Chapter 13
Electricity and Gas

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One of the most interesting regulatory challenges in the energy sector during the next decade will be to cope with the multiple dimensions of the interaction between the markets and the infrastructures of gas and electricity.

This chapter provides a very brief introduction to the natural gas industry and its regulatory structure, in which the focus is on the factors that affect the electricity industry.

While the electricity and natural gas sectors followed distinct parallel courses during most of the twentieth century, they have been gradually converging in the last 25 years. On the one hand, the use of gas as a fuel to produce electricity has risen steeply, albeit from a very low level. On the other hand, the problems arising around electric and gas industry liberalisation are often similar, mostly because both are grid industries.

Natural gas is extracted from the fields where it is deposited, transported to consumer hubs through gas pipelines or as liquefied natural gas (LNG) and finally distributed to end consumers. Taken as a whole, this supply, transmission and distribution system is known as the natural gas chain. Production and transmission to consumer countries and regions, i.e. the upstream end of the chain, is usually distinguished from transmission and distribution within consumer countries and regions, or the downstream end.

Upstream, gas and oil systems are similar. Investment in exploration and production is made primarily in non-OECD countries. In some cases, political risk is highly significant. Gas companies typically enter into agreements with local public companies, which entails taking account of factors such as royalties, local taxes, and the possible existence of State shareholdings. Exploration involves high technical and financial risk and requires a long-term approach. The medium-term horizon is more relevant for development and production and is expertise and capital intense. The upstream portion of the industry often falls outside the competence of national regulators with jurisdiction over end consumers.

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The downstream system, in turn, is more like the electricity system. Transmission and distribution are natural monopolies. Significant technical constraints (balancing, transmission constraints, quality standards…) must be handled by a System Operator. The business involves a number of very expensive and industry-specific infrastructures, designed to accommodate security of supply issues, among others. Moreover, in both gas and electricity, procurement and supply (i.e., retailing, not a network activity) to end consumers is an activity that can potentially be conducted on a competitive market. Finally, the national regulator for gas is often the same body that supervises the electricity industry.

The first section of this chapter describes the basic technical structure of the gas industry, including the nature of the activity, production, transmission, storage, distribution and consumption, as well as the *modus operandi* in each step along the way. The second addresses industry regulation, focusing on the downstream end of the business, which is the most relevant from the standpoint of electricity industry actors. The third section deals with security of supply, as regards the gas industry per se and its impact on the electricity industry. The last section discusses market power problems stemming from the existence of large companies that conduct business in both industries.

13.1 Technological Aspects of the Natural Gas Sector[1]

Natural gas is a mix of methane and other gaseous hydrocarbons such as ethane, propane and butane. It also contains nitrogen, carbon dioxide and water vapour. Geologically speaking, the origin of gas and oil is similar and they are often found in the same fields. In such cases, the gas is known as wellhead, oil well or associated gas. Non-associated gas is the gas deposited in fields containing gas only.

The nature of a given hydrocarbon depends primarily on the proportion of hydrogen to carbon atoms in its molecule. Hydrocarbons with a high proportion of hydrogen have very low melting and boiling points, lower densities, less combustion energy per unit of volume and more combustion energy per unit of weight, than materials with a lower hydrogen to carbon ratio. Methane (CH_4) and ethane (C_2H_6), for instance, are gases at ambient temperature, while propane (C_3H_8) can be readily liquefied at ambient temperature by raising the pressure. The boiling point for butane (C_4H_{10}) at atmospheric pressure is 1 °C below zero. Since it can be liquefied at ambient temperature by raising the pressure, it can be transported in bottles. All hydrocarbons with five (pentane) or more carbon atoms are always liquid under normal conditions. Pentanes and heavier liquids are known as condensates or natural gasolines, whereas ethane and heavier liquids (including condensates) are natural liquid gases.

[1] For general reference of technical aspects, see [11].

Natural gas is regarded as wet when it contains significant amounts of natural liquid gases (NLGs) and dry otherwise. The NLG content may vary widely from one field to another, from nearly nil to up to 30 %. Hydrogen sulfide, another impurity in natural gas, must be separated because of the corrosion it induces. Gas with high hydrogen sulfide content is called sour, while sweet gas has a low proportion of H_2S.

13.1.1 Reserves and Resources[2]

Prospecting for natural gas is a resource-intensive activity that calls for considerable know-how. Due to technological limitations, however, not all the gas found can be extracted. A distinction is therefore drawn between resources or the total amount of gas in the field and reserves, which is the amount that can be economically extracted.

Reserves depend on both technology and the market price for gas at any given time. Moreover, both resources and reserves are subdivided into additional categories depending on how reliable the estimate is believed to be. Reserves with a probability of recovery of 90 % or higher are proven, when the likelihood of recovery is 50 % or over they are probable, and when the certainty of recovery is 10 % or higher, possible. Nonetheless, these estimates generally entail a certain amount of discretion on the part of the geologist concerned and are often reported by companies or governments with an agenda.

Natural gas reserves are highly uncertain, but much more abundant than oil reserves. The ratio between reserves and output has held at around 60 years over the last 10, with a slightly upward trend, because reserves have risen more rapidly than the amount of gas extracted. The largest reserves are found in Russia (around 24 % of the world-wide total), Iran (16 %) and Qatar (14 %).

The quantities quoted above are for conventional gas. In addition, there are also huge amounts of unconventional gas: shale gas, coal bed methane, tight gas (from low permeability reservoirs) and gas (or methane) hydrates. Total and recoverable volumes are very uncertain, but the IEA estimates that, excluding gas hydrates, they might amount about double of those of conventional gas.[3] Generally speaking, unconventional gas is more evenly distributed than conventional gas.

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[2] Global information on natural gas reserves, resources, transportation and consumption can be found in the IEA report *World Energy Outlook*. The report is updated every year and can be downloaded from the IEA website www.iea.org.

[3] IEA, World Energy Outlook 2010.

13.1.2 Production[4]

The decision to exploit a field depends on whether the gas is associated or otherwise. If it is not, exploitation depends strictly on profitability considerations. Wellhead gas, however, has to be extracted to bring the oil to the surface. If no gas pipeline is available to transport it, it must be flared or reinjected. The advantage of reinjection is that it enhances oil recovery (by maintaining the field pressure) and allows for future recovery of the gas. In the short term, however, it raises drilling costs.

Non-associated gas may contain over 85 % methane. Under these conditions, it may be injected directly into a gas pipeline. By contrast, where the natural liquid gas content is significant, it must be separated before injecting the natural gas into the pipeline, given its higher economic value and because its possible condensation inside the pipes could hinder transmission.

The location of world-wide production appears, a priori, to be illogical. Output tends to be higher where reserves are lower and extraction most expensive: in Siberia (under particularly severe meteorological conditions), North America (often with high production costs, in light of the small relative size of many fields) and the North Sea (offshore production in an unfavourable climate). One of the main reasons is that gas is difficult to transport to consumer hubs. Nonetheless, the declining cost of shipping liquefied gas on LNG tankers is contributing to the development of fields that have traditionally been only scantly exploited, or not at all, such as in the Near East.

13.1.3 Transmission

Gas transport, unlike oil transport, is complex and costly. For that reason, it is a characteristic of countries sufficiently developed to have invested the capital needed to finance gas transmission and distribution grids. The two main transport media are gas pipelines and LNG tankers.

Pipelines

Pipelines are steel pipes, normally 36–142 cm in diameter, that carry gas at pressures of 80–100 bar. They constitute the primary transport medium and may be hundreds of kilometres long.

The gas moves through the pipe because of the difference in pressure at the two ends. Field pressure itself sometimes suffices to transport it for considerable distances, but normally compressors need to be installed at regular intervals (typically every 100–150 km) to raise the pressure. The energy required is often obtained by

[4] Upstream activities are not the focus of this chapter. However, as a reference of engineering aspects, see [8].

burning some of the gas carried, although electrical compressors are used in some systems. Valves may also be installed to facilitate grid operation.

A gas pipeline may be able to carry on the order of one million or more cubic metres of gas per hour, at normal pressure and temperature. This rate may be raised if the operating pressure is increased, although the trade-off is higher compressor operating costs.

LNG chain

The LNG chain, i.e. the shipment of gas from the field on tankers to markets normally thousands of miles away, comprises the following stages.

- Liquefaction trains are the most technically complex and expensive part of the process. They consist of several cooling cycles to lower the temperature of the gas to –160 °C, thereby reducing its volume 600-fold.
- The LNG is loaded onto LNG tankers, a specific type of vessels normally with a cargo capacity of 140,000 m^3 of LNG, equivalent to approximately 900 GWh and shipped to its destination, where it is unloaded.
- Regasification includes LNG tanker mooring and unloading, as well as the measurement, storage and vaporisation of the natural gas, which may alternatively be loaded onto trucks.

The energy expended in the entire process is on the order of 10 % of the energy of the gas shipped. The chain is flexible, but only to a limited degree. Liquefaction plants are designed to operate with a high and constant load factor and LNG tankers cannot store gas for long periods of time because it evaporates slowly. Consequently, the chain is designed on the assumption of a constant flow of tankers from the liquefaction to the regasification plant. Some flexibility is nonetheless possible (by re-routing a vessel from one regasifier to another, for instance), particularly in the long term, where operating plans can be amended.

As noted, these infrastructures are expensive. The cost of a gas pipeline is approximately proportional to its length. A high pressure line, for instance, may cost on the order of over 1 million dollars per kilometre, although this varies widely depending on the type of terrain involved. LNG transport, in turn, entails both the fixed costs (regardless of the shipping distance) incurred to liquefy and regasify the product and variable costs that rise moderately with volume due to the need for a larger number of tankers. A gas pipeline may be preferable for relatively short distances (1500–3000 km, depending on circumstances), while LNG is more cost-effective for longer range shipping.

As in the case of electricity transportation, the construction of the transmission network may be much postponed because of delays in administrative authorization, either because of environmental concerns or because it involves an international agreement. Construction itself uses to be much speedier (sometimes the pipeline can be built within a year) and it involves high capital intensity and high economies of scale.

13.1.4 Storage

Gas is stored to attain:

- a strategic objective, namely to ensure a reserve from which to draw if imports are interrupted.
- a technical objective, to be able to supply the demand for gas, which is characterised by wide daily and seasonal variations (the demand for hot water, for instance, rises in the morning and at night and heating may be necessary in the wintertime only).

Several types of storage can be identified.

- Linepack is storage in the transmission network. Whilst the volume is small and serves primarily as a daily balancing tool (flexibility), since all users are present, it constitutes a good trading platform.
- LNG is also stored in regasification terminals. The volume involved is larger than in linepack storage. It also constitutes good operational storage, allowing logistic users weekly/monthly flexibility and accommodating changes in demand. It may be used by the System Operator to quickly respond to disruptions in supply.
- Underground storage, which accommodates larger volumes than the other two, serves seasonal purposes, although it takes about 12 h to reverse injection/withdrawal cycles. It comprises strategic reserves and is much more inexpensive than LNG storage. A number of geological or man–made structures can be used for underground storage, including depleted gas fields, aquifers, salt caverns or mines.

13.1.5 Distribution and Consumption

Gas is distributed through pipes that operate at pressures of under 20 bar. Certain large consumers (such as electric power plants) may, however, be connected directly to the transmission grid. Like electricity grids, gas distribution networks are organised hierarchically: the high pressure distribution grid[5] (4–20 bar), which is fed by the transmission grid, feeds the medium pressure network (50 millibar to 4 bar), which in turn feeds the low pressure grids.

The end consumers of natural gas have traditionally been and in most systems continue to be manufacturers and households (particularly for domestic heating). Nonetheless, gas has been increasingly used to produce electricity over the last 20 years, particularly since the advent of combined cycle gas turbine plants.

[5] All the pressures cited are differential, i.e. the difference between the pressure of the natural gas and atmospheric pressure. Residential facilities are typically designed for differential pressures of 15 millibar.

13.1.6 Downstream Gas System Operation

As in the case of electricity, the existence of a meshed network requires the presence of a System Operator to coordinate operations and ensure system security, also known as system integrity in this context. The gas system is simpler in two respects, however.

- As gas transmission is not subject to Kirchoff's second law,[6] gas flows can be directed through specific paths. The path of a certain gas parcel may even be traced from source to destination, a possibility that makes no sense in electricity systems, from the standpoint of their physics. From the perspective of transmission planning, then, one of the most significant sources of network externalities is absent in gas systems.
- Dynamics are much slower in gas than in electricity, because significant amounts of gas can be stored in the network, typically enough to balance the system during an entire day. By contrast, the amount of electrical energy stored in the grid only suffices to "balance" the system for milliseconds, which is why the electricity network must be balanced instantaneously.

Such slower dynamics naturally render system operation easier. The trade-off is that gas System Operators typically have fewer resources from which to draw when operation goes awry.

Operational procedures

Specific operational procedures vary between systems, although they all have certain similarities. The following description is based on the procedures followed in Spain,[7] where system operation is organised further to a "process chain" consisting of several steps.

- The first is programming. All agents using gas system facilities are required to submit a programme to the System Operator and the operators of the facilities they intend to use. They must inform the amount of estimated gas input, output, supply or storage in a given period. Programmes, which are usually merely informative, are drawn up for different time frames: yearly, monthly and weekly. The shorter the time frame (and

[6] Formally, the role played by pressure in gas transmission is similar to the voltage angle function in electric power grids. Valves and bypasses are simple and reliable devices, however, for which there is no inexpensive equivalent in electricity.

[7] The specific procedures can be downloaded from the SO website www.enagas.es (search "Procedures" under "Technical Management of the System").

the closer to injection/withdrawal), the more detailed and realistic is programming.

- Nomination, the second stage, is also required of all agents using gas system facilities but, as opposed to programming, is binding. Agents notify the System Operator and facility operators of the estimated gas input, output, supply or storage during a given day, broken down by gas system injection or withdrawal point. Notifications can call for more capacity than previously contracted by the agent with the facility operator, subject to availability. They may also be rejected, e.g. if specific requirements required for short-term storage are not met.
- Measurement, sharing and balancing are standardised procedures used to measure volumes and qualities, establish each agent's share in the gas transported, regasified, distributed or stored and physically balance the various facilities.

Throughout the chain, agents must maintain a balance; i.e. the amount of gas injected into the system must equal the amount withdrawn plus the inventory difference. Users' inventories must be below their maximum assigned capacity, defined to be the contracted capacity plus any amount allocated by the SO based on a regulated procedure. Otherwise they must buy or sell gas, modify their programming or notification, execute supply interruption clauses, negotiate supply interruptions, use underground storage or modify consumption. Failures to comply are fined or otherwise penalised.

13.2 Structure and Regulation of the Downstream Natural Gas Industry

Upstream structure and regulation in the gas and oil industries are similar and often involve the same actors (companies and regulators). Unlike the oil market, however, the natural gas market is not global, due to its high transport costs.

The three chief natural gas markets are found in North America (essentially US and Canada), Europe and Asia (Japan, South Korea and Taiwan). Certain national systems, such as in Russia, Brazil and China, have dynamics of their own. While mean yearly prices tend to move in the same direction in all these markets, in a shorter time frame trends may vary from one area to the next. The conditioning factors also vary widely: North America produces most of what it consumes, Europe depends heavily on gas pipeline imports from Russia and northern Africa, and the East Asian countries import their gas in liquefied form from Indonesia, Australia or the Persian Gulf. The convergence among these markets due to the falling costs of LNG tanker shipping has led some observers to predict that a single global price will prevail in the long term.

A distinct US phenomenon has been the huge increase in shale gas production that presently amounts to more than 20 % of total US gas production.[8] As a consequence, gas prices are now low in the US (especially when compared with past years' expectations), gas has displaced coal to a very significant degree for the US electricity production, and coal prices have collapsed in the US and elsewhere.

As in electricity, the downstream sector of the natural gas business has traditionally been regarded as a natural monopoly. The reasons are similar in the two sub-industries: economies of scale, capital-intensiveness and the geographic specificity of assets, to name a few. Certain particulars have led to regulations with industry-specific characteristics, however. As in the electricity industry, in some parts of the gas business, which are being liberalised or de-regulated, competition is being furthered, whilst others continue to be regarded as regulated monopolies.

13.2.1 The Traditional Model

The gas industry was traditionally structured around vertically integrated companies that produced gas in their own fields or purchased it on the wholesale market, built, operated and maintained the major infrastructure (regasification terminals, transmission pipelines, storage facilities and even distribution networks), and sold the gas either to local distributors or end consumers. Local distributors were often owned by towns or cities, regions or States.

In these systems, the regulator (usually a ministry, for independent bodies were seldom created for this purpose) was normally involved in long-term central planning, including energy balancing, choice of technologies and determination of the additional capacity needed. Since gas utility capital was often held by the State (region or city), the regulator was also involved in company management. Regulatory authorisation was required to conduct commercial or technical business. One of the regulator's most important tasks was to set the tariff to be paid by end users. Where a market of any description existed in the gas industry, it was restricted to bilateral agreements between producers and buyers. Long or very long (up to 30 years) wholesale supply contracts were the norm, with upstream gas prices being pegged to oil or by-product prices. Despite the use of the past tense here, the regulatory framework described is still in place in many systems.

Some of these features are also characteristic of traditional electricity regulation, which is ultimately the outcome of the fact that distribution grids constitute a natural monopoly. The rationale for others is specific to gas, however. Connecting a gas field to consumers is a capital-intensive endeavour. Therefore, upstream investors require assurance that they will be able to profitably sell the gas for a number of years. Similarly, downstream companies require guarantees that they will be able to sell the gas bought to final consumers. The traditional solution was

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[8] Environmental concerns (Europe) and high extraction costs and sophisticated technology (elsewhere) have up to now mostly prevented shale gas production outside the US.

to conclude long-term agreements for a fixed volume (meeting upstream party concerns) and a price pegged to oil (or oil product) prices, which removed any end consumer incentive to switch fuels[9] (meeting downstream party concerns). Such agreements are somewhat misleadingly known as "take or pay" contracts, for what they actually stipulate is a buyer commitment to pay for a given amount of gas.

Such contracts, however, neither guaranteed a profit margin for the supplier (e.g. oil prices could decline) nor protected the buyer from demand swings (power plants might demand less than expected because of unexpectedly high hydro production, for instance). Nonetheless, they normally included price revision clauses to accommodate periodic adjustments in the pricing formula, as well as an arbitration procedure to provide for a solution where no agreement could be reached. That notwithstanding, given that suppliers and buyers were often based in different countries, long and bitter disputes have been known to ensue.

Other clauses of these agreements provided that the buyer would not resell the gas outside its own franchise zone or country, although they were allowed to resell the gas under discriminatory terms, charging residential customers substantially more than fertiliser factories, for instance.

13.2.2 The Deregulated Model

Gas deregulation is a relatively recent development and only feasible where the gas system is mature (i.e., large) enough. First, given the huge volumes involved in gas supply contracts, competition can only be sustained by very large-scale systems. Network investment by comparison is typically much smaller, and much more linear (looping[10] and other incremental upgrades may be preferred to huge investments reflecting economies of scale), reducing both the need for long-term commitments[11] and the likelihood of hold-ups.[12]

As in electricity markets, liberalisation is advisable only where competitive pressure is sufficiently strong. Under such circumstances, competition should yield

[9] Gas prices have been typically always slightly lower than oil prices (taking into account switching costs, technical efficiencies, and so on).

[10] Looping consists of building a bypass along a given section of pipeline (e.g., the first 20 km of a 100 km pipe). Because the volume for gas transportation is greater in the "looped" section, a smaller pressure differential is required to move a given quantity of gas in that length of pipeline. The resulting greater pressure differential for the rest of the line raises transmission capacity.

[11] When initially developing the system, investments are made to accommodate both the existing demand and future demand growth due to the huge economies of scale involved, but this further exacerbates the problems discussed in the preceding item.

[12] These consist of the exercise of market power created when a specific facility is needed for system operation. For instance, if the gas transmission grid is not densely inter-connected, an LNG importer may be forced to use a specific regasification facility. Although third-party access (TPA) provisions are usually in place to address these concerns, facilities with reduced or no TPA obligations may also exist. Such measures at least lower the incentive to hoard capacity (see below).

more efficient prices, higher quality and innovative products. Concerns arise, however, around the possible decline in reliability and in bargaining power with supply side oligopolies in heavily import-dependent systems.

Effective competition calls for unbundling of the businesses involved. Distribution is a natural monopoly that must be conducted by regulated companies. By contrast, wholesale gas procurement and retail gas supply are potentially competitive activities. As in electricity systems, transmission, which lies in between procurement and distribution, must be regulated and is the natural platform for wholesale gas trading.

Transmission

Wholesale market agents buy gas from producers, sell it to consumers or distributors and hire the services required to ship it from the entry to the exit points. Both the access to transport facilities (mainly pipelines and regasification plants) and the tariffs to be paid must therefore be regulated.

Access rights or transmission capacity hired by agents may be defined in three ways, broadly speaking.

- In point-to-point access, both entry and exit points are specified in advance. The right consists, for instance, of transporting 10 GWh of gas from Entry harbour to Metropolis.
- In entry/exit, entry and exit rights are granted separately, i.e. neither the origin nor the destination of the gas need to be specified. A right may be acquired to inject 10 GWh at Entryharbour, for instance, regardless of whether the gas is to be shipped to Metropolis or Gotham.
- Zonal access entails purchasing the right to inject or withdraw gas at any node inside a zone.

Ratemaking or tariff setting can be similarly classified.

- Point-to-point charges are based on the established entry and exit points and typically computed with a distance-related formula (such as a distance matrix).
- In entry/exit arrangements tariffs are computed independently for each point pursuant to a pre-established methodology.
- The zonal charge is a flat rate levied on transactions anywhere in the zone.

Different methodologies may be used for defining access rights and tariffs. In electricity transmission, connection access rights are typically defined on an entry/exit basis (the generator can deliver any amount of power to the grid, up to its rated capacity). The use of system tariff for electricity transmission is typically a flat charge (postage stamp),[13] although some systems apply charges with locational components, as explained in Chap. 6 of this book.

[13] Entry/exit tariffs are therefore analogous to electricity locational pricing (a different locational component for the electricity price in each bus). However, in gas there is nothing analogous to spot pricing for electrical energy, as gas tariffs with locational components are computed from long-term transmission infrastructure costs.

Entry/exit tariffs

Entry/exit tariffs may be computed in one of two ways [2].

- Long-range marginal cost arrangements are associated primarily with network expansion. The tariff can be computed from a transmission model that computes optimal expansion during peak hours. This is a sensible approach if expansion costs are linear or quasi-linear, which is more likely to be the case in mature systems. The resulting marginal costs can be adjusted to maintain an equal split of revenue between entry and exit or to attain a revenue target. As tariffs depend on network expansion, this system is appropriate wherever significant growth is expected, i.e. in congested systems.
- In average accounting cost schemes, the goal is to allocate the fixed costs of prior investments to system users and is more appropriate if no significant further expansion is anticipated.

In both cases, the same formal methods can be used to obtain consistent entry and exit tariffs, given measures of usage (e.g., average participations) and elements (pipelines, compressors, etc.) and costs (long-range marginal or accounting ones).

A primary market for capacity arises around the access rights or contracts sold by pipeline and regasification facility owners at regulated prices. In liberalised systems these contracts can be re-sold on secondary markets.[14] The characteristics of these secondary markets depend on the nature of the capacity rights. Entry/exit capacity booking may be regarded to favour competition, since it enables new entrants to book capacity without specifying the contractual path followed by the gas. Incumbents may have an advantage in point-to-point systems because, thanks to their large capacity portfolios, they can optimise their gas flows, therefore lowering their average transport costs. Entry/exit systems may also favour market development, since financial players should prefer anonymous trading. Be it said that despite the foregoing, the most highly developed gas market (in the US) is organised around point-to-point transport contracts. The existence, on the one hand, of regulated tariffs that set price caps only and on the other of significant pipe-to-pipe competition may constitute the critical features of that market.

[14] Although the primary rights holder may still be liable for notification and other obligations vis-à-vis the System Operator.

The US transmission market[15]

Since the entry into effect of FERC Order 636, issued in 1991, the US pipeline companies are no longer allowed to deal in the gas commodity itself. Rather, they are required to offer unbundled transmission services to other gas owners. Firm transmission capacity must be offered at a price capped by a regulated formula. Interruptible services may be also offered at a capped price.

Transmission services are purchased from pipeline companies during the so-called "bid-week", usually the third week of each month. Shippers notify the gas volumes they plan to transport in the following month, specifying the injection and withdrawal points and the volume, which is limited to the amount of their firm transmission rights. Unused firm transmission capacity reverts to the pipeline, which sells it as interruptible transmission ("use it or lose it" clause).

The US market is characterised by competition among pipeline companies that offer alternative routes between two markets. At the same time, other companies offer storage services enabling actors to compete for different time slots. As a result, negotiated tariffs are often lower than the regulatory ceilings.

Hubs

Hubs are platforms for wholesale gas trading. They may be divided into physical hubs, typically placed where several pipelines meet and are directly connected to storage facilities, and notional hubs, also known as virtual trading points. Examples of the former are Henry Hub in the US and Zeebrugge in Belgium, and of the latter the National Balancing Point (NBP) in the UK and the Title Transfer Facility (TTF) in The Netherlands.

Transition to a deregulated system

Most physical assets in downstream gas systems are regulated facilities. The role played by generation plants in electricity systems is played by long-term procurement contracts in gas markets. Like the former, long-term contracts are huge long-term investments whose recovery, planned under a regulatory regime, undergoes dramatic change when markets are liberalised. Unsurprisingly, these contracts have generated a good deal of controversy.

Discriminatory clauses are much more difficult, not to say impossible, to enforce in a liberalised market: trading activities tend to equalise prices. Existing contracts therefore come under stress and may be re-negotiated. At the same time, for competition to be effective, a suitable number of agents must supply gas to the system. Since the volumes provided in long-term contracts are likely to account for

[15] See, for instance, [22].

a large share of future needs, gas release programmes may be engineered to oblige incumbent companies to sell part of their contracts to new entrants.

These developments are likely to lead to incumbent company downsizing, although other responses include expansion into foreign markets, the electricity industry or upstream activities.

Henry Hub and the National Balancing Point

US physical hubs were greatly expanded in the wake of FERC Order 636 of July 1991 and the subsequent unbundling of the gas transmission system. As pipelines no longer offered some of the services required by transmission system users, such as storage or balancing, new companies arose to meet these needs. Parallel administrative services and trading platforms became available. About 25 hubs are presently in operation in the US.

Foremost among these junctions is Henry Hub, located on the Louisiana coast that interconnects 14 pipeline systems. That, in addition to its proximity to a large salt-dome storage cavern facility means that huge volumes of gas are physically exchanged. It also owes its notoriety to being the pricing point for natural gas futures contracts on the New York Mercantile Exchange (NYMEX). These derivative contracts enable parties to hedge against price changes at Henry Hub and, given the high price correlation among all the US hubs thanks to a competitive transportation market, in the US as a whole.

The National Balancing Point was created in 1996 as a virtual hub operated by National Grid, the System Operator. Under British regulation, all gas injected into or withdrawn from the transmission system is assumed to pass through it. Trades are not required to be balanced. If a shipper is unbalanced at the end of the day; however, it is required to buy or sell the required amount to balance its position. National Grid is also responsible for keeping the system as a whole balanced by trading on the NBP. Trades are anonymously placed on an electronic platform operated by APX-ENDEX. The NBP price on the International Petroleum Exchange of London is the underlying value for futures and other derivatives.

13.2.3 Interactions with the Electricity System

In a number of systems, recent gas demand growth has been mainly due to increasing penetration of gas-fired power plants. As a consequence, gas and electricity systems have become interlocked and subject to new stresses because of the unusual requirements that each one imposes on the other one.

From the point of view of the gas-fired power plants, the constraints imposed both by gas supply contracts (e.g. "take or pay" clauses) and gas network access (e.g., nomination requirements) are unknown for more traditional thermal generators.

Efforts have been done in order to model both kinds of effects.[16] Gas network constraints can be the source of additional externalities to the operation of gas-fired power plants.[17]

From the point of view of the gas system, demand for electricity production is both volatile and difficult to forecast when compared to the more predictable traditional residential and industrial demands. Actually, special operation requirements are sometimes imposed on gas-fired power plants because of this reason.[18] In any case, electricity generation tends to require more flexibility of the gas system than average. However, flexibility is costly, because it requires additional transportation capacity to provide the needed operational margin. On the other hand, gas system design regulations are traditionally focused in a situation in which the infrastructure is used almost ever close to its maximum capacity.[19] The appearance of new large shale gas fields in locations with low gas demand—presently in the US and perhaps in other parts of the world—will require a tight coordination of electricity and gas transmission network planning.

13.3 Security of Supply

13.3.1 Natural Gas Security of Supply

While gas security has been the object of growing concern, often associated with geopolitical issues, an analysis of actual supply disruptions leads to a rather less troubling view. Further to Stern [16] and [17] incidents can be classified into source, transit and facility events, depending on where the cause lies. Source and transit incidents tend to draw more public attention. Examples are the cut-off of Algerian gas to Italy after the explosion of a device on the Trans-Mediterranean

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[16] Example [3], where an electric utility company that owns some gas-fired power plants decides its optimal supply portfolio of different natural gas products considering its risk preferences; or the extension of the previous work to the decisions related with the gas nomination made in [23]. The drawback of "take or pay" clauses that may origin an excess of natural gas in a centralised hydrothermal dispatch has been discussed in [18], in which natural gas flexible contracts for industrial natural gas consumers are introduced. In the short term, [7] propose an optimisation model in order to solve jointly the unit commitment of thermal power plants and the flows in the gas network.

[17] Example if the output of a gas-fired power plant is limited, because the gas network has no capacity to deliver all the required gas due to functioning of other gas-fired power plant feeding from the same gas system.

[18] Example in several national regulations gas-fired power plants are required to submit nominations for each hour instead of for each day as customary for other consumptions.

[19] An in-depth analysis of this question is made in [6]. An open question is how to provide to the different agents with the incentives that lead to a socially optimal gas and electricity expansion. In particular, gas agents should provide the optimal flexibility and electricity generation agents should pay for the full cost that impose on the gas system.

Pipeline (a "terrorist" incident) and the recurring crises in connection with the transport of Russian gas across Ukraine and Belarus.

Facility incidents have also been known to occur, however. The liquid contamination at the UK Interconnector pipeline in 2002, the fire at the Algerian Skidka liquefaction plant in 2004 and the fire at the Rough storage facility in the UK in 2006 are a few examples.[20] "Engineering" risks may be contended to be especially high in stressed and ageing gas systems.

Reliability analysis is more developed in electricity than gas systems, from both the academic and the regulatory standpoints. Nonetheless, similar simulation techniques can be applied to both, see e.g., [14]. In addition to the specific technical characteristics of the models used, the assumptions made and results required must be carefully defined. The specific questions that should be addressed are listed below.

- How is reliability to be valued? Do indexes such as the loss of load probability or energy not supplied suffice, should priority be given to economic indicators such as the expected loss of social welfare, or should both be taken into consideration? Where a highly developed market is in place, the loss of welfare attached to gas supply interruptions might be estimated from market data,[21] although this is not usually the case and specific methodologies must be deployed.
- What events should be considered? No model can possibly cover all the scenarios leading to security of supply incidents. Rather, a list of incidents must be drawn up a priori. Not only engineering-related events (such as pipeline failure), but also geopolitical incidents (such as disruption of supply due to transit disputes) can be modelled, often in a similar fashion. The difficulty lies in determining the respective probabilities, although the existing operation research techniques can be used for the systematic analysis of subjective probabilities.
- What measures can be implemented? Models are generally used to compare the merits of different strategies, making this a critical issue, as discussed below.

Improving security of supply

Security of supply can be improved in a number of ways, including the non-exhaustive list of measures given below by way of illustration.

- Construction of additional infrastructure is one such measure. Redundancy in gas systems is typically lower than in electricity systems, particularly as regards transmission. Certain types of infrastructure, such as storage and regasification facilities, may impact reliability heavily, however. The availability of sufficient storage capacity is critical to deal with disruptions in gas supply. Concerns about

[20] The incident would have had more dire consequences than the price spikes observed if it had occurred earlier in the winter.

[21] From the prices and volumes specified in supply contracts with interruptible clauses or the risk premiums attached to forward contracts, for instance.

over-dependence on a single source of supply can be eased considerably by the installation of regasification facilities.

- Another measure is enhancement of demand-side response. Even moderate response can lead to significant decreases in energy not supplied. This objective may be attained by requiring or incentivising dual-fuel capabilities in gas-fired electricity plants and other large industrial facilities, instituting especially tailored tariff systems, or applying real pricing and other "smart gas" applications.
- In security-driven system operation, storage facilities can be operated very conservatively, keeping as much gas as possible available for possible contingencies. As in water management in electricity systems, however, a trade-off exists between security and economic efficiency.
- Capacity mechanisms consist of imposing or incentivising contracts for greater amounts of deliverable gas than is expected to be needed. As when building additional generation capacity in electricity systems, this approach raises a "missing money" issue that must be dealt with. Capacity mechanisms may be implemented in several ways, through shippers or the System Operator, for instance, for domestic only or total demand.
- Balancing requirements may need to be fine-tuned if shippers contract less gas than required to optimally meet demand, because they perceive that the cost of not being balanced is less than the marginal outage cost. This may occur if the cost of imbalance is inappropriately set by the authorities or if shippers perceive that in the event of a contingency they will not bear the full cost because of politically motivated action taken by the authorities.
- Lastly, inter-system connection may be enhanced. Unlike electricity system interconnectivity, interconnection between gas systems is seldom if ever based on reliability considerations. A larger interconnected system is intrinsically safer than its separate parts, however. Measures such as providing for bidirectional gas flow in pipelines or un-impeded access to storage capacity in neighbouring systems can improve security.

Market regulation and security of supply

A number of legal and regulatory considerations must be addressed to attain an adequate level of security of supply. One possibility is to allow markets to decide on the appropriate level with minimum regulatory intervention. This is the system in place in the US.

The US market is characterised by intense spot trading at many hubs, a robust forward market that has dispensed with most traditional long-term contracts and a competitive gas transport market. In that country, most gas is pipeline (as opposed to LNG) gas, see [9]. Pipeline construction has grown to meet needs since the advent of deregulation in 1985.

Adequate pricing facilitates security of supply. The graph below shows gas prices at Henry Hub since 2004. Note the peaks in the second half of 2005, associated with the disruptions caused by hurricanes Katrina and Rita. Parallel movements can also be observed in the forward price curves and in the

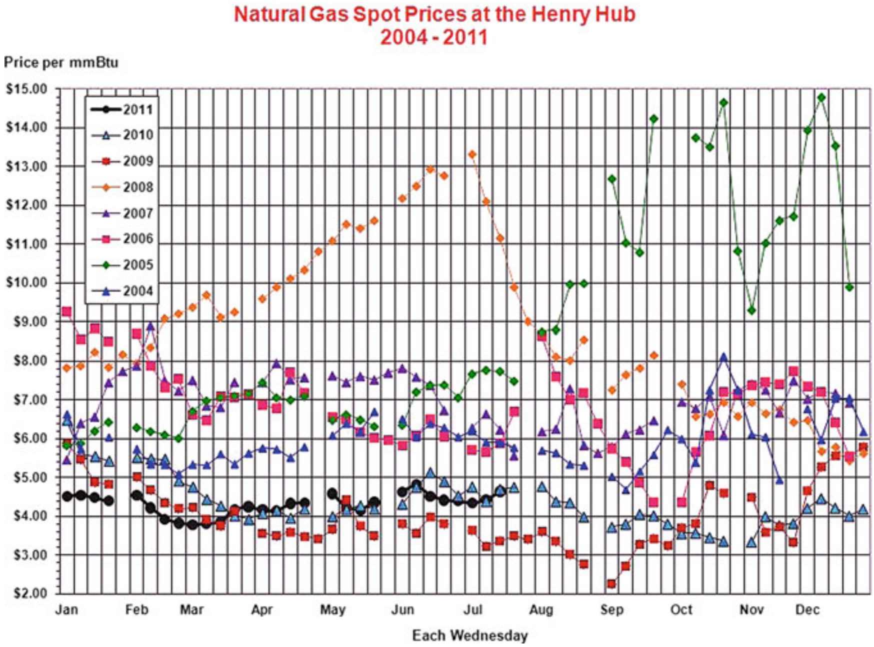

Fig. 13.1 Natural gas spot prices at Henry Hub (www.neo.ne.gov)

differentials between hubs. These price signals incentivise changes in consumption patterns, e.g. gas use by gas-fired electricity plants (Fig. 13.1).

The first factor to be borne in mind with regard to the construction of new transmission capacity is that pipeline companies must be fully unbundled from the shipping and distribution businesses.[22] Long-distance (inter-state) transmission is regulated by a single authority (the FERC). Primary capacity is remunerated under cost-of-service arrangements, while secondary capacity trades are liberalised. New capacity projects must show that they are able to support their own regulated costs (by submitting a portfolio of letters of intent from committed shippers, for instance, that therefore acquire long-term capacity rights).

The reliance in the US on light-handed regulated markets is unique. Physically, Europe's gas system is almost as large and complex as the US's. European gas networks are mainly regulated by each National Regulatory Agency (NRA); however, unbundling is much less thorough than in the US[23] and spot and forward trading is considerably less intense.

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[22] This makes it difficult for any one shipper to monopolise a given transmission route because a well informed market unveils such attempts and the pipeline company is both entitled and has an incentive to sell unused capacity in secondary markets.

[23] Even if the Third Energy Package provisions are fully enforced.

Decision making on transmission facility construction is incumbent upon national or even sub-national Transmission System Operators (TSOs) and approved by the NRAs. The resulting cost is added to the regulated assets base and passed on to users as an access charge. European regulations require TPA provisions. One concern expressed around this sort of regulation is that it may potentially result in certain users subsidising network expansion needs created by others (e.g. a new regasification facility), particularly in the absence of an effective zonal price system.[24]

Facilities straddling several jurisdictions require an agreement among the TSOs and NRAs involved, a development that has been historically slow in materialising. Most of the pipelines used for third country (mainly Russia and Algeria) provision of gas in Europe were built by vertically integrated utilities and are subject to long-term contracts. The European Commission and many NRAs have consistently called for revision of these contracts ("gas release programmes") on the grounds of concerns about market foreclosure. The Commission has also encouraged more comprehensive unbundling of pipeline networks. Incumbent companies have systematically contended that such a measure would weaken their bargaining power *vis à vis* large foreign producers and ultimately compromise security of supply [19].

LNG facilities, whether built by TSOs or commercial companies, are initially subject to TPA provisions. The frequent exemption from TPA obligations granted by the commission, however, narrows the difference in status between these facilities and their US counterparts. The commission has considered the impact on market competitiveness and security of supply when granting such authorisation. Large numbers of LNG facilities have been built in Southern Europe (Spain in particular), often driven by electricity companies.

Japan depends wholly on regasification facilities for its supply. The Japanese Government (through its MITI and Japan's Export–Import Bank) has orchestrated the financing of gas trains see [1, 21]. The infrastructure consists of a cluster of LNG terminals that supply a number of relatively isolated markets. Therefore, each local monopolist is protected from competition and can invest under cost-of-service arrangements. The unavailability of nuclear electricity is seen as a relevant concern and national gas infrastructure expansion including storage and pipeline capacity as possible countermeasures [12].

Government involvement is even greater in the rest of the world,[25] as most gas systems outside the US and the EU are heavily regulated.

Import security

Traditional wisdom regards domestic supply as "secure" and imports as "unsecure". Nonetheless, international gas trade has been growing continuously despite certain incidents. In Europe, gas trade has survived both the collapse of the Soviet

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[24] Such a system should, moreover, be compatible with the electricity pricing scheme to prevent investment decisions from being distorted.

[25] For a review, see [21].

Union and Islamic unrest in Algeria unscathed. More dramatic political upheavals in the near future cannot be readily envisaged.

Governments should nonetheless pursue a policy of import diversification. Discussion has been particularly intense in the European context that is described in the following.[26]

In the EU, the overall import mix for gas and oil differ very little, although the former is somewhat less diversified.[27] Unlike the global oil market, however, gas markets are still highly segmented along national borders. Eastern European Members States, for instance, are almost wholly dependent on Russian gas, while the Iberian countries depend heavily on Algeria for their supply. Gas from Russia has become a very divisive issue in the EU, particularly because the largest consumers are Germany and Italy, countries with a much wider diversity of supply than the smaller but highly dependent economies in Eastern Europe [13].

Diversifying the source of gas, whether by building new pipelines to tap resources in the Near East (the Nabucco project) or new LNG facilities, will increase security of supply in Europe.[28] But internal action, which may be more cost-effective, should not be overlooked. New intra-European transmission capacity (via the intensification of bidirectional gas flows such as in the Eastern EU or allowing gas transit from Iberian LNG terminals to Central Europe) should ease security concerns.[29] Strategic gas storage guarantees between neighbouring Member States might be another effective measure in this regard,[30] along with fairly simple action, such as coordinating EU government and regulator emergency plans.

To the extent that the costs of these and other measures are to be shared by the parties concerned in inconspicuous ways,[31] implementation is very challenging and arguably requires the supervision of a pan-European agency.

[26] Although diversification is sought by most governments in import dependent countries. For the Japanese case, see [10].

[27] Eurostat, *Panorama of Energy,* 2009.

[28] The ability to change supplier is an additional advantage in LNG facilities. LNG shipping is not nearly as flexible as oil shipping, however. Harmonisation of technical standards among European regasification facilities might be an effective strategy for building the EU's internal energy market and enhancing security of supply (by enabling tankers to berth in as many terminals as possible).

[29] It might also contribute to greater gas market competition, for European consumers would have access to a larger number of shippers and importers.

[30] In other words, the host Member State should allow this gas to be shipped to the State storing it, irrespective of any security concern on the part of the host Government.

[31] Pipeline cost allocation proportional to the length of the pipeline in each Member State is unlikely to reflect the benefits and incentives deriving from such a facility for the users in each State.

13.3.2 Gas and Electricity Security of Supply

Gas now constitutes a significant and even a predominant part of the generation mix in a number of electricity systems. The need for reliable gas plants may be reinforced in systems where intermittent energy penetration is high, for in such systems gas-fired steam plants, which constitute a more reliable technology, can stabilise most of the fluctuation. In light of this, electric system reliability depends not only on electric system components, but also on the reliability of the gas system.

Natural gas plants do not store large amounts of fuel, but are fed by high pressure gas pipelines. Consequently, incidents in these gas pipelines or in general in the gas grid or system severe enough to obstruct the supply determine unit shut-down. Such incidents may affect more than one generating set or unit. Unavailability in a regasification plant, for instance, affects all the gas plants fed by it. Such failures may naturally impact the system very significantly.

Where the unavailability is purely technical, its duration depends on the respective repair time. In some cases, the situation may last for several weeks. Interruptions in supply may be the outcome of other issues, however, such as problems in transit countries or simply a colder than normal winter, leading to higher than expected residential consumption and consequently less gas available for generating electricity.

From the regulatory standpoint, these should be among the issues dealt with in the mechanism in force to guarantee security of supply in both the electricity system (to correctly assess the contribution made by gas and other technologies) and the gas system (to correctly assess gas plant security of supply). No procedures to confront this problem are presently in place. Nonetheless, electricity system operators in various areas of the world are beginning to factor gas system reliability into their analyses [5]. The mechanism to handle system-wide incidents may be particularly difficult to design, however, for while the event is even less likely than individual plant failure, its impact is much greater.

In the long term, electricity and gas grid design should be coordinated, in part for purely economic reasons. Determining whether gas or electricity transmission is more suitable is seldom a clear-cut issue. This, incidentally, means that the respective transmission tariffs should be developed in a coordinated manner to provide consistent incentives to generation investors. The other reasons for coordinating electricity and gas networks are more closely associated with security of supply, which is normally one of the main reasons for expanding the system. Computer models have been developed to plan such joint expansion [20], although they are not yet being routinely used by regulators, operators or transporters.

13.4 Multi-Commodities Utilities and Market Power

In the wake of liberalisation, a sizeable number of energy companies decided to expand into industries traditionally unrelated to their line of business. The strategy consisted of using their privileged relationship with their electricity or gas customers to offer them gas, electricity, water, or telecommunications, television and internet services. The contention was that the economies of scale in customer management that these multi-utility companies could reach would afford a significant competitive advantage [4].

Such predictions have not always held, however.[32] Part of the reason may lie in the need to master highly specialised technical businesses. One significant exception has been observed, however: so-called gas-electricity convergence. No small number of former electricity companies have successfully entered the gas market, and vice versa. The explanation may lie in a number of circumstances.

- The type of electricity generation plant favoured most by investors in recent years is based on natural gas combustion. Natural gas combined cycle plants have been particularly popular, along with open cycle and co-generation or CHP facilities. Their profitability depends on the conditions of gas supply.
- Insofar as a substantial part of electricity generation is powered by natural gas, opportunities for arbitration between the two markets may arise, although they call for an in-depth knowledge of both.
- Industrial consumers may be offered more comprehensive service, particularly for flexible heat units or co-generation units.
- The same authority generally regulates the two markets and usually broaches issues in comparable ways. Moreover, the regulation of gas and electricity grid expansion should be coordinated. All these factors imply regulatory synergies for companies engaging in both businesses.

With the inter-relations resulting from the convergence between the electricity and gas industries, market power problems in one may spill over into the other. Consequently, market power analyses must address not only horizontal concentration in each or vertical concentration between wholesale and retail markets, but also the "diagonal" relationships between gas and electricity. Problems only appear, however, if the dual company holds a predominant position in one of the two industries. Some of the situations that may arise are listed below (see [15]).

- Input foreclosure arises when the dual company uses its predominant position in the gas market to hamper its electricity industry competitors' access to gas. The basic idea is that by raising the gas price it might induce an electricity price

[32] Significantly, a considerable number of European electricity companies (VIAG, VEBA, RWE, Scottish Electricity, United Electricity, Endesa, ENEL) entered the telecommunications market, while disappointing results have since determined their exit in most cases.

increase and possibly a deterioration of the competitive position of its electricity competitors from which it profits as an electricity company.

- Customer foreclosure is the use by the dual company of its predominant position on the electric power market to buy gas only from its gas division, limiting competition on that market.
- Conglomerate effects on the retail market are the result of electricity or gas distribution companies' position of privilege with respect to their customers, which may often exclude other retailers. Their most powerful competitor, and consequently their greatest incentive to keep prices competitive, is the rival gas or electricity distributor. Therefore, it is arguable that companies should be prevented from simultaneously being gas and electricity distributors in any given franchise.

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