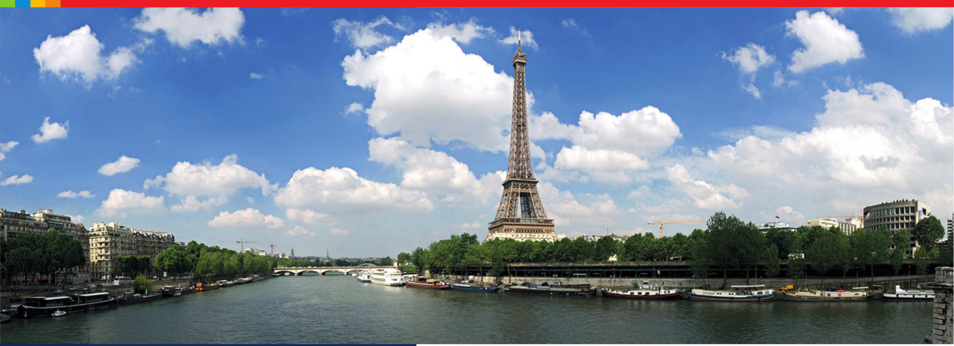
2012-2015 Triennium Work Reports



IGU Working Committee 4
Distribution

Committee report

Dietmar Spohn / Uwe Klaas

June 2015

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WORLD GAS CONFERENCE

IGU
INTERNATIONAL GAS UNION
UNION INTERNATIONALE DU GAZ

2012-2015 Triennium Work Report
June 2015

IGU Working Committee 4

Distribution

Executive Summary:

In the "French" triennium between 2012 and 2015, IGU Working Committee 4 "Distribution" dedicated its work to the following three subjects:

- Regulation of Third Party Access to Gas Distribution Networks – A Standard Approach
- Diversification of Gas Quality and Nonconventional Sources in a Carbon-free Future
- Smart Grids in Gas Distribution

For each of these subjects, a study group was installed. The findings and conclusions of their work, along with a report of the committees other work, is given in this triannual report.

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1 Introduction

IGU Committee 4 “Distribution” is covering the most complicated part of the natural gas infrastructure. The gas distribution systems are present in every country where gas has customers for its use, which are by far most of them. Situated centrally in the gas infrastructure, gas distribution system operators are encountered with almost all problems and challengers coming from either end of the system. To solve and cope with these, their resources are often rather limited, most of these thousands of companies operating on a local or eventually regional base and being of a limited size.

IGU Working Committee 4 "Distribution" examined in this triennium the effects of three "fields of action" onto the operation of gas distribution grids, whereof each states a substantial challenge to the operator, although there are differences in detail due to political or economic different environments:

- Regulation of Third Party Access to Gas Distribution Networks
- Diversification of the gas quality, including gases from non-conventional sources
- Smart Grids in Gas Distribution

Gas distribution companies are experiencing often more than one of these challenges simultaneously, and all of them have their effect on the financial result of running such a company.

2 Gratitude and members’ list

IGU WOC 4 expresses its thanks to all those who made its work possible in the last three years, be it by taking up tasks within the committee work or be it by inviting and contributing to the meeting of IGU Working Committee 4. Without the help of a good number of experts and without the generosity of inviting companies and institutions in both, financing and manpower, the work of out committee and its progress would not have been possible.

In particular, the members and alternate members of IGU Working Committee 4 and of its three study groups providing their expertise and contributing to this report deserve our gratitude. Between 2012 and 2015, the following experts were active members:

Country	Member	Company/Organization
Algeria	Mohamed Hakkoum	Sonelgaz SDA
	Ahmed Zine Hassanine	Sonelgaz CREDEG
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	Ralph Mignone	Envestra Ltd.
Austria	Manfred Pachernegg	Energienetze Steiermark GmbH
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Belgium	Hilde Vinck	KVBG/ARGB
	Kim Vrancken	EANDIS - Synergrid
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	Martin Gregor	ISKA SCHON GmbH
	Steffen Hommel	Stadtwerke Bochum GmbH
	Uwe Klaas (Secretary IGU WOC 4)	German Association of Gas and Water Experts (DVGW)
	Dietmar Spohn (Chairman IGU WOC 4)	Stadtwerke Bochum GmbH
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Iran	Behzad Babazadeh	National Iranian Gas Company N.I.G.C.
	Saeid Momemi	Fars Gas Company
	Mojtaba Sheikhbahaei	National Iranian Gas Company N.I.G.C.
Ireland	Rory Somers	BGN
Italy	Stefano Cagnoli	Iren Emilia
Japan	Akiharu Asada	Osaka Gas Co., Ltd.
	Tohru Takahashi	Tokyo Gas Co., Ltd.
	Ryoichi Toriumi	Tokyo Gas Co., Ltd.
	Yoshii Yoshiaki	Osaka Gas Co., Ltd.
Malaysia	Ahmad Hashimi Abdul Manap	Gas Malaysia
Korea	Hong Seong Kyeyong	Korea Gas Corporation
	Jang Jin Seok	Korea Gas Corporation

Pakistan	Muhammad Riaz Khan	Oil & Gas Development Company Ltd. (OGDCL)
	Faisal Tayyab	Sui Northern Gas Pipelines Company
	Latif Amjad	Sui Northern Gas Pipelines Company
	Iqbal Shazad	Sui Northern Gas Pipelines Company
	Shoaib Warsi	Sui Southern Gas Pipelines Company
Poland	Maciej Chaczykowski	Warsaw University of Technology
Portugal	Armando Magalhaes	Dourogas
	Gabriel Sousa	GALP energia
Russia	Norayar Arzumanov	OAO Gazprom
	Natalya Borokinova	Gazprom
	Anna Dyuzheva	Gazprom
	Konstantin Fedorov	Gazprom
	Vladimir Klimenko	Gazprom
	Tatiana Kopina	Gazprom
	Natalia Kruglova	VNIIGAZ
	Valery Matyushechkin	Gazprom
	Igor Tverskoy	Gazprom
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Serbia	Milan Gavran	Gas feromont
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Slovakia	Peter Demec	SPP Distribucia AS
Slovenia	Franc Cimerman	PLINOVODI d.o.o.
Spain	José Maria Almacellas González (Vice-Chairman of IGU WOC 4)	Gas Natural Fenosa
	Alberto Saiz Gamarra	REPSOL
	Carlos Villalonga Torres	Spanish Gas Association (SEDIGAS)
Thailand	Wijuck Krisnakri	PTT Public Company
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	C.J.A. (Kees) Pulles	KIWA Gas Technology
	Peter Verbeek	Enexis
Tunisia	Ezzine Abdelwaheb	APTG
United Kingdom	Rosemary McAll	DNV GL Noble Denton
	Steven Vallender	National Grid
United States of America	Nicholas Biederman	Gasopalliance
	Christina Sames	American Gas Association (AGA)
	Paul D. Wehnert	Heath Consultants

3 Meetings

IGU Working Committee 4 held 6 meetings in the current triennium:

- 9^{th} to 12^{th} October 2012 in cologne, Germany
- 19^{th} to 22^{nd} March 2013 in Sao Paulo, Brasil
- 8^{th} to 11^{th} October 2013 in Paris, France
- 4^{th} to 7^{th} March 2014 in Madrid, Spain
- 30^{th} September to 3^{rd} October 2014 in Vienna, Austria
- 2^{nd} to 6^{th} March 2015 in Prague, Czech Republic

4 Study Group Reports

In the following three chapters of this report the reports of the three study groups are included. Apart from their respective task which was formulated by IGU WOC 4, the study groups and their experts were entitled to develop their subject on their own. To meet, each study group had sufficient time to do so in the framework of the meetings of IGU WOC 4; the working committee members were kept informed at the end of each study group meeting session by means of a presentation of the results by the study group leader or, at some meetings, by his appointed deputy.

The three study groups were:

- Study group 4.1 “Regulation of Third Party Access to Gas Distribution Networks – A Standard Approach”, chaired by Mr. José Carlos Broisler Oliver, Brazil;

- Study group 4.2 “Diversification of Gas Quality and Nonconventional Sources in a Carbon-free Future”, chaired by Mr. Peter Flosbach, Germany;

- Study group 4.3 “Smart Grids in Gas Distribution”, chaired by Mr. Pascal Vercamer, France.

5 Report of IGU Study group 4.1

Regulation of Third Party Access to Gas Distribution Networks – A Standard Approach

Study Leader: José Carlos Broisler Oliver, Brazil

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5.1 Introduction

The large scale commercial use of natural gas as an energy source started in the beginning of the XX century. Since then natural gas has been recognized as a potential monopolistic market. To prevent companies from taking advantages from its privileged position, the natural gas market has always traditionally been highly regulated.

In some places, this highly regulated model has led to inefficiency and an imbalance between production and demand of natural gas. To overcome this problem a liberalization process had begun during the 1970's. Many state-owned companies had been were privatized. After privatization, the next step to liberalize the market is to implement open access and unbundling regimes to ensure that natural gas is approached as a commodity and infrastructure operators as service providers.

5.2 Background and Purpose

5.2.1 Background

Third Party Access (TPA) is much more frequently applied to transmission networks rather than to distribution. In some cases TPA is applied to distribution networks, however, its application often does not occur as effectively as in transmission. Another aspect is that much of the regulation for TPA in distribution is basically a copy of the rules for transmission, thus it is hard to notice any difference that could be applicable to distribution.

Third party access presents a wide variety of concepts and stages of development worldwide. The level of implementation is usually directly related to the maturity of the gas industry in the studied area. Due to their effectiveness on TPA models natural gas markets such as U.S. and the E.U. are considered as references of TPA regulatory frameworks. It is also important to highlight that increasing the supply of gas and reducing the final cost to consumers are the pillars that are used to justify and support the implementation of TPA, However, these regulatory objectives are not always effectively achieved.

5.2.2 Purpose

TPA has gained attention of the gas industry and its regulatory bodies within the last decade. However, its meaning is still misunderstood or it is not well developed or applied in several countries. The purpose of this document is to describe the relevance of natural gas markets around the world; present different experiences worldwide regarding TPA legislation and regulations, its stage of implementation and evolution describing benefits and problems.

5.3 Terminologies and Definitions

This section has the objective to familiarize readers to common terms used in this paper. It is presented. Below several terminologies and definitions are presented that are frequently used in this document:

Third Party Access (TPA) - can be categorized as either:

(a) Costumers being able to use a system that they do not own or control in order to transport gas for their own use or for resale;

(b) Suppliers being able to use a system that they do not own or control in order to transport gas for sale to costumers.

Negotiated Third Party Access (NTPA): NTPA is a form of open access regime wherein access is provided based on voluntary agreements negotiated between producers and service providers. The main terms for these agreements shall be set and published by the system operator in order to guarantee non-discriminatory conditions. This regime may be considered as a more lenient TPA regime.

Regulated Third Party Access (RTPA): this form of TPA assumes that contracts between energy retailers and system operators will be based on regulated conditions and prices. There is a regulatory authority that designates prices in non-liberalized segments such as storage, transportation and distribution. This regime can be considered as a more rigid TPA regime.

Transmission System: System used to transport natural gas over long distances through high pressure pipelines. Generally this system feeds gas to Distribution Systems although some customers may be connected directly to this system.

Distribution System: System used to transport natural gas regionally through local pipeline networks. Most customers are connected to these networks.

Distribution system operator (DSO): A company responsible for the operation, maintenance and development of a distribution system in a given area.

Transmission system operator (TSO): A company responsible for the operation, maintenance and development of a transmission system in a given area.

Local distribution company (LDC): A natural gas company which is responsible for the distribution of natural gas.

Independent System Operator (ISO): it is defined as vertically integrated companies that retain the ownership of their network assets, but the transportation network itself is managed by an independent party known as Independent System Operator.

Unbundling: Separation of energy network activities from production and supply activities. Unbundling can be categorized such as:

(a) **Functional unbundling**: Requires independent organization and decision-making of gas infrastructure companies. Functional unbundling focuses on substantial separation including physical separation operation of gas infrastructure and non-gas infrastructure business.

(b) **Ownership unbundling:** Is the process by which a company is divested of some of its assets via legislation.

(c) **Legal unbundling:** Requires the separation of infrastructure functions from non-regulated functions of vertically integrated company in independent legal persons.

(d) **Account unbundling:** Requires gas companies to separate accounts for each different gas business.

(e) **Service unbundling:** The separation and itemization of product, transmission and distribution costs in the customer bill. Service unbundling focuses on separation of tariffs and rates for each service related to the supply of natural gas.

Regulatory framework: System of regulations and the means used to enforce them – usually established by the government to regulate specific activities.

Open Access: The possibility of customers to choose their natural gas suppliers and their transportation arrangements.

5.4 Open access in North America

5.4.1 United States of America

5.4.1.1 Natural Gas Market

The USA natural gas market may be described by three main characteristics: it is very mature, well developed and independent from importations.

Around 25.6 trillion cubic feet of natural gas were consumed in the USA in 2012, 94% were produced locally, which points out that natural gas supply does not depend on importation. Approximately 40% of the natural gas produced in USA corresponds to shale gas. The increasing shale gas production is having a big impact in USA´s natural gas market and the expectation is that U.S. will become a net exporter of natural gas by 2018.

The US natural gas supply system is composed of:

- 305,000 miles of interstate and intrastate transmission pipelines;
- 24 hubs or market centers that provide additional interconnections;
- 400 underground natural gas storage facilities;
- 49 locations where natural gas can be imported/exported via pipelines;
- 8 LNG (liquefied natural gas) import facilities and 100 LNG peaking facilities.

A combination of regulatory and legislative initiatives led to a more competitive market and to changes in the role of the natural gas distribution companies. This progress was started up by the restructuring of the transmission operations in 1990, and by the increased competition between the transportation segments and the local distribution. Consequently, the LDCs had to restructure their operations to remain economically viable and competitive. The study indicates that in 2006 approximately 60% of the natural gas consumed in the country was delivered by LDCs, the remaining amount was delivered directly, via transmission pipelines.

After restructuration of the market, supply to end users via LDC declined, despite the increase of the client base served by LDCs (8 million of new clients). This decline was generated by several factors, among them:

- Increased competition between the LDCs and the natural gas transportation companies;
- The direct negotiation and the strategic localization of electric generation plants together with natural gas transportation companies;
- The increase of natural gas equipment efficiency in residences and in commercial facilities.

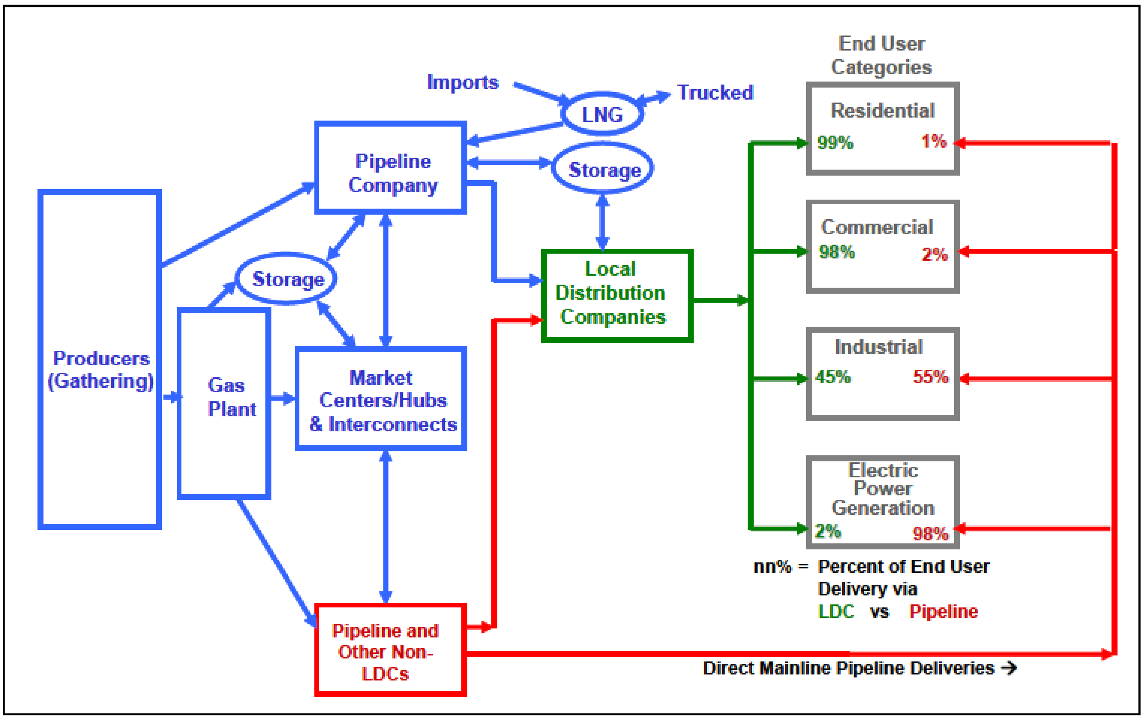

Figure 5.1: Natural Gas Supply for different segments

Source: Energy Information Administration, Office of Oil and Gas

5.4.1.2 Natural gas market before deregulation and unbundling

The natural gas industry in the USA started to grow in the early 20's when flaring at the wellhead was prohibited. Over the 30´s the concern with the energy market growth led to the implementation of regulations, among them, The Natural Gas Act of 1938 (NGA). According to the NGA the gas industry is a potential monopolist sector and thereby the Federal Government decided to define the tariffs charged by the inter-state transmission companies. The federal regulator also took part in the certification of the new companies and in order to optimize the infrastructure resources, NGA established that it was not permitted to build a new interstate network to deliver natural gas in a market that was already supplied by an existing network.

The NGA tried to establish fair and moderate tariffs and wellhead prices were regulated only if the producer and the transmission network were affiliated companies. Otherwise, the market would maintain the wellhead prices in a competitive way. However, in 1954 the High Court´s ruling in Phillips Petroleum Co. v. Wisconsin - 347 U.S. 672 decided that producers should be considered as “natural gas companies” according to NGA. That meant that wellhead prices would also be regulated. At that time the traditional cost-of-service based rate was adopted to regulate wellhead prices.

The price of natural gas at the wellhead was regulated from 1954 to 1978. During this period, three different approaches were used to calculate the natural gas price, however, none of them was efficient enough to maintain the natural gas price within fair parameters to both producers and consumers. This tariff system depended on the supply service cost, not on the product market value. The prices established by the Federal Power Commission (FPC) during this period were not profitable enough to attract new investments from producers, and, at the same time, the natural gas prices were competitive in the market pushing its demand. Therefore, the 1970´s brought a strong crisis in terms of natural gas supply.

5.4.1.3 Regulation Development towards the Free Access Liberalization

In November 1978, during the peak of the gas supply crisis, the Natural Gas Policy Act (NGPA) was enacted. The NGPA´s main target was the gradual liberalization of wellhead prices. Furthermore, to eliminate the barriers between the interstate and intrastate markets, the federal regulator, was reorganized as FERC (Federal Energy Regulatory Commission) received jurisdiction over intrastate transportation companies. With the liberalization of wellhead prices, there was an increase in the total cost for end users which resulted in a decrease in the demand. This fact resulted in take-or-pay fine payments, made by the transmission companies to the suppliers, leading to market imbalance.

The process for implementing open access began in 1985 when the FERC issued Order No. 436, which introduced the voluntary unbundling to separate the natural gas transportation service from the product supply. This ruling provided to every end-user the opportunity to obtain transportation services, which had been available since the early 1980s only to Special Marketing Programs (SMPs) developed for large, fuel-switching customers.

While Order No. 436 was influenced by FERC’s rulings on SMPs, these had been found discriminatory by the US District of Columbia Circuit Court of Appeals in several 1985 cases. The court ruled that SMPs were discriminatory in that they unreasonably limited the class of customers with the ability to purchase their own natural gas and transport it in a pipeline. As a result of this, SMPs were eliminated in October 1985.

Although Order No. 436 was voluntary, all major interstate pipelines were later required to offer open access, unbundled transportation by Order No. 636 in 1991. The reason behind accepting the “bargain” offered by FERC in Order No. 436 could have been that companies volunteering could take advantage of "blanket certification" of new transportation. Blanket certification meant that new transportation services would be authorized generically, eliminating the need for long and costly individual certification proceedings.

Order 436 brought immediate consequences, such as the increase of “take-or-pay” payments made by transportation companies, as the clients were less interested to buy high priced gas from the transportation companies; moreover, several litigation proceedings between the transportation companies and the gas suppliers.

In order to minimize the effects on the take-or-pay contracts, FERC issued Order No. 500 in 1987. The intention was the liquidation of “take-or-pay” contracts by the interstate pipelines, passing on cost burden to the transmission tariffs. The LDCs that received it could, by their turn, pass on the cost burden to retail customers, as ordered by several US State Regulatory Bodies.

The Natural Gas Wellhead Decontrol Act of 1989 (NGWDA) completed the liberalization of natural gas prices at the wellhead. The NGWDA replaced the NGPA and removed all the remaining wellhead ceiling prices. The NGWDA also gave the FERC more power to regulate the natural gas market and prepare the liberalization Order, the FERC Order 636 in 1992.

Continued fine tuning of open access happened with FERC Order No. 636 enacted on April 8th, 1992. This Order introduced the mandatory unbundling in the natural gas sales and transportation infrastructure activities. The adopted unbundling model required the separation of the accounts in order to prevent crossed subside between regulated and non-regulated activities (account unbundling). Order 636 also adopted Standards of Conduct requirements (functional unbundling) to maintain the infrastructure activities separate from the supply activities and avoid anti-competition practices. On the top of that, the referred Order also demanded the legal separation of sale branches affiliated to infrastructure companies (legal unbundling).

The US General Accountability Office[1] (GAO) issued its report on the cost/benefits of Order No. 636 in 1993. GAO report estimated that the order’s mandated change in rate design would shift about $1.2 billion per year nationally from the pipeline industry’s fixed costs (approximately 11% in 1993) to customers requiring guaranteed delivery of gas, i.e., residential and small commercial end-users. Based on the analysis of 5 pipeline companies serving the US east coast the GAO estimated that residential users could see an increase of up to 9% in their gas bills. Non-residential customers it was estimated could see decreases by as much as 7%. However, these results, GOA pointed out, could not be extrapolated to the entire US. At the time the report cited that the FERC estimate of benefits would exceed costs by from $2 billion to $6 billion annually on average. GAO doubted that benefits would be this high in that it felt that costs of implementation could be significantly higher, but offered no estimates of its own of net benefits.

[1] Effective July 7, 2004, the GAO's legal name was changed from the General Accounting Office to the Government Accountability Office.

The GAO report also voiced concerns from upstream operating companies. Distribution companies that served residential and small commercial end-users were worried not just about cost increases, but also about the potential for supply interruptions. This they argued would result from a decrease in the operational control combined with an increase in the number of buyers and sellers in the market place. These events, the distribution companies opined, "could increase the potential for transportation bottlenecks or other threats to the delivery of gas supplies…"; particularly since FERC did not require pipeline companies to give their customers priority over other end-users. While there were price adjustments and costs did rise in some parts of the US the concerns about supply interruption turned out to be unfounded.

In 2000 FERC issued Order No. 637. This order essentially fined tuned Order No.636, under which the industry by then had 6 years of operating experience. In Order No. 637, FERC amended its regulations in response to the growing development of more competitive markets for natural gas and the transportation of natural gas. In the rule, the FERC revised the existing regulatory framework with the intent of improving the efficiency of the market and providing "captive customers" with the opportunity to reduce their cost of holding long-term pipeline capacity while continuing to protect against the exercise of market power.

FERC revised its pricing policy by waiving price ceilings for short-term released capacity for an experimental, two-year period, and permitting pipelines to file for peak/off-peak and term differentiated rate structures. It was FERC's intent that the changes under Order No. 637, including changes relating to scheduling procedures, capacity segmentation and pipeline penalties, would improve the competitiveness and efficiency of the interstate pipeline grid. Order No. 637 also narrowed the right of first refusal to remove economic biases in Order No.636, while protecting captive customers' ability to re-subscribe to long-term capacity. And it was intended to improve FERC's reporting requirements for pipeline operators in order to provide the FERC more transparent pricing information, and permit more effective monitoring of the market.

Most important to the pipelines in order to remove economic biases in the existing regulations, Order No. 637 narrowed a shipper's "right of first refusal" to re-subscribe to long-term capacity.

5.4.1.4 Present Regulation

<u>Service Unbundling</u> – After the liberalization of the natural gas market, the tariffs and rates for product and transportation services are separated in the bill. All transportation services were unbundled, such as transmission, underground storage and LNG facilities. Distribution service also was unbundled in the stats that adopted retail unbundling.

<u>Legal Unbundling</u> – In vertically integrated companies the infrastructure functions subject to regulation are required to be separated from non-regulated functions in independent legal persons.

<u>Account Unbundling</u> – The account unbundling was introduced in order to avoid crossed subsides between production and service companies after gas liberalization. The account unbundling obliges

the gas companies to unbundle their accounts concerning every type of business related to gas. Viewing the implementation of the account unbundling, the detailing of accounts, formulary and statements were modified several times: Order 581 (1995), Order 637 (2000) and the most recent one, the FERC Order 710.

Requirements for account unbundling have also been introduced in the States that adopted the retail unbundling, such as, New York, Maine, Pennsylvania, etc. In State level, the LDCs must also submit the wheeling and sector accounting to the State Regulator, to be duly inspected. For example, in Pennsylvania, each LDC must prepare and deliver the Natural Gas Distribution Annual Report Form. This Formulary includes the Wheeling Accounts, such as the Deliveries of Gas Transported or Compressed for Others' and Sectoral Accounts for LNG terminals, distribution, underground storage, etc. A similar requirement to submit the sector and wheeling accounts is also applied to LDCs in New York State.

Functional Unbundling – The concept of functional unbundling was introduced after gas liberalization in order to regulate anti-competition practices of the market affiliates of gas infrastructure companies, and to avoid the discrimination in these infrastructure companies in favor of their affiliates. In general, the functional unbundling regimes are done to change the organization and the decision making process in gas companies. Even if the infrastructure of a gas company classifies it as a subsidiary in a vertically integrated company it should act independently and fair, in the act of offering infrastructure to its market affiliates and to other companies. The functional unbundling step is introduced differently in Federal and State levels.

Regulated Open Access – In addition to the unbundling requirements, some other requirements were put in place to help the gas purchasers to access the gas infrastructure with the same rights and services, independently of the origin of the gas. These requirements are based on the transparency and non-discrimination principles.

Standards of Conduct – FERC first adopted "standards of conduct" to regulate natural gas pipelines' interactions with their marketing affiliates in 1988 in Order No.497. The Commission issued new, revised regulations in 2008 in Order No. 717 that continued and elaborated restrictions on transmission provider actions relative to affiliated marketing personnel.

Capacity Rate and Capacity Release – As per FERC Order 636, the regulations defining the capacity must observe the non-discrimination and transparency requirements. Being part of the FERC Order 636, the capacity release program was adopted to help the open access regime. The purpose of this program is forcing the existing infrastructure capacity holders to reallocate their capacity infrastructure, to be used by other market players. For instance in 1993, although the LDCs remained holders of most of the firm transportation market, the capacity holders sold part or all of their capacity into the market. A lot of effort was put to review the capacity release market. One example is FERC Order 637, which allowed capacity holders to trade their rights in secondary market transactions.

Tariffs – After gas liberalization, the determination of non-discriminatory and non-preferential tariffs and prices is also important. Several reforms concerning the transportation and storage tariffs were started, in order to define the principles for open access to tariffs. These reforms helped the transportation and storage process to accept the present market conditions. Some of these reforms are listed below:

- FERC Order 436 introduced a flexible rate structure;
- FERC Order 636 mandated straight fixed-variable rate design (where all fixed transmission and storage costs are billed through the pipeline's reservation charge) for transportation and storage services, according to the mandatory open access regime. For instance, all the operators of interstate pipelines were compelled to calculate the transportation service tariff using the same criteria;
- Other tariff reforms were established by FERC Order 637 in 2000;
- FERC Order 678 focused on reforming the storage tariff planning in 2006;
- FERC Order 712 lifted price caps on short-term (1 year or less) released capacity, but kept price caps on primary sales of capacity by pipelines.

Finally, according to Section 4 of Natural Gas Act and Subpart D of Part 151 of FERC's regulations, every gas company must keep an electronic file of its tariffs, which must be available for public consultation.

Information System – According to the transparency requirements, it is necessary to establish an information platform, permitting that potential users have access to the same information related to gas infrastructure. Recently, FERC took some measures to reinforce the transparency requirements. For instance, some reforms were established to make more information regarding interstate gas infrastructure available. Concerning the open access regime handling, the information systems are normally used as transaction platforms and as the interface between the gas companies and the consumers. They implement not only the transparency conditions, but also the non-discriminatory requirement. The information available on the website has been previously approved by FERC, therefore, it represents concrete information. For instance, the open access and tariff conditions must observe the non-discriminatory requirements.

Gas Quality – According to the FERC and the pertaining regulations, the companies must supply information about gas quality. The information must include the date, relative density, heating value in BTU (British thermal unit), chemical composition of carbon dioxide, methane, ethane, propane, i-butane, n-butane, i-pentane, n-pentane, hexanes, among others. This information helps the shipper meet gas quality requirements in certain facilities. These details are very important, as they are used to specify the open access tariff.

Imbalance Information – Following the pertaining regulations, the intestate companies must post imbalance information to ensure non-discriminatory and transparent imbalance management.

5.4.1.5 Gas market liberalization at the US State level

The State policies determine if the sales services must be unbundled from distribution and storage services. Due to the concern in relation to public service obligations, not every State introduced the unbundling regulations. The Natural Gas Residential Choice Program of 2010, developed by the US Energy Information Administration indicates that 22 States had implemented unbundling programs (limited, completed or pilot programs); on the other hand, 29 States had not implemented unbundling programs and 2 States discontinued their pilot programs.

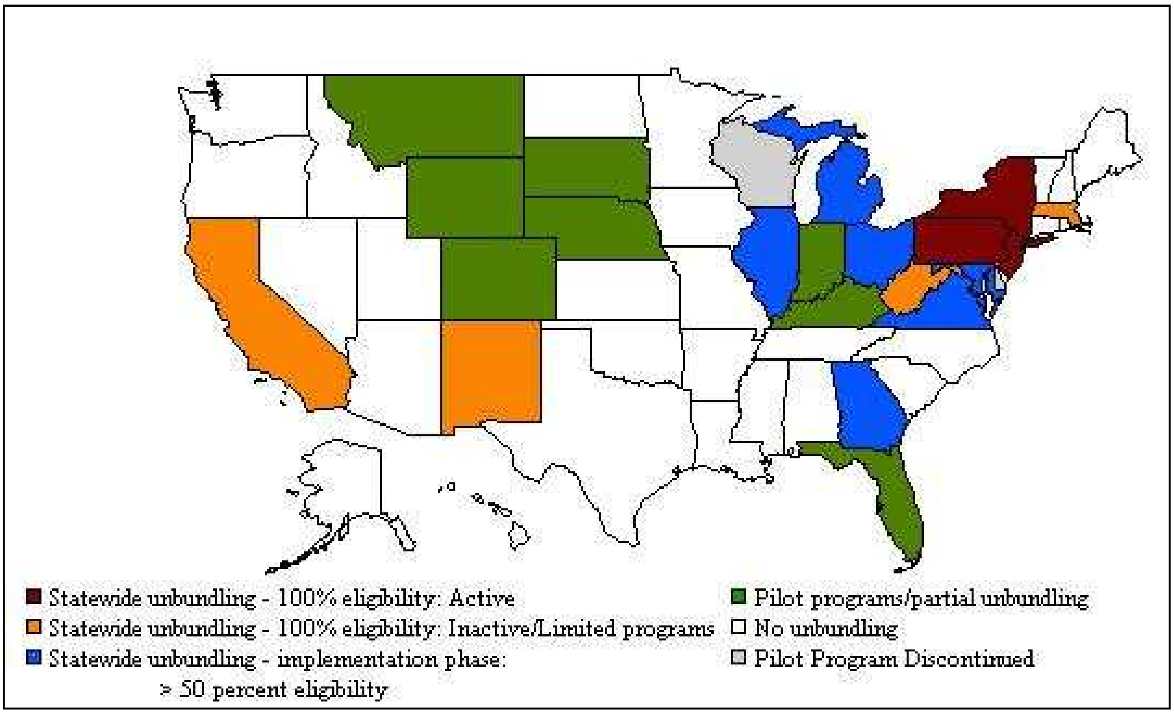

Figure 5.2: Status of Natural Gas Residential Choice Programs by State as of December 2009

Source: US Energy Information Administration (2010)

States were allowing unbundling of gas service to all customer classes generally since the mid-1990s. One exception, however, where unbundled service had been "on the books" to all natural gas customers since 1986 is West Virginia. Under West Virginia State Senate Bill 117, passed in 1983, intrastate pipeline companies and LDCs were required to be common carriers. The procedural laws were completed in 1986 and covered all customer classes. In order to receive unbundled service, customers must install metering equipment or pay standby charges.

The state commissions often follow open access polices similar to those set out by the FERC. Many of the US states have enacted laws that allow the ultimate, end-use customer to purchase gas from an individual producer/supplier and have that gas delivered to their premises by using the transmission system that delivers it to the local supplier (Local Distribution Company: "LDC") with the ultimate responsibility of delivering it to the customer.

The term for those selling natural gas to end-users is "marketers." Most state utility commissions require that marketers must file a copy of their standard contract with them. A separate standard contract is required for residential and commercial customers. These contracts must then be approved by the state regulatory commission. Once these requirements are met a letter is sent to the marketer stating that it is in compliance. The marketer will then present the letter and required financial information to the local utility company for determination of creditworthiness before it can offer services. Generally, each local utility company has its own criteria for creditworthiness.

After utility acceptance, marketer information is usually placed on the utility commission website, and made available to any consumer upon request. Consumers may also be able to obtain marketer information from the local utility.

The state utility commissions continue to maintain regulatory authority over the transmission and distribution of natural gas within their states. The commissions will usually also monitor the transition process, and identify and remove barriers that may impede the growth of a competitive market within their state.

Customer rights and obligations are generally the same across the US. In California for example, customers of major CPUC-regulated natural gas utilities have the option to obtain their supply of natural gas from a non-utility supplier. For "core" gas customers, i.e. mainly residential and small commercial customers, this program is referred to as either the "core aggregation" service or the "core transportation" service. It has been in place since the early 1990's.

In California the non-utility natural gas suppliers are not regulated, licensed, approved or endorsed by the CPUC. The CPUC does not approve the gas prices that a non-utility supplier offers the end-user. If the end-user has a complaint against a non-utility natural gas supplier, it may not be possible for the CPUC to resolve the complaint with the non-utility supplier.

Under the core aggregation service in California, the natural gas utility still delivers natural gas supplies, and the end-user pays the utility for that service. The billing for the gas supply may be done by either the gas supplier or by the utility.

For core customers, the CPUC-regulated utility is the back-up supplier in the event that the non-utility supplier fails to deliver adequate supplies to the utility system or goes out of business. The end-user will still receive uninterrupted gas service from the utility, but will then be billed for the supplies provided by the utility, at the CPUC-approved utility procurement rate.

5.4.1.6 Summary

The present study indicates that the unbundling, together with the FERC Regulatory Orders and the affiliated agencies, besides increasing competition in natural gas market sectors and decrease the market power of the transmission companies, also re-structured the market in USA.

Residential, commercial and small industrial customers can now purchase gas from companies other than their LDC. This gas, however, is still delivered through the mains and services maintained by their LDC. Large industrial customers can by-pass their local distributors by establishing direct contracts with interstate natural gas companies and producers if the economics of installing a separated delivery system allows. This flexibility offered a larger range in terms of natural gas purchase, and several transportation standards to render services to the end user.

5.4.2 Canada

5.4.2.1 Natural Gas Market

Canada's natural gas pipeline system is highly interconnected with the U.S. pipeline system. TransCanada operates the largest network of natural gas pipelines in North America, including thirteen major pipeline systems and approximately 37,000 miles of gas pipelines in operation. Within Canada, TransCanada Pipeline operates a 25,600-mile network that includes the 10.6-Bcf/d Alberta System and the 7.2-Bcf/d Canadian Mainline. Spectra Energy operates a 3540-mile, 2.2-Bcf/d pipeline system connecting western Canadian gas supply regions with markets in the US and Canada. Spectra Energy also operates the Maritimes and Northeast Pipeline linking eastern Canadian supplies with consumers in the eastern US. Finally, the Alliance Pipeline, a 2311-mile pipeline system, is a significant source of natural gas for the U.S. Midwest that delivers 4.6 Bcf/day to both Canadian and U.S. markets.

The Canadian pipeline system expanded rapidly in the 1989-1993 period, primarily to accommodate the large increases in export sales to the US. Total export capacity on Canadian pipelines in 2012 was approximately 396 million cubic meters per day (14.0 Bcf/d). The development of US shale gas reserves has dampened the Canadian export market, since 2005. In 2011 Canada exported 3.3 Tcf (8.5 Bcf/day) of natural gas. In somewhat of a turnaround the US exported 1.1 Tcf of gas to Canada in 2011.

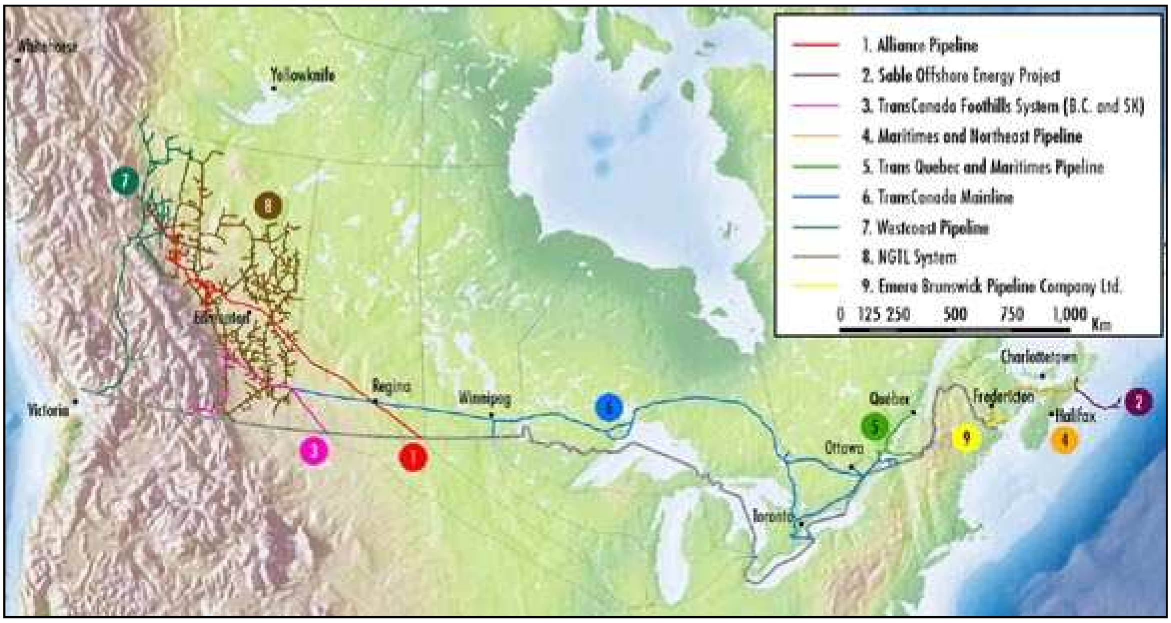

Figure 5.3: Major Natural Gas Pipelines Regulated by the NBE

Source: Canadian Pipeline Transportation System - Energy Market Assessment – April 2014

5.4.2.2 Present Regulation

The Canadian National Energy Board is an independent, quasi-judicial federal agency whose purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade.

The NEB's main responsibilities include regulating:

- The construction and operation of interprovincial and international oil and gas pipelines;
- Tolls and tariffs on these pipelines;
- International power lines;
- Imports and exports of natural gas, oil, natural gas liquids (NGLs) and electricity
- Oil and gas exploration and development on frontier lands and offshore areas not covered by provincial or federal management agreements.

NEB is required by the National Energy Board Act to ensure that applied-for long-term natural gas exports will be surplus to reasonably foreseeable Canadian requirements before it issues an export license. In July 1987, the NEB adopted a new procedure, known as the Market-Based Procedure (MBP), by which it makes this assessment. The basic premise of the MBP is that the market will work to satisfy Canadian requirements for natural gas at fair market prices. For this to be fulfilled, markets must be competitive, there should be no abuse of market power, and all buyers should have access to gas on similar terms and conditions.

The NEB implemented the MBP shortly after the Governments of Canada and the 3 gas producing provinces of British Columbia, Alberta and Saskatchewan signed an agreement on Natural Gas Prices and Markets on 31 October 1985. This agreement provided for a landmark change in the Canadian natural gas market by allowing gas buyers, for the first time, to directly contract for supplies with producers, marketers and other agents at freely negotiated prices.

While the 1985 agreement created the necessary conditions for the establishment of a competitive natural gas market, the signatory parties recognized that the pipeline transmission sector of the gas industry would continue to be regulated, because of its natural monopoly characteristics. A necessary requirement for establishing a competitive gas market was that open non-discriminatory access be provided to all shippers on interprovincial gas pipelines. The NEB subsequently ensured that such access was provided.

The NEB reported in their 1996 report that "…[f]ollowing price deregulation and the establishment of open access, eastern Canadian local distribution companies (LDCs) who used to rely on TransCanada for all of their gas supplies began to purchase from a variety of suppliers. In turn, most industrial gas users quickly elected to buy their gas directly from suppliers, rather than from their LDC. Many new companies jumped into the business of natural gas marketing, including gas producers and newly-formed marketing companies, as well as subsidiaries of the pipelines."

"Natural gas wellhead prices fell by 40 percent from 1985 to 1987 and fell a further fifteen percent by 1995. During the same time, production and exports grew rapidly".

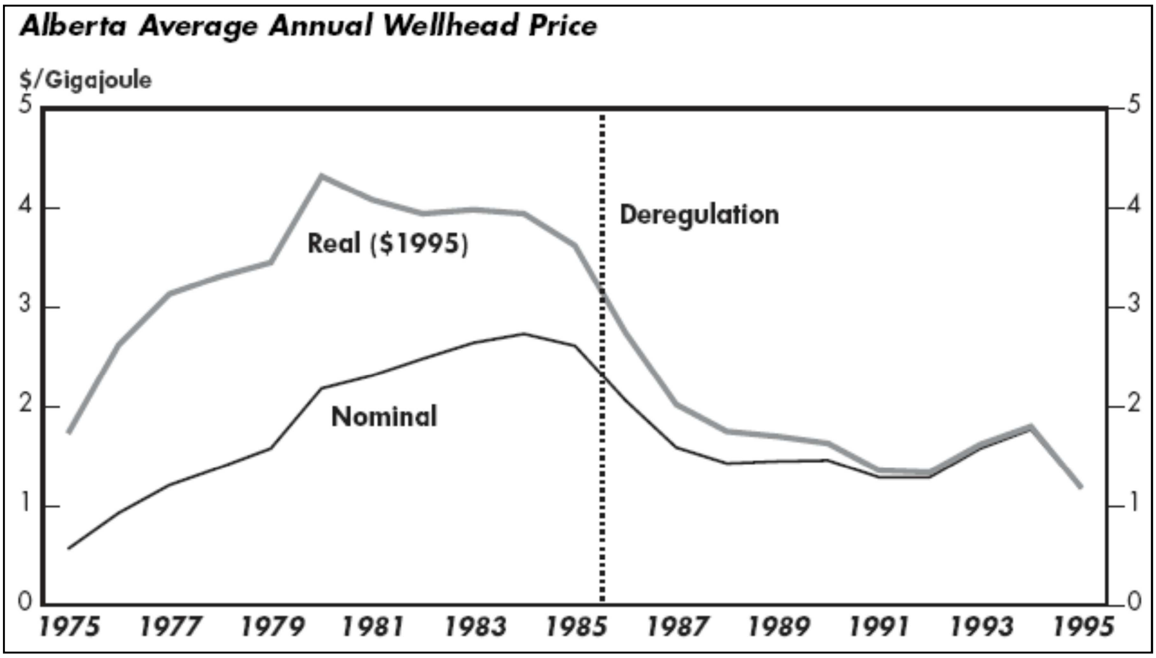

Figure 5.4: Alberta Average Annual wellhead Price

Source: Natural Gas Market Assessment – Ten years after deregulation, November (1996)

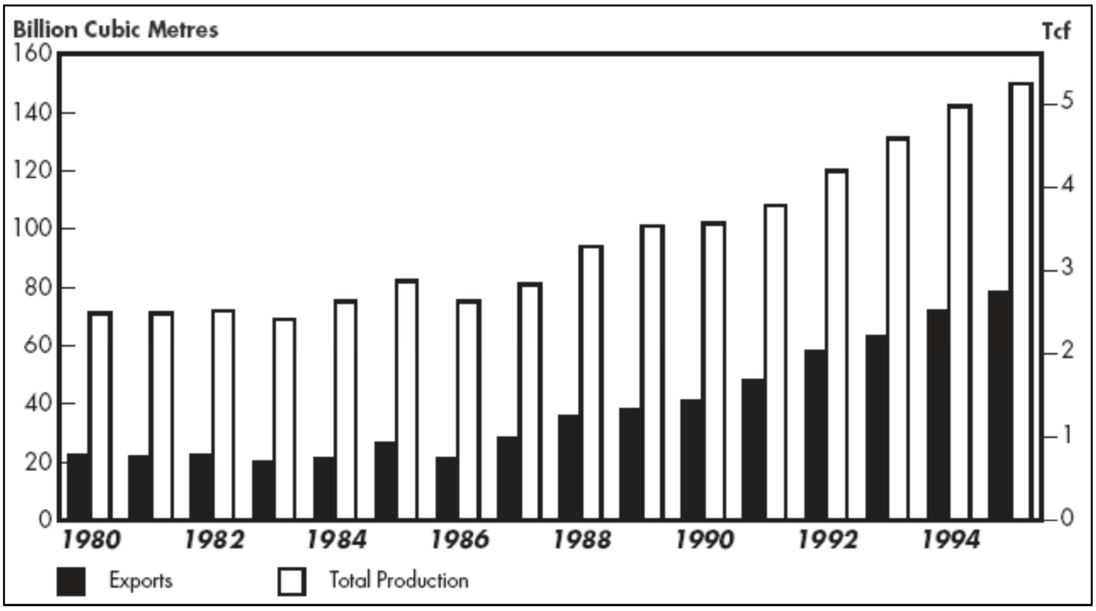

Figure 5.5: Natural Gas Production and Exports

Source: Natural Gas Market Assessment – Ten years after deregulation, November (1996)

In the 10-year period from 1985-95, Canadian pipelines implemented a number of service options for enhancing the flexibility of gas transportation, according to the NEB. One example of increased flexibility is that under the terms and conditions for firm service on TransCanada, shippers were now permitted to divert gas to points other than those specified in the shipper's contract. Under the concept of “backhaul service”, TransCanada could then allow shippers to borrow gas from the system at an upstream point and repay it with downstream gas. This procedure is useful when a shipper needs to deliver gas upstream of the point at which the shipper’s gas is delivered to the pipeline. Thus, pipeline capacity can be fully utilized and the risk to shippers having to pay demand charges for unused capacity is reduced.

In 1988 and 1989 the NEB approved changes to the market creating the secondary market for transportation service rights. At this time the TransCanada system was allowed to let shippers re-assign firm transportation rights to third-party shippers.

In the evolving regulatory environment, the NEB decided in 1995 that to establish electronic bulletin boards (EBBs) for providing the means for mandatory posting of capacity trades. At his same time the NEB endorsed the removal of the price cap on transportation. This cap had limited the price of transportation capacity sold on the secondary market to the level of the firm service toll. Thus, the price of capacity on the secondary market was allowed to move freely reflecting its market value at any point in time.

As a result of these rulings, a number of pipelines formed a company known as the NrG Highway. The purpose of this entity was to provide a single point of contact for multiple pipeline systems. The NrG Highway developed an EBB of its own to allow shippers to advertise that they had capacity to sell or to search for another user who has expressed interest in acquiring capacity on a number of pipeline systems. Negotiations still take place between parties, but the EBB feature helps to bring buyers and sellers together.

The establishment of the secondary market then has:

- Provided a means for capacity to be transferred to those users who value it most;
- Helped to ensure that the pipeline system operates efficiently and at high levels of utilization;
- Improved the ability of the industry to deliver gas in the lowest cost way;
- Increased the ability of shippers to manage the risk of holding long-term transportation contracts;
- Reduced the need to construct additional facilities.

The 1985 regulations also ushered in a new pricing regime. In the regulatory environment prior to the 1985 Natural Gas Agreement, end-users purchased gas from their LDC at a fixed price per unit of gas. In these cases, the end-user would not have been aware of the separate charges for gas, transportation, storage services, or delivery by the LDC. After the 1985 ruling, most consumers had the option of purchasing gas from their utilities or through a direct sale, in which the end-user enters into a gas purchase agreement with a supplier.

Large end-users, such as industrial customers, generally purchase gas directly from suppliers. Smaller gas end-users who opt for direct purchases usually utilize the services of an agent/broker/marketer (ABM). There are generally 2 options offered by LDCs to facilitate direct purchases: a transportation service arrangement (T-service) and a buy/sell mechanism. Under T-service, the shipper arranges for transportation by transmission and/or distribution companies. The delivery arrangement on the transmission system provides for delivery of gas to an LDC at a bundled price that includes the cost of gas plus the cost of transportation. The delivery arrangement on the distribution system may be bundled or unbundled. A bundled service on an LDC's system includes load balancing. The shipper may be a producer, a distribution company, an end-user or an ABM representing the end-user. Most industrial customers choose T-service for their direct purchases.

According to the NEB, in most provincial jurisdictions, the LDC is the "supplier of last resort" in the event of supply failures. The LDC has an obligation to serve within its franchise area. Incremental costs associated with back-stopping services provided by the LDCs are generally recovered from the suppliers who failed to deliver the gas supplies. On the other hand, storage and load balancing costs are included in the LDCs' distribution rates.

The next step towards a fully-deregulated gas market was to allow all core customers (residential and small commercial) to purchase gas directly from the supplier of their choice. Many regulatory initiatives have been undertaken since the 1985 agreement to provide more choice to core market gas users. Provincial core market policies currently vary across Canada. Several provinces allow ABMs to market gas directly to core customers, subject to requirements that they obtain licenses or pay registration fees and post a bond. ABMs are also expected to follow a code of conduct which is intended to protect core customers from unethical trade practices.

In the late 1980s, active spot markets began to develop at various locations in North America, some of which later turned into market hubs. By 1995, spot markets had a large influence on the pricing of gas throughout the market. The pricing in many sales contracts, including long-term contracts, is market-responsive and is often determined according to indices of monthly spot prices in the relevant market region.

5.5 Open access in Europe

5.5.1 European Union

5.5.1.1 Introduction

Natural Gas is considered a commodity in the European Union (EU), and its users receive the natural gas via a transportation network and an infra-structure that is very complex, composed of transnational piping, storage facilities, transportation infrastructure and LNG re-gasification, besides other co-related infrastructures.

Despite the fact that the local conventional reserves are almost depleted, the demand for natural gas is still increasing, as well as its importance to the EU fuel sector. The EU State members consider that the development of an efficient inland market is the best way to face the challenges and uncertainties of the future. A reliable and interconnected system can minimize a series of complex issues, for example, supply security.

It is the EU´s intention to promote the full integration of its energy market until the end of 2014, offering to the consumers the guarantee of having the best products and services, higher competition and security of supply.

A big step forward has been already taken, as consumers can choose their gas and electricity suppliers, and the suppliers must give clear and precise information about the supply´s terms and conditions. Other steps to be taken refer to the alignment of national operation rules, and to facilitate investments in transnational infra-structures.

5.5.1.2 General View of the Market

Although oil and its by-products are dominant in the European energy matrix, their consumption has been decreasing in the region. At the same time, the relevance of natural gas and renewable energy sources has expanded.

Since 2005, the increased integration of the markets is leveraging competitiveness in the wholesale energy market in Europe. Countries with well-developed gas hubs tend to have greater price stability, besides having cheaper prices to import gas via pipelines. Based on it, one can consider that these markets, besides having a higher level of energy safety, also have lower wholesale gas prices in view of the increased competitiveness.

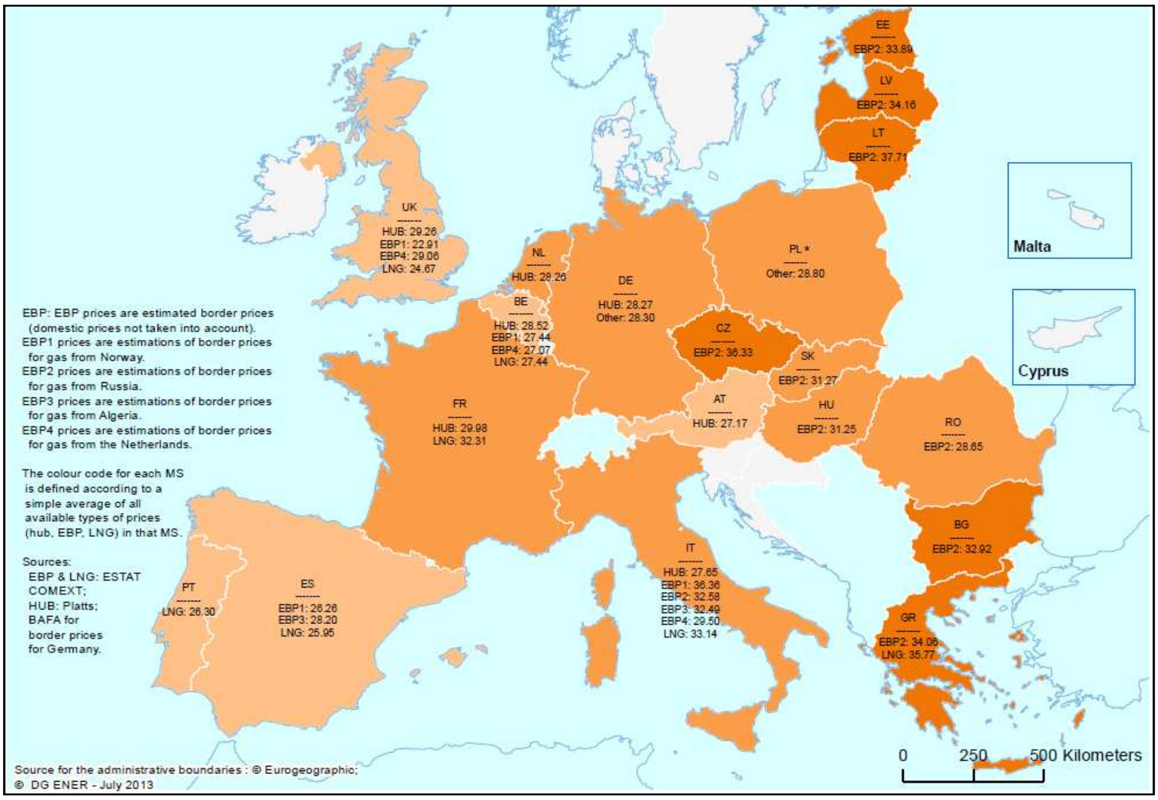

Figure 5.6: Comparison of EU wholesale gas prices (€/MWh)

Source: Quarterly Report on European Gas Markets – Second Quarter 2013

In most of the Member States, there are more than 10 natural gas suppliers. However, in 13 Member States, the biggest supplier has more than 50% of the market, and in eight of them this share is even larger: more than 80%.

The prices charged to retail customers had an average increase of 10% in the natural gas price. Prices vary greatly from country to country; the richest countries normally have higher prices (except the UK). However, the prices in some Member States may be considered artificially low, as they still have regulations controlling the natural gas retail price to some households and industries.

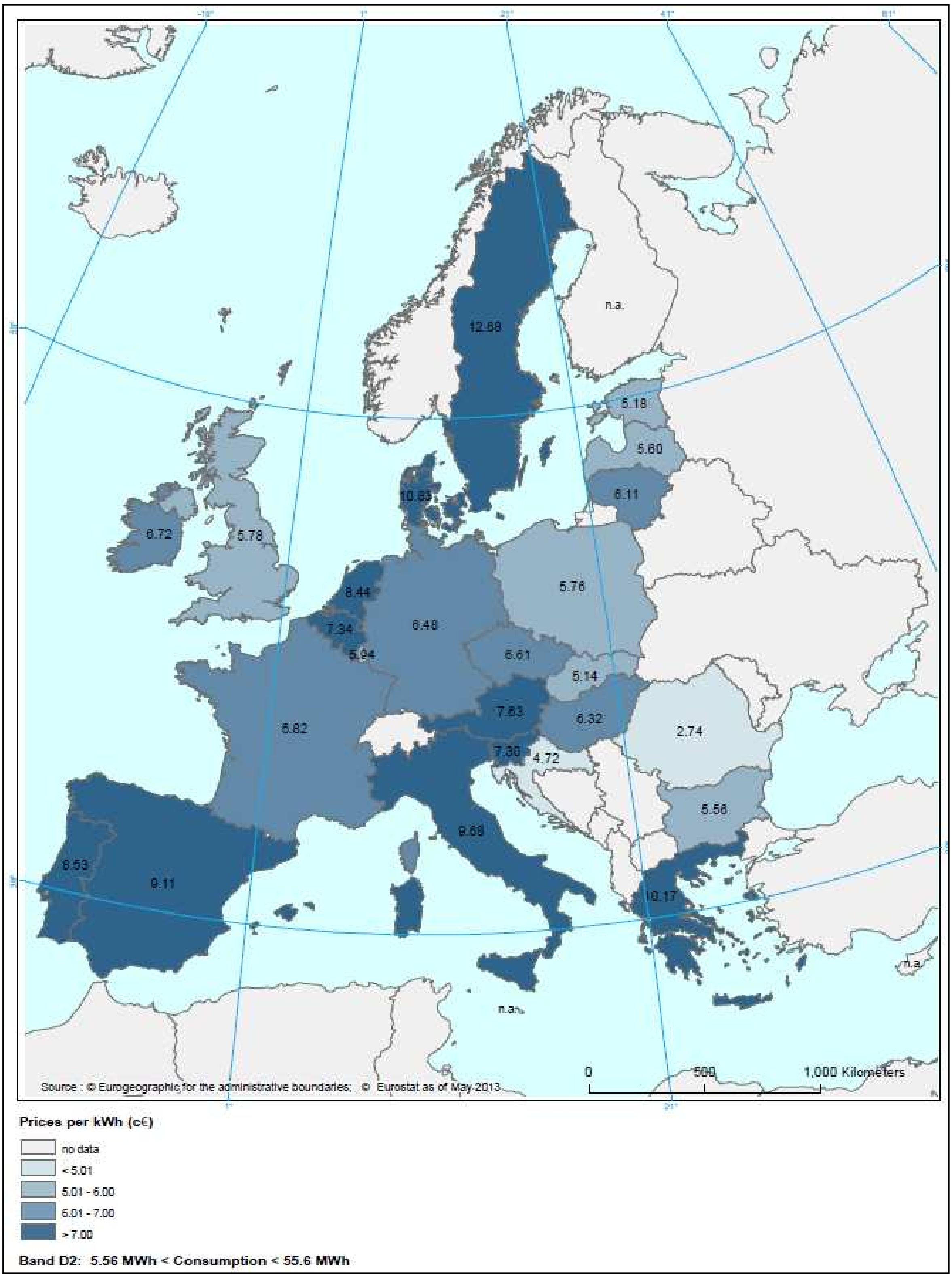

Figure 5.7: Gas prices for Households – 2nd Semester 2012

Source: Quarterly Report on European Gas Markets – Second Quarter 2013

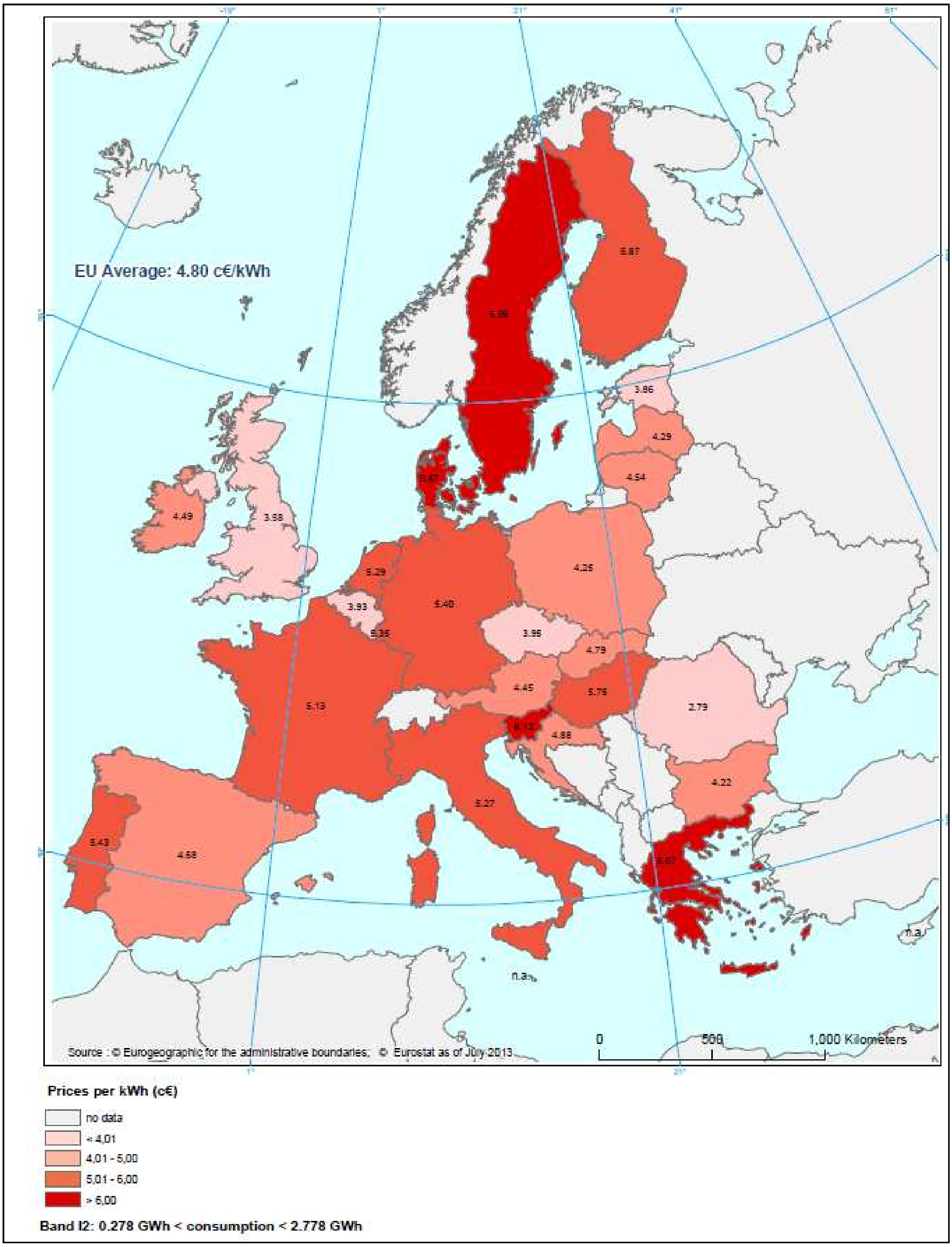

Figure 5.8: Gas prices for Industrial Customers – 2nd Semester 2012

Source: Quarterly Report on European Gas Markets – Second Quarter 2013

5.5.1.3 Regulation Development towards the Free Access Liberalization

Before the beginning of the liberalization in the 1990s natural gas businesses were considered a natural monopoly, subject to strict rules. The market structure in all the EU Member States was very similar: some state-owned companies controlled the exploration, production, importation, wholesale trade, and natural gas transportation; and several municipal companies had the monopoly in terms of distribution and retail sale. There was not any competition, as the big national companies either produced or imported the natural gas, selling it to the distribution companies that, in their turn, sold it to the end-users. Only some large consumers were able to buy gas directly from the national companies.

At that time the legislation applied to natural gas market was the domestic national legislation; although the Treaty establishing the European Community included regulations to foster competition, natural gas market was classified as an exception, as per Article 86 of the Treaty. There was not common legislation at that time, but several aspects were present in every Member State. Some of these aspects are:

- Exclusivity to build and operate the networks, a right guaranteed by concessions and licenses;
- Vertically integrated operations;
- Remuneration based on past costs;

However, this model presented some disadvantages, among them, the high cost of gas generated by the low efficiency of incumbent gas companies.

In July 1987 the Single European Act (SEA) was enacted. Its objective was the establishment of a single market in the European Union. The development of an integrated natural gas market was closely linked to the commitment established by the SEA, and it became the most important subject of the European agenda.

The first initiatives to develop a natural gas inland market were adopted in the beginning of the 1990s, with the release of the Gas and Electricity Price Transparency Directive in 1990, the Gas Transit Directive in 1991, and the Hydrocarbon Directive in 1994. These directives, although they did not open the market to competition represented the initial base of the market liberalization that started in 1998, with the First Gas Directive (Directive 98/30/EC).

The First Gas Directive was a big step to promote the natural gas market reform, including measures to abolish the national monopoly, and presenting mechanisms to promote competition via the re-regulating of gas infrastructure sectors. A system known as NTPA (Negotiated Open Third Party Access) was implemented for transportation, distribution, storage and LNG facilities. Regulations were established to implement account unbundling.

Many political issues impeded the practical implementation of the competition. Consequently, the Second Gas Directive (Directive 2003/55EC) was launched in 2003. This directive gave industrial consumers the possibility to choose their gas suppliers as of July 2004, and it gave residential consumers the same opportunity in July 2007. The transmission, storage, LNG, and distribution infrastructure operators should guarantee the possibility of non-discriminatory and transparent access to all the users. Access should be based on fair and objective tariffs, according to the

Second Gas Directive. Access to transportation, distribution and NGL facilities was provided for in the Regulated Third Party Access (RTPA). Access to storage infrastructures was protected by specific rules, thus permitting the complete implementation of NTPA.

In order to avoid discrimination regarding network access, it was required that the transmission and distribution activities were legally and functionally unbundled from other activities in vertically integrated companies. However, this separation had not required ownership unbundling.

The Second Gas Directive also anticipates specific cases where its requirements can be derogated or laid down:

- Isolated Markets (not connected to system of another Member State, and that have one sole main external supplier);
- Emerging Markets (in which the first long term gas supply contract was not established more than ten years ago);
- Geographically limited areas;
- Lack of capacity;
- During the development of new infrastructures or new capacities;
- In case the access may impede the fulfillment of the public service obligations;
- Due to serious financial difficulties faced by the gas companies; mainly the ones that have take- or- pay contract commitments.

During 2005 the practical results of the Second Gas Directive were considered by the EC, however, the 2007 results still indicated that other measures had to be taken in order to reform the market. Based on that, the Third Gas Directive (Directive 2003/55/EC) was launched in 2009.

5.5.1.4 Present Regulation

The main regulation currently in force in the gas market is known as the Third Gas Directive (2009/73/EC). This Directive was implemented to increase the transparency of the natural gas internal market. It had to be transposed into the National Law of the Member States no later than March 2011.

Together with Directive 2009/73/EC, the Third Energy Package contained two additional regulations relevant to the natural gas market.

This directive is applied to all sources of gas supplies, i.e., it includes natural gas, LNG, biogas, biomass gas, and other gaseous sources that can be injected into natural gas delivery system. Therefore, considering the establishment of quality requirements, the member states must guarantee that there will not be any discrimination concerning the access of biogas to the system. This Directive requires that the member states impose on the companies the following measures, in terms of public services:

- Installation safety;

- Supply security;
- Regularity and service quality;
- Prices and tariffs;
- Environmental protection;
- Energy efficiency.

The member states must also guarantee to every consumer the right to choose its suppliers, changing it easily, with the operator´s assistance, within a period of three weeks. The member states are also in charge of monitoring the supply security, the network maintenance, and the regional markets´ integration, as a first step to complete integration.

Regulation EC 713/2009 established the Agency for the Cooperation of Energy Regulators. The function of this agency is executing, at the community level, the tasks performed by the national regulators. The agency presents its opinion concerning every issue related to energy regulation, participating in the generation of network codes and making decisions in relation to the transnational networks.

A framework was generated to develop the European-wide Network Codes, formed by a set of technical and commercial rules that govern the access to and the use of the networks, in terms of capacity allocation mechanisms, gas balancing, tariff structure and inter-operability.

According to the Third Gas Directive, companies in the transmission, distribution, LNG and storage sectors must keep separate accounts concerning each activity performed (i.e., account unbundling). The accounting records must be available for presentation to the local regulators. Moreover, the state members must adopt either the Ownership Unbundling System or the implementation of an Independent System Operator (ISO).

In the Ownership Unbundling System the companies involved in gas supply cannot have infrastructure assets. In the ISO the vertically integrated companies can keep ownership of their infrastructure assets, however, the asset must be operated by an independent operator, i.e., a company not related to the vertically integrated one.

After the Third Gas Directive was established, access to the system can only be denied in case of lack of capacity or degradation in the fulfillment of the public service obligations, and, even so, it is necessary to indicate one of these conditions in a sustainable way.

EC Regulation 715/2009 of the European Parliament and Council, issued on July 13th, 2009, establishes rules for the transmission networks, storage facilities and LNG. This regulation also defines access conditions, determines tariffs for access to networks, services to be rendered, allocation of capacity, transparency and network balance.

Other important regulations have been issued in addition to the Third Gas Directive, such as Directive 2008/92/EC, which establishes the rules guaranteeing transparency regarding the prices charged to industrial consumers. Directive 2003/96/EC establishes a framework for energy product taxation, defining minimum excise rates for different energy types and uses. By doing this, the functioning of the inland market is improved, as there is less distortion among the Member States. This regulation also provides incentives to promote cleaner energy, and less dependency on importation.

The regulators must determine the tariffs and the calculation methodologies. The state members can take decisions in relation to tariffs; for instance, the organization of Bidding Auctions. The Transmission System Operators (TSO) must supply their services equally to all users of the network, in the short and long-term. LNG facilities and storage must also offer open and equal access to their services.

5.5.1.5 Practical Application of the directives

In fall 2011, the European Commission started infraction legal suits against 19 state members, alleging non-implementation of the rules of the Third Package. In 2012 and in the beginning of 2013 official opinions were sent to the 16 member states that had not completed implementation. Around the end of 2012 and beginning of 2013 some member states were referred to court. The Commission is still studying the situation of the remaining member states.

Gas prices must be based mainly on supply and demand factors. According to EU legislation, the regulated prices can only be applied in exceptional cases, not as a general rule, to price composition. In the case of Poland, the Commission considers that Polish legislation does not observe the EU legislation in the following aspects:

- A limited period to apply the regulated prices has not been fixed;
- The regulated tariff is to be applied to every non-residential consumer, regardless its size or status.

A reconsideration procedure was initiated concerning this issue in 2009, and despite the several alterations done by Polish authorities, the price regulation system was never in conformity with the EU legislation. Therefore, in July 2013, Poland was referred to court by the Commission.

5.5.1.6 Summary

The European Union is experiencing a slow and gradual process to actually implement competition in natural gas market and to establish a sole and integrated market. This process seeks to improve competition and the quality of rendered services, guaranteeing fair prices to the consumers, and, mainly, increasing supply security.

The competition´s integration and incentive tend to increase supply security via the following mechanisms:

- Diversification of supply sources and transport routes;
- Incentive to investment;
- Balance between supply and demand according to market forces;

- Foster the efficiency in offering competitive prices.

The permitted access of third parties to the networks also contributed to sustainable development, as it allows suppliers of renewable gas to also have access to the market.

The models adopted in the First Gas Directive (account unbundling plus NTPA), and in the Second Gas Directive (account, legal and functional unbundling plus RTPA) had limited results due to discriminatory access, lack of capacity and lack of transparent information.

However, the Third Gas Directive adopted more rigid unbundling rules (full ownership unbundling or ISO) and presented more rigid transparency requirements. This has resulted in promising results that still have to be confirmed in the long run.

Full ownership unbundling is seen as the most economically viable option, besides fostering competition in the inland market. This model not only eliminates the system operators´ conflict of interest, but also eliminates the necessity of having excessively detailed and complex regulations.

5.5.2 Non-European Union Countries

5.5.2.1 General View of the Market

The Balkans conflict during the 1990´s led to the disintegration of a unified energy system that went from the Black Sea to the Aegean Sea. Despite the definition of the frontiers, after the end of the conflicts, the isolated entities still depended on one another to work well in terms of energy sources. On July 1, 2006, a treaty was set forth, establishing the European Energy Community (EEC) to reintegrate the countries.

EEC´s main object is establishing a stable regulatory base and market conditions that lead to:

- Attracting new investments in infra-structure, to guarantee social and economic development;
- Increasing supply security;
- Improving environmental conditions in relation to energy supply.

EEC is presently formed by 17 countries of the European Union (Austria, Bulgaria, Croatia, Cyprus, Czech Republic, Finland, France, Germany, Greece, Hungary, Italy, Poland, Romania, Slovakia, Slovenia, The Netherlands and United Kingdom) and 8 contracting parties (Albania, Bosnia and Herzegovina, Kosovo, FYR of Macedonia, Moldova, Montenegro, Serbia and Ukraine). Besides these, Armenia, Norway and Turkey are classified as observer members, and Georgia, as a candidate.

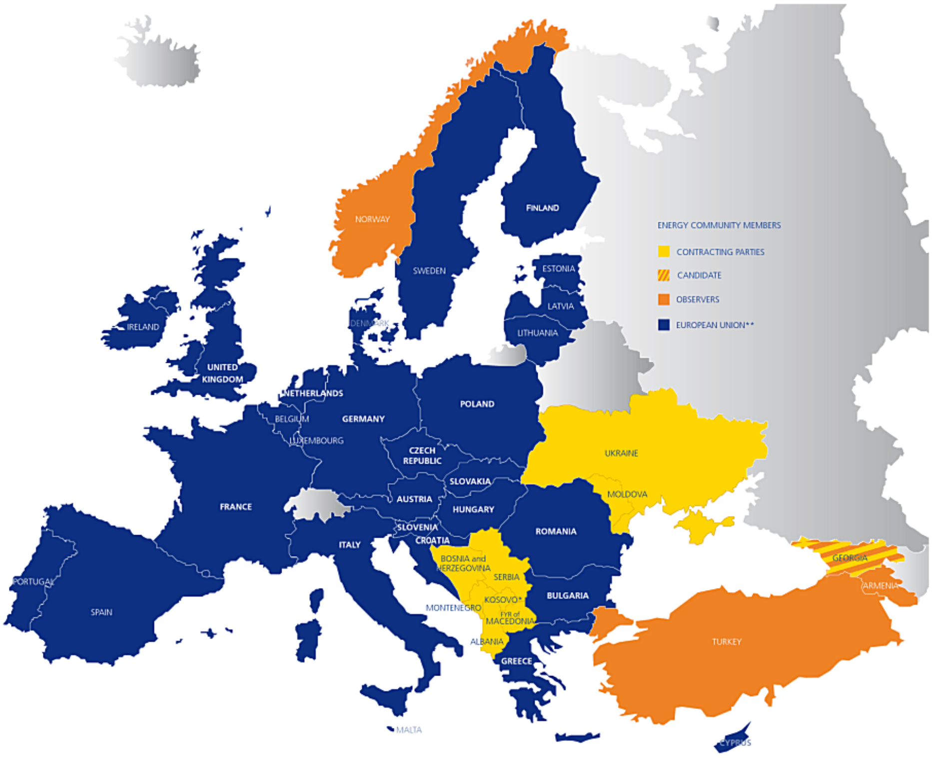

Figure 5.9: Members of the European Energy Community

Source: Energy Community – Members

Despite being a much diversified energy market, the EEC has several points in common. West Balkans and Moldova are strongly dependent on fossil fuels. Except for coal, there is not any other indigenous fuel source in this region. Ukraine´s energy market is, by far, the biggest market among EEC´s contracting parties.

Five of the eight contracting members are developed natural gas markets; however, three of the contracting members (Albania, Kosovo and Montenegro) do not have a natural gas market. Very few gas pipelines cross the EEC region, and those that do it, are not interconnected. The transportation agreements concerning these pipelines are almost totally bound to long term contracts. Due to the dependency on imported gas, the contracting members have little access to the markets and facilities of their counterparts.

Most of the natural gas importations are from Russia. Bosnia and FYR of Macedonia depend totally on the gas supply from Russia, while in Serbia and Croatia Russian gas represents, respectively, 88% and 39% of the total consumption.

Individual large-volume contracts established by operators with Gazprom define and potentially impede the wholesale market. The existing retail market is over regulated, with prices that are sometimes strongly subsidized that do not reflect the real cost to most of the consumers.

5.5.2.2 Current Regulation

Regulation practiced by the EEC is limited to transport and downstream markets, it does not apply to exploration and production. In 2011 the EEC decided to apply the Third Energy Package also to the contracting members, which must be reflected it in the National Legislation not later than 2015. These countries´ energy sectors are gradually completing their liberalization process, which includes the definition of deadlines to meet the TEP´s requirements.

The clauses regarding the unbundling must be in force as of June 1, 2016, and the exemptions to certain clauses related to the shareholders´ rights and to the commitments of the transmission companies´ council are to be accepted by June 1, 2017.

The contracting members had to decide by October 6, 2011 about applying either the Full Ownership Unbundling model or the Independent Transmission Operator (ISO) model.

Regulatory decisions of the contracting members must be submitted to the Energy Community Regulatory Board (ECRD), which was set forth by article 58 of the Treaty that established the EEC. One of ECRD´s roles is issuing official opinions regarding cross-border disputes involving two or more national regulators.

5.5.2.3 Summary

The period between 2012 and 2013 was highlighted by important developments that may change the present scenario including the Trans Adriatic Pipeline (TAP) – South East Europe Expansion Project.

These developments indicate the investors´ trust in a transparent market, well organized by means of the implementation of the Third Package. However, other developments are still required, mainly in relation to unbundling. This applies specially to Bosnia-Herzegovina, where natural gas market legislation is lagging behind. To push its development, the Secretariat presented its first Reasoned Request to the Ministerial Council in October 2013.

The supply of gas to the non-EU countries will be based on the “gas ring” concept. In this concept each of the principal transmission gas pipelines are interconnected, forming a ring. The construction of this gas ring requires an investment of approximately US$ 1 billion.

The construction of the gas ring will be done in parallel to the construction of gas-fired power plants, total capacity of which will reach 2,000 MW and will cost approximately US$ 2 billion. The construction of the gas ring will also leverage the investments in distribution networks, representing a total of approximately US$ 1.7 billion.

5.5.3 Russia

5.5.3.1 Overview

Russia is one of the biggest oil and natural gas producers and exporters; its economy is focused on energy exportation. In Russia gas is the cheapest and hence the most widely used fuel. Gas accounts for over 50% in Russian primary energy consumption. In contrast with many industrial countries where gas consumption is predominantly residential, in Russia gas is supplied first of all to electric power generating companies, and metallurgy and chemical industry enterprises.

According to the Oil and Gas Journal, Russia has the largest natural gas reserve in the world, with 1,688 Tcf. as of January, 2013. The Russian natural gas reserves represent around one fourth of the global reserve.

5.5.3.2 Current Regulation

Consumer gas prices are regulated by Russian Federation law. The price is set with regard to costs of production via the unified gas supply, gas transportation via gas distribution networks, and the cost of gas delivery to the end consumers.

The Russian gas market is divided into regulated and non-regulated sectors. Gazprom is the biggest regulated sector supplier, while suppliers of the non-regulated sector include independent gas and oil producers. The regulated sector plays the prevalent role, with independent producers satisfying approximately one-fourth of the domestic demand.

The Russian state regulates:

- Wholesale gas prices at which Gazprom and its subsidiaries sell gas in the domestic market;
- Tariffs for services of gas transportation via main pipelines as are rendered to independent producers or for transportation via gas distribution networks;
- Distribution and logistical support service charges.

The opening of the Russian market to independent producers started in 1997 with Ordinance Nº 858 which set terms and procedure ensuring access to available transport capacities of the Unified Gas Supply System. Distribution networks were also opened through Ordinance Nº 1370 of 1998. The Federal Law Nº 69-Ф3 of 31.03.1999 set anti-monopoly regulations and defined access of organizations to the gas transport and gas distribution networks.

In compliance with Russian law, Gazprom grants access to the transmission system if there is capacity in the pipeline and the gas meets the required quality.

Table 5.1: Independent producers' gas conveyed through Gazprom's gas transmission system

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Transmission volume, billion m^3	95.4	99.9	114.9	115.0	119.8	111.2	59.3	64.5	72.8	87.0	104.3

Source: http://www.gazpromquestions.ru/en/transmission/

Presently the Federal Anti-monopoly Service (FAS) is completing a draft ordinance "[o]n ensuring non-discriminated access to the gas distribution networks" that is to substitute for the acting Government Ordinance of 24 November 1998 Nº 1370.

5.6 Third Party Access in Asia

5.6.1 Asian Natural Gas Market

The Asian natural gas market is fragmented, i.e., it does not have interconnected natural gas high pressure networks. There are three main markets in terms of natural gas, each one with its idiosyncrasies. The well-established market is comprised of Japan, Korea and Taiwan. This market is isolated and depends on LNG importation. China and India form a growing market that tries to answer to the demand for natural gas via natural gas networks and LNG. Russia and the South-East Asia region (Malaysia, Indonesia and Brunei) are characterized by several large natural gas producers.

5.6.2 Japan

5.6.2.1 Overview

Japan is the second biggest market for natural gas in the region, recently bypassed by China, and it will carry on being the biggest LNG importer, due to its low natural gas production, and to its geographic isolation that practically impedes the pipeline connections with other markets.

After Fukushima´s nuclear incident several issues concerning safety and the Japanese nuclear energy program policy were raised. Consequently, there were impacts on the natural gas sector, increasing 5% the demand for natural gas instead of nuclear energy.

5.6.2.2 Unbundling

The natural gas distribution and transportation system is controlled and operated by private vertically integrated companies. Despite the fact that financial unbundling is required for a part of customers by Japan's Gas Business Act of 2004, the functional unbundling is not mandatory in companies with LNG infrastructure.

It limits the separation of transmission and distribution activities from the supply activity.

Therefore, the distribution, as a whole, depends a lot on the commercial activities of a few LNG importers.

5.6.2.3 Third Party Access

The Japanese government began the process of deregulation of natural gas prices in 1995. The government introduced legislation to gas and electricity industries to improve the consumers´ choice. This measure led to the gradual introduction of free choice for large consumers (>2 million m^3/year) in 1995, to consumers above 1 million m^3/year in 1999, above 0.5 million m^3/year in 2004, and above 0.1 million m^3/year in 2007.

Open access for third parties to the transmission and distribution pipeline networks was introduced in 2004, and must be negotiated individually per groups that want to supply natural gas to consumers.

However, the Negotiated Third Party Access (NTPA) model was adopted for the LNG terminals limiting the companies´ obligation to offer access. Some companies developed guidelines, but in general, it is difficult to establish TPA at LNG importation terminals, as they are developed to serve importers with a specific supply and sale profile. The lack of interconnections between the regions also makes the competition via TPA more difficult.

5.6.3 The Republic of Korea

5.6.3.1 Overview

The increase of the economic development led to the increase of natural gas consumption in Korea over the last decades. The development of the natural gas sector was guided by the establishment of the State-owned Korean Gas Corporation (KOGAS) in 1982, which established the diversification of the Korean economy that became less dependent upon coal and petrol.

The first cargo arrived in 1986 and the natural gas consumption increased 14% annually, from 3.2 bcm in 1990 to almost 45 bcm in 2011. This volume was reached from LNG importations and the small volume of domestic production from Dohnghae-1 offshore, operated by the Korean National Oil Corporation (KNOC). The natural gas consumption is dominated by the electric sector, totalizing 44% of the consumption in 2010, while the residential sector consumed 28%.

5.6.3.2 Current Regulation

The Korean government initiated a privatization and liberalization framework in 1997, which was detailed in 1999. However, this plan suffered from fierce opposition from the labor unions and did not continue. KOGAS is now a partially state-owned company shared between the South Korean government, with a 27% stake, the state controlled Korea Electric Power Corporation (KEPCO) with 25%, and with the remaining equity split among local government and institutional investors.

In 2003 the restructuring plan was revised and a new approach was defined. Private companies now are allowed to import LNG under a licensing system. It was anticipated that LNG receiving terminals, storage and pipeline networks owned by KOGAS would be opened to TPA.

Currently a voluntary service unbundling and negotiated third party access scheme is in place. Companies are allowed to import LNG for their own use by constructing their own LNG facility or negotiating access to KOGAS facilities.

KOGAS no longer has a monopoly over LNG facilities as a fourth LNG terminal was completed in 2005 by POSCO, the largest steelmaker in South Korea. KOGAS still dominates the natural gas market as it holds 98% of the LNG importation capacity, while the forth terminal of Gwangyang has, as of 2014, four clients that cannot resell its imported LNG.

The distribution sector remains operated under a monopoly system within each region and there is no unbundling or TPA in the retail market.

5.6.4 China

5.6.4.1 Overview

China´s natural gas market was poorly developed until two decades ago. The consumption of natural gas is five times bigger since 2000; it increased approximately 26 billion m^3 between 2000 and 2011 to almost 130 Billion m^3. This change gave China the fourth position in the world´s natural gas market. It is estimated that the consumption of natural gas will increase around 13% per annum over the next five years.

IEA´s survey indicates that natural gas consumption may reach 260 BCM by 2017; this would represent at least two times the total 2011 consumption. This forecast is the result of the Chinese ambition to get rid of the dependence on coal due to environmental reasons. The expectation is having natural gas supply coming to China from three sources: domestic production, importation using Myanmar and Central Asia pipeline networks, and the LNG market.

Although China´s domestic natural gas production will supply most of the demand, it is expected that natural gas importation via pipeline and LNG will also increase; supplying a bit less than half of the Chinese demand in 2017 (IEA, 2012a).

The gas pipelines connecting Myanmar to Central Asia are controlled by China National Petroleum Company (CNPC), which also operates 90% of the national natural gas transmission. LNG importation terminals have developed quickly and are now adequate to supply natural gas to the urban regions on the coast.

5.6.4.2 Current Regulation

The Chinese natural gas market is focused on increasing the infrastructure in order to accommodate the increased demand for this alternative in the energy sector. Therefore, the investments in transportation are directly linked to the upstream development and to the subsequent marketing activities of each company. Presently, the transportation activities are not separate from the commercial ones, as these activities are developed in vertically integrated companies.

The prices of natural gas are regulated by local and central governments. Generally, the Government established the prices according to the different stages in the value chain (wellhead, transport, ex-plant/ city gate) using a cost-plus basis and taking into consideration the differences in requirements of end-users. The prices are also regulated by end-use sectors. The price differentiation in relation to the different consumption segments has a clear social and political purpose.

As there is neither a TPA (Third Party Access) regime nor a regulator to monitor natural gas transportation, the companies must negotiate access to the networks, as well as the capacity. Consequently, market competition is limited.

5.6.5 India

5.6.5.1 Overview

The Indian energy sector is dominated by coal, biomass and oil. Natural gas represents only 6% of the internal energy demand nevertheless the Indian natural gas market is expected to be one of the fastest growing markets in the world over the next two decades. At the end of the 1990's natural gas consumption was constrained by shortfalls prompting the Indian government to approve some reforms to encourage domestic production and construction of LNG terminals.

In India there are two main transportation companies: the public owned GAIL, and the new entrant and privately owned Reliance Gas Transportation Infrastructure Ltd (RGTIL). GAIL has more than 7,850 km of transmission pipelines and represents 78% of India's transmission business. RGTIL completed 1,400 km of pipelines in 2008.

5.6.5.2 Current Regulation

A draft of regulations addressing access to transmission and distribution pipelines was made in 2007 by the Petroleum and Natural Gas Regulator Board of India. The stated objective of the regulations are to establish "…industry wide transparent and uniform principles for allowing entities to gain/ allow access to the pipeline systems and CGD [city gas distribution] networks. The present access code covers providing access to both the natural gas transmission pipelines and CGD Networks."

Under the regulations the transporter declares the design volume capacity at each entry and exit point, and the available capacity of the pipeline system on its web site at the beginning of each month. The transporter also specifies the specification band in regards to gas quality.

Prospective shippers requesting access are required to make a request to the transporter. Within a 7-day period the transporter is required to confirm enough spare capacity "exits to satisfy the request and specify the charges and terms and conditions" under which the transporter makes the service available. If the transporter denies it has capacity investigators are dispatched within a 15-day period to confirm to the Board the lack of capacity.

5.6.6 Pakistan

5.6.6.1 Overview

The recoverable Pakistan reserves of natural gas have been estimated at approximately 30 trillion cubic feet. During July-March 2008-09 the production was 3986.5 million cubic feet per day representing an increase of 0.52% in relation to same period in the previous year. Presently 26 private and public sector companies are engaged in oil and gas exploration and production activities.

The Sui gas field is the biggest natural gas field in the Pakistan and accounts for 26% of Pakistan's gas production. The operator of the field is Pakistan Petroleum Ltd.

Sui Northern Gas Pipelines Limited (SNGPL) and Sui Southern Gas Company Limited (SSGC) are the two major companies of the country, which are involved in purification, transmission and distribution of natural gas throughout the country. SNGPL supplies gas to consumers in the northern part of the country. Its franchised areas include two of the four provinces of Pakistan - Punjab and Frontier. SSGC is responsible for the southern part of the country and supplies gas to customers in the remaining two provinces of Sindh and Baluchistan.

5.6.6.2 Current Regulation

Third party access to gas transmission lines is granted on case-by-case basis by the Pakistan Oil and Gas Regulatory Authority (OGRA). The rules for determining TPA are called the Oil and Gas Regulatory Authority (OGRA) Natural Gas Regulated Third Party Access Rules, 2011.

The rules are applicable to all pipelines (including spur and branch pipelines) and associated facilities downstream of gas producer's/ importers processing plant on shore, which are used for transportation of natural gas from one point to another except gas producer processing plant piping within the battery limit isolation valves of the plant.

According to the provisions of the OGRA rules, "[t]he gas marketers/shippers licensed by OGRA will have access to the pipeline network subject to the minimum threshold of 10 mmcfd for a single buyer when such a network is opened for competition at the end of the period of exclusivity from the purview of Common Carrier or Contract Carrier of Contract Carrier allowed to the entity under the Natural Gas Regulatory Authority (Licensing) Rules 2002 for exclusivity for distribution pipeline network."

In establishing access the rule requires transporters to declare on the first calendar day of each month the total and available capacity in the pipeline system. Access can be granted either on a firm or interruptible basis. Firm capacity is granted for a minimum of 1 year. Interruptible capacity can be offered for 1 or more days. More than a single shipper can hold capacity at all entry and exit points, according to the rules.

5.6.7 Indonesia

5.6.7.1 Overview

Indonesia contains large reserves of natural gas and is one of the 10 largest producers of natural gas producing more than 71.1 billion of cubic meters of natural gas in 2012. Approximately 50% of this gas is consumed locally and the remaining is exported. Although Indonesia produces twice as much natural gas as it consumes, shortages were experienced by domestic industries due to lack of capacity in the transmission and distribution system operated by the State-owned company Perusahaan Gas Negara (PGN) .

5.6.7.2 Current Regulation

Historically, Indonesian law 44 of 1960 established that the right of ownership and operation of essential energy infrastructure such as gas pipelines was exercisable solely by Indonesian state-owned enterprises.

In 1994 the Indonesian government passed Regulation 37/1994 that transferred Pertamina's exclusive authority to transport gas to another state-owned enterprise: Perusahaan Gas Negara (PGN). Under Regulation 37 PGN was mandated to develop a network for the transmission and distribution of onshore natural gas pipelines.

In November 2001, Law 22 of 2001 replaced Law 44 of 1960 and Law 8 of 1971. The effect of the new oil and gas law was the abolition of the monopoly exercisable by state enterprises over functions such as gas transportation. While this law was enacted no actions were taken to implement it.

The next action taken was the Ministerial Regulation No.19 of 2009 on Business Activity through Natural Gas Pipeline. This regulation was also ratified, but was not implemented for all of the national gas pipelines.

In selecting pipelines for open access, the Director General of Oil and Gas, Ministry of Energy and Mineral Resources, indicated the Ministry of Energy will select gas pipeline segments depending on whether the operator's investment has been returned. Conversely, if the operator's investment has not been returned, the pipeline does not need to allow open access.

The issue of open access hinges around PGN opening its pipeline access to other companies as stipulated by the Energy and Mineral Resources Ministry. PGN reportedly controls 80% of the gas pipelines transport capacity in Indonesia. There is also an issue involving the ability of the government under the Indonesian 1945 Constitution to allow the liberalization of the oil and gas markets.

5.7 Third Party Access in South America

5.7.1 Argentina

5.7.1.1 Overview

The energy sector in Argentina is highly regulated, including policies that reduce the number of private investors, but protect the Argentinean consumers in terms of price increases. Its natural gas production dropped around 10% since production peaked in 2006. The country has been, during a long period, a natural gas exporter, however, it is presently dependent on imports.

Recent assessments point out that Argentina has one of the biggest shale gas reserves in the world; consequently, one of the priorities of the country is making the extraction of shale gas viable.

In the end of the 2000's and beginning of the 2010's there were shortages of natural gas over winter, during which the industrial consumers had their supply either interrupted or reduced, in order to serve the residential sector. There were also some seasonal scarcity over summer, due to the increase of electric energy demand, a consequence of high temperature levels. The State-owned energy company is increasing the importation of LNG in order to reduce the probability of similar occurrences in the future.

5.7.1.2 Current Regulation

Natural gas production in Argentina is a deregulated activity; the producers explore, extract and commercialize the product freely, under the umbrella of the country´s Energy Agency (Secretaría de Energía de la Nación).

On the other hand, the natural gas transportation and distribution networks are regulated public services, and the companies must report to ENERGAS, the Regulator in Argentina (Ente Nacional Regulador Del Gas), an independent national committee. Its objectives are:

- Ensure the consumers´ rights;
- Foster competition in the natural gas market;
- Guarantee long term investments;
- Regulate transport and replacement services;
- Guarantee fair and non-discriminatory tariffs;

In order to combat inflation, price control was imposed on end-users in 2001; due to that, natural gas is relatively cheap, following regional rules. Analysts of the sector affirm that natural gas´ frozen prices besides affecting the sector´s investment and production, gave incentive to added consumption, causing the necessity to import larger volumes.

The government established the program entitled Gas Plus, to foster the exploration of un-conventional gas sources and revitalize domestic production. The program authorizes the companies to sell natural gas from new or unconventional fields at higher prices. The price authorized for the recently approved projects represents double the national average price.

5.7.2 Brazil

5.7.2.1 Overview

Brazil has approximately 14 Tcf. of natural gas reserves and its production is growing quickly. Despite this quick growth, most of the natural gas consumed in Brazil comes from Bolivia.

The main gas transmission pipeline is the Bolivia-Brazil Gas Pipeline, through which most of the imported natural gas arrives in the country. There is a large concentration of transmission gas pipelines in the region near the coast line; however, the country´s inland still requires future development.

Brazil´s gas distribution market is still being developed; three of its States still do not have natural gas distribution concessionaires, and in many states the current market share represents a small part of its potential. All the natural gas distribution concessionaires have their prices regulated according to the guidelines of the State Regulatory Agencies, which must follow ANP´s regulation ordinance.

5.7.2.2 Current Regulation

Concerning third party access to natural gas transportation and distribution networks, Brazil took an extended period of time to establish the required legislation and constitutional amendments.

In 1995, Constitutional Amendment nº5 ended Petrobr ás´ monopoly in natural gas distribution, opening the market to local service renders.

Petrol Law (9.478/97) was set forth in 1997 and made the Federal Monopoly more flexible, setting the basis for market liberalization. Based on this law, the ANP (Petrol National Agency) was established, becoming the regulator for oil, natural gas and bio-fuels.

In 1998 ANP set Ordinance 169 that regulates the use of gas pipelines by third parties. The owner of the gas pipeline has to inform ANP about the capacity available in each gas pipeline. Depending on this report, the gas pipeline´s owner is obliged to permit its use by third parties, which will pay a transportation fee.

In 2005, the Gas Bill presented by the Senate, proposed the following resolutions:

- Resolution 27 – access to networks;
- Resolution 28 – resale and transportation capacity;
- Resolution 29 – tariff criteria.

This bill was approved on 04/03/2009, and Gas Law 11.909 is enacted, defining the regulatory landmark of activities like importation, re- gasification, liquefaction, transportation, storage, and commercialization of natural gas. Law 11.909 was passed based on the need for having legislation that is specifically for the natural gas sector.

Concerning access to transportation networks, the transportation companies must render the following modalities of service:

- Firm Transportation Service;
- On-going Transportation Service;
- Extra transportation Service.

The Firm Transportation Service must be contracted through the mechanism of public bidding, done by ANP. Therefore, the maximum tariffs must be applied to parties interested in contracting the transportation capacity.

Access is guaranteed to all the parties interested in contracting the transportation services. ANP is responsible for publishing the existing excess handling capacity, as well as the modalities that are available to be contracted.

5.7.3 Bolivia

5.7.3.1 Overview

The production of natural gas in Bolivia is one of the most important businesses for the domestic economy. Oil and Gas production accounts for approximately 6% of the Gross Domestic Product (GDP), 30% of the government revenues and 45% of the exports. Almost 80% of its natural gas production is exported to Argentina and Brazil. Production has increased significantly since 1999 when exports to Brazil begun and reached 558 billion cubic feet (Bcf) in 2011. Bolivia has over 9.9 trillion cubic feet (Tcf) of proved natural gas reserves. Recent analysis indicated Bolivia has approximately 48 Tcf of recoverable shale gas.

Natural gas accounts for nearly 34% of the energy mix in Bolivia, and electricity production accounts for over half of natural gas consumption in the country. The Bolivian government is promoting the domestic use of natural gas as a substitute for oil products. Efforts to integrate more households into the natural gas grid, and to convert most of the motor vehicle fleet to compressed natural gas are being undertaken.

5.7.3.2 Current Regulation

In 2006 President Evo Morales and his Movimiento al Socialismo (MAS) published a nationalization decree. This decree was atypical as the military was sent to take control over oil and gas facilities, but have not intervened in foreign assets. The decree increased taxes and royalties by 32% and has granted ownership of hydrocarbon reserves to the State-owned company Yacimientos Petroliferos Fiscales Bolivianos (YPFB). Since the decree, contracts with foreign firms were renegotiated and Bolivia's partially privatized companies were nationalized. Tax and compensation incentives were put in place to encourage foreign companies to increase their exploration and production.

Prices for domestic natural gas are fixed by the government. Price varies from $0.90 per thousand cubic feet (Mcf) to $1.98 per Mcf depending upon its end-use.

There is no open access to transmission or distribution facilities and most of these facilities are owned by the state-owned YPFB Transporte. There are also smaller pipelines that are operated by various public and private companies.

5.8 Third Party Access in Africa

5.8.1 Open Access in Algeria

5.8.1.1 Overview

Algeria's domestic natural gas pipeline system transports natural gas from the Hassi R'Mel fields and processing facilities, owned by Sonatrach, to export terminals and liquefaction plants along the Mediterranean Sea. Algeria has three transcontinental export gas pipelines, two for the transport of natural gas to Spain and one to Italy.

5.8.1.2 Current Regulation

The 1986 hydrocarbons law put the state in control of the entire exploration and transportation value chain of natural gas. Sonatrach controlled all local hydrocarbon marketing activities. Foreign companies at the time could engage in petroleum activities by partnering with Sonatrach in one of four ways:

1. Production sharing contract
2. Service contact
3. Joint venture
4. Joint stock company.

In 2005, the Hydrocarbons Law No 05-07 (dated 28 April 2005) came into force and replaced Law No 86-14 (dated 19 August 1986). This law made significant changes to the rules governing the petroleum industry in Algeria up until that time. This law created two new agencies and terminated Sonatrach's monopoly; liberalizing upstream, midstream, and downstream activities; and simplifying the legal and fiscal system for hydrocarbons.

However, President A Bouteflika significantly amended the 2005 Hydrocarbons Law by Presidential Order No 06-10 (dated 29 July 2006). The institutional framework and the new contractual regime set up by the 2005 Hydrocarbons Law remained unchanged, but the market liberalization has been almost entirely abandoned. Presidential Ordinance No. 2006-10 maintains Sonatrach's monopoly, requiring foreign companies to joint venture with Sonatrach on exploration, exploitation and processing contracts. Similarly, transportation activities can only be undertaken by either Sonatrach or a local company, in which Sonatrach owns at least a 51%.

The last law passed by Algerian legislation is the 13-01 Law of February 20th, 2013, which modifies and completes the 05-07 Law. This law expanded the National Agency for the development of hydrocarbon resources (ALNAFT) authority. Among other areas the ALNAFT processes transportation license applications and rates the open access to transportation of oil and natural gas pipelines. The intent of this law is apparently to encourage more foreign investment in the hydrocarbon sector.

5.9 Conclusions

Third Party Access (TPA) is usually connected with gas market liberalization that includes concepts such as open access and unbundling regimes. TPA is conceptually motivated to get benefits such as: a) creating competitive gas markets, b) reducing prices, c) securing supply, and d) improving services to the customers, among others.

TPA has been applied much more to gas transmission pipelines, but may also be implemented for gas distribution systems where it is generally considered as unbundling.

Since its beginning the natural gas industry has been highly regulated. In some places, especially in developed markets, this highly regulated model has led to inefficiency and an imbalance between production of and demand for natural gas, as well as price disparities.

A staged liberalization process began in the 1970s leading to the important step of implementing open access and unbundled regimes. The liberalization process began in the United States and Canada, followed by the European Union. Some other regions and countries took initiatives to implement TPA, but up to now the effects of the new regulatory rules in those places seem to be limited.

The results of the WOC4 Study Group 4.1 analysis show that TPA presents a wide variety of concepts and stages of development worldwide. There is not a unique answer. The level of implementation seems to be directly related to the maturity of the gas industry in the studied area. The US/Canada and EU adopted different approaches to TPA regulations, but were successful in implementing an effective TPA model. The reason for this success relies on the regulatory framework adopted and on market conditions. Being two of the major and most mature markets in the world, the conditions for the implementation of TPA were favorable because of the large number of supply sources, the highly interconnected systems and their saturated market territories.

Many other countries have demonstrated interest in implementing TPA. Up to now, none of them have been able to achieve this objective effectively for different reasons. Among those reasons are:

- TPA is not mandatory for all gas infrastructures: LNG terminals and storage facilities are vital for some natural gas systems;
- A single company is responsible for almost all gas supply;
- The system is not interconnected;
- The gas market is still being developed.

It is necessary to recognize that the availability and low cost of the resource (natural gas) could be as important as TPA legislation and regulation to obtain the expected benefits from its implementation. In other words, adequate supply and low prices do not encourage the effort needed to implement the regulations.

TPA rules adopted in other countries may be considered less rigid and, thus, similar to those adopted in the early stages in the US/Canada and EU. While these lenient rules were also not initially effective in the mature markets, they were the means for a transition to mandatory TPA.

Further, it should be considered that the non-effectiveness of TPA in other countries may not only be due to the lenient rules adopted, but also to some underlying market conditions. Therefore, in addition to more rigid rules, it is necessary to give incentives time to grow and develop the market in order to create an effective TPA model. It requires time. TPA implementation is a process under continuous evolution, and accumulated experience must be used to improve the regulation and the ability of the market to work with it. TPA can be an important tool to accelerate market development; it can ensure more transparency and provide clear rules to the stakeholders. It will not necessarily reduce costs depending on the conditions of a particular market.

Thus another aspect that should be further evaluated is whether the implementation of TPA in the retail market is advantageous; especially in the case of small commercial and residential customers. Distribution companies may increase distribution costs because of the additional requirements of a TPA regulatory framework, caused by the increased regulation and complexity. The resulting increase in administrative costs may not overcome the price reduction in the gas supply because of these low volumes consumed by small customers.

Although there are no recent detailed studies, the US, Canadian and EU experiences tend to show mixed results for reducing the final price to small customers, reinforcing the need for further evaluation of this aspect.

In conclusion we can say TPA is not a panacea that can transform by itself the conditions of one particular gas market. Instead it can be a powerful tool, if properly used, to get this desired market evolution.

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6 Report of IGU Study group 4.2

Diversification of Gas Quality and Nonconventional Sources in a Carbon-free Future

Study Leader: Peter Flosbach, Germany

Table of Contents

6.1 List of abbreviations

%	percent
℃	degree Celsius
bcm	billion cubic meters
BUP	biogas upgrading plant
CBG	compressed bio gas
CEN	European Committee for Standardization
CHP	Combined Heat and Power
CO	carbon monoxide
CO2	carbon dioxide
DNO	Distribution Network Operator
DSO	Distribution System Operator
DVGW	German Technical and Scientific Association for Gas and Water
e. g.	exempli gratia
EASEE-GAS	European Association for the streamlining of Energy Exchange
Enagás	Technical Manager of the Spanish Gas System
FIT	feed-in tariff
GCV	Gas Calorific Value
h	an hour
ISO	International Organization for Standardization
LNG	liquefied natural gas
MARCOGAZ	Technical association of the European gas industry
MG	manufactured gas
MJ	megajoule
NG	natural gas
NL	the Netherlands
NOx	Nitrogen Oxides
PGC	Process Gas Chromatograph
ppm	parts per million
PSA	pressure swing adsorption
SG	Study Group
Sm^3	volumetric unit of measurement
SNG	Synthetic Natural Gas
Tcf	trillion cubic feet (
WGC	World Gas Conference
WI	Wobbe Index
WOC	Working Committee

6.2 Index of figures

6.3 Index of tables

6.4 Abstract

For decades the source of natural gas supplies to any given location remained stable. Generally, distribution grids comprised of one or possibly two sources of supply based on long-term delivery contracts.

In many parts of the world, this is no longer the case. The situation has changed over the past few years and the rate of change is increasing. The reasons for this change are:

- growing diversification of gas quality;
- different sources of supply due to short-term contracts;
- change between pipeline-based and LNG-based supplies;
- development of local gas fields (e.g. shale gas);
- increasing injection of gases from non-conventional sources in a move towards a carbon-free future;
- bio-methane;
- hydrogen; and
- SNG

This Study Group 4.2 examines different options available for managing diversification of gas quality and the way distribution companies can address the growing challenge to secure stable gas supplies for their customers.

6.5 Introduction

Study Group 4.2 within the Working Committee 4 – Distribution is looking at the diversification of gas quality and nonconventional sources in a carbon-free future.

The focus of the Study Group's work was the examination, from the perspective of a distribution grid operator, of different options for the management of this diversification of gas quality.

For more than 50 years natural gas has benefitted from continuous and stable growth. As the fuel of choice natural gas steadily conquered increasing market share in competition with other fuels such as coal and oil.

Amongst these competitors, natural gas enjoyed the image of being clean and environmentally friendly with the lowest CO_2 emissions of all fossil fuels.

Today, however, the energy panorama is rapidly changing. Four major issues are driving this change and are part of the following report:

- the quest for cleaner energy;
- the development of a global gas wholesale market and regulation for gas grid infrastructures;
- the challenges relating to renewable energy storage; and
- the shale gas boom – natural gas resources for another century.

6.6 Study group members

Team Members of WOC 4 Study Group 2 (SG 4.2)

Chairman: Peter Flosbach, Westnetz GmbH (RWE) and Dortmunder Energie- und Wasserversorgung GmbH (DEW 21), Germany

Vice Chairman: Rory Somers, Gas Networks Ireland, Ireland

Study Group Members:

- Jose Maria Almacellas Gonzalez, Gas Natural Fenosa, SDG, S.A., Spain;
- Danijela Bušetinčan, Gradska plinara Zagreb d.o.o., Croatia;
- Franc Cimerman, Plinovodi d.o.o, Slovenia;
- Maciej Chaczykowski, Warsaw University of Technology, Poland;
- Remy Cordier, GDF SUEZ / CRIGEN, France;
- Flemming Jensen, DONG Energy, Denmark;
- Tohru Takahashi, TOKYO Gas CO., LTD., Japan;
- Uwe Klaas, DVGW, Germany;
- Vladimir Klimenko, JSC Gazprom promgaz, Russian Federation;
- Christian Schicketmüller, OÖ. Ferngas Netz GmbH, Austria;
- Dragan Vucur, JP Srbijagas, Serbia;
- Paul D. Wehnert, Heath Consultants, USA – Texas.

6.7 Topics of the Study Group Report

During the committee meetings the following topics were examined:

1. Historical experiences & Review
    a. Europe, Russia, US and other markets;
2. Future Paradigm and Challenges
    a. Gas Quality
    b. Technology
3. Strategy & Global Market effects
4. Developing a Marketing concept
5. Regulation, Tariffs, Incentives & Third Party Access

6.8 Introduction

The quest for cleaner energy is driving the introduction of more legislation and regulation for the reduction of CO_2 and the fulfilment of the Kyoto targets. As gas is both clean and flexible compared to other fossil fuels this development is clearly favourable for natural gas.

Increasing LNG trade is linking the regional gas markets and improving access flexibility. We also see a clear trend towards strictly regulated markets for gas transportation and distribution infrastructures.

There is increasing demand for energy storage capacity following the introduction of renewable electricity production such as wind and solar. This is due to the fact that electricity cannot be stored adequately in the required amount in order to balance supply and demand. Excess electricity can be used to produce hydrogen which can be stored in the gas grid.

Finally, the production of shale gas is reshaping firstly the US market and, increasingly, the rest of the world.

However, the merits of natural gas are often not fully appreciated by the general public. As a consequence, further introduction of renewable gases and a stepping up the gas advocacy campaign are necessary to highlight the eco-friendly image of natural gas.

Why should the gas industry promote new technologies and new gases?

Government and climate protection targets demand the introduction of fuels and technologies that reduce CO_2emissions. Substituting gas for coal and oil can substantially contribute to the overall reduction of the emissions of CO_2 and particulates, while gas-fired power generation is best suited to complement intermittent renewables. Moreover, the CO_2 balance of natural gas can be positively influenced by “greening” it through renewable gases.

As well as the political arguments for new gases and technologies, it should be remembered that natural gas storage and pipeline systems are the most capable energy storage available and therefore should be a major part of the energy plan of the future.

6.9 Background and purpose

Even today, gas is competitive and abundant. The consideration of environmental as well as economic aspects plays an increasing role to further guarantee the continuation of the global natural gas growth success story.

The shale gas boom in the US (a market which was originally forecast to require increasing imports of LNG) has led to the switching of LNG cargoes to other markets where they have had a downward impact on wholesale prices. Wherever gas distribution infrastructures are available, natural gas is the most competitive fuel for heating and other domestic use. With recoverable conventional and unconventional gas resources increasing all over the world, no shortage for the next two generations is expected.

In addition, it is a fact that regions without gas distribution infrastructures have a fundamental competitive disadvantage in economic growth. Innovative technologies for efficient processes with low emissions due to efficient gas combustion are restricted in these regions.

They need to be supported by political decision making to further the geographical expansion of gas grid infrastructures and enable economic growth.

However, an alarming example of governmental intervention can be seen already in different European markets where ministries raise regulations for more renewable energy in private buildings with severe burdens for the use of fossil fuels such as natural gas in newly built homes or the renovation of heating systems.

As alternative technology (in many cases electrical heating e.g. with heat pumps) is preferred, local district heating solutions with highest efficiency are the only choice for natural gas.

What are the market changes requiring the diversification of gas quality?

For decades, the source of natural gas supplies to given locations remained unchanged. Generally, distribution grids comprised one or possibly two sources of supply, based on long-term delivery contracts. However, we no longer have such long-term physical stability in the grids, due to the fact that in many parts of the world new sources of gas are entering our gas grid infrastructures. The situation has changed over the past few years and is continuing to change. The reasons for this are several:

- increasing gas trading activities with a trend to short-term contracts with an impact on physical gas flows;
- substitution of pipeline-based supplies by LNG;
- growing diversification of gas quality combined with an increase of decentralized entry points;
- injection of renewable gases such as biomethane, bio syngas (hydrogen or synthetic methane) in a move towards a carbon-free future;
- increasing injection of gases from nonconventional sources following the development of local gas fields (e.g. shale gas); and
- gas distribution operators are thus increasingly challenged to manage significant variations of gas quality.

Where gas quality limits are exceeded, the following possible measures have to be considered:

- shut down the injection causing the problem and take the necessary technical measures to ensure that there is no reoccurrence. Note: this can conflict with security of supply needs and may require significant investment;
- shut down of critical consumer. Note: the threat of losing customers can have a negative impact on the industry’s image.

- Improvement of the flexibility of the gas quality tolerances of gas installations. Remark: can only be realised long term.

Despite the challenges mentioned above, it is vital that we as the global gas industry promote and enable the entry of renewable gases to our gas grid infrastructures and develop new technologies in order to carry forward the natural gas success story.

6.10 Long term LNG experience in Spain on gas compositions

6.10.1 Natural gas in Spain, the history

Before 1969, gas fuels were generally only used in the domestic/commercial market, with negligible utilization in the energy and industrial markets. Few cities had access to manufactured/town gas.

- Natural gas distribution started in 1969;
- LNG from Libya to Barcelona Terminal (Very heavy LNG);
- Supply limited to Barcelona and the surrounding area (most of natural gas used in industrial market or to produce manufactured gas (MG)).

In 1970, the gas fuel market in Spain was dominated by LPG (18 % (NG + MG) vs 82 % LPG).

After 1970, the natural gas market share started to steadily grow.

- Manufactured gas production had a minimum growth;
- In 1975, natural gas consumption was higher than manufactured gas;
- The first natural gas transmission pipeline was commissioned in 1979.

Natural gas market share passed LPG gas at the end of 1980s. At the same time, manufactured gas consumption started to decline and in 2002, manufactured gas disappeared.

6.10.2 Current Spanish natural gas market

The Spanish gas system has always been known for having facilities capable of receiving natural gas from different origins (12 countries in 2013) and composition (see Figure 6.1 and Figure 6.2).

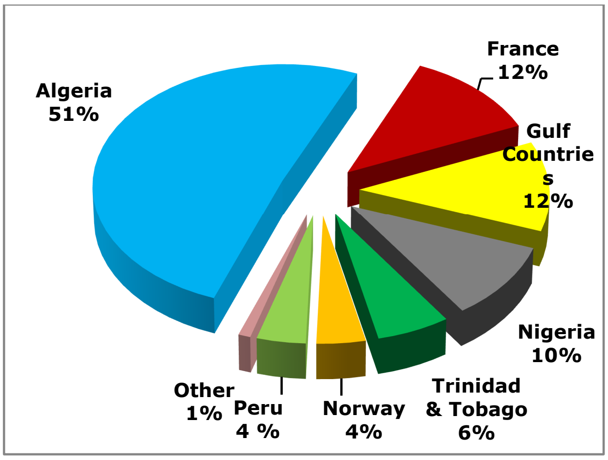


Figure 6.1: Natural gas origin, year 2013

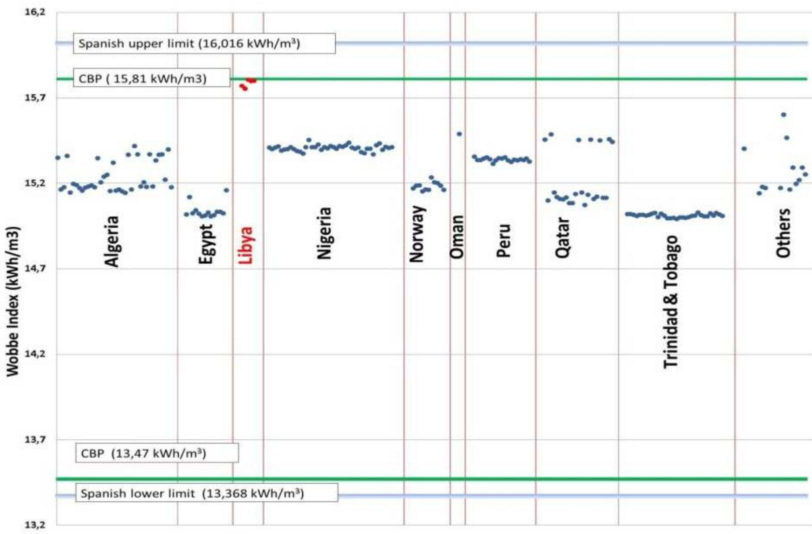


Figure 6.2: Spanish Wobbe Index range MJ/m³ (Data 2011-2012)

The strength of the system has been manifested mainly in relation to security of supply. This is due to the fact that Spain has always depended on natural gas import (nearly 100 %).

Figure 6.3: 2013 LNG/NG share

Despite this wide range of our sources, the Spanish gas system never had problems in accommodating the many LNG tankers that have been intended for our market to the current quality specifications collected in the Spanish gas regulation.

No treatment is made to any natural gas arriving to Spain. Blending, as a gas treatment, is not done at LNG terminals, except for when there are operational or efficiency reasons, such as:

- "Hot" LNG arrival;
- Control of boil off generation;
- Amount of LNG unloaded: Qflex & Qmax ships.

6.10.3 Spanish natural gas quality specification

Spanish gas quality specifications were defined with the liberalisation of the natural gas market in Spain (BOE 7-01-2013 no. 6 section 1):

- Needed to allow new traders in the market;
- Clear rules for everybody.

All natural gas introduced at the entry points of the natural gas system, must comply with the regulated gas quality specifications: WI range: maximum 54,7 MJ/m³, minimum 45,7 MJ/m³. . (See

Figure 6.4)

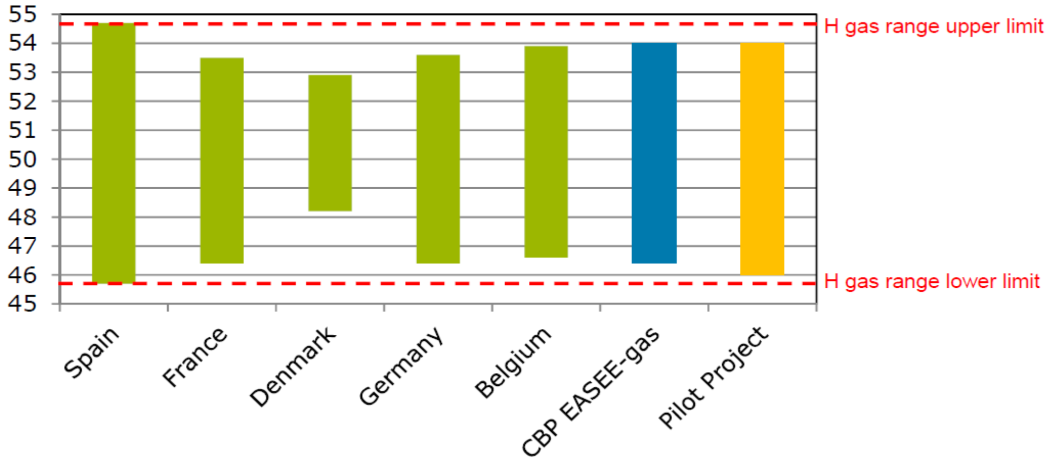


Figure 6.4: WI Range MARCOGAZ Pilot Project

According to the information provided by Enagás, regarding the average values in most of the entry points (by pipeline and regasification plants) to the Spanish natural gas transmission network taken from 1st January 2009 to 30th June 2012, the **minimum** WI value recorded during that period was **49.08 MJ/m³**, while the **maximum** was **53.57 MJ/m³** (an interval of 4,49 MJ/m³).

The maximum difference recorded in one day of **3.62 MJ/m³** (being very likely that this difference of one point is even lower) and the difference medium value of 2.45 MJ/m³.

However, hourly variations of Wobbe Index in the grid might take place due to unloading with a different quality or production from alternative tanks in LNG terminals. Variations up to 6 % in a short time have been recorded, without evidence of any impact on the final-users.

Figure 6.5 provides data on the minimum and maximum WI values recorded in the entry points to the national natural gas system. It can be observed that for several years there have been LNG cargoes whose WI have been closer to the maximum limit (54,7 MJ/m³). On the other hand, only biomethane WI value is close to the lower limit.

Despite a wide range being needed for security of supply, in practice a more narrow range results from what is really distributed. The Wobbe index range referred to above is between the limits set in EN 437 (i.e. between 39.1 and 54.7 MJ/m³ for Group H & L 2nd family gases), which is the European Standard approved in 2003.

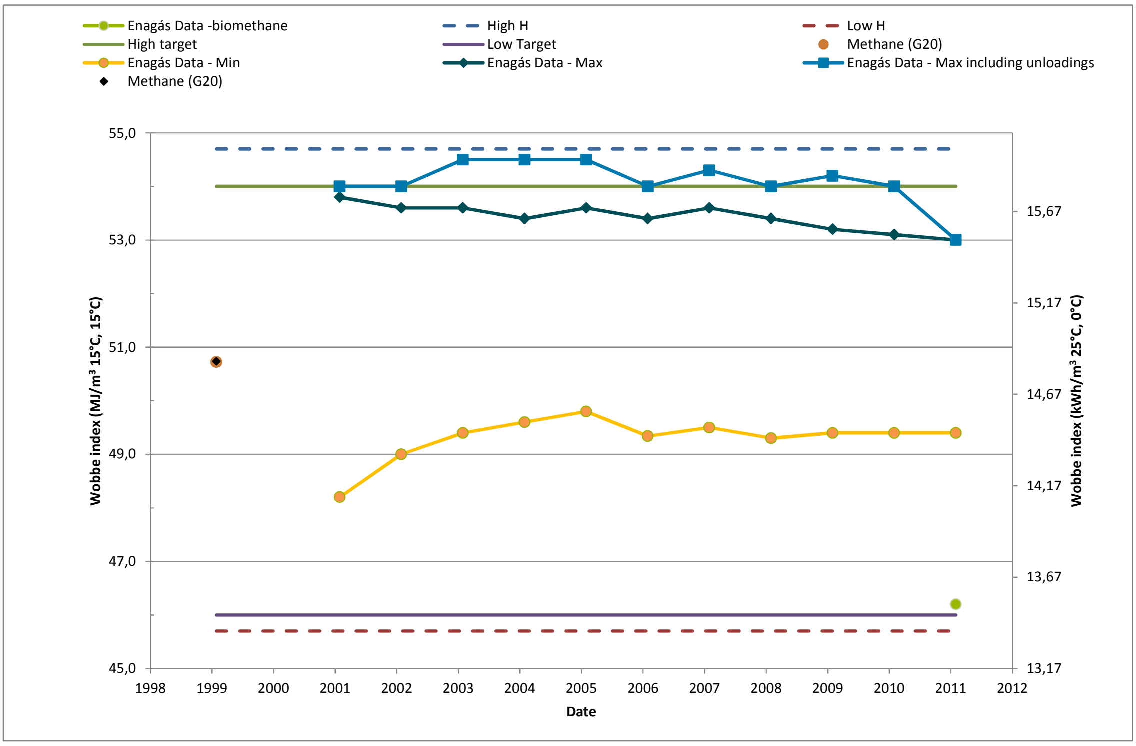


Figure 6.5: Historical minimum and maximum WI values recorded in the entry points to the Spanish natural gas system

Despite all the information provided, there is no guarantee that the same ranges of WI will be maintained in the future as the gas composition will depend on the sources of gas that shippers bring to Spain. Inevitably, the range must fall within the standards and regulations in effect in each member country.

6.10.4 Spanish experience in using wide range natural gas

1. In the context of The Gas Quality Harmonisation Implementation Pilot Project proposed by MARCOGAZ (Technical association of the European gas industry) and EASEE-GAS (European Association for the streamlining of Energy Exchange), to get the assessment from different stakeholders on the impact of the WI on the appliances behaviour, different stakeholders from the Spanish natural gas industry, were invited to integrate, either through professional associations or directly through companies.

2. According to the information provided by the report

- There has not been registered any evidence in Spain of problems in gas appliances caused by gas quality variations either by the inspections, maintenance or urgent attendance of systems in more than 40 years;
- Current investigations seem to show that the hypothetical problems are more related to WI variations within a short period of time than with high or low WI gas;
- Malfunctions found in appliances are due to other causes, normally scarce maintenance of the installations.
-

Domestic appliances

The Manufacturers feel comfortable with the WI range of the natural gas currently distributed in Spain, and they have not identified any problem caused by variations of the WI .They are aware of the quality of the natural gas distributed in Spain and they appropriately adjust their appliances in the factory and afterwards in-site too, according to it. They have specific charters for Spain regarding pressure injectors.

DSOs agree that fluctuations in WI can produce reductions in the performance (lower efficiency) when the WI is in the low range. In this case there is no implication for safety (CO emissions). In the opposite case, when the WI is high, it is possible to have higher CO emissions when the appliances are adjusted for lower values of WI. However, they consider that WI variations around 10% would be acceptable without major deviations in the appliances´ performance.

The Spanish regulation requires safety inspections at the customers' premises every 5 years and an annual maintenance for boilers.

The combustion parameters are checked on both inspections and maintenance.

In Spain the current limits for CO are 1000 ppm on combustions products in commissioning and inspections and 50 ppm in the rooms. The relevant legislation is under review and it is very likely that these limits are lowered.

Industrial users

Current investigations (GASQUAL) seem to show that the hypothetical problems are more related to WI variations within a short period of time than with high or low WI gas.

In the especially sensitive sector of internal combustion engines no special problems have still not appeared:

- More than 3000 NGVs, mainly buses & trucks, in Spain (2011);
- More than 400 cogeneration units with engines (2010).

Power generation

In Spain there are more than 60 Combined Cycle Thermal Plants for power generation. All of them are equipped with pre-mixed turbines.

Basically, the market is distributed among 4 turbine manufacturers. three of them have pre-heating equipment to adapt the WI to their specifications, so if WI were over the upper limit, they would pre-heat the gas to redirect the value into the established range.

The 4th manufacturer does not have those pre-heating equipment, but the relevant turbines have been working without any problem with the natural gas received so far.

6.10.5 Near Future

During recent years the share of LNG in comparison with pipeline gas has increased significantly and it is expected to grow much further in the mid to long term. Some Spanish suppliers have signed several long term contracts (1.8 bcm for pipeline and more than 10 bcm by LNG).

In the future there will be many new suppliers due to:

- New pipelines will come into operation that bring gas from new fields;
- Increase in the number of LNG receiving terminals from different sources. Normally, in the upper limit of WI specification range;
- Possible development of unconventional gas and renewable energy development (biomethane and hydrogen). Normally, in the lower limit of WI specification range;
- Change in gas flows;
- Future gas qualities are unknown but it is expected that they tend to force the end of the range;
- A wide natural gas quality specification is very important to allow new suppliers (especially LNG) to enter the market.

6.11 General description of LNG application in Russia

6.11.1 Introduction

Despite considerable potential of biogas production, presently the Russian Federation can successfully ensure consumer natural gas supply via system of gas distribution stations connected to trans-continental gas mains transporting gas recovered from the subsoil.

In winter at gas distribution stations biogas can be used as natural gas source for peak-shaving purposes. It is more preferable, however, to use methane produced from biogas for supply of consumers in the proximity of biogas plants in locations where consumer gas supply is hampered or impossible.

LNG can be used to deliver gas to consumers that cannot be supplied via pipelines. LNG plants can use as raw material methane produced from biogas.

In the LNG-based gas supply and distribution case, as distinct from the pipeline-based one, gas is delivered to and stored at the place of application (settlements /districts - high populated areas/, industrial and agricultural facilities, etc.) in the liquefied form.

Major LNG advantage lies in the fact that gas during liquefaction is reduced in volume by 600 times approximately, which makes its transportation practicable without laying gas pipe-lines and allows to compactly store it at gas-use sites as well as in vehicle fuel tanks in the case of gas use as motor fuel. At that storage site the traditional scheme of network gas supply and distribution is implemented within the boundaries of the settlement connected to gas supply. This traditional scheme includes intra-settlement low-pressure gas lines. In the local gas distribution system of intra-settlement gas lines gas is supplied from the storage facilities once it is regasified up to the required pressure level.

LNG sources may include LNG terminals or LNG production plants. LNG terminals and their regasification satellites can operate as natural gas supply sources for gas transport and important gas distribution lines. In case of local gas distribution systems remote from LNG terminals and for small-scale LNG consumers LNG can be supplied from small-tonnage (small-scale) production plants[2]. Small-tonnage LNG application can be considered an alternative to gas supply via trunk-lines and an extension of operating distribution system.

6.11.2 Sources of small-tonnage LNG production

Small-tonnage LNG production is oriented to local natural gas (NG) sources including:

- Small-scale NG fields;
- Biogas producing plants;
- Gas distribution stations for LNG plants using natural gas potential energy in the high pressure gas line;
- Autonomous gas fuelling compressor stations for LNG plants using available compressor potential;
- Spur gas lines and gas distribution lines for 100 % liquefaction LNG plants.

[2]LNG production not higher than 10-20 t/h is considered a small-tonnage one, though some sources classify as small-tonnage production not exceeding 40 t/h.

6.11.3 Technological chain of small-scale liquefied natural gas production, transport, storage and use

LNG-based gas supply consists of the following major stages:

1) Collecting gas from low and high pressure gas lines;
2) Gas delivery to the plant of partial or complete liquefaction;
3) Natural gas liquefaction and its delivery to the cryogenic LNG storage tanks;
4) LNG storage in the cryogenic storage tank until shipment in the big cryogenic tank;
5) Pouring LNG in the automotive cistern for shipment to the consumption site;
6) Discharging and storing LNG in feed-tank at the consuming facility;
7) LNG re-gasification in the atmospheric evaporators;
8) Natural gas pre-treatment and supply to the thermal energy equipment via metering unit.

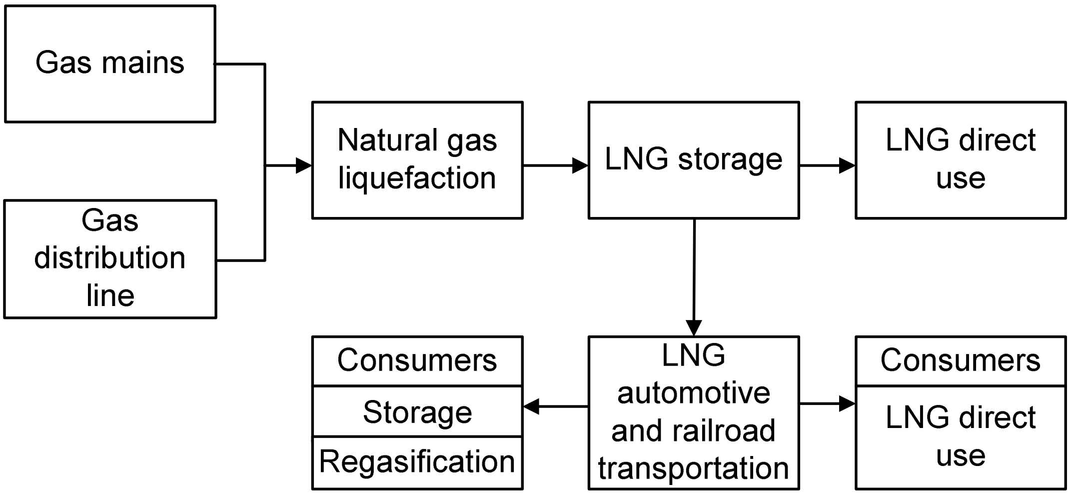


Figure 6.6: Technological chain of LNG-based gas supply and distribution

6.11.4 Small-tonnage LNG application field

Small-tonnage LNG uses in gas supply and distribution (Figure 6.7) include:

- Autonomous (without pipelines) gas supply of diverse consumers situated far from gas mains, like population, heat and energy facilities of social importance (residential and communal sector), industrial facilities, energy blocks of generating facilities;
- Consumer mobile gas supply in the situation of gas lines being repaired without gas supply interruption;
- Establishing back-up gas supply of settlements (of socially important gas consuming facilities) where supply is effected via single spur track as well as for facilities with continuous work cycle (metallurgy ones, for instance);
- Use of LNG as fuel for automotive and railroad transport;
- Generating extra natural gas sources for peak shaving[3].

[3]By way of example we refer to small-tonnage LNG plant (Peaк Shaver) with 30,000 m3 storage located in Stuttgart

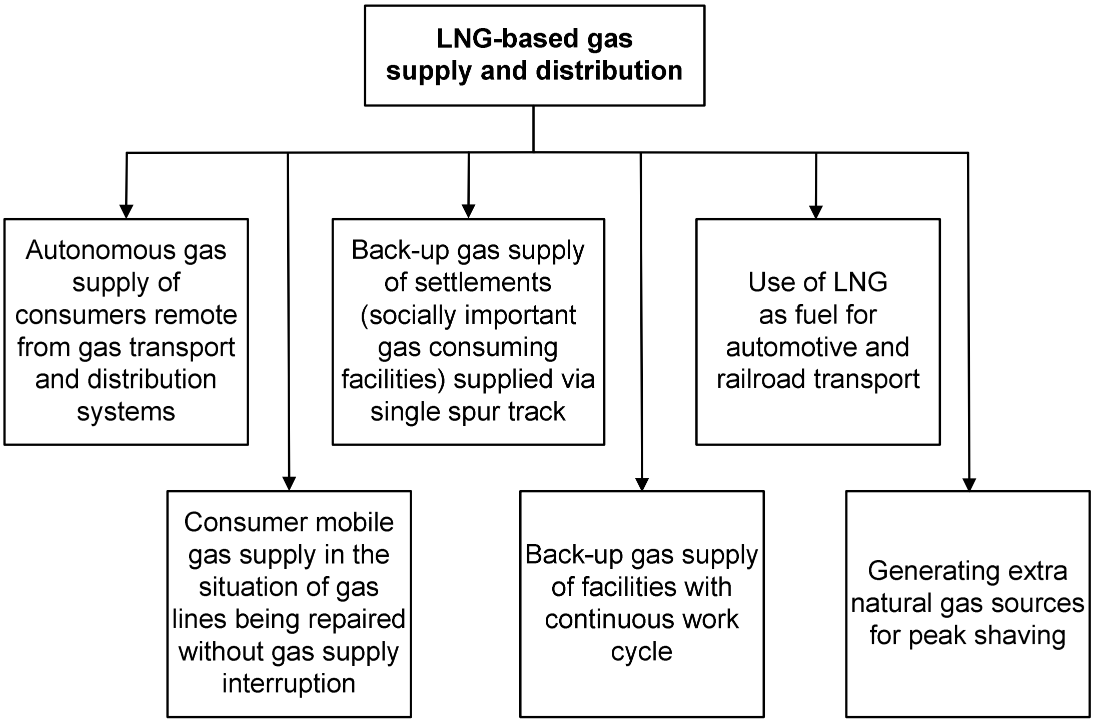


Figure 6.7: LNG uses in gas supply and distribution

LNG application is preferable for supply of settlements and industrial facilities in locations topographically unsuitable for gas pipe line construction:

- Unstable seismic situation at the potential gas line construction site;
- Complicated relief of the gas line prospective route;
- Location of gas consuming facility or projected gas line route in unique natural environment;
- Presence of insurmountable obstruction (sea, rivers, mountains) in the projected gas line route.

6.11.5 Selection of gas supply and distribution options

In some situations consumer gas supply via pipelines might be economically unfeasible, and autonomous LNG-based gas supply of industrial and societal facilities and settlements as associated with lower capital investments become attractive for investors.

Selection of gas supply and distribution option is based on economic efficiency (depends on capital and operation costs) as well as on price formation and regulation requirements. As capital and operation costs differ for gas supply via trunk-line system and for LNG-based one, amounts of these costs vary according to potential consumer capacity and remoteness from gas supply source.

LNG gains advantages with increase of consumer distance from gas supply source and diminishing consumer consumption.

6.12 Bio-methane to grid in Austria

6.12.1 The initial situation

At the beginning of this millennium about 100 biogas plants were in operation in Austria. This number increased rapidly due to a good regulatory incentive scheme, as shown in the following diagram.

The diagram shows the number of plants and the aggregated electrical power output.

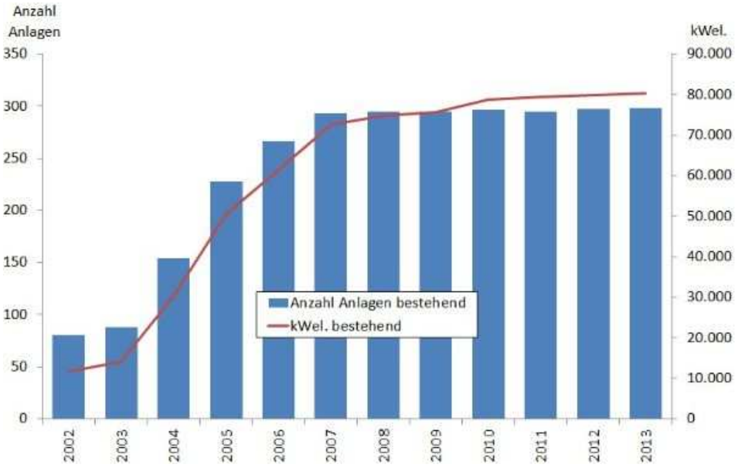


Figure 6.8: number of plants and the aggregated electrical power output

Nearly all of these installations are operated by farmers or agricultural co-operations. And also all of them are utilizing the biogas in CHPs to produce electrical power and heat. The common problem of all the plants is the lack of permanent heat consumers. Some have heat reservoirs for heating buildings during winter, drying of products at harvest time or similar. However, the same problem of poor overall efficiency is everywhere, as there is no optimised heat utilisation utilisation and no storage solutions. This could be improved by cleaning and injecting bio methane into the existing grid.

6.12.2 Pilot project in Pucking

The first Austrian plant for bio methane to grid started up 2005. An existing biogas plant was equipped with a desulphurisation and Pressure Swing Adsorption plant. The bio methane was supplied to a specific island of household consumers. This test installation performed well during its five years of operation and thus supplied a lot of knowledge and understanding about the processes and its premises.

6.12.3 Today’s situation of bio methane in Austria

At present some 7 installations are under operation. There are various cleaning processes installed. We find pressure swing adsorption (PSA), membrane systems and chemical cleaning (i.e. amine-washing). The raw materials for those installations also vary. There are renewables, bio waste and sludge from water treatment plants.

The following picture shows the geographical distribution of bio methane into grid-plants in Austria. The aggregated capacity is 1,000 Sm³/h.

Furthermore there are another two bio methane producers, but these are not yet connected to the NG-grid but sell their gas for natural gas vehicles. In this case the product is called CBG (compressed bio gas).

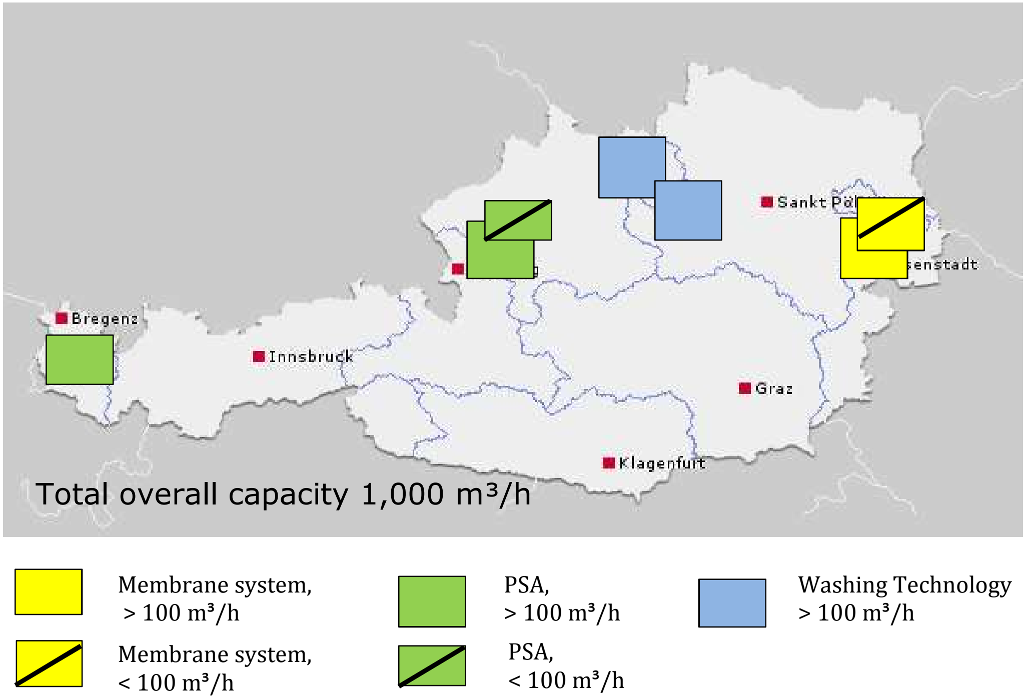


Figure 6.9: Total overall capacity 1,000 m³/h

6.12.4 Specific situation in Austria

The biomethane plants in Austria show some specific features compared to international usage.

6.12.4.1 The plants are quite small on average

The biggest plant produces a 380 m³/h bio methane; all others less than 150 m³/h. This corresponds to the small structures in our agricultural farms. Also in animal farming and production of food you can find these small structures. An advantage of the small sizes is also the short transportation distance for the raw materials and the residuals. So the local production of renewable energy gains a very positive market reaction.

6.12.4.2 The target is to clean and supply the gas directly to households

Consequently the produced bio methane must have high purity and the same calorific value as standard NG. This can only be achieved by addition of LPG and requires odorisation also. The advantage is the possibility to keep the pressure level as low as less than 4 bar, some plants less than 1 bar. This considerably reduces the energy consumption for compression. However in some grids this philosophy finds its limits during mild summer night times, when the consumption is lower than the foreseen production rate.

It appears that each technology for gas cleaning shows specific characteristics:

1. The PSA suffers from high electricity consumption and the methane losses to the environment. It may be the best solution if a small CHP is operating additionally.

2. Washing technologies have high energy consumption for the required process temperatures. They operate with complex apparatus and processes and require a well-trained operating workforce.
3. Membrane cleaning has methane losses to the environment. Also the operating costs are high especially due to expensive membrane materials. However, this system is quite easy to operate, also with less permanent supervision than others.

It depends on the specific situation of each plant which cleaning technology is the optimum solution.

6.12.5 Outlook for bio methane to grid in Austria

- At present costs of bio methane are high. The production, cleaning and injection requires efforts that are at the moment not comparable to natural gas. New pricing models or regulatory conditions are under discussion;
- conflict of land usage for food or energy. This is an socio- economic topic and needs consideration and discussion;
- positive market involvement of CNG vehicles operated by bio methane. The combination of the two environmentally friendly technologies go hand in hand;
- the bio methane discussion is already conceptually linked to Power-To-Gas discussions. Distributed production and utilisation of bio methane may support the same targets as Power-To-Gas;
- gas grids have much higher energy transport capacity than electrical grids. We took note of the distribution problems due to high production of renewable electrical energy resulting in unstable networks. The gas grids are removed from such problems;
- bio methane may require certification. It was suggested that only a certified green production line would entitle a green labelling of bio methane. This is subject to future discussions;
- the regulatory requirements of bio methane injections shall be amended. A producer injecting 100 m^3/h has only small influence to the grid. Consequently the rules (e.g. capacity guarantee, which mean costs) for these producers could be reduced.

6.13 Bio-methane to grid in Germany

6.13.1 The history of the "Energiewende"

The story of biomethane injection started in Germany as early as 1956. That year, a major sewage plant near the town of Mönchengladbach started to inject the sewage gas after some treatment into the local gas grid which was operated on town gas. In the 1960ies, another sewage plant in Stuttgart did the same. However, those activities were terminated in 1995 when sewage plants needed more energy for thermal sewage treatment.

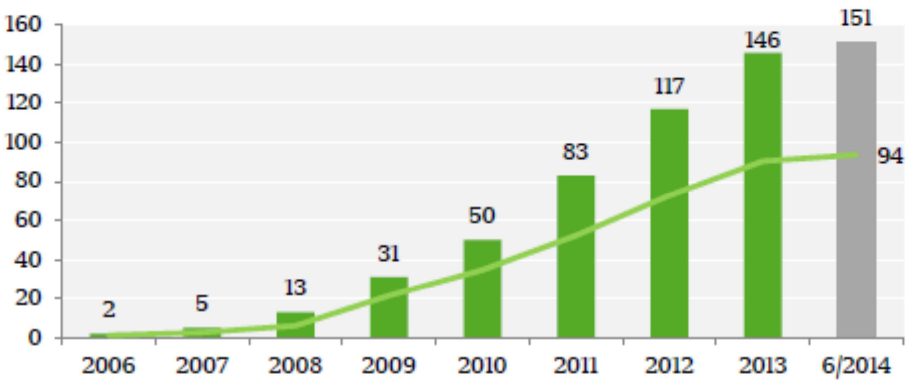
However, the idea was revived around the change of the millennium, and in late 2006 the first two purpose-build biogas plants were able to inject their treated biogas into the gas grid. This was a consequence of the rapid growth of biogas production plants in agriculture because legal requirements forbid bringing out "fresh" sewage including that from farm manure. Instead, a treatment of the manure and sewage was demanded to reduce the effects onto the environment. The result is that today there are more than 7 500 biogas production plants in Germany. Most of those use the biogas for local power production, feeding the power in the electric power grid. This went in parallel with the installation of thousands of windmills and solar panels.

This was fostered politically because there was always a strong opposition in Germany against nuclear power production. It was already difficult to build a nuclear power plant in the 1970ies, and the subsequence of the events in Harrisburg (USA), Chernobyl (USSR) and Fukushima (Japan) resulted in a complete repulsion of nuclear power which the government finally couldn't neglect. This all went to the profit of two energy sources: lignite, because being a dirty, but cheap domestic energy, and renewables.

Figure 6.10: Treated Biogas leaving the plant for injection at Pliening Biogas plant near Munich

6.13.2 Biogas production and injection: present and future

As mentioned above, more than 7500 biogas plants exist in Germany. Of those currently (June 2014) 151 plants are injecting biomethane (= treated biogas) into the natural gas grid, with a total capacity of 93 650 m³/h biomethane. The increase since 2006 thus has been quite impressive:



(Source. dena)

Figure 6.1: Number of injecting biogas plants and development of injection capacity in Germany

However, as the graph shows, the increase lost its momentum in 2013. The reason is that the newly elected government kind of “pulled the plug” on biogas: due to a change in legislation new biogas plants will no longer enjoy the subsidized energy price as existing ones, and therefore their business model is far less lucrative than it is until now. The effect is that after 2015 the construction of new biogas plants will come to a grinding halt. There are several reasons for this turn of action. One is of course that if something enjoys a higher price someone has to pay it which in Germany is every energy customer by means of a renewables surcharge on his energy bill. A steep increase in energy prices is of course bad news if a politician wants to be reelected but is blamed for that increase. The other reason is a public “tank or plate” discussion: the most common substrate for biogas production in Germany has become corn, in particular some hybrid not producing that many cobs, but growing tall just to produce a maximum of biomass. Besides the simple fact that house owners in rural areas don’t like 4 m tall corn to restrict the view from their premises, the question was publically raised that how can we afford to grow crops just for biogas production whilst in poorer regions of the planet people are starving? So, already back in 2011 government officials started to talk about the “maization of the landscape” which needed to be avoided, resulting in an ordinance that the substrate for biogas production shall be no more than 50 % be made up of corn.

However, the 151 plants already injecting can be operated economically and can expect a long future, and depending on the development of overall energy supply, eventually some more of the 7500 existing biogas production plants may be hooked up to the gas grid one day.

Figure 6.2 Fermenters in a biogas plant

6.13.3 The technical rules for biogas production and injection

Over the years, a number of technical rules and codes of practice have been developed in Germany, most of them to enable the injection of biomethane into natural gas grids at an acceptable level of technical safety. Most of them come from DVGW, the German association of gas and water experts which is also the German charter member of the IGU.

The first technical rule was published in 1992 under the number DVGW G 262. In its first issue the injection of biomethane was only one option of the use of gases from Sewage plants, agricultural biogas plants and landfills. The second issue, published in 2004, set its main focus already onto the injection of biogases into natural gas grids, but was rather restrictive to answer fears of the unknown which were very present in the gas industry then. The latest issue from 2011 was developed in close cooperation with the German biogas association, and the focus has changed to allow as much biogas as safely possible into the natural gas grid. In parallel, a federal ordinance was issued for the access to gas grids which actually was not only indiscriminative towards biogas (as the European Union demands), but even gave biomethane a preferred "right of way" in the gas network.

However, the same ordinance imposes by reference the use of three codes of practice of DVGW:

- DVGW G 260 (Gas quality);
- DVGW G 262 (Quality of gases from renewable resources);
- DVGW G 685 (Gas billing).

The next technical rule covered the safe design, construction and operation of biogas treatment, conditioning and injection plants (DVGW G 265-1 and -2): after having had a closer look to a number of biogas plants some deficiencies concerning technical safety were identified because a number of makeshift constructions existed. However, unsafe supply plants would never be accepted by the grid operators, and the result was the codes of practice DVGW G 265-series.

Another code of practice (DVGW G 415) went further into the biogas plant, giving advice for the design and construction of raw biogas pipelines.

The federal ordinance does not only grant preferred access for biomethane, it also imposes that a grid operator has to grant access even if the grid is full. Therefore it is possible in some grids with injection that in summer the entire gas in the grid is biomethane. To cope with the issue, they are required either to store the gas or to feed it back upstream. How to do this is described in DVGW regulation G 290, including the needs for compressing and deodorization.

Finally, DVGW regulation G 291 offers a number of questions and answers connected with biomethane injection to both, injector and grid operator.

This set of technical rules enables grid operators to cope with the fundamentals of biomethane injection. In most cases, after removal of sulfur, carbon dioxide and surplus water, the biomethane needs to be conditioned with either propane, propane/butane mixtures and air to adopt the calorific value to the one of the natural gas in the pipeline. This is required because the mixing rate will vary, and thus the calorific value over time. The variation, however, is limited by code of practice DVGW G 685 to ± 2% during a billing period.

The quality of the biomethane is usually controlled by a Process Gas Chromatograph (PGC) before the injection of the gas. Both, the biomethane injector as well as the grid operator have the right to stop the injection if the biomethane becomes out of specification.

6.13.4 Exchange gas or augmentation gas?

By far the majority of biomethane injections in Germany are based on biomethane in exchange quality. The biomethane can fully replace the natural gas in the respective grid, and most consumers won't even notice. Only in a few cases is the biomethane not treated to full exchange gas quality. In those cases, usually some remainder of carbon dioxide may be left in the biogas. However, then by contract the access to the natural gas grid is limited so that the resulting gas mixture still fully adheres to the specification given by DVGW code of practice G 260. These few injections usually take place at transport pipelines so that a relatively small amount of biogas is injected into a major stream of natural gas. Of course, "unlimited access" is not given.

6.13.5 Hydrogen – an old gas has its comeback

One of the newer concepts for a sustainable future is the one called "power2gas". Its basic consideration is that the production of renewable energy can be achieved in a environmentally friendly manner and sustainably, but not really reliable enough so that it could replace base load power plants. This is true for both windmills and solar panels: in a night without notable movement of air neither of them will produce any power, and on a windy day with a lot of sun both will produce a surplus in electric power that at that moment is useless for everyone. The way around this problem would of course be to store the surplus energy for times when it is needed, but to store electric power for a long period appears difficult. The two exemptions in "green energy" are hydropower (because it usually includes already a big storage of energy in shape of water behind a dam) and biogas which is produced relatively stable throughout the year. However, if the surplus energy gained from sun and wind could be turned into something gaseous which then could be stored in the underground storages of the natural gas supply system things would change, and all this renewable energy would be enabled to become base load. To get there, the surplus electric power from renewable resources is used for electrolysis to produce hydrogen. This hydrogen could then either be injected as such into the natural gas grid, or, if its concentration in the gas would get too high, undergo a methanation process to create synthetic natural gas (SNG) which could then be added to the grid in unlimited amounts, given sufficient grid and storage capacity. That is, in principle, the concept and currently there are approx. 20 pilot projects in Germany under construction or operating to achieve one or the other outcome.

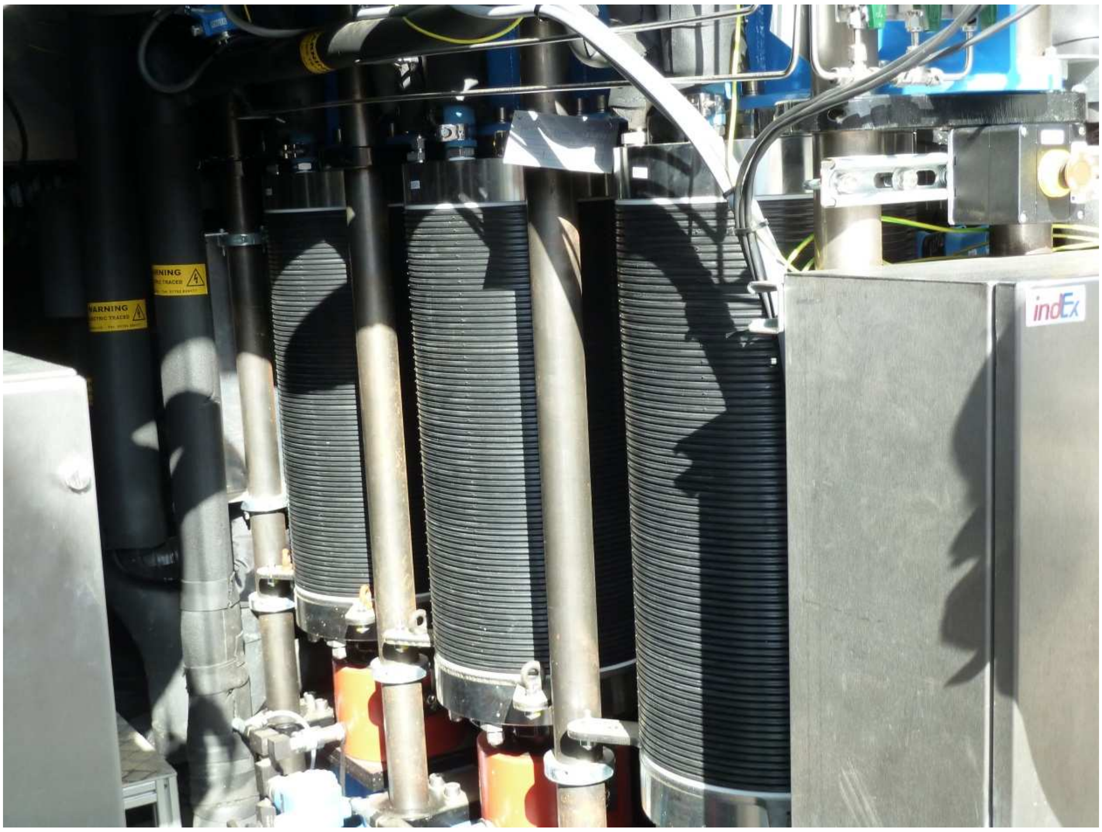


Figure 6.3: Electrolyzer stacks to produce Hydrogen for grid injection from renewable power in a pilot plant in Frankfurt

These activities are accompanied by a new framework of technical rules developed by DVGW:

Its brand-new code of practice DVGW G 265-3 covers the design and construction of hydrogen treatment and injection plants. The code of practice G 262 which generally addresses the injection of biomethane also addresses the injection of hydrogen because in German legislation, Hydrogen is treated as a kind of biogas. The big question is how much hydrogen would be permissible for a natural gas grid?

The solution is a case-to-case answer because in a given natural gas grid and its ancillaries you will encounter one or more piece of equipment limiting the access of hydrogen:

a) From a metrological point of view, it may be as low as 0,2 %. So it is in Germany, set by the authority in charge of that (PtB), unless the hydrogen content is measured. The reason is that hydrogen obviously contributes to combustion and is a carrier of energy, but to a different extent than Methane. Thus, to achieve correct billing of the gas/hydrogen mixture, both, hydrocarbons and hydrogen quantities need to be known. However, legal measurement of gas energy content in Germany is normally done using accredited PGCs, and all those put into service before 2013 wouldn't measure hydrogen (some new ones do). Therefore the authorities stipulate: Measure – or less than 0,2 %. Actually, calorimeters would do the correct job as well, but with few exceptions, they've been replaced by PGCs over the last decade.

b) Gas turbines are the equipment for which their manufacturers stipulate limits of the hydrogen content between 1 % and more than 15 %. They are often used to drive gas compressors in transit pipelines, besides those used by different industrial customers. Therefore to be on the safe side, it is required to assess the system the hydrogen is supposed to be injected into, and find out what gas turbines are present, and then contact their manufacturers to find out how much hydrogen those turbines are good for, and, if too low, consider with the manufacturers to solve the problem.

c) A limit of 2 % hydrogen in natural gas used as vehicle fuel is derived from the technical rule UN ECE R 110 which regulates on-board natural gas systems for propulsion purposes in road vehicles and stipulates this limit for steel tanks in natural gas vehicles (NGV). Of course, no one is forced to install steel tanks into an NGV, there are also other types of natural gas onboard reservoirs available, e.g. composite tanks for which the limit does not apply. But it is impossible to rule out that all types of NGVs will fill up at a given CNG station. In reality, all NGV manufacturers worldwide use UN ECE R 110 for the construction of their NGV products.

d) Another issue that limits the Hydrogen content in natural gas are underground storages. Their operators indicate without giving a limit value that hydrogen could damage the storage, either by fostering corrosion or by chemical silt production in the geological formation used.

Normal domestic gas appliances in general do note state a major obstacle to hydrogen injection. They usually can take more than 10 % hydrogen whose Wobbe-index is very near that of methane. However, if natural gas is used as a feedstock e.g. for the chemical industry this will be very reluctant to accept hydrogen in the natural gas because there are a number of negative effects of hydrogen on methane-based reactions. The most common is a negative influence onto the reactivity of the methane, thus resulting in unwanted products.

If there is more hydrogen available than safe to inject the option is the methanation of the hydrogen, resulting in methane and water:

$$CO_2 + 4\,H_2 \rightarrow 2\,H_2O + CH_4$$

If possible, the carbon dioxide comes from regenerative sources as e.g. a biogas plant as well, but another option is to use the exhaust gases of e.g. a power station running on fossil fuels (coal, lignite, oil, natural gas).

For the methanation itself, usually a catalytic thermal process is applied, but current promising developments also point to the possibility to let the job be done by bacteria in a bioreactor similar to the ones in biogas plants, with less energy to add, but slightly more time.

An interesting detail is that not only the “classic” energy producers are involved in the development of such concepts and plants, but also e.g. the automotive industry, see Figure 6.14 and Figure 6.15.

Figure 6.4: Large scale electrolyzer producing hydrogen for methanation

Figure 6.5: Partial view of the Audi™ methanation plant in Werlte

6.14 Experience on bio-methane introduction in Japan

6.14.1 Background

In Japan, there are 209 gas supply companies and gas suppliers are not unbundled (separation of E&P, transmission, distribution from the retail business.

The large volume gas market, with over 100,000 m3 / year per customer, was liberalized from 2007 onwards. Third parties can supply gas to large volume gas customers by using the gas pipeline networks of gas companies.

In July 2009 the Law Concerning Sophisticated Methods of Energy Supply Structures was passed with the aim of the law to promote a low-carbon society.

The law makes the introduction of bio-methane mandatory for gas companies that are more than 90 billion m3 / year. Tokyo Gas, Osaka Gas and Toho Gas correspond to this category.

6.14.2 Preparation for bio-methane injection

Gas companies drew up and published guidelines to receive bio-methane into their pipeline networks in 2008.

Japan Industrial Standard K 2301 (Fuel gases and natural gas – Methods for chemical analysis and testing) was revised to add continuous measurement methods of gas impurities including bio-methane.

6.14.3 Introduction of bio-methane injection

In 2010, Tokyo Gas and Osaka Gas began injecting bio-methane into their pipeline network derived from food waste and sewage sludge, respectively. Table 6.1 shows the records of bio-methane injection in Japan.

Table 6.1: Records of bio-methane injection in Japan

Gas company	Tokyo Gas	Osaka Gas
Start year	2010	2010
Site	Tokyo	Kobe
Feed material	Food waste	Sewage sludge
Volume	800,000m^3/year	800,000m^3/year
Upgrade	PSA	Water absorption

6.14.4 Easing of regulations

In 2013, the Ministry of Economy, Trade and Industry decided to relax regulations for the measurement of gas impurities. Based on the research for bio-methane gas quality, a part of gas impurity measurement was excluded from legal obligations.

6.14.5 Perspectives

After introducing bio-methane in two sites, there have been no new bio-methane injection sites.

In 2012, feed-in tariff (FIT) of renewable electricity was introduced.

FIT is to promote bioenergy as a fuel for power generation so it seems that a great increase will not be realized in the near future.

6.14.6 Scenario assessment & evaluation

Table 6.2: Estimation of the introduction of renewable gases in Japan

	Now	2020	2025	2040
Natural Gas	≒100	≒100	≒100	≒100
Biomethane	0.002	0.01	0.02	0.1
SNG	0	0	0	0.002
H2	0	0	0.002	0.05

6.15 French case for change between pipeline based and LNG-based supplies

6.15.1 GCV or WI variations: an old issue in France but which is tending to increase

A consequence of the diversification of gas sources:

- Started at the end of the 70s;
- Pipeline gas (A, B, D) from Norway, Russia and others: 75 % of H gas;
- LNG (E, F) from Algeria and others: 25 %;
- L gas (C) from the NL (specific network).

French gas quality specifications:

- Wobbe index: 46.5 < < 53.5 MJ/m3 at 15℃;
- GCV: 36.5 < < 43.6 MJ/m3 at 15℃;
- No specification for RD.

Gases may be blended in the network

- e.g. at the output of underground storages.

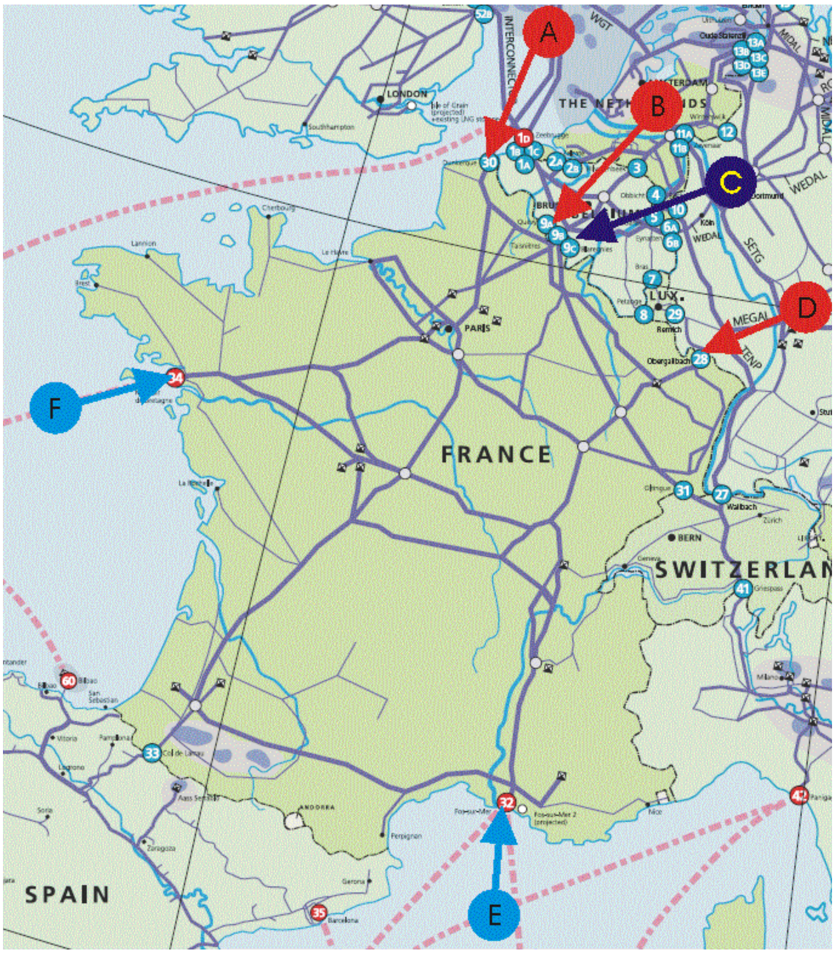


Figure 6.6: Map of gas supplies to France

6.15.2 French case: Change between pipeline based and LNG-based supplies

Regarding gas supplies with LNG in France:

- represents 25 % of H gas consumptions;
- range of WI variations : 51.3 to 52.6 MJ/Sm3 (higher allowed limit : 53.5);
- for more than 30 years LNG has fed the national grid as well as other gases (pipeline gases whose typical WI variations are 48 – 50.5 MJ/Sm3).

Consequences for customers:

- may be supplied only by LNG (near terminals) but, more often, alternatively by LNG and pipeline gases;
- local variations in WI from 5 % to 7 % is a common situation;
- no significant impact for most applications:
  - e.g. for gas appliances set with G20, it means variations less than +/- 5 % in excess of air (no impact on safety, little impact on efficiency and NOx emissions).
- but well-known industrial processes are more sensitive :
  - glass furnaces, steel or ceramics heat treatments, lime kilns, gas turbines, ..
  - specific technical solutions to cope with the issue have to be implemented (Wobbemeters, chromatograph, oxygen probes,..).

6.16 ISO/ CEN standards framework on gas quality in Europe

Below in Table 6.3 is a list of published and draft standards which are being used and developed by the gas industry to manage issues in relation to standardisation of minimum requirements for meeting gas quality specifications.

The purpose of the new draft standards is to build on the current framework of published standards to enable biogas/bio-methane producers and network operators to deliver safe, reliable and stable supplies of renewable gas to customers.

In particular we can see work through CEN (European Committee for Standardisation) on Gas Quality (prEN 16726) and Natural gas and biomethane for use in transport and biomethane for injection in the natural gas network (prEN 16723-1, 2). Furthermore, IGEM (Institute of Gas Engineers and Managers, UK) have published a standard on biomethane injection and one on Steel and polyethylene pipelines for biogas distribution.

It is very important that published standards are developed in tandem with technological developments of processes and equipment for renewable gas so that all aspects of the provision of renewable gas supplies are supported by clear, industry approved safety guidelines, specifications and standards. These will then be used consistently by operators and safety authorities to ensure the robustness and safety of the supplies to the end user.

The framework of current standards and where they apply in the vertical chain of biogas and biomethane production and utilisation can be seen in **Fehler! Ungültiger Eigenverweis auf Textmarke.** below.

Table 6.3: ISO/ CEN standards framework on gas quality in Europe

Gas	Publishing Body	Reference Number	Title	Status
Natural Gas	ISO	ISO 6974: 2002	Determination of composition with defined uncertainty by gas chromatography -- Part 6: Determination of hydrogen, helium, oxygen, nitrogen, carbon dioxide and C1 to C8 hydrocarbons using three capillary columns	Published Standard
Natural Gas	ISO	ISO 6976: 1995	Natural Gas – Calculation of calorific value, density, relative density and Wobbe Index from composition	Published Standard
Natural Gas	ISO	ISO 13686: 2013	Natural gas - Quality designation	Published Standard
Natural Gas	ISO	ISO 15403-1: 2006	Natural gas -- Natural gas for use as a compressed fuel for vehicles -- Part 1: Designation of the quality	Published Standard
Natural Gas	ISO	ISO/TR 15403-2:2006	Natural gas - Natural gas for use as a compressed fuel for vehicles -- Part 2: Specification of the quality	Technical Recommendati on
Natural Gas & Bio-methane	ISO	ISO 23874	Gas chromatographic requirements for hydrocarbon dewpoint calculation	Published Standard
Natural Gas	CEN	EN 15001	"Gas Infrastructure – Gas installation pipework with an operating pressure greater than 0,5bar for industrial applications and greater than 5bar for industrial and non-industrial installations"	Published Standard
Natural Gas	CEN	EN 13480	Metallic Industrial Piping	Published Standard
Group H gas	CEN	prEN 16726	Gas infrastructure - Quality of gas - Group H	Draft Standard

Natural Gas & Bio-methane	CEN	prEN 16723-1	Natural gas and biomethane for use in transport and biomethane for injection in the natural gas network Part 1: Specifications for biomethane for injection in the natural gas network	In development
Natural Gas & Bio-methane	CEN	prEN 16723-2	Natural gas and biomethane for use in transport and biomethane for injection in the natural gas network Part 2: Automotive fuel specifications	In development
Bio-methane	IGEM	IGEM/TD/16	Biomethane injection	Published Standard
Bio-methane	IGEM	IGEM/TD/17	Steel and polyethylene pipelines for biogas distribution	Published Standard

Summary Standard descriptions:

ISO 6976: 1995 "Natural Gas – Calculation of calorific value, density, relative density and Wobbe Index from composition " specifies methods for the calculation of the superior calorific value and the inferior calorific value, density, relative density and Wobbe index of dry natural gas and other combustible gaseous fuels, when the composition of the gas by mole fraction is known.

ISO 6974: 2002 "Determination of composition and associated uncertainty by gas chromatography" describes a gas chromatographic method for the quantitative determination of the content of helium, hydrogen, oxygen, nitrogen, carbon dioxide and C1 to C8 hydrocarbons in natural gas samples using three capillary columns. This method is applicable to the determination of these gases within the mole fraction ranges varying from 0,000 1 % to 40 %, depending on the component analysed, and is commonly used for laboratory applications. However, it is only applicable to methane within the mole fraction range of 40 % to 100 %. These ranges do not represent the limits of detection, but the limits within which the stated precision of the method applies. Although one or more components in a sample may not be present at detectable levels, the method can still be applicable.
ISO 6974-6:2002 is only applicable if used in conjunction with ISO 6974-1:2000 and ISO 6974-2:2001.

This method can also be applicable to the analysis of natural gas substitutes. Additional information on the applicability of this method to the determination of natural gas substitutes is also given where relevant.

ISO 13686: 2013 "Natural gas - Quality designation" specifies the parameters required to describe finally processed and, where required, blended natural gas.

The main text of ISO 13686:2013 contains a list of these parameters, their units and references to measurement standards. Informative annexes give examples of typical values for these parameters, with the main emphasis on health and safety.

ISO 23874: “Gas chromatographic requirements for hydrocarbon dewpoint calculation” describes the performance requirements for analysis of treated natural gas of transmission or pipeline quality in sufficient detail so that the hydrocarbon dewpoint temperature can be calculated using an appropriate equation of state. ISO 23874:2006 can be applied to gases that have maximum dewpoint temperatures (cricondentherms) between 0 ℃ and - 50 ℃. The pressures at which these maximum dewpoint temperatures are calculated are in the range 2 MPa (20 bar) to 5 MPa (50 bar).

The procedure given in ISO 23874:2006 covers the measurement of hydrocarbons in the range C5 to C12. n-Pentane, which is quantitatively measured using ISO 6974 (all parts), is used as a bridge component and all C6 and higher hydrocarbons are measured relative to n-pentane. Major components are measured using ISO 6974 (all parts) and the ranges of components that can be measured are as defined in ISO 6974-1

ISO 15403-1:2006 “Natural gas -- Natural gas for use as a compressed fuel for vehicles -- Part 1: Designation of the quality” provides manufacturers, vehicle operators, fuelling station operators and others involved in the compressed-natural-gas vehicle industry with information on the fuel quality for natural gas vehicles (NGVs) required to develop and operate compressed-natural-gas vehicle equipment successfully.

Fuel meeting the requirements of ISO 15403-1:2006 should provide for the safe operation of the vehicle and associated equipment needed for its fuelling and maintenance, protect the fuel system from the detrimental effects of corrosion, poisoning, and liquid or solid deposition and provide satisfactory vehicle performance under any and all conditions of climate and driving demands.

Some aspects of ISO 15403-1:2006 may also be applicable for the use of natural gas in stationary combustion engines.

ISO/TR 15403-2:2006 “Natural gas - Natural gas for use as a compressed fuel for vehicles -- Part 2: Specification of the quality” addresses the specifications of natural gas as a compressed fuel for vehicles as an addendum to ISO 15403-1. Specifically, ISO/TR 15403-2:2006 is intended to satisfy requests for quantitative data.

The critical items regarding gas composition are water content, sulphur compounds, particulate matter, higher hydrocarbons, CO_2, free oxygen, glycol/methanol, oil content and corrosive components.

ISO/TR 15403-2:2006 pertains only to compressed natural gas as it enters the fuel containers on the vehicle. It does not apply to the natural gas delivered to a refuelling station.

EN 15001: "Gas Infrastructure – Gas installation pipework with an operating pressure greater than 0,5 bar for industrial applications and greater than 5bar for industrial and non-industrial installations" specifies detailed functional requirements for the design, selection of materials, construction, inspection and testing of

- industrial gas installation pipework and assemblies with an operating pressure greater than 0,5 bar, and
- non-industrial gas installation pipework (residential and commercial) with an operating pressure greater than 5 bar in buildings

starting from the outlet of the network operator's point of delivery up to the inlet connection to the gas appliance; normally the inlet isolation valve. This standard also covers the inlet connection to the gas appliance comprising of the pipework that does not fall within the scope of the appliance standard.

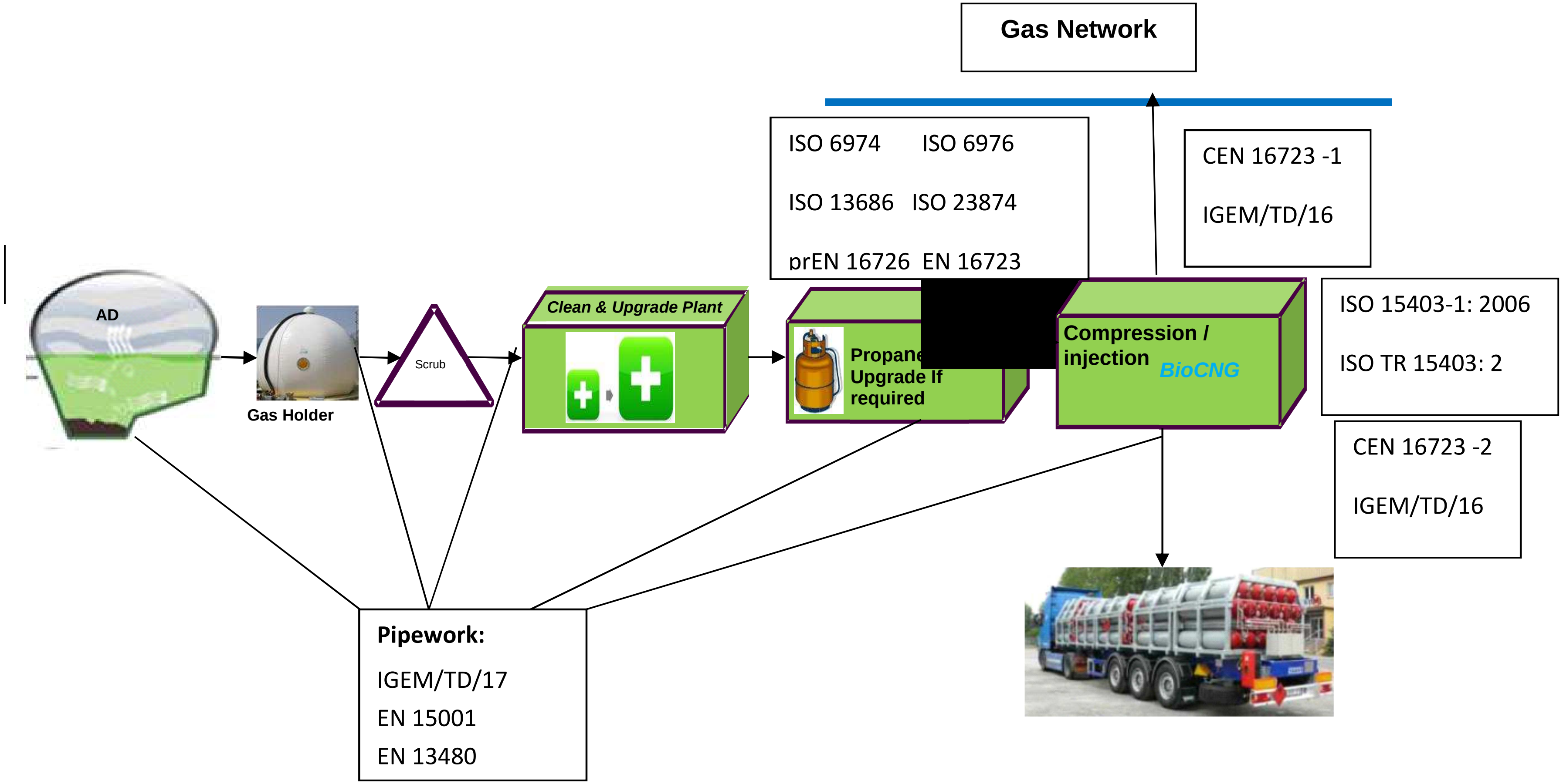
EN 13480: Metallic Industrial Piping" describes the requirements for industrial piping systems and supports, including safety systems, made of metallic materials with a view to ensure safe operation

prEN 16726 "Gas infrastructure - Quality of gas - Group H" specifies gas quality characteristics, parameters and their limits, for gases classified as group H, as in EN 437:2003+A1:2009. This standard does not cover gases conveyed on isolated networks or gases prior to their entry in a transmission network in Europe. This European standard is applicable to gases that are to be transmitted, stored, distributed and used.

IGEM/TD/16 "Biomethane injection" covers the requirements for design, construction, installation, inspection, testing, operation maintenance and de-commissioning of Biomethane Network Entry Facilities (BNEFs). Biogas Upgrading Plant (BUP) are outside the scope of this Standard, however, consideration of the BUP and its impact on the design and operation of the BNEF may be appropriate.

IGEM/TD/17 "Steel and polyethylene pipelines for biogas distribution" covers the additional requirements for design, construction, inspection, testing, operation and maintenance of stainless steel and polyethylene (PE) pipelines for the conveyance of biogas. This Standard covers pipelines distributing biogas of MOP not exceeding 2 bar and at a temperature from 0ºC to 40ºC (see Note 2) inclusive for PE and -40ºC to 100ºC inclusive for stainless steel. This Standard covers the predominantly underground network of pipes that convey biogas from biogas production plants to a suitable point where it can used in the industrial/commercial sector or upgraded (via a biogas upgrading plant (BUP) to biomethane, either for use as a vehicle fuel or for injection into the Natural Gas network following enrichment and odorisation if appropriate.

Figure 6.7: Illustration of Applicable standard scope locations



6.17 Variation of gas qualities in Denmark

6.17.1 SITUATION BEFORE 2010

Until 2010 Denmark have had a very homogeneous gas quality with small variation from the production in the North Sea.

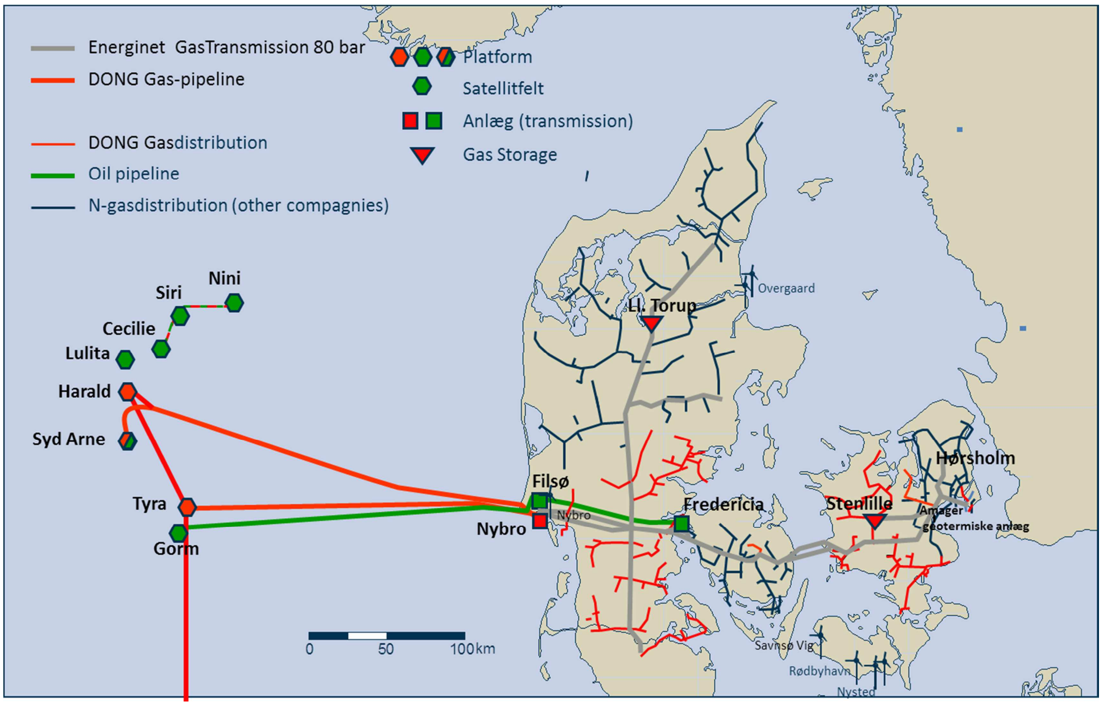


Figure 6.8: import/export

6.17.2 Gas-quality from the North Sea

From 1984 gas supplied from the North Sea to Denmark, Sweden and Germany.

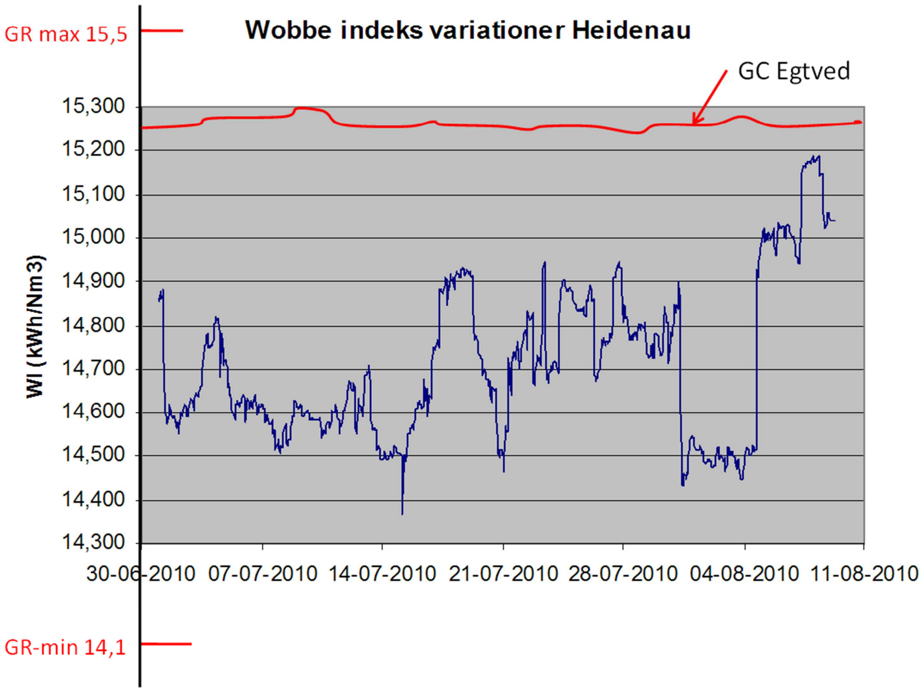
Very stable quality

- GCV: 12,1-12,3 kWh/Nm³
- WI: 15,2 – 15,3 kWh/Nm³

The Danish Safety Technology Authority defines the Danish Gas Regulations.

Allowed range in WI: 14,1 - 15,5kWh/Nm³

Since 2013: "Emergency situation" down to WI: 13,9 kWh/Nm³



Typical North Sea quality: red,

Germany (Heidenau) 2010: blue,

Regulation WI limits 14,1-15,5 kwh/Nm³

Figure 6.9: Wobbe index variations at Heidenau

In 1998 a new gas-field – "Syd-Arne" – started producing gas with a very high contents of Butane and Propane => high Wobbe-index.

This higher Wobbe-index caused domestic boilers to be adjusted according to the North Sea quality, instead of using factory settings (G20 test gas).

This procedure was used in DK until 2011.

6.17.3 WHAT HAPPENED IN 2010

Due to a still growing market for international gas trading and downward production from the North Sea, imports from Germany were expected to occur in 2010.

First gas-import from the Germany grid occurred in Oct. 2010 for a few days.

Wobbe-index was close to the lower permitted limit (14,1 kWh/Nm³) for a few hours during these first imports.

Figure 6.20: Import 9 - 10 October 2010: WI North Sea: 15,3 kWh/Nm³ -> Heidenau-mix 14,5 kWh/Nm³ (and with peak: 14,15 kWh/Nm³)

Response from customers because of the variation in the gas quality:

Domestic market:

Many phone calls from customers and fitters. Boilers with pre-mix burners, especially Beretta and Bosch, were making noise, vibrations and in some cases the boiler tripped. When making noise high CO-values were registered.

Why: As the calorific value dropped, the gas/air ratio became too lean and the flame started to fluctuate with a high frequency, thus making a noise like a lawn-mower engine.

Further investigations showed, that the noise-problems happened when Wobbe-index was 14,3 kWh/Nm³ or below.

Industry

Less output from forced draught burners, few trips due to unstable flame.

Most process-burners are running with a large excess of combustion air, making them less sensitive to variations in gas quality.

Some factories, with highly sensitive production, had in advance installed gaschromatographs to give input-signals to burner-controls.

In general very few problems were observed.

CHP with large gas engines

Caterpillar, Rolls-Royce (Bergen), Wärtsila and Jenbacher are the four suppliers of large engines for CHP.

Only minor problems except for Caterpillar engines.

Caterpillar:

- A few could not start.
- A few observed off-spec. parameters causing trip of engine.
- Rough running

Rolls-Royce: Minor adjustments were prepared as well as new software was installed within a few months.

Wärtsila and Jenbacher: no problems.

6.17.4 WHAT WAS DONE

The Actions

New methods of adjustment were ordered by the Authorities and developed by Danish Gastechnology Centre.

- Methods were, in short, to return settings of domestic boilers to factory settings, equivalent G20 test-gas.
- Forced draught burners, minor change in existing methods
- 1500 fitters in DK were educated to use the new methods in 2011.
- The Authorities changed the Regulations accordingly.

Media

Danish newspapers tried for a few weeks to make a bad story of this low value gas: "DONG Energy is cheating the customers"

The TSO, distribution companies and the Authority made a coordinated information campaign towards the media.

After a few weeks the newspapers lost interest in the story.

Information to customers

Domestic customers

Direct mail to all customers informing about:

- Reason for import
- New adjustment methods that fitters would use at the next service (normally every two years)
- The gas-bill is (and have always been) corrected to a standard calorific value.

Customer Service (Call-centre) prepared with Q/A lists.

These actions were successful and "good-will" was restored.

Industry and CHP

Before import started:

- Industry- and CHP-customers informed.
- Gas industry and service-providers informed.

After first import:

- Direct mail to all customers.
- Big scale customers invited to information-meetings.

- SMS-service, informing about import or export-situation to Industry, CHP, gas-service firms and all who wishes this information.

6.17.5 Status June 2014

Despite massive import from the German grid, no problems have been reported so far.

From 2013 the Authorities have allowed an "emergency supply" in the Wobbe-range 14,1 – 13,9 kWh/Nm^3. Should this situation occur, a plan will be activated, to test the quality of combustion in, what we have identified as "trouble-boilers" (Nefit turbo derivatives and forced draught burners of make BOX-1).

Evaluation of this test will enter into decision if the lower Wobbe-limit can be extended to 13,9 kWh/Nm^3.

6.18 Analysis of the challenges of gas quality diversification

A remarkable example can be seen in the German market as a tremendous increase in renewable electricity capacity originated from wind and solar has led to a situation in parts of the country where the daily renewable injection capacity often exceeds the demand. As electricity cannot be adequately stored, the gas industry took the opportunity to initiate the planning of a double-digit number of pilots for the conversion of surplus electricity into hydrogen or synthetic methane.

An accompanying research programme of the German Technical and Scientific Association for Gas and Water (DVGW), in cooperation with the German gas companies and representative application technology providers was conducted to find out acceptable hydrogen concentrations in natural gas for individual installations and other gas applications.

From the first results and corresponding analysis in SG 4.2, it can be concluded that the most sensitive installations are:

- Natural gas turbines which are used in gas compressor stations for transmission and storage, but also in industrial plants;
- Natural gas vehicles, where mainly the on-board high-pressure steel tanks for the gas, but also engine technology tolerate only limited hydrogen proportions;
- Underground pore storages such as aquifer storages where the potential impact of hydrogen on the geological structure needs to be researched;
- Metering technologies for gas chromatography need to be developed for an accurate measurement of enlarged gas quality compositions; and
- In Germany it is seen as relatively uncritical to accept up to 2% hydrogen in natural gas on today´s given quality standards. More hydrogen concentration seems to be realistic but demands an analysis of the individual situation.

6.18.1 Analysis of the challenges of gas quality diversification

In several markets commercial and industrial gas use has a long history before natural gas was introduced. First coke gas or wood gas were already invented in the late 18^{th} century and utilised for illumination. The proportion of hydrogen in town gas exceeded 50 %. In the following years the gas composition was characterised by a broad range. After initial gas discoveries in Europe with local use more than 100 years ago, the first large natural gas fields in Europe were developed from 1959 onwards and this then replaced the town gases.

Due to this history the gas industry gained substantial experience in the treatment and management of different kinds of gases; and we as the gas industry should not hesitate to actively take the challenge to upgrade natural gas with renewable gases. Based on the experience gained in numerous markets, the upgrading of natural gas to biogas, biomethane, hydrogen, synthetic gases or shale is manageable from the technical standpoint.

Also the change between pipeline-based supplies and LNG-based supplies offers additional opportunities as the gas treatment at LNG terminals can be done as a large-scale industrial application at lower costs.

6.18.2 Finding new solutions for the introduction of renewable gases and new technologies to manage the changes in the distribution grids

Besides technical feasibility, the economic aspect of feasibility needs to be considered. In the end customers need to pay for every kind of innovation and we have to ensure that gas will defend its role as a competitive fuel. Therefore, it is of significant importance to analyse the acceptable admixture rates of the individual renewable gases. This is one of the biggest challenges SG 4.2 worked at.

One of the key challenges is to define tolerable ranges for the individual regional Markets and the future development.

6.18.3 Scenario assessment and evaluation for the introduction of renewable gases

It also became apparent that, for a global view on this, a scenario impact assessment and evaluation of the individual renewable gases needs to be developed for the individual markets. The wider we can define concentration tolerances, the less investment to upgrade our grid infrastructures needs to be made and consequently the more competitive our “green” gas fuel will be. This is one of the major challenges we face.

Therefore it is necessary to elaborate ways that distribution companies can address the growing challenge to:

- Manage the increasing complexity of a stable gas composition in alignment of the market standards and specifications;
- Secure stable gas supplies for their customers in order to guarantee security of supply for their distribution system; and
- Guarantee economic competitiveness of natural gas versus other fuels.

6.18.4 United States Shale Natural Gas & Liquids Revolution

Shale Gas production in the United States has increased rapidly since the mid 2000's primarily because of technological advancements of hydraulic fracturing and horizontal drilling. It is estimated that the United States currently, and depending what source you hear it from, has a hundred (100) year supply or 2,000 to 3,000 trillion cubic feet (tcf) of potential natural gas reserves in these shale plays.

For the past three (3) years the United States has been the world's fastest growing hydrocarbon producer.

The United States natural gas production has increased by 25 % since 2010.

Some estimate industrial natural gas usage to increase by 19 % by the year 2020.

The United States just recently surpassed Russia as the World's largest gas producer and soon will become one of the World's largest exporters. This will fundamentally change pricing and trade patterns in global energy markets. Shale natural gas, crude oil, condensate and natural gas liquids (NGL's) production is going on all across the United States where even those wells with dry gas only have moved drilling rigs to wet gas fields where companies can benefit with both gas and liquids production.

This unconventional production of gas and liquids has benefited even in areas of conventional production where unconventional practices are reviving many of these fields. It all began in the Barnett shale of Texas, and then to the Fayetteville shale in Arkansas, the Woodford shale in Oklahoma, the Haynesville-Bossier shale in eastern Texas and northwestern Louisiana, the Marcellus shale of the Appalachian basin, and the Eagle Ford shale in south Texas. Other plays have begun to emerge where more liquids are present like the Bakken shale in North Dakota and the Niobrara shale in Colorado and other areas in the Eagle Ford shale in south Texas.

In some areas where pipeline infrastructure is not currently in place the liquids are transported by highway trucks and railroad tanker and the natural gas is flared. Regulations are currently in place to prevent natural gas flaring and provide must faster options for natural gas transportation.

Production has outpaced the infrastructure to handle in many areas not previously known for oil and gas development.

Affordable domestic natural gas and liquids have been essential to rejuvenating the refining, petrochemical, manufacturing, fertilizer and steel industries.

There is a cheap and abundant supply of natural gas and liquids, primarily ethane, which is currently providing 100,000's of jobs and billions of dollars in federal, state and local tax revenue and billions of dollars in industrial expansions. Because of this cheap, clean burning natural gas the majority of coal fired power generating plants are switching over to natural gas. Natural gas due to its clean-burning nature relative to other fossil fuels and favorable economics is an increasingly popular fuel choice of electric utility generators that were primarily coal or nuclear but due to economic, environmental, technological and regulatory changes natural gas is the fuel choice for new power plants.
Domestic natural gas prices are at a low not seen in many years which obviously is helping with lower utility and feedstock prices.

Environmentalists and environmental regulators continue to play a strong role in the safe removal of natural gas and liquids from these shale plays all across the United States. This not only covers air, water, surface land, wildlife, community, seismicity, etc. to make sure that it is being done properly and that the environment is not affected detrimentally. There is also a big environmental push currently that there is a perception that the natural gas industry wastes a lot of natural gas from the wellhead to the burner tip and studies are being performed in all phases of the industry in upstream, midstream and downstream operations to determine actual natural gas losses in each of these sectors. In other words it is known that natural gas is abundant, domestic, cheap and clean burning but many are saying that the natural gas lost to the atmosphere unburned along the production channel is a detriment to the environment as a greenhouse gas and contributing to global warming.

Many say this goes against the benefits derived by the consumption of natural gas over other fossil fuels.

Minimizing environmental impacts while maximizing the benefits of shale gas development require continued advancements in technology and collaborative effort to accurately quantify both potential risks and the potential benefits.

The United States experienced some of the coldest weather on record this past winter and in early January 2014 had its single largest consumption day where it delivered 134.3 billion cubic feet (bcf) of natural gas. It can be said that had it not been for the shale gas revolution in the United States and because of gas delivery and storage it most likely would not have happened without some curtailment across the delivery network.

Many believe that the United States will switch from a net importer of energy to a net exporter around 2018. A lot of politics currently going on internally in the United States with domestic fear of higher prices of both natural gas and liquids if exports continue as many feel there will be a happy balance and especially to eliminate current imports. Liquefied Natural Gas (LNG) facilities are being permitted and constructed all along the Gulf of Mexico and up the Eastern and Western seaboards of the United States. Many of these were previously constructed to receive LNG imports and are now being reversed for LNG exports. It's amazing to think that not too long ago the United States was going to run out of natural gas and was planning to have to rely on natural gas imports. Along came the Shale Gas revolution and times have certainly changed not only in the United States but numerous other countries around the world looking to do similarly the same.

Domestic use of natural gas for vehicles continues to be increasing with the lower cost, domestic abundance and clean burning particularly with long haul trucks and city fleet vehicles. There are a lot of derived benefits compared to gasoline and diesel not only cost but environmental that is driving the resurgence once again and not seen since the 1980's.

We are seeing a lot of favorable conversions from domestic and commercial fuel oil in the northeastern portion of the United States where natural gas infrastructure is already in place but the cost differential heavily favors natural gas and eliminates storage tanks, repeated filling and environmental laws from leakage.

The Shale gas, crude oil, condensate and natural gas liquid revolution in the United States has really changed the dynamics domestically as well as globally. The tax revenues and job creation to the industry itself as well as the industries that utilize the gas and feedstock components have been anything short of incredible. The changes have been seen all across the United States primarily in the producing States but the effects have been seen all across the Country and it appears to see no downturn anytime soon.

6.19 Gas quality tracking

More interconnected global gas markets through the development of the LNG infrastructure and the possible development of the shale gas resources in the selected national gas markets will lead to stronger variations in gas quality. Furthermore, future gas distribution networks will have an increasing number of biogas, biomethane, and hydrogen entry points causing the gas composition and gas calorific value to vary with time and location. The gas quality tracking software application allows us to determine the gas heating values at all delivery points in the network to ensure correct (i.e. more accurate) custody transfer operations.

Basically, gas quality tracking is a numerical procedure integrated in a simulation software package, which models the dynamic changes in gas composition in the pipeline system and tracks individual gas components along the pipelines. Generally, simulation software allows us to study the behavior of gas networks under different operating conditions using mathematical models of gas flow in pipes. Depending on the character of the gas flow in the system we distinguish steady-state and transient analyses of pipeline networks (Osiadacz, 1989). A network is in the steady state when the values of the properties characterizing the gas flow (pressures, temperatures, and flow rates) are independent of time. The aim of transient simulation is to estimate the time evolution of the values of pressures and temperatures at the nodes, and flow rates in the pipes.

6.19.1 Steady-state analysis

The problem of simulation of gas networks in steady state is usually that of computing the values of nodal pressures and the values of flows in the individual pipes for known values of source pressures and of gas consumption in the delivery nodes. Gas quality tracking problem arises when gases with different qualities are transported in the system under consideration. There are nodes in the network where two or more gases come together and where the quality of the blended gas mixture is to be determined. Moreover, there are stations on the network where two or more gases of different quality come together, and the gas with prescribed quality at the outlet is required. The specific ratio of the flows which is set by flow controlled compressors or pressure regulators is to be determined. The quality of a mixture is the flow weighted mean of the qualities of the constituent gases. At a first glance the simulation of blending of gases seems to be not difficult, but some convergence problems in the steady-state simulation of such pipeline systems may occur (van der Hoeven, 1998).

The aim of the steady-state simulation with gas quality tracking in its simplest form is to estimate the values of gas pressures and qualities at the nodes of the network, with the delivery nodes in particular, and the values of flow rates in the pipes. At the supply side, the gas quality and either the gas pressure or the gas flow rate are required, while at the offtake side the values of demands are to be known. The values of pressures at the nodes and the flow rates in the pipes must satisfy the pressure drop formula (flow equation). Together with the values of loads and the values of flow rates at the sources, they must fulfil Kirchhoff's first and second laws. Due to large dimensionality of the simulated networks, the problem of the efficiency of the solution methods arises.

Another problem may result from the fact that currently, pipeline operators perform system balancing in the units of energy rather than units of volume. Consequently, the demands are expressed in energy per time units (power delivery) instead of standard volume per time unit (volumetric flow rate). However, pressure drop equation is given in terms of volumetric flow. This can give convergence problems in certain circumstances.

6.19.2 Transient analysis

The need for dynamic simulation of gas network occurs when the parameters characterizing gas supply to the system or the gas demand are a function of time, and, on the other hand, the geometric dimensions and the amount of gas in the network resulting from system operating pressure allow for the gas accumulation. Unlike the simulation of steady states in gas networks, which are described by systems of algebraic - in general non-linear – equations, the dynamic simulation requires the numerical solution of a system of initial valued partial differential equations for given boundary conditions. Dynamic model leads to simulation which is computationally much more complicated.

The gas quality tracking under transient conditions is defined as a problem of estimating the gas property that is assumed to move at local fluid velocity through the network and mix at connection points according to a specific rule - either mass mixing or mole mixing. The mathematical problem which has to be solved is the solution of a 1-D transport equations for the pipes (Hager et al., 2012).

6.19.3 Equation of state

The simulation of the transport of natural gas through pipelines requires the accurate knowledge of the thermodynamic properties of natural gases and their mixtures. For this purpose, the GERG-88 and AGA8-DC92 mixture models have been successfully used in the gas industry for decades. However, when non-conventional gases are present in the gas mixture, for example high fraction of hydrogen and binary mixtures of natural-gas components with hydrogen as well as natural gases with a low calorific value, more accurate mixture models should be used. The GERG-2008 mixture model has been developed for accurate description of natural gases consisting of high fractions of nitrogen, carbon dioxide, ethane or higher alkanes. Moreover it also enables the accurate description of CNG, LNG and natural gases containing a high fraction of carbon dioxide, nitrogen and hydrogen.

6.19.4 Modelling and simulation of the gas network with quality tracking

The modelling of the gas network requires two types of input data. First, topology of the network in the form of incidence matrix with node geographic coordinates, and pipe geometry data (internal diameter, roughness) need to be obtained from a GIS system. Next, the operational data regarding the supplies, non-pipe elements, and customer demands need to be provided.

Each supply of gas in the network can have in principle a different quality. In order to fulfill contractual restrictions concerning gas quality at the offtake points we have to solve a matching problem. It is often possible to identify the sub-networks within the system having their own quality regime. In case the network structure precludes segmentation by gas quality, online-simulation is used for tracking of gas quality parameter, for example the heating value The boundary conditions, i.e. the gas parameters at supply nodes and the loads at delivery nodes are obtained from the measurement data available in the SCADA system. Thanks to the simulation algorithm, less number of measuring equipment (gas chromatographs) need to be installed in the field. Furthermore, the tracking of the gas calorific value for all nodes, including the delivery nodes, on an hourly basis is usually possible, and the computed results can be applied for billing purposes after the official permission of the measurement authority (board of measures) is obtained.

It needs to be stressed, though, that real-time data regarding pressure and temperature measurements along the pipelines as well as customer online flow metering data are available predominantly in high-pressure gas networks. In a low/medium pressure distribution network, only limited amount of data is available online. Likewise, the distribution systems are equipped with limited number of consumer smart metering systems allowing for real-time data transmission, which results in the necessity of the estimation of their hourly demands based on yearly or quarterly readings. The use of standard load profiles is one of the possible approaches (Schley et al., 2011), but the method introduces additional uncertainty on the simulation results.

6.19.5 Conclusion

In summary, network simulator with gas quality tracking is a powerful tool which gives us the possibility to obtain complete information about the gas properties and flow behavior in the network. Reliable measurement data at selected nodes in the network allow for appropriate calibration and validation of the flow model, resulting in high accuracy gas quality simulation results, which are acceptable for custody transfer and billing purposes. This simulation method effectively supports the management of gas distribution grids and allows for the avoidance of many costly measurement devices in the network.

6.20 Conclusion & Perspectives

The study group's work shows that today we are far away from a master plan for a global strategy into a carbon-low gas future and to achieve the Kyoto targets in 2050.

To generate a common global understanding of the regional gas market mechanisms and gas quality standards, fundamental work was done by SG 4.2 in the current triennium.

The research on gas infrastructures including acceptable gas quality compositions, possible technological and regulatory measures and timelines will provide us with a good basis for the development of the master plan for the future.

Figure 6.10: biomethane production an injection plant in Horn-Bad Meinberg, Germany

The following aspects should be further elaborated in the next triennium:

- standardisation targets of specifications for gas quality in the individual regions;
- opportunities to further standardise application technologies in cooperation with the providing industry in order to develop efficient, economic but flexible installations;
- the development of best practices and standards for the shale gas injection in gas distribution infrastructures;
- the implementation of gas quality tracking technologies on distribution level at economical prices;
- the further development of "Power to Gas" to a competitive technology for storing electricity in gas infrastructures;
- develop gas quality standards for distribution systems and implementation schemes for these to allow for the adaptation of new supply conditions and the gas utilization structure.

By now it already seems clear that the "diversification of gas quality and nonconventional sources in a carbon-free future" will for many reasons be characterized as a "green gas evolution" instead of a "revolution". We have no doubt that this will be a very important process that will help us to continue the global natural gas success story.

6.21 Authors Responsible of the contributions

- ✓ Abstract, Introductions, Topics of the Committee Report as well as Background and purpose
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- ✓ Report of study group 4.2
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  - Analysis of the challenges of gas quality diversification
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    Flemming Jensen, DONG Energy, Denmark
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  - Gas quality tracking
    Maciej Chaczykowski, Politechnika Warszawska, Poland
  - Conclusion & Perspectives
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6.22 Literature

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7 Report of IGU Study group 4.3

Smart Grids in Gas Distribution

7.1 Executive Summary

IGU was lead to consider the role of gas distribution networks in the future energy grids. Smart gas grids is a very wide concept which can include different aspects: network safety, monitoring, maintenance, inspection, remote operations.... It involves also questions about the injection of gases like biomethane, hydrogen, syngas and the way of using energy equipments like micro CHP (Combined Heat and Power) device which allows an arbitration between gas and electricity, related to new considerations about the concepts of Power to gas and Gas to Power.

This report, established during the triennium 2012-2015, gives an overview about the different aspects of smart gas grids based on DNO's experience throughout different countries.

The examination of these numerous use cases has inspired different recommendations. In particular, there is a consensus to tell that design and construction of smart gas grids must take into account direct and indirect benefits to network operators (remote control, optimization of grid design and maintenance, to customers (costs of energy, new services to customers based on data analysis, availability of CNG refueling stations), to producers (possibility of new energy sources such as biomethane or syngas) and to society (improvement of safety and environment, benefits linked to a decentralized energy system,…)

Elsewhere, the development of future smart grids will be strongly influenced by technological changes in particular in the fields of communicating and cheap sensors, ICTs and data management (open data, big data concept).

There is not an unique type of smart gas grids: DNOs must build their road map to go from a traditional network to a smart network, considering the functionalities they really need in their local environment and regulation. "**Do not look for a smart grid, build your own**"

Table of Contents

7.2 Introduction

Network operators are providing gas distribution services. But, in the future, the energy landscape will change in which sustainability and energy efficiency are to be increasingly important.

The current and traditional gas grids are demand-driven and operated in a passive way. Tomorrow, they are called, under variable conditions, for becoming active networks including interactive functionalities.

In gas distribution, the main reasons to make a grid an active grid can be summarized in three points:

- Increased need for transparency and responsibility;
- An integrated energy supply for the customers where gas plays an important role;
- A grid operation based on real time information, actively controlled in order to ensure safety and reliability.

These needs are pushed by technological innovations that are today bringing cheap, reliable and efficient solutions with new sensors, remote control device and real time simulation of gas flows, able to better monitor pressure and gas quality in the whole network. The concept of smart gas network (to use either "networks" or " grids" throughout the report) can be defined as a gas grid that is fully remote controlled and, in its ultimate form, operates and adjusts automatically for fulfilling a set of needs connected with customers' expectations and network performance.

Our purpose here is to present some key points about this new concept, including an analysis of the possible uses of smart grid concept in the future of gas distribution, of the impact on the design and operation of distribution systems and of the needs in new technologies. We try also to pinpoint the different technical difficulties and costs that can appear for Distribution Network Operators.

7.3 Acknowledgements

Thank you for all contributors of WOC 4.3 Subgroup members:

Asada, Akiharu – Japan
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7.4 Aims

This report aims at presenting the different components and applications of the new concept of smart grids for gas distribution systems and give updated information to:

- Clarify the aims and drivers of smart gas grids
- Help DSO (Distribution System Operators) managers to build a roadmap for the network of the future
- Give arguments to face public authorities regarding the design and the performance of future gas networks
- Show that gas can be as smart as electricity and interact with other energies in the aim of more efficient and sustainable energy system
- Highlight examples of smart gas grids already operating today in some countries or identified as promising

Smart is not the target - the target is to identify the best ways, both technical and economical, for the network of the future using new technologies.

7.5 Approach

7.5.1 Definition of smart gas grids

Smart grids is a concept that first appeared for electricity networks where many projects have been launched that consist of interactive networks where electricity needs to be instantly covered by a combination of multiple sources driven automatically in real time. In electricity, smart grids are related to the development of decentralized sources and also the needs of insulated zones like islands or urban zones located far from production sites.

A smart gas grid is somewhat different because processes do not need real time balancing. A gas network has a storage function. A smart gas grid does not need to be physically as reactive as an electricity grid which has to be balanced in real time.

The expression “smart grids” includes the communicative linking and regulation of power production, storage, consumer and grid operation in energy transport and distribution grids. This enables an optimization and control of the linked components with the objective to guarantee energy supply on the basis of an efficient and reliable system operation.

7.5.2 Possible use of smart gas grids

Smart gas grids can cover a large number of functionalities. A smart grid will of course not necessary comprise all the possible functionalities, according to the needs of the operator who is on his side, driven by the network configuration, its supply sources, safety and security considerations, possible links with other energy systems, types of customers and of gas uses.

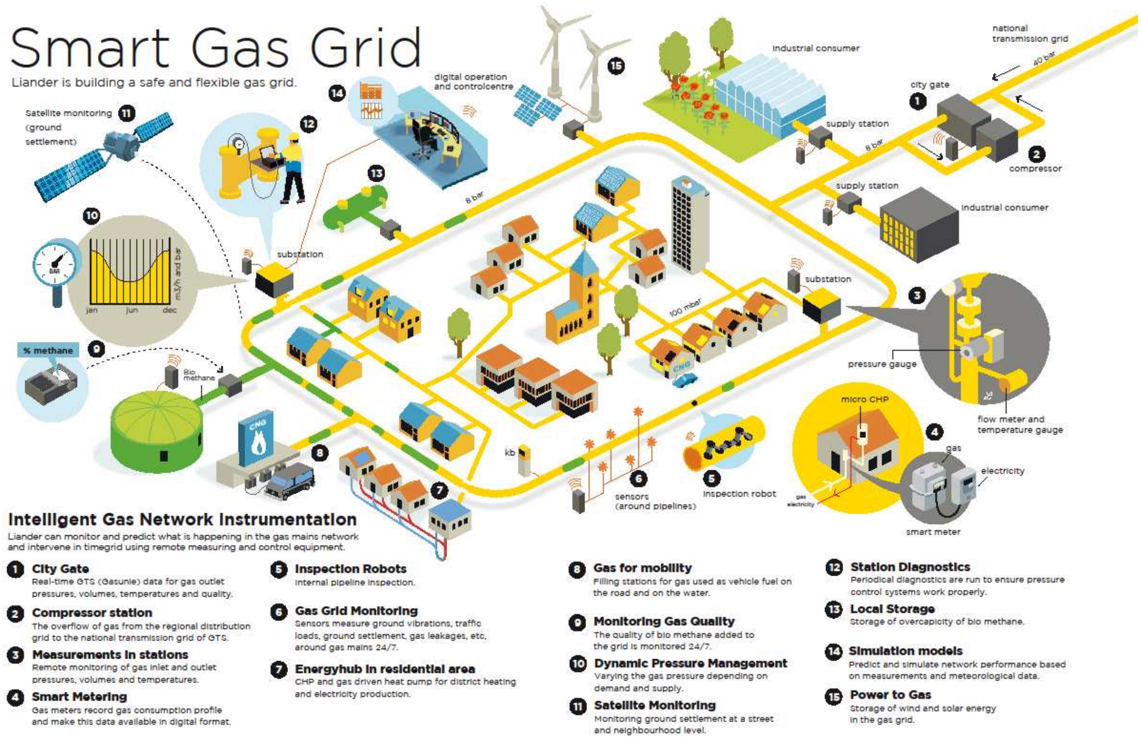


Figure 7.1: Schematic smart distribution grid

The opportunity of building a smart gas grid in the future can be studied following different drivers:

- Potential technological solutions
- Maturity of technology (existing usage, under development, examples, pilots…)
- Technological and economic challenges and obstacles (regulation, law…)
- Benefits: safety, environment, development of gas, optimization of the use of gas networks, efficiency, reactivity, possibility of synergies with another use cases

A large number of use cases grouped by main functionalities, are listed below. They are grouped in three main chapters:

- Gas grid operation
- Gas quality
- Connection with electricity and other energy systems (including new uses)

7.5.3 Gas grid operation

Here are included all functionalities involving a remote and/or automatic management of gas grids:

- Earthquake risk prevention

- ➔ Aims to preserve safety in case of an earthquake by automatically insulating networks blocks and shut off service lines through a communicating network of remote sensors giving information about seismic vibrations
- Pressure monitoring – optimization of network by feedback - dynamic pressure management
  - ➔ Aims to minimize gas losses from the network, to insure an optimized operation of the network, adjust the pressure level or to guarantee the pressure at delivery points. It can also create some extra storage capacity which can be used to store green gas in times of low consumption.
- Smart pressure regulating station
  - ➔ Allows automatic changes in the configuration of regulating stations supplying a city in order to optimize pressures in the network and guarantee a better metering accuracy by imposing flows in the meters operating range. As a complement, this can encourage remote operation of devices able to produce electricity in pressure reducing stations at the city gates
- Maintenance monitoring, traceability and Localization
  - ➔ Installation low cost RFID (Radio Frequency Identification.) sensors or nano-sensors which are passive and do not need batteries that can be used for localizing the network, store and communicate all maintenance actions made on fittings or equipment (see details in annex)
- Cathodic protection monitoring , damage alert
  - ➔ Assess the level of cathodic protection by automatic. Use of remote sensors to alert in case of acceleration of corrosion phenomena on pipes
- Workforce monitoring
  - ➔ Equipment of operators with PDA or tablets in order to communicate and remote real time update data on the network
- Innovative pipeline:
  - ➔ Pipelines equipped with sensors using technologies such as RFID in order to give more possibilities for the localization, the characterization and the maintenance of the pipes and fittings. These sensors can be remotely checked with possibilities of connection with computerized management systems
- Leakage and incidents monitoring - Third party interference sensors (see example in next chapter)
  - ➔ Install remote gas sensors or vibration or acoustic detectors on sensible sites (important regulating stations, pipes located in working zones etc…), even infrared cameras systems with an automatic alert system in case of leaks. Installation of remote vibration or acoustic detectors to detect public works or risk of third party interference in the vicinity of pipes with a remote alarm or shut off system
- Smart metering and remote measurements data management

➔ Smart metering systems can give a real time information about consumptions by all customers and about volumes or energies entering the gas network at the different delivery points. This information can be used for internal analysis, in order to optimize the design and the operating configuration of the network or to help to identify leaking parts of the network or dysfunctions of gas meters. It can be also used to bring information and detailed consumption analysis to suppliers or customers.

Even if it is not always considered as a smart gas grid functionality, it is useful to notice the use of regular surveillance of the network by drones or satellites which can send automatically update information about the network which are automatically compared with data available on the network.

7.5.4 Gas quality

These functionalities are also discussed in the Study group 4.2 “Gas Quality” which details the objectives and the methods that can be used to ensure the respect of gas quality requirements in particular in the case of injection of non-conventional gases such as biomethane, syngas or hydrogen.

Following functionalities can be covered by smart gas grid systems:

- Remote operation of network including biomethane injection management
  - ➔ Monitoring the gas distribution through SCADA systems including the monitoring of biomethane injection in networks by controlling in any point the acceptability of the injected gas – Monitoring and remote control of biomethane plants with adapted sensors and controls.
- Power to gas (H_2, Syngas,…)injection including storage conditions
  - ➔ As for biomethane injection, of such gases shall be monitored for gas quality reasons, with higher constraints because their GCV can be very different from natural gas. These gases can be produced by the use of electricity, from fatal production of renewables overcoming the needs of consumers. Remote monitoring of electricity production devices can be remote controlled
- Odorization control
  - ➔ The objective is to remotely monitor and adjust more efficiently gas odorization in order to avoid under odorization or over odorization.
- Gas composition and GCV monitoring :
  - ➔ Thanks to new types of micro gas chromatographs and by the dynamic simulation of the network, the objective is to control gas quality at any point

7.5.5 Connection with new uses of gas including the links with electricity and other energy systems

- CNG(Compressed Natural Gas) stations, peak shaving storage, local storage
  - ➔ Real time monitoring of CNG or peak shaving stations can lead to several applications: safety issues, detection of leaks or of thefts of gas, physical intrusion, gas flow control. It can also be used for optimizing maintenance of the station components. In another extent it can be the base of information systems dedicated to customers (availability of gas filling device, etc…). Remote systems are particular useful for helping the deployment of CNG programs in large Countries like those in India, Pakistan, Algeria, etc…
- Individual NGV compressors monitoring
  - ➔ remote control and surveillance systems can be applied to individual filling compression stations
- Gas Heat Pumps, hybrid heat pumps (use gas for the peaks and flexibility) Micro CHP and Fuel cells (interaction between electricity and gas uses, problem of non-sulfur gas)

These types of equipment can lead to integration and competition between the use of gas or of electricity. The customer can benefit from this. Smart gas grid is therefore linked with smart electricity grid with the objective of optimizing energy supply in particular to avoid electricity supply peaks and to take benefit of overproduction of electricity from renewables. The result is a smart energy system.

7.6 Some major examples of use cases of smart gas grids

7.6.1 Earthquake disaster prevention measures – experience coming from Japan

The table below summarizes the role of an automatic prevention system concerning earthquake hazards.

Description	Gas grid including automatic shut off and quick resumption in case of big earthquake
Drivers / Context	Immediate Safety of the public Shut off of consumers and of network mains Prevent additional damage due to explosions or fire Quick resumption of city gas supply to eliminate inconvenience for customers
Technological solutions (Including potential or under development technologies)	Meters equipped with shut off valves operated in case of seismic movements Network Valves linked with seismic sensors Possibility of shutting off network valves from the control center Remotely resumption valves of the district supply governors from the control center after safety surveys
Maturity of technology	Operates in Japan (Tokyo gas, Osaka gas, Toho gas) since 1996 (after Kobe earthquake) for earthquakes higher than a given intensity (acceleration over 200 gals)

	In quick resumption supply system , operates in Japan (Tokyo gas) since July 2014 Linked with a adapted structure of the distribution network (independent blocks)
Technological and economical challenges and obstacles (regulation, law,…)	Risk based decision taken by the companies (not by regulation) Costs have to be supported by the tariff and are justified by the level of risk Development of particular shut off valves and small seismic sensors Fukushima: a few local valves shut off and no leak and no breakage occurred Development of shut off and resumption valves fitted the district supply governors
Additional benefits	A well structured network easier to operate and to manage with the different blocks High reactivity in case of incident on the network thanks to remote controlled valves Gas shut off in case of excessive flow of gas Alarm in case of continuous flow of small volumes of gas during 30 days Shut off in case of abnormal pressure drop Possibility of an option in case of gas leak alarm in the house - Optional round the clock security service (charged to the customer) Radio infrastructure easing the installation of remote meters (communication adaptor) (regular phone or internet lines can be also used

Background

Earthquake damage can pose a major threat to the supply of city gas. Major city gas companies in Japan (Tokyo Gas, Osaka Gas, Toho Gas, and so on) have prepared a series of measures to meet any such eventuality. Three principles lie at the heart of our earthquake disaster prevention measures: “Prevention”, “Emergency” and “Restoration”:

- “Prevention measures” to provide a firm response to any strong earthquake.
- “Emergency response measures” to prevent secondary disasters in the event of an earthquake.
- “Restoration measures” to ensure a speedy resumption of service after an earthquake.

The Japanese experience about “Emergency” and “Restoration” is described below.

Emergency shutoff devices are installed in principal equipment (Tokyo Gas)

If a gas pipeline were to break, the supply of city gas would have to be shut off instantly. To achieve this, we have installed “emergency shutoff devices” in all major equipment, including supply equipment such as LNG terminals and gasholders, as well as in underground malls and high-rise buildings. These take two forms: “emergency shutoff valves (ESV)” that can be controlled remotely, and “automatic shutoff devices” that work automatically in tandem with seismometers. These serve to ensure safety in a number of situations besides earthquakes. If necessitated by the level of damage, moreover, gas inside the pipelines can be safely released into the atmosphere through vent towers installed in major equipment.

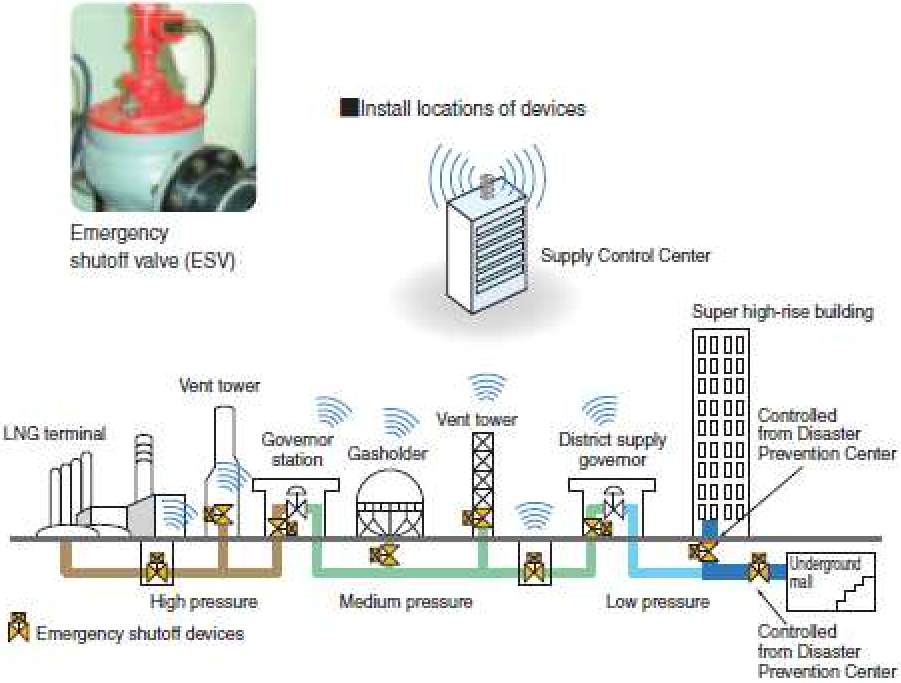


Figure 7.2: Emergency shutoff valve (Tokyo Gas)

Fully-integrated anti-seismic gas supply system (Osaka Gas)

Osaka Gas has developed and introduced pipes that are highly resistant to earthquakes and shifted our company-wide communications network to wireless communications. In addition to these measures, we divide our entire pipeline network into areas in preparation for disasters. This allows the suspension of gas supply only in the severely damaged areas in order to prevent secondary disasters in case that damage has occurred to the gas pipes, while continuing supplying city gas to the non-damaged areas.

These areas are classified into super blocks, middle blocks, and little blocks. The whole service areas are divided into 12 super blocks according to the physical features, such as the mountain ranges and rivers, which helps us to suspend gas supply to seriously disaster-stricken blocks over remote radio communications. Each super block is further segmented into 85 middle blocks and 157 little blocks for easier local response as well as safe and efficient restoration.

In addition, to prepare for tsunami generated by south-eastern sea and southern sea earthquake, Osaka Gas established 15 of the 157 little blocks as tsunami countermeasure blocks so that it can remotely or manually suspend gas supply to the tsunami-stricken areas announced by the government.

Osaka Gas has installed its own seismometers in the service areas in order to obtain information, such as seismic intensity data, quickly and use the information to make decisions on emergency measures when an earthquake occurs. Such information is collected and processed with computer.

While the seismometers were installed in 34 points at the time of the Great Hanshin-Awaji Earthquake, the number has now increased to 253.

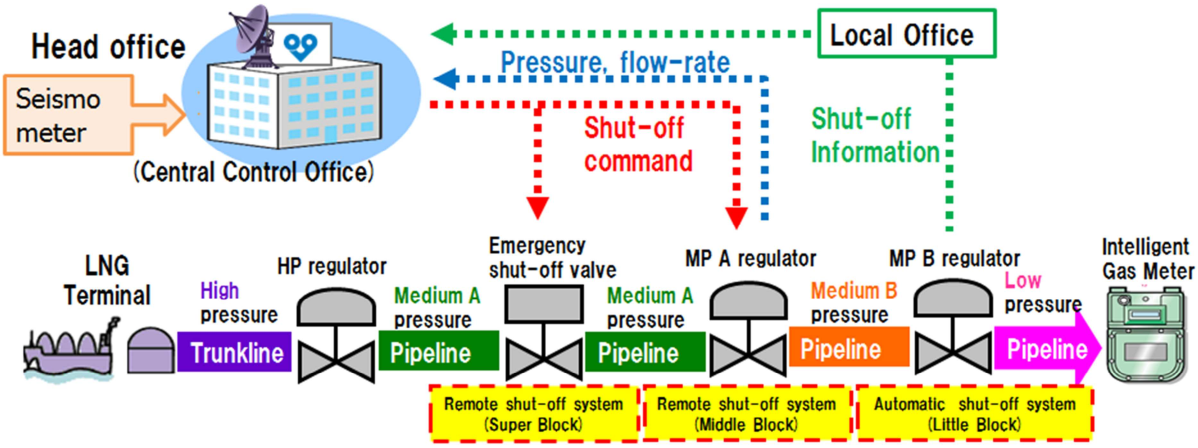


Figure 7.3: Network isolation system (Osaka Gas)

Remote-controlled shut-off systems are installed at 400 locations. Automatic shut-off systems for low pressure pipelines are installed at 3000 locations. Intelligent gas meters which automatically shut off gas supply at seismic movement of over 200 gals (seismic scale of 5) are installed at almost all our customers' sites (7 million).

Intelligent gas meter

Since 1987, city gas companies in Japan have been installing the intelligent gas meter which shuts off gas upon detecting abnormal conditions in customer's use of gas appliances. With the amendment of gas utility regulations in February 1997, the installation of the meter has become mandatory for all residential and small commercial customers and that we have completed the installation of the meter for these customers.

Features of the intelligent gas meters are:

・Gas shut-off in case of excessive flow of gas

・Gas shut-off in case of major earthquake (seismic movement of over 200 gals)

・Alarm on thirty days' continuous flow of small volume of gas (such as gas leaks)

・Gas shut-off in case of abnormal pressure drop

・Gas shut-off interlinked with gas leak alarm (optional)

Figure 7.4: Intelligent gas meter

Ultra high density seismograph network and quick resumption of gas supply to eliminate inconvenience to customers (Tokyo Gas)

Tokyo Gas has anti-seismic gas supply system. In Tokyo Gas, the medium-pressure pipeline network in supply area is divided into 21 large blocks and the low-pressure pipeline network is divided into 207 little blocks.

Tokyo Gas also has the district supply governors that supply city gas at low pressure are fitted with SI sensors (seismometers). When they detect an earthquake of a magnitude that could damage gas pipelines or structures, they automatically shut off the gas supply and thus protect the safety of the entire district. The gas supply can also be shut off remotely using SUPREME (Super-dense real-time monitoring of earthquakes). “SUPREME” is an earthquake disaster prevention system unparalleled anywhere in the world. It consists of SI sensors (earthquake sensors) installed in all district supply governors, numbering about 4,000 in total, thus achieving a very high density of one per square kilometer or so. As well as enabling us to shut off the supply from district supply governors remotely, this also helps to prevent secondary disasters promptly and accurately by using the ultra-high density earthquake data gathered from SI sensors to estimate the scale of damages.

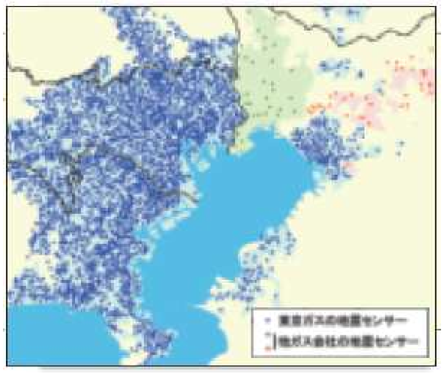


Figure 7.5: Ultra high density earthquake data in Tokyo Gas supply area by “SUPREME”

Whenever a severe earthquake occurs, gas supply to areas with damaged equipment (supply governors in districts) has to be cut off by a remote control system in order to prevent secondary disasters. Gas companies in Japan ensure a speedy resumption of district supply governors after conducting safety surveys in the field. However, during the Great East Japan Earthquake in 2011, restoration was delayed in several areas because of traffic congestion. In 2014, Tokyo Gas developed and introduced a new system for quick resumption of gas supply. Remote-controlled bi-directional valves have been installed in the governors, and pressure information of the governors is collected by SUPREME. When the pressure becomes stable after the occurrence of a severe earthquake, the system recognizes undamaged pipelines through safety surveys using the information from SUPREME, and the system can resume the governors remotely from the control center.

7.6.2 Smart monitoring of gas distribution grids – Belgian example

Background

As grid operator for a well-defined part of Belgium, Eandis manages, builds and services the distribution grid for electricity and natural gas. Furthermore, Eandis promotes the rational use of energy, manages the access registry and acts as a social supplier for domestic customers who have been 'dropped' by their commercial supplier.

Some key figures: 4,050 employees, active in 234 towns and municipalities, ± 42,000 km gas grid, ± 94,000 km electricity network, 1.6 million connections for natural gas, 2.5 million connections for electricity.

Here, we will not talk about well-known aspects of a future smart gas grid, such as "power to gas", injection and grid management of new gases (biomethane, hydrogen…) nor will we discuss a new, state-of-the art smart appliance. Instead we will explain how Eandis is able to monitor the low pressure network (≤ 98 mbar), a basic yet very important issue of safely operating the grid and ensuring a continuous supply, by using a mature technology in a smart way.

Despite the fact that the low pressure grid (which is about 7/8ths of our total gas grid) has global monitoring and well-working regulation stations, it lacks intelligence (e.g. telecommunication). In medium pressure gas distribution, it is common practice to telemonitor or even teleoperate the grid (e.g. altering its pressure) from the gas stations.

In several stations, we still had analog pressure loggers with paper registration. These last 10 years, these were replaced by digital pressure loggers, but still without telereading.

Aims

First of all, Belgian legislation forces us to monitor the low pressure grid (although the 'how' and 'where' are not specified). So why is it important to monitor in a smart way? There are 3 important aspects:

- Supporting new grid investments because of faster availability of measurements (monitoring the grid load, investing "right on time" while avoiding overinvestment, supporting studies with accurate data…).
- Ensuring, on a daily basis, a safe and reliable exploitation of the gas grid (effective handling of gas incidents, monitoring pressure, managing received complaints…).
- Optimizing the technician's workload (i.e. not having to drive around to collect data).

Eandis wants to operate a safe and reliable gas grid ready for future challenges by investing cost-consciously and in a well-thought-out way. In Eandis' Asset Management philosophy, considering different solutions before making a decision is paramount.

It was clear from the beginning that we wanted a smart way to monitor the pressure of the low gas grid. But just 'how smart' should this solution be? Deciding this will have an important impact on implementation (equipment, operating system software, maintenance costs…) because each requirement has a direct impact on the system's total cost.

The following requirements were decided upon in the cost-benefit business case:

- requirement of **having 2-channel loggers**
- **battery powered** (and explosion safe)
- **continuous measuring** of the pressure:
    - o the smaller the measuring frequency, the bigger the data to be sent wirelessly
    - o pressure is measured every 10 seconds and the average value is saved every 15 minutes
- **wireless communication**
    - o not in real time; data will be communicated once a day (GPRS)
    - o day-to-day communication happens at night when the data traffic is low
- **an 'automatic' warning system:**
    - o real time GPRS communication (via mail/SMS)
    - o setting an alarm for a maximum and minimum level
- **the ability to also monitor the medium pressure** in a gas station with the same logger
    - o provide 1-channel and 2-channel loggers
- a **common company policy** towards positioning and managing the loggers
    - o This is a very important requirement before implementing a system with a length of 34,000 kilometers: how many loggers are necessary, where to place them, which investment budget is necessary… .
    - o We need a policy that takes into account the legislation and solves bottlenecks known by exploitation or studies ('measuring is knowing').

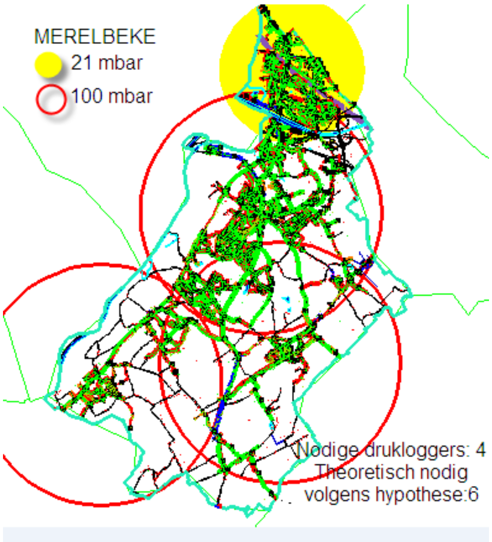
The following technical requirements were not admitted:

- differential pressure measurements
- having more possibilities in input/output controlling in the gas station

Methods

The new asset was successfully implemented as a result of:

1) Development, testing and analysis
   - Development of the technical policy
     - o Duration: 1 year
     - o Key issues:
       - ▪ Evaluating the most effective way to monitor the entire grid Solution: a fixed radius depending on distribution pressure (20/25/100mbar)
       - ▪ Determining the alarm levels, in order to avoid false alarms due to specific fluctuations of a low pressure grid
       - ▪ Analysing the entire low pressure grid
         - • Example:



         - • Total amount of necessary loggers:
           - o ± 1,200 loggers placed (fixed) at gas stations
           - o ± 180 mobile loggers
           - o 30% is 1-channel and 70% is 2-channel
       - ▪ Setting up a data management system
         - • Creating a data model (difference between static en dynamic data)
         - • Adjusting existing databases for the static data
         - • Creating a database for the dynamic data (first stage: outsourced)

7.6.3 Applied Sensors on Underground Pipelines (Example given project STOOP - Netherlands)

The gas network companies replace mains on the basis of a risk assessment. The prioritization of the projects is currently based on a number of criteria, such as location of the pipe, diameter, number of residents in the area, planned work, etc. For a more accurate decision making process extra information about soil processes and forces should be included in the risk assessment. This study of such models and monitoring system is integrated within the project Applied Sensors on Underground Pipeline Infrastructures (STOOP). The project is carried out by TNO, Deltares, SkyGeo, Kiwa Stedin and Liander. The water network companies will join as a partner in the third phase of the project.

STOOP uses a sophisticated model for extrapolating soil settlements based on local measurement of movements and basic soil properties. The actual values for the model parameters are derived from the in situ measurements, which improves the predicting power of the model in the specific local situations where it is applied.

The aim of the project is to demonstrate

a) the predictive power of the soil settlement model

b) that suitable sensors providing real time data can be successfully integrated in the model prediction process

c) the performance of a full scale prototype measurement and failure prediction system

Therefore the project is divided into three phases:

1. Proof of Principle
2. Proof of Concept
3. Prototyping

The measuring system provides information about the deformation of the substrate (soil settlement). With this information, the actual stress on and deformation of the pipe can be determined and the critical sections of the pipeline can be monitored more closely and their condition can be extrapolated into the future. This information is then used to optimize the replacement policy.

The system currently being developed monitors the condition of the pipeline by measuring ground deformations. In the future (outside the scope of this project) in addition to these ground deformations, vibration, groundwater fluctuations, acidity and traffic load etc will be taken into account. This is done by measurements with sensors in the immediate vicinity of the pipeline. These measurements are then the input for detailed prediction models for the short and long term condition of the pipes.

The monitoring system is designed to be applicable for all piping materials.

Proof of Principle

The proof of principle (STOOP phase 1, 2011/2012) comprises a pure software approach. Its aim is to show that all physical elements (soil, pipe and sensors) can be simulated in a mathematical model and that inclusion of measurement results in the model reduces the uncertainty in the prediction of the pipeline failure rate.

Only a single failure cause ("fracture stresses in the material") and a single property ("soil movement") are used. In the future the model could be extended to include other causes of failure, such as corrosion, and other measurements, such as vibration or traffic load.

The specific condition simulated was that of a sudden increase in top load on a pipe segment, resulting in a more or less gradual settlement of the subsoil.

Proof of Concept (PoC)

The PoC of phase 2 (2013/2014) is carried out with physical elements. Sand and clay is used, as well as a pipeline and physical sensors inserted into the ground. As a practical case was chosen once again the addition of top load on a buried pipeline. In addition a second case "soil compaction" was investigated. The compaction in this case was caused by vibrating sheet piling into the ground. The experiments were carried out on a 1:10 scale in a laboratory environment.

Figure 7.6: Example of the effects of vibrating sheet piling

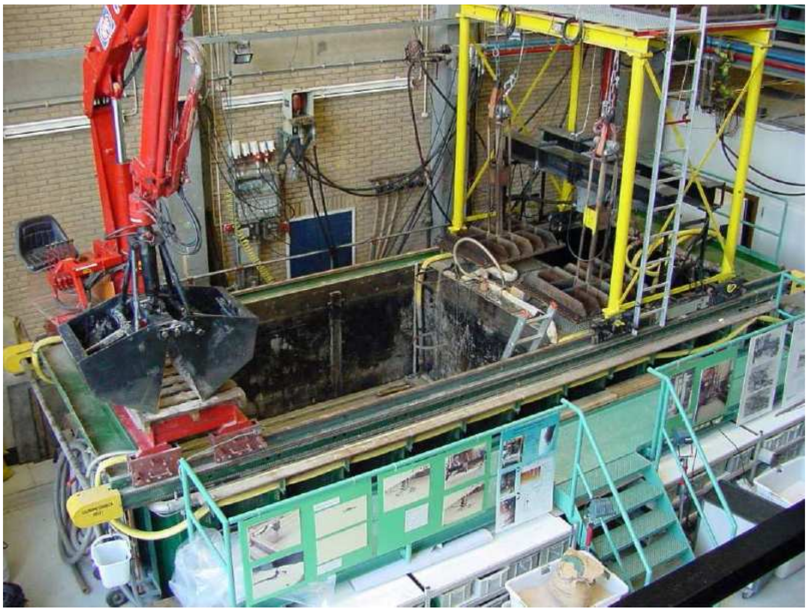


Figure 7.7: Laboratory used for the experiments

Results of the experiments match with the modelling and calculations of phase 1 study:

• experiments proved to be well reproducible

• results from the models are in line with the experimental results

During the experiments a sensor type Shape Accel Array Field (SAAF) was used. For the next phase of the project, sensors that are cheaper and easier to install are necessary.

Prototyping

The project is now (Q1 2015) at the start of phase 3. The goal of this phase is a validation of the methods developed in phase 1 and 2 in a practical environment using a prototype measuring system.

7.6.4 The role of robotic techniques in smart gas grids (example given from the Netherlands).

Modern miniaturization techniques such as MEMS and electronic micro-chip technology in general, enables us to construct versatile and smart devices, that are small enough to be used in gas network piping. The purpose of the devices would be the assessment of the quality of the pipes.

In this chapter, we will give an overview of the available technology and we draw a sketch of potential future development and requirements.

State of the art

Pipelines can be divided into piggable and non-piggable pipelines. The piggable pipelines being designed for inspection by sensor platforms (pigs). Generally the design involves using only a single diameter, having no tight bends, no t-joints, only full bore valve, entrance and exit locks and sufficient pressure to propel the platform through the pipe without additional power. However, in this text is concerned with non-piggable pipelines.

As a primary enabler of the application of sensors, one needs to provide suitable platform on which those sensors and data handling equipment can be mounted. Numerous robotic sensor platforms have been proposed and developed for those purpose too. Most of them, if not all, are targeted for 6” (150 mm) pipes or larger (and high pressure), obviously because there are many lengths of pipe of this diameter or larger that require inspection, and the technological challenge for smaller diameters add significantly to the design and project costs. Nevertheless, the build-up of a typical gas distribution grid in the Netherlands consist of a lot of smaller diameter pipes (typically about 2/3 is smaller than 4”, see figure below). Selective replacement of the aging grid by robotic inspection could be a viable business case. If we want a universal solution for the whole network, we must also construct a platform for non-piggable smaller diameter pipes.

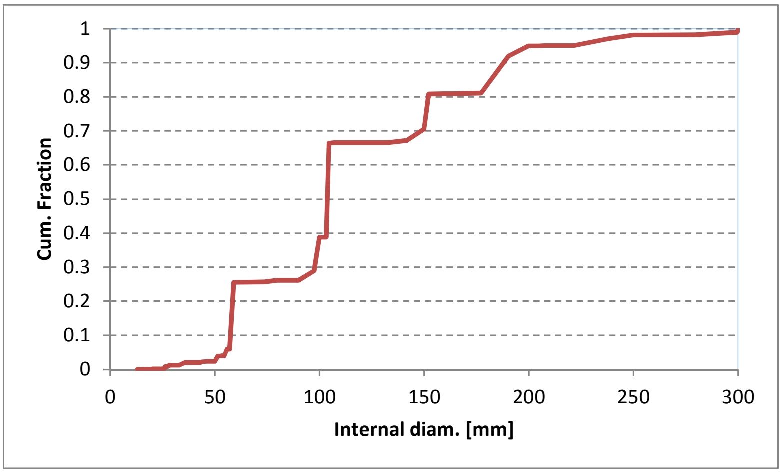


Figure 7.8: Cumulative distribution of pipe length by inner diameter of a typical Dutch town (100 mbar, including part of historical low pressure towns gas network)

In the next sections some typical examples of robotic platforms for a pipe network are discussed.

MAKRO

Figure 7.8: MAKRO version 1.1

MAKRO is an articulated inspection robot of worm-like shape and is designed for autonomous navigation in sewer pipes of 30 to 60 cm width. Its case design, consisting of six segments connected by five motor-driven active joints, allows for simultaneously climbing a step and turning, e.g. at a junction consisting of a 600 millimeter pipe and a branching 300 millimeter pipe with equal top levels MAKRO carries all the needed resources on-board, (currently) allowing for an autonomous uptime of about two hours.

Explorer

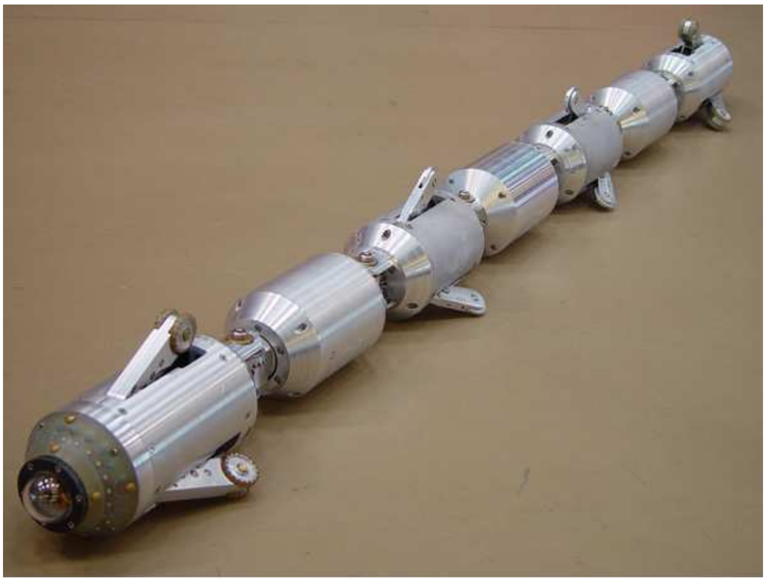


Figure 7.9: Explorer inspection robot

Explorer is a long range, untethered, modular inspection robot for the visual inspection of 6" and 8" natural gas distribution system pipelines. A 7-element articulated body-design houses a mirror-image arrangement of locomotion, battery-, support and computing electronics in purged and pressurized housings... Each module is connected to the next through an articulated joint; the joints connecting the locomotion-module(s) to the rest of the 'train', are pitchroll joints, while the remaining (four) joints are only pitchjoints. The system is capable of multi-mile travel inside pipes using custom on-board battery-packs.

Explorer is still being further developed. A longer version with more segments is available (Explorer-II).

Pirate

Figure 7.10: Pirate, working prototype II.

Pirate (Pipe Inspection Robot for AuTonomous Exploration) is a miniature pipe inspection robot capable of moving through very small pipes (down to 55 mm inner diameter). The requirement to negotiate bends, T-joints and steep inclinations pose another set of strict design constraints. The robot consists of a modular design (5 modules) with a relatively low number of active degrees of freedom. The system uses a clamping mechanism with a series-elastic drive. The design of this mechanism has resulted in a high spreading factor allowing the system to operate in a wide diameter range of 63 mm to 125 mm nominal (outer) diameter. The robot is able to negotiate sharp bents and T-joints (R = ½ D) and can be launched via a vertical pipe lock.

Pirate is the only design that fulfills the requirements of small dimensions and t-joints, as far as the author is aware of.

Required sensor techniques

The robotic platform is just the enabler for the use of advanced miniature sensors inside the piping. Typical indicators of the quality of any piping segment and the sensors that could be associated with that are tabled below.

Quality indicator	Possible sensor	Remarks
Fouling, dents, discoloration	solid state camera (ssc)	needs light, relatively high bandwidth
Wall thickness (metal)	eddy current, magnetic flux detector	relatively high power consumption
Wall thickness (plastic)	ultrasonic transducer	need coupling liquid
Deformation (cross sectional, static)	ssc with optical pattern projection	needs image analysis computing power (or high bandwidth)
Deformation (longitudinal, static)	optical beam sensor	multiple platform
Deformation (longitudinal, dynamic)	optical beam sensor	requires stability and repeatability
Leakage noise	ultrasonic microphone	limited sensitivity (background)
Surface hardness	micro indenture sensor	to be developed
Infrared fingerprinting (plastic)	miniature spectrometer	to be developed
Density (plastic)	ultra sound attenuation sensor	to be developed

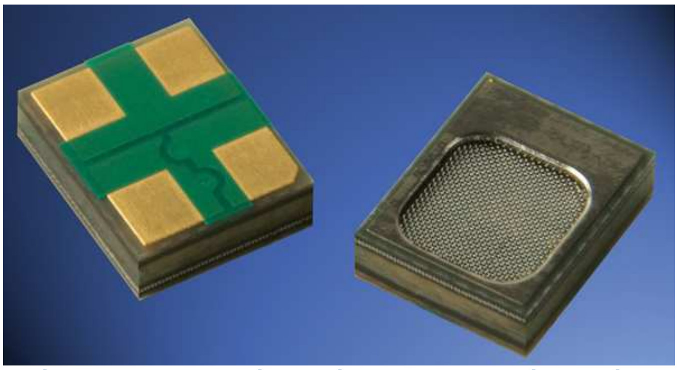


Figure 7.11: Knowles SPM0404UD5 ultrasonic MEMS sensor (appr. size 5 x 4 x 1.5 mm3).


Figure 7.12: Miniature CMOS Camera (Awaiba GmbH)

Other basic properties of the piping system are also of interest, in particular the depth below the surface and the piping route and location of branches (to service lines) or repairs (‘balloon holes’).

Not only the sensors need to be small. Also their support electronics and other auxiliaries must be small. Cameras need lights, magnetic sensors need magnets or ac-coils. All need a power supply and all need their raw data be processed and stored. Whether a sensor is usable or not depends as much on the sensor itself as on the requirements of the supporting hardware.

It must also be recognized that further research is needed for many of the quality indicators. A sufficient reliable or accurate relation between a measured value and the remaining technical lifetime of the pipe is not always available. Nevertheless, repeated inspections and comparison between different piping segments can provide useful information and support rational replacement decisions, even with imperfect an incomplete models.

Next generation maintenance of gas infrastructure

Smart maintenance of gas infrastructure is nothing else than monitoring the quality of the components and replacing them just in time. The challenge is: how to be sure that you are not too early or too late and how to be sure about the extent of the replacement?

The important issue is the recognition that the grid operator needs more than just a sensor. What is needed is a complete system comprising the sensors, the robotic platforms and a data evaluation model and a decisions support tool.

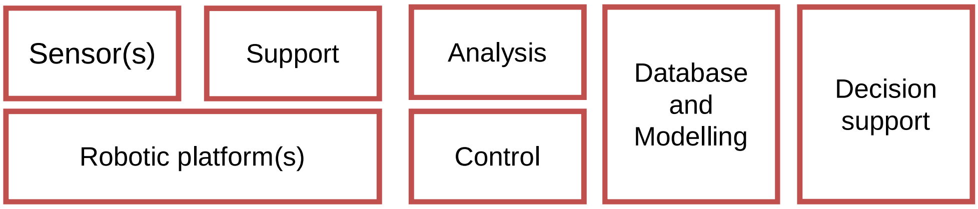


Figure 7.13: Building blocks of smart maintenance system

Such a system could also be based on sensors at fixed locations. In our point of view this option should also be carefully reviewed and can be part of an integral solution. Nevertheless, mobile sensors can make a difference. They enable the grid to be inspected at every location without a prohibitive number of sensors or a logistically infeasible calibration effort.

A next step would be not only passive measurements but also a more active intervention. The ideal is to provide the means for the repair of small leaks or small scale reinforcement (rerounding) of pipe sections or connections without much interruption in the street. A source of inspiration is provided by Cisbot.

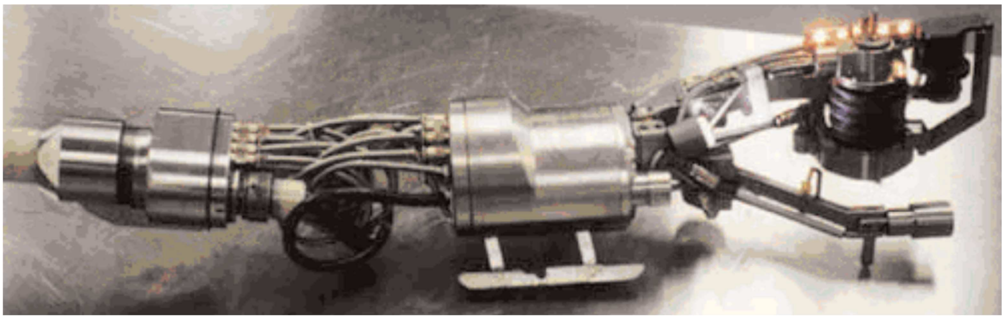


Figure 7.14: Cisbot, cast iron joint repair robot

Conclusion about roboting techniques for network inspection

Sophisticated maintenance technologies will be part of the smart gas grid concept. By using these technologies and these ideas maintenance, especially of aging gas infrastructure, can be cost effective without compromising the safety and reliability of the gas network. It will require not only new hardware but also the corresponding aging models, risk assessment tools and decision support.

Nevertheless, as the examples in this text show, new technologies are arising. It is just a matter of time (and money) that those exiting new possibilities are integrated in smart grids.

7.6.5 From Smart metering (GAZPAR project) to Smart gas Grids - Interactive management of gas distribution grids (France)

In France, DSOs face three main challenges:

- The change of the gas being injected in our network which is becoming green and local,
- The change of the uses for our customers that are becoming smarter,
- The changes of the way to operate our network that is becoming also smarter mainly with the revolution of IT technologies but not only. All these changes push towards smart gas grid that shall be part of a global smart network including gas, electricity, heat and may be others.

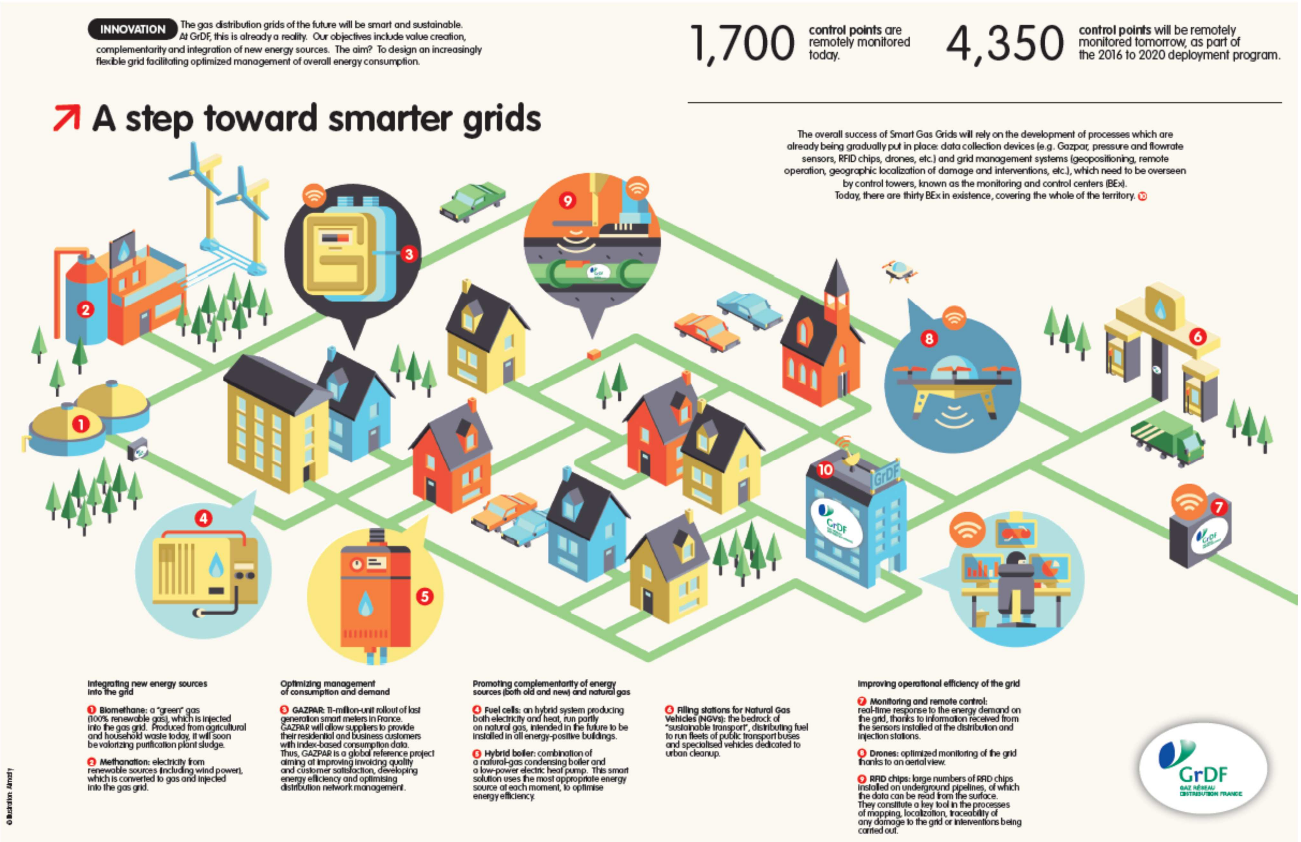


Figure 7.15: Options for a smart distribution grid

The coming energy transition means not only new gases but also new uses. It also means new ways to operate the existing grid because of IT revolution. The major French DSO GrDF is proactive in anticipating this change driven by the customers' needs and by technological evolutions. These changes are inevitable and they bring us new opportunities. So far better to be proactive than just to undergo them!

In the open market defined by European regulation, DSOs in France, and especially GrDF, are in a neutral and independent position, operating the gas network for all suppliers (30 suppliers in France including 7 supplying residential customers) and for all customers. They are clearly involved in this move towards the future to bring their contribution to reach these targets.

The first green gas generation is waste methanisation. It is also possible to produce green gas with agricultural production. France focuses on waste because of a large potential of waste and because gas production and food are not considered to be in competition with land use. The estimated potential of this first generation is about 200 TWh. Green gas production is already a reality for GrDF with 6 injecting sites and about 400 projects under study.

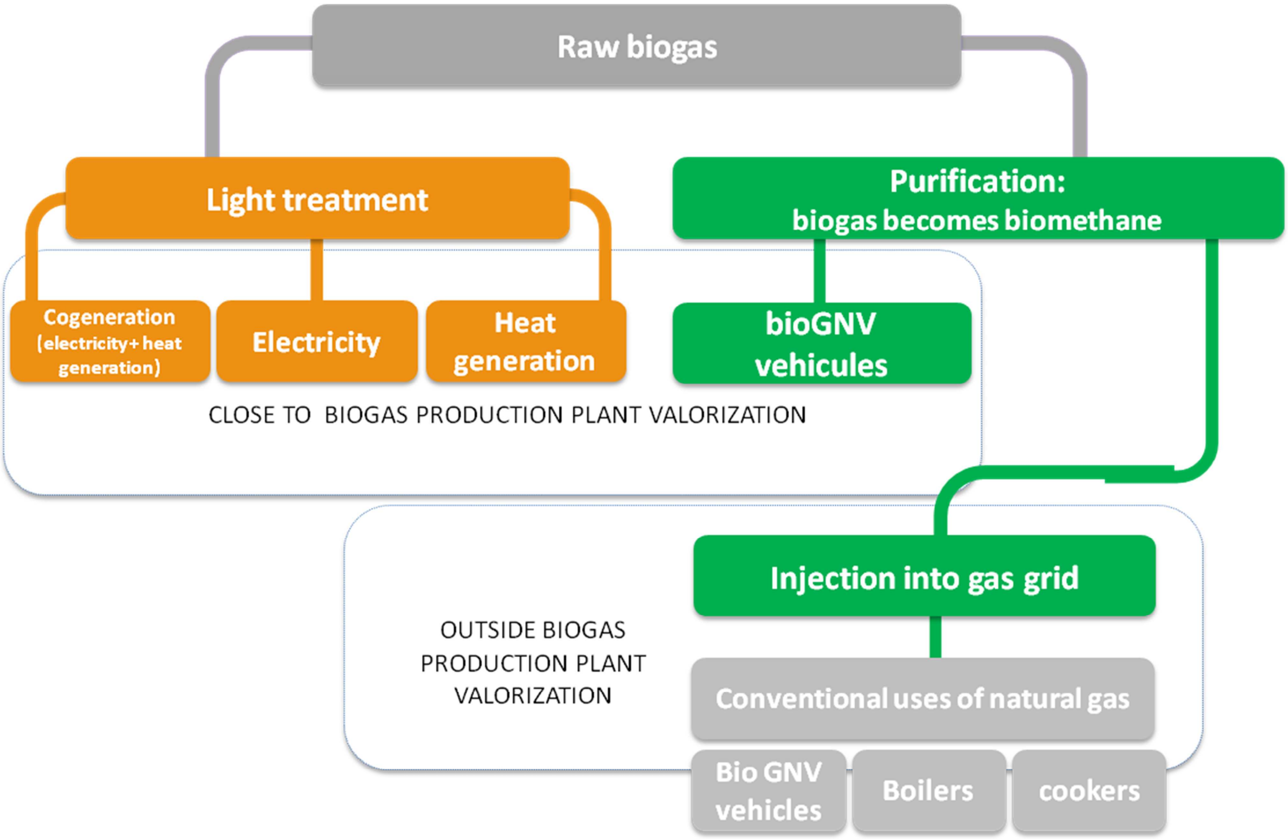


Figure 7.16: Different ways for biogas valorization

The second green gas generation is biomass gasification. It's a high temperature process about 800℃ using dry biomass. The French estimated poten tial is also very important probably around 200 TWh. This process is not fully mature today but several demonstration units are going to be built in Europe with an interesting project in France called GAYA.

Next steps can be microalgae and power to gas. The estimated potential in France is much less important and we are today in the research stage.

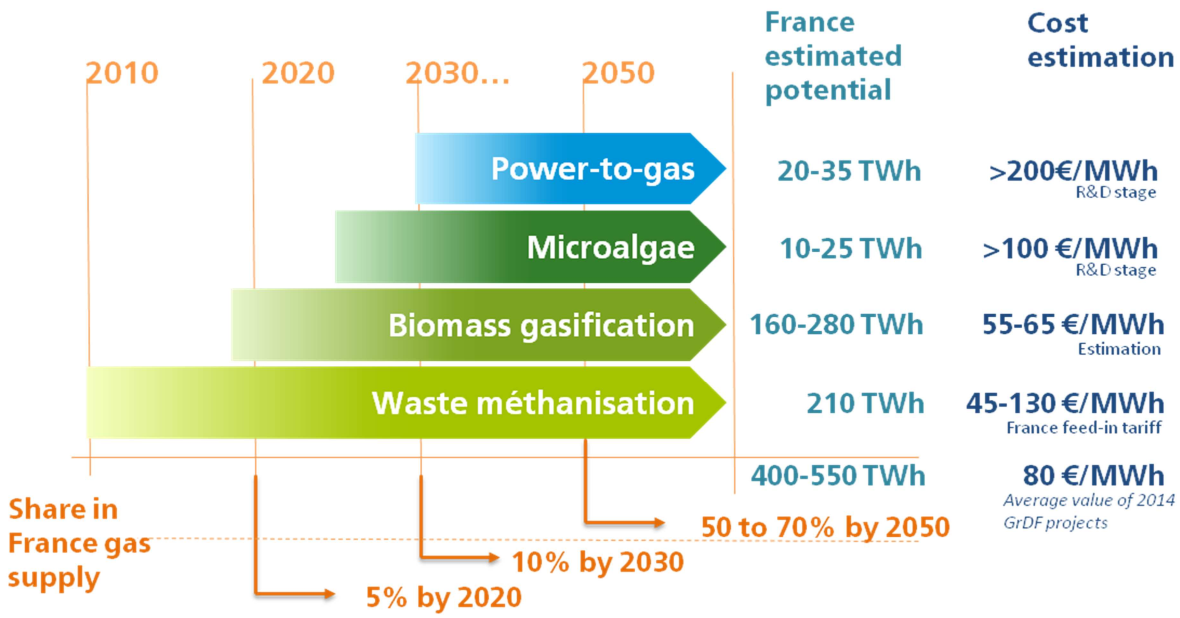


Figure 7.17: The green gas roadmap

There is also a challenge that renewable electricity production could reach very high peaks and require massive storage capacities. In Germany as well as in France, this will be an issue for the future. In 2050, studies show that renewable electricity surplus will reach up to 75 TWh, 5000 to 6000 hours of yearly production.

Therefore, the gas grid could has an important role to play in electricity storage with electrolysis and methanation. Renewable electricity in excess could be used to produce hydrogen with a good efficiency over 80%. It is possible to inject this hydrogen directly in the gas network up to 6%. In the past there was hydrogen in town gas. Over 6%, hydrogen needs to be transformed in methane with CO_2 before injection in the network. This methanation is also a process with a good efficiency over 80%. Electrolyses and methanation are well-known processes but we still are at the experiment stage for massive electricity storage capacity. A demonstrator is going to be realized in France in Dunkirk (North of France) with the injection of hydrogen in the distribution network. GrDF is one of the stake-holder of this project called GRHYD.

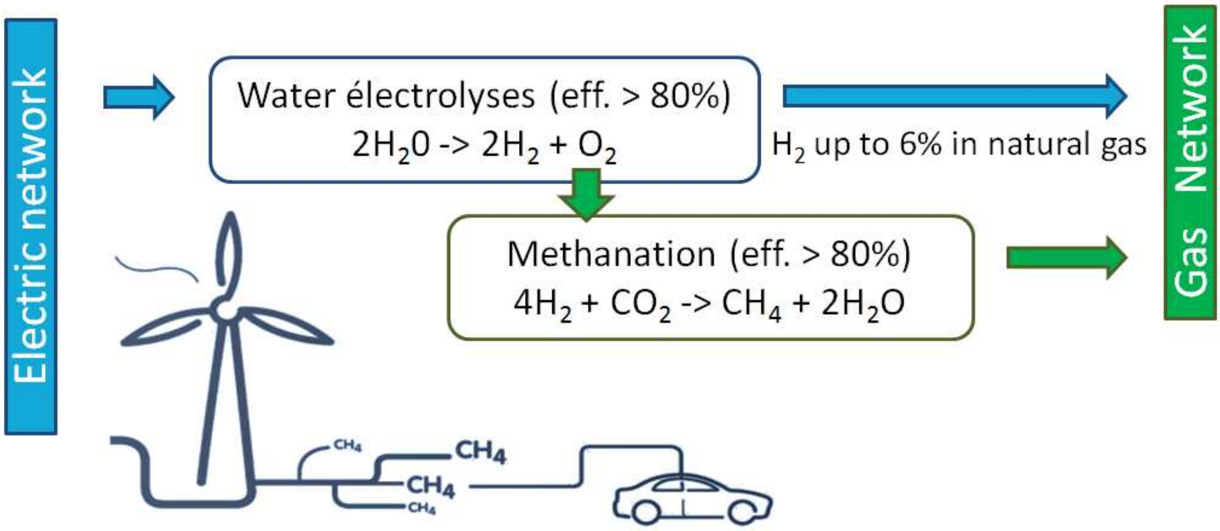


Figure 7.18: Power-to-gas as a link between electricity and gas infrastructures

Green gas is perhaps the most symbolic change we are facing but the new customer's needs and uses are also very important indeed. After a long time of stability in gas uses things are changing quickly now with a lot of new gas uses arriving. Three examples can be presented:

- the ecogenerator: it is a micro cogeneration with a stirling engine. It is a very efficient CHP because heat and power are produced in the customer's home very close to the needs.
- the hybrid boiler: it's a condensing boiler with a small electric heat pump. Both equipment is integrated in the same device. So you use the cheapest energy at any given moment according to efficiency of the different processes.
- the absorption heat pump: this equipment has 170% of efficiency through recovery of geothermal energy.

In addition, NGV and bio-methane for vehicles appear today in the world as the first alternative ecological solution for petrol with 13 million vehicles. The NGV vehicle fleet is developing quickly with 18% progression each year. The evolution in France is still slow with only 15, 000 vehicles manly buses, waste trucks and captive fleet of light vehicles. Bio-methane is also a very efficient bio-fuel when it is used as fuel for vehicles. BioNGV brings an additional gain in terms of CO_2 with a sustainable and local fuel.

To face this transition, GrDF aims to build a smart gas system where customer is also one of the spearheads of this transition. The smart metering system Gazpar is the perfect example of a project driven by and for customers with three major goals:

- to improve invoicing quality and customer satisfaction: today, we read indexes of consumption only two times a year. Tomorrow we will have one index every day and invoicing will be based on real consumption data. It is very important to have frequent consumption data in an open market.

- to develop energy efficiency: daily data will be enable customers to follow precisely their consumption and forster energy efficiency The minimum energy efficiency expected impact on the project perimeter is 1,5%.
- to optimize distribution network: with GAZPAR we will have plenty of data and a new communication network. This will give us new opportunities like predictive maintenance, gas flows optimization and probably many others. These potential benefits are not included in the business case.

Figure 7.19: GAZPAR : a project driven by customers

From a technical point of view our gas smart metering project is quite simple, robust and reliable. It consists of 3 technological blocks:

- 11 million new meters with a radio device,
- a fixed radio network with 20 thousand concentrators,
- a new data collection and management system.

The project timeline of Gazpar was very well set out, including the following phases.

2010: experiments to try different technical solution with all our stake-holders: consumers, municipalities, suppliers and all public authorities.

A second phase was the framework setting again with all of our stake-holders leading to common work with technical suppliers to prepare the construction phase.

The next steps will be the pilot deployment during 2016 and the full scale deployment from 2017 to 2022. The deployment pilot will be implemented in 4 different regions and 24 different municipalities to test deployment in all possible conditions and to secure the full scale deployment.

This project is profitable for customers and that is mainly down to the energy efficiency savings:

- The total overall cost is about 1 billion of capital expenses and 300 hundred millions of operational expenses; roughly the cost of the new meters represent more than 80% the total cost, about 10% for the information system and less than 10% for the radio network.
- a lot of savings have been identified; the stop of foot reading activity is a large part of our savings but savings are also expected for GrDF and for suppliers from a reduction of customers claims and invoicing mistakes.
- Savings resulting from the energy efficiency improvement have been included to the business case. Experiments in England show that energy efficiency in similar condition is between 2 and 3%. Our objective with only 1.5% of energy efficiency is conservative.

Finally the business case is positive by more than 800 million €.

After the new gases, the new uses and the news needs of customers, new ways to operate the existing network are appearing. GrDF is not building a new network, but aims to connect the new green gas production unit with some extensions and profitable modernization of the network. The major change is not the network itself, but it is the way to operate this network with the strong evolution in I&T systems.

From now already 3000 operational devices are mainly used for remote monitoring.

The first stage in 2015 will be to industrialize the remote monitoring for pressure control and cathodic protection and to centralize the information.

Afterwards, the objective is to build a unique monitoring and management tool. This second stage means development and implementation of a SCADA. (Supervisory Control and Data Acquisition) and to achieve active network management including bio-methane injection.

Real complementarities exist between energies, uses and networks. French DSO believe that an optimum energy system valorizes existing energy assets and infrastructures.

It is why an affordable future will be made of the combination of energies, uses and networks.

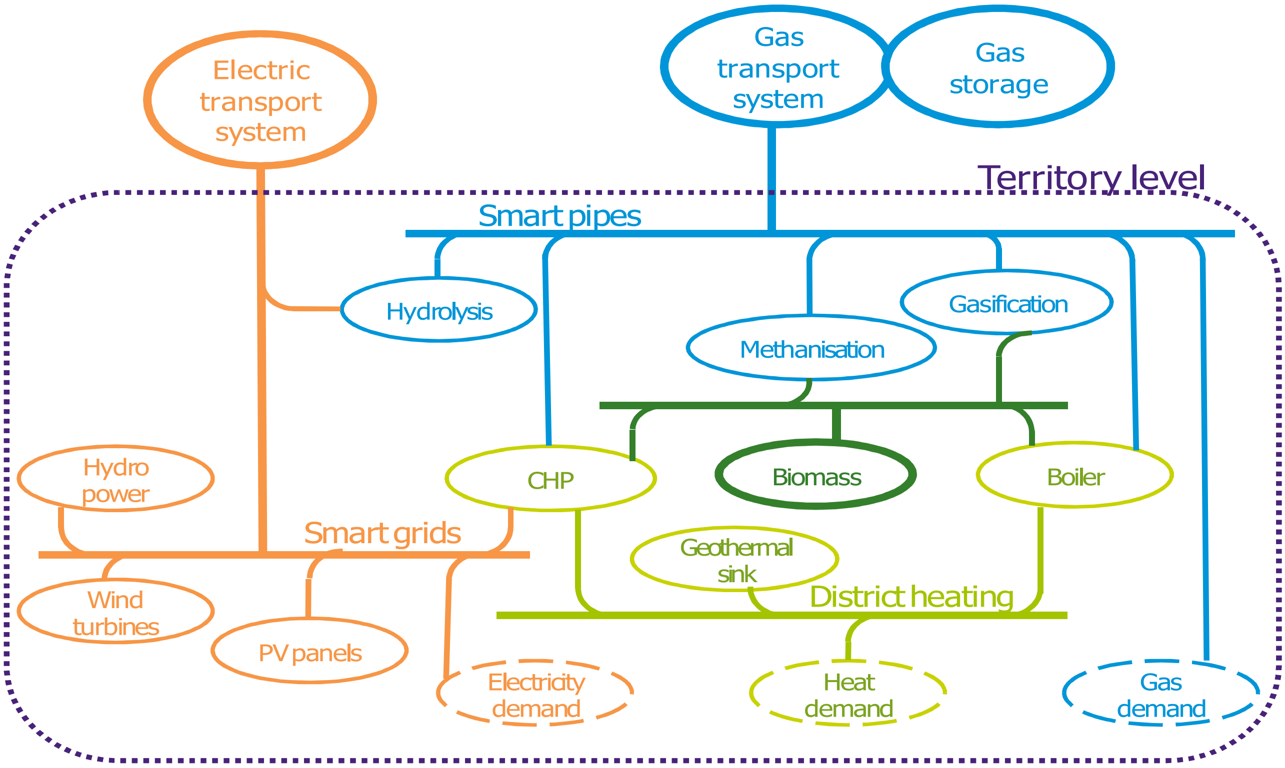


Figure 7.20: The smart gas grid part of a wider smart networks project

7.6.6 Compressed Natural gas (example given on Algeria)

Figure 7.21: CNG bus in Algers

Natural gas vehicles have a highly positive impact on environment: 25% less CO_2 and 85% less NOx than traditional vehicles, which can provide a good environmental solution for polluted urban areas.

In Algeria, the use of CNG began in 1998 by th Société Nationale de l'Electricité et du Gaz (Sonelgaz), with two CNG stations in Alger, 10 buses and the conversion of 85 vehicles of Sonelgaz in 2002.

To develop CNG two programs have been launched by the Energy and Mines administration: a first one (2007-2011) with 175 buses (100 in Algiers), 40 CNG stations, conversion of 14 000 taxis and 4 places for refueling and maintenance of vehicles. The second program takes place from 2012 to 2015 with 152 stations and 500 buses.

This program implies the development of infrastructures, for CNG equipment and connections with the distribution network for which a remote operation can have a big benefit

The automation of the operations concerning CNG:

Description	Remote operation and maintenance of CNG stations
Drivers / Context	Diminution of operating costs – real time and remote operation in case of problems encountered on the filling station
Technological solutions **(Including potential or under development technologies)**	Remote technologies for detection of leaks or of thefts of gas, physical intrusion, pressure and gas flow control at the delivery point on the network Real time information systems to detect the occupancy of filling stations
Maturity of technology	Available but must be implemented in DNO IT systems
Technological and economical challenges and obstacles (regulation, law,…)	Conditions about safety rules of CNG filling stations Conditions about telecommunication systems
Additional benefits	Possibility of additional services for customers

7.6.7 Integration of micro CHP in the energy systems (example given from Japan)

Background

In April 2014, Japanese government made 4th strategic energy policy. Basic viewpoint of energy policies are Energy security, Economic efficiency, Environmental and Safety (3E+S). Also, principle of energy policy about natural gas is important energy sources as a main intermediate power source. Future of the secondary energy supply structure are promoting micro CHP and introduction of storage batteries, and realising of the “Hydrogen Society”.

High efficiency boiler and co-generation system for household use micro CHP are developed in Japan. Main products are condensing boiler (“Eco-Jose”), co-generation system with gas engine (“Eco-Will”), and Fuel cell (PEFC, SOFC) system (“Ene-Farm”).

Product name		Eco-Jose	Eco-Will	Ene-Farm(PEFC)	Ene-Farm(SOFC)
Type		Condensing boiler	Co-generation system with gas engine	Fuel cell sytem (PEFC)	Fuel cell sytem (SOFC)
Exhaust CO2 Volume		△0.2 t/year	△1.1 t/year	△1.5 t/year	△1.9 t/year
Decreased Rate	CO2 Emission	△13%	△11%	△35%	△35%
	Primary Energy	△13%	△39%	△48%	△50%

Eco-Will in residential field

System configuration of Eco-Will is described in figure below. The system has a gas engine micro CHP unit, hot water and heating unit. Controllers are connected to the hot water and heating unit. Visualization of energy consumption and utility cost is installed in the system.

As saving energy and environment friendliness, energy use in primary energy is 73% and CO_2 emission is 62% compared to conventional system. Also, self-leaning function and energy saving navigation function the system are main features of Eco-Will. The electrical efficiency is 26.3% and the total energy efficiency is 92.0%.

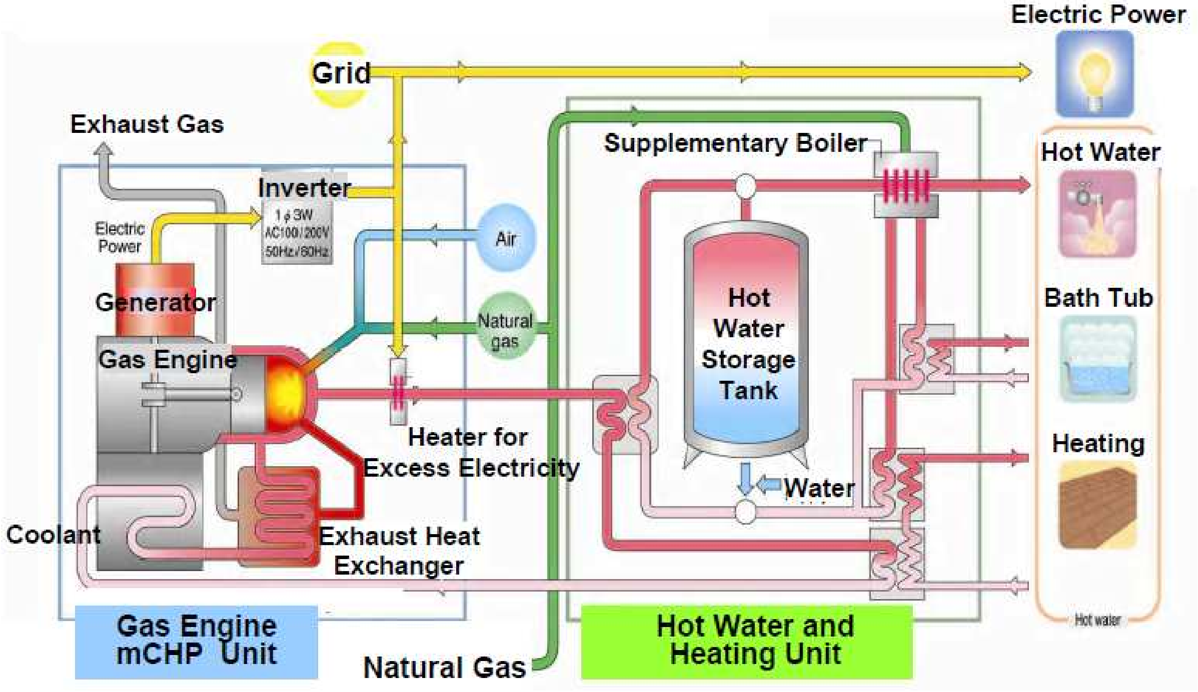


Figure 7.22: System configuration "Eco-Will"

<u>*Ene-Farm in residential field.*</u>

Japanese government decided to set a huge number of units sold by 2030 based on some environmental issues in Japan. The future sales target is 5.3 million units in Japanese market.

<u>Concept of Ene-Farm</u>

Fuel cells generate electricity using a principle equivalent to the electrolysis of water, in reverse. The Ene-Farm fuel cell systems utilize this principle to create electricity and hot water simultaneously in homes using utility supplied gas. Specification and installation of Ene-Farm system are described in table and figure below.

Type	Polymer Electrolyte Fuel Cell(PEFC)	Oxide Fuel Cell (SOFC)
Electrolyte	cation-exchanger membrane	stabilized zirconia
ion	H^+	O^{2-}
Maximum temperature of the stuck	About 100℃	About 1000℃
Electrical efficiency(LHV)	33～44%	44～72%
Manufacturers	1.Panasonic Tokyo-Gas 2.TOSHIBA	1.JX-ENEOS 2.TOYOTA Aishin Kyosera Chofu Osaka-Gas
Pictures		

Figure 7.23: Specification of Ene-Farm in residential field

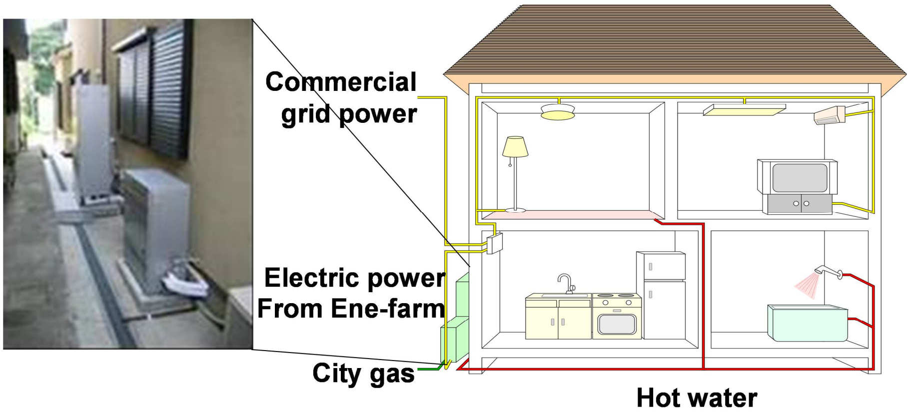


Figure 7.24: Residential Ene-Farm installation

In Ene-Farm PEFC type, the total energy efficiency is 85.8%. Reducing 37% energy consumption and 49% carbon dioxide emission compared with the general house in Japan.

The owner can check the condition of generating quantity of electricity, the amount of electric power used and selling quantity of electricity, etc… using remote control panels.

Ene-Farm drives automatically saving energy in the house. It comes with a smart function to predict the future energy consumption. The computer stores the pattern of customer life style. Automatic operation control minimizes primary energy consumption by maximizing utilization of hot water by recovered heat (see figure next page).

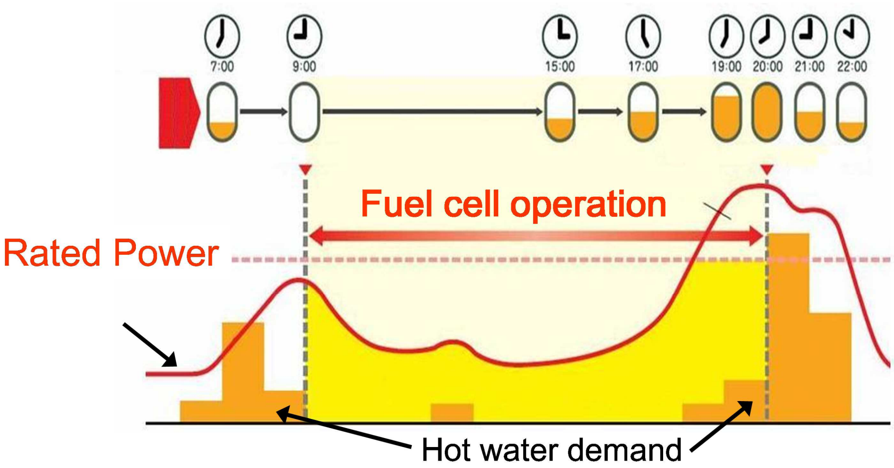


Figure 7.25: System operation concept of Ene-Farm

Expanding the market

It is important to establish it in urban area due to the high ratio of condominiums compared to individual houses. To expand the market, new Ene-Farm for condominium was commercialized from 2014 in Japan.

7.7 Questions about smart gas grids

For network operators, elaborating a roadmap for the design and construction of smart gas grids starts with the choice of functionalities which in turn determine the technologies that have to be implemented on the network. These must be challenged in terms of performance and economics.

The functionalities shall be defined by answering different questions:

- What interactions are there between electricity, gas, heat and cooling in a given system?
- In terms of planning future investments are new networks or renovation of existing networks envisaged?
- What smart / combined energy utilization will there be (e.g. cogeneration and micro-CHP)?
- What monitoring of system operations in real time and optimization of pressures/flows will there be?
- What is the data exchange between different market players? Data volume? Which ICT network? Dedicated or common communication grid?
- Is there a need for bidirectional energy networks?

The answers to these questions are highly dependent on local considerations about DSO needs, local energy supply, urbanism, type of gas and electricity utilizations etc. They will not be the same in all countries or even in all towns. The smart grid is a universal concept with many possible configurations.

7.8 Conclusions

Smart gas grids are key to enable a safe and efficient transition to a fully sustainable energy supply. Making the gas grid fully active and self-adaptive is an ambition. One of the most immediate issues for the smart gas network is facilitating the feed-in of biomethane, but more opportunities lie ahead.

To develop a smart gas grid, the elaboration of a dedicated roadmap is needed. Data management will certainly play a central role in the framework of the smart energy system, of which the smart gas grid will be an essential part. Therefore, it is not too soon to start thinking and discussing the appropriate IT architecture for managing data to optimize network maintenance and control as well as to deal with suppliers or of energies switching.

What are the success factors for smart grids? To achieve the ambitions explored in this report, some recommendations have already been identified:

- ➔ Promote gas appliances which accept a wider range of gas compositions. This would allow a wider range of gas compositions in the network and introduce more flexibility in the operation of the mixtures of different gases including biogas.
- ➔ Allow for more interaction between energy carriers, especially electricity.
- ➔ Promote NGVs, especially in relation to public transport and commercial / goods vehicles (can work well without).
- ➔ Stimulate projects on smart gas grids, including the inputs of new types of gases such as bio and synthetic methane and exchange about the results.
- ➔ Develop smart metering systems also for gas.
- ➔ Promote biomethane injection as a route to decarbonizing. This would facilitate the continued efficient use of the existing extensive gas network while achieving greenhouse gas reduction targets. Reduction of the costs of grid injection will also be an important component of this activity, to avoid project developers choosing to use biogas for low-efficiency electricity generation rather than gas grid injection.
- ➔ Develop a regulatory framework adapted to the deployment of smart grids, combined with the development of international standards useful for getting industrial and efficient technological solutions.

In the future, flexible grids will enable the integration of electricity, gas, heating and cooling with the aim of optimizing the overall efficiency of the grids. The result will be a sustainable, economic and reliable future energy system.

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8 Conclusions

The issues covered in this report will remain issues for gas distribution worldwide, although to different extends.

Third party access and regulation have almost everywhere been subject to gas transport first, with unbundling of gas grid operation and gas trade. However, it is increasingly becoming also an issue for gas distribution companies as well, as shown in the report of study group 4.1. In particular, the regulation and unbundling of integrated companies is taking place in a way "from large to small" in different countries. Third party access obviously depends of the availability of gas suitable for grid injection at distribution level. The major gas streams remain an issue for gas transport first, but the increasing number of smaller gas wells (shale gas) and the increase of gases not coming from the soil (biomethane, synthetic natural gas) are indeed an issue for distribution grid operators as well.

Those gases from non-conventional sources are becoming an issue in more and more countries, and their access to the grid is eased in some countries by legislation, in particular in Europe. However, it is in general the gas distribution grid operator who is left with the task to accept such gases for grid access on the one hand and to safeguard the gas quality delivered to the gas consumers on the other hand. With increasing diversification on both ends, the challenge for the distribution grid operator grows as well. In particular a number of industrial clients for the gas can be very demanding about the stability not only of gas supply, but also of gas quality, and alone the seasonal variation of share of e.g. an injected amount of biomethane in a natural gas grid can pose some severe problems. There are some possibilities to cope with such challenges, and the report of study group 4.2 indicates some of them, but also the future challenges on the way to a "carbon-free" future.

The report of study group 4.3 allows to look a bit into the technical future of gas distribution. Smart grids will help to enable the operating companies to integrate gases from different sources, with different qualities. However, the installation of smart grids is demanding, not only by means of financial investment. It requires careful and thorough planning and the report of study group 4.3 gives some advice how to get to an active and self-adaptive gas distribution grid, fully integrated with other energy services.

9 Outlook

IGU Working Committee 4 "Distribution" is looking forward to a new triennium, in line with the themes defined by the hosts of the World Gas Conference in 2018, the United States:

- Access
- Markets
- Social license

It is intended to concentrate the work on the following subjects:

Access:

Virtual Pipelines: Supply chain transporting natural gas to final consumers or isolated distribution networks in the form of CNG or LNG, using road and sea means of transportation, such as truck, vessels and rail. Useful to supply remote and dispersed consumers. Technical, economic and regulatory issues.

Markets:

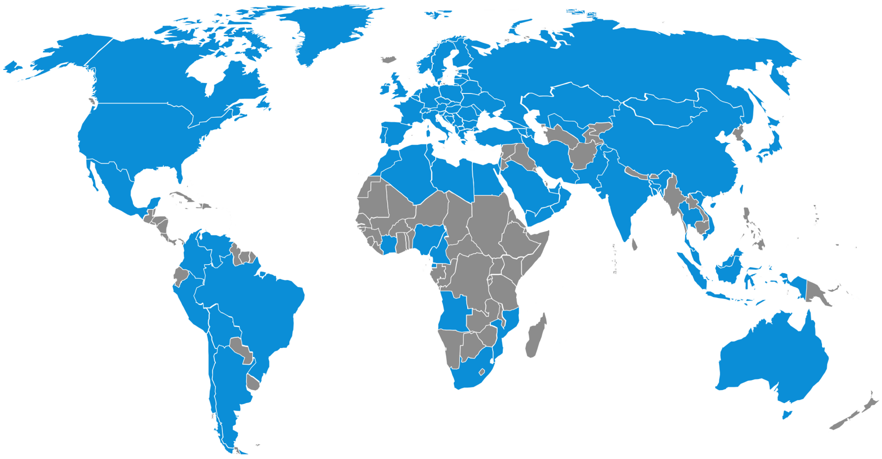
1. **The role of DSO in the expansion of the natural gas market:** Placed at the end of the gas chain, and close to local economic actors and gas consumers, DSOs have an essential role as an active deployer of natural gas networks, by promoting current and new efficient uses of natural gas and by investing on them. All stakeholders benefit from the corresponding natural gas market enlargement. Best practices in different countries and Recommendations.
2. **The DSO as Market Facilitator:** Technical (IT and information systems) and Regulatory issues in the relationship of DSOs with other market actors: Suppliers and Customers.

Social license:

1. **Distribution of green natural gas:** Injection of biomethane, H_2 from P2G, etc. Technical, Economical and Regulatory issues. Including certification of biomethane.
2. **Safety of personnel working on gas distribution mains:** Models. Training, Skill assessment and Certification of personnel.
3. **Integrated Quality Management Systems in Gas Distribution Companies:** Key Performance Indicators of Quality of Distribution Service (regulated or voluntary adopted) including safety checkups of customer's premises . Quality management systems.
4. **New laying technologies:** Laying of distribution networks more respectful with the urban environment. Technologies. Best practices. Economical results.

We invite You to participate actively in the develo0ment of these subjects, looking forward to meeting you at our first new committee meeting in Spain in fall 2015.

NOTES



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