K: LIST OF ABBREVIATIONS

ASME	American Society of Mechanical Engineers
CNG	Compressed Natural Gas
CV	Calorific Value
DGC	Danish Gas Technology Centre
DONG	Danish gas network companu
GERG	Groupement Européen de Recerche Gazière
GHG	The Green House Gas Group
GTI	Gas Technology Institute
GWP	Global Warming Potential
HDPE	High Density Poly Ethylene
HNG	Danish utility
HP	High Pressure
HTL	High Pressure Transmission System
IEA	International Energy Agency
IGT	Gas Technology Institute
IGU	International Gas Union
IP	Intermediate Pressure
LP	Low Pressure
MDPE	Medium Density Poly Ethylene
MN	Methane Number
NCC	Nederlands Corrosie Centrum
NGV	Natural Gas Vehicles
PE	Polyethylene
PVC	PolyVinylChloride
RTL	Regional Transmission System

Slochteren is equivalent to the gas quality depleted from the large gas field in Groningen (NL)

UV	Ultra Violet
VROM	Dutch Ministry of Environment and Country Planning