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**Document title**
ENERGY (ELECTRICITY & GAS) SECTOR PERFORMANCE ASSESSMENT AND IMPROVEMENT UNDER THE REGULATORY PERSPECTIVE

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Acronyms

ACER  Agency for the cooperation of Energy Regulators
AGI   Above Ground Installation
AHEF  Ad-Hoc Expert Facility
BETTA British Electricity Trading and Transmission Arrangements
BM    Balancing Mechanism
BoP   Balance of Plant
BSIS  Balancing Services Incentive Scheme
BSUoS Balancing Services Use of System
CAPEX Capital Expenses
CCGT  Combined-cycle gas turbine
CDM   Clean Development Mechanism
CEER  Council of European Energy Regulators
CFU   Compressor Fuel Use
CGWC  Capacity goes with the customer principle
CHP   Combined Heat and Power
CVS   Calorific Value Shrinkage
CWV   Composite Weather Variable
DA    Day Ahead
DLN   Dry Low NOx
DSO   Distribution System Operator
EEA   European Environmental Agency
EGIG  European Gas pipeline Incident data Group
ENTSO-E European Transmission System Operators for Electricity
ENTSO-G European Transmission System Operators for Gas
ERDF  Electricite Reseau Distribution France (DSO in France)
ERGEG European Regulators’ Group for Electricity and Gas
ETS   EU Emissions Trading Scheme
GC    Gas chromatographers
GCV   Gross Calorific value
GDP   Gross Domestic Product
GGPSSO Guidelines for Good TPA Practice for Storage System Operators
GHG   Green House Gas
GIS   Geographic Information Systems
GSP   Grid Supply Point
GT    Gas Turbine
GWP   Global warming potential
HHV   Higher heating value
HRSG  Heat recovery steam generator
ICF   Incomplete Combustion Factor
IEA   International Energy Agency
IGCC  Integrated Gasification Combined Cycle
IPCC  Intergovernmental Panel on Climate Change
LCC   Lifecycle costs
LDAR  Leak Detection and Repair
LHV   Lower heating value
LI    Lift index
LNG   Liquefied Natural Gas
MN    Methane Number
MOV   Motor operated valves
MRP   Mains Replacement Planning
MS  Member State
NRA  National Regulatory Authority
nTPA  negotiated Third Party Access
OCGT  Open-cycle gas turbine
OECD  Organisation for Economic Co-operation and Development
OPEX  Operational Expenses
OTC  Over-the-Counter (trading)
OUG  Own use Gas
OVA  Organic vapour analyser
PEX  Power exchange
PSO  Public Service Obligation
RAB  Regulated asset base
RPI  Retail Price Index
rTPA  regulated Third Party Access
SCADA  Supervisory control and data acquisition
SI  Soot index
SMB  Social benefit
SMC  Social cost of production
SSO  Storage System Operator
T&D  Transmission & Distribution
TANAP  Trans Anatolian Natural Gas Pipeline
TAP  Trans Adriatic Pipeline
TGSC  Total gas storage capacity
TLF  Transmission Load Factor
TNUoS  Transmission Network Use of System
TOC  Total Organic Compound
ToR  Terms of Reference
TSO  Transmission System Operator
UfG/ LAUF  Unaccounted for Gas / Loss and Unaccounted gas
UGS  Underground Storage
UNECE  United Nations Economic Commission for Europe
UNFCCC  United Nations Framework Convention on Climate Change
VOC  Volatile organic compound
WGC  Working gas capacity
WI  Wobbe index
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1 Executive Summary
The Tariff (Price) Council of the Republic of Azerbaijan has worked during the period February–October 2014 on a study in respect to regulatory treatment of losses for the “Electricity and Gas networks”. The study was implemented under the Ad-Hoc Expert Facility (AHEF) of “INOGATE Technical Secretariat & Integrated Programme in support of the Baku Initiative and the Eastern Partnership energy objectives” project, funded by EC/Europeaid.

The fundamental recommendations of this study stem from the diagnosis of fundamental differences that exist between the EU (and other OECD countries) and the regulatory practices exercised in Azerbaijan. More specifically, regulating the energy sector in Azerbaijan presents fragmented authority, responsibilities and powers, information asymmetry and a monopolistic structure.

In general efficiency and losses are terms that may denote different notions depending on the context. This study briefly discusses some background knowledge on these terms in the context of engineering and economics which are considered relevant to the role and responsibilities of a Regulatory Authority. More specifically, a general distinction is made to what gains economic
efficiency may be able to bring to the energy system and what part of it depends on efficiency as it is understood in engineering terms. Both of them are interrelated and deserve equal attention.

Electricity generation efficiency is discussed in this study with emphasis on natural gas-fired CCGT generation which appears to be a promising option for the future of the electricity generation system of Azerbaijan.

![Gas-fired electricity generation by region](image_url)


The Tariff Council exercises price control in the electricity sector by means of setting the generation and end-user prices and can affect losses only through the prices / tariffs mechanism. But there is certainly an information asymmetry on the end of the regulatory body as the information on fuel energy content and efficiency of the generation plants are not reported to the Tariff Council but to the Ministry of Energy. On the other hand the absence of competition in the generation sector provides no incentives for increasing their efficiency and thereby reducing their costs to the lowest possible level.
Evolution of T&D losses in several INOGATE PCs and the EU (average)

Source: IEA Statistics – Electricity Information (transmission and distribution losses, includes pilferage)

Regulation in the EU role with regards to transmission and distribution network efficiency focuses on the setting the framework for the definition of network losses as well as their valuation and procurement. Given the fragmentation of powers, information asymmetry and generally little transparency of the existing regulations in the price setting mechanisms there is one key recommendation that can be made at this point and that is related to the future possible revision of the electricity tariff structure with a concurrent implementation of an accounting unbundling.

In the gas sector the first area in which this regulatory review concentrates has to do with storage. Storages are clearly to play an even more important role for Europe in the future and in terms of regulation they are not by default considered “unique infrastructures”. This simply means that they are not natural monopolies as is the case of transmission and, many EU, distribution networks. The EU legislation includes provisions for the divergence from strict third party access rules for storage facilities and regulatory intervention is often only ex-post, limited to cases of disputes.

Regardless of the access regime, transparency is key to ensure (a) the most efficient operation of storages, (b) access of all interested parties under non-discriminatory conditions and (c) that security of supply obligations are respected. Transparency is inherently linked to regulatory monitoring which in turn safeguards both competition and consumer interests.
Regardless of the access regime, transparency is key to ensure (a) the most efficient operation of storages, (b) access of all interested parties under non-discriminatory conditions and (c) that security of supply obligations are respected. Transparency is inherently linked to regulatory monitoring which in turn safeguards both competition and consumer interests.

The Republic of Azerbaijan is amongst the ten countries in the world with the largest underground storage facilities, in terms of volume of working gas\(^1\). It is also known that the role of Azerbaijan as an exporter of natural gas to Europe is bound to increase in less than a decade. It is valid to assume that Azeri UGS facilities will be receiving increasing attention in the years to come for their potential role to meet swings in the production of both oil and gas as well as to serve national demand.

Gas distribution losses in the European Union in the period 1990-2012 (Data from Eurostat)

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Transmission and distribution losses are herewith discussed with emphasis on European Networks. The sources of losses were discussed and methods to identify, quantify and reduce natural gas losses in transmission networks, together with associated costs were presented.

EU Member States report extremely low values of losses that do not exceed in their majority an upper level of 1%, if only fugitive emissions are considered. Considering own use of gas (e.g. for powering compressors), gas losses in Europe could at most reach 2% of total gas demand although in many Member States the values are considerably lower. These values have been achieved through continuous improvements in networks over the last fifteen-twenty years.

As far as the energy regulator’s involvement in the treatment of losses is concerned, there is no harmonized approach in the European Union and there is no specific obligation for transmission system operators to procure the energy required for losses as is the case in electricity. Conversely, transparency requirements for the whole process are imposed by the regulators as it happens for the electricity sector.

Last but not least this study includes an additional short note on the effect of natural gas quality in general, and of the natural gas calorific value in particular, to the overall performance of electricity and gas systems. Natural gas is a generic term to define a mixture which varies in composition or quality as a result of different sources, extraction and processing. Even gas from the same region or even from the same production site can exhibit some variations in composition.

Source: Brooks, F.J. GE Gas Turbine Performance Characteristics, GE Power Systems

The regulatory requirements for low emissions from gas turbine power plants have increased during the past 20 years. Environmental agencies throughout the world are now requiring even lower rates of emissions of nitrogen oxides (NOx) and other pollutants from both new and existing gas turbines. Nitrogen oxides are a by-product of all combustion processes with quantities increasing dramatically as a function of combustion temperature, the latter strongly linked to the fuel-to-air ratio in the combustor. Operation of the turbine at the so called “lean premixed regime” where the air and fuel

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2 The term nitrogen oxide is used to refer to the sum of NO and NO₂, with the former predominantly generated during the combustion process (referred to as thermal NO) and the latter formed further downstream.
have already been mixed in a uniform fuel poor mixture can achieve very low levels of NOx. This operation mode however is at the expense of flame stability and requires consistency in the variables that affect combustor operation, including fuel properties. Small variations in the fuel concentration (i.e. in the natural gas composition) can lead to autoignition, flame flashback or self-induced combustion oscillations. To avoid such phenomena gas turbines are designed to operate within a narrow range of the Wobbe Index.

Gathering enough information in order be able to assess the potential variations in gas quality in Azerbaijan was beyond the scope of work of this AHEF assignment. Such an analysis would at least require time series of the composition and calorific value of gas injected in the Azeri network on a daily basis. However, as Azerbaijan is relying on indigenous sources -with only a small part of gas sourced from Iran and injected to a comparably isolated network- it may be postulated that variations in gas composition will be minor, larger ones, if any, occurring on the case of faults in the gas processing equipment.
2 INTRODUCTION

The present report comprises the final deliverable of an assignment carried out under the Ad-Hoc Expert Facility (AHEF) of “INOGATE Technical Secretariat & Integrated Programme in support of the Baku Initiative and the Eastern Partnership energy objectives” project, funded by EC/Europeaid. An application for provision of Technical Assistance with respect to regulatory treatment of losses for the “Electricity and Gas networks” has been submitted by the Tariff (Price) Council of the Republic of Azerbaijan and filled under Component B: Electricity & Gas in the AHEF Registry under the code “14. AZ: Energy (Electricity & Gas) Sector Performance Assessment and Improvement under the Regulatory Perspective”. The assignment has been implemented over the period of February–October 2014.

2.1 Objectives of the study, key findings and recommendations

According to the ToR the specific objectives of this project were:

- To review relevant EU practices with respect to the definition of losses, their valuation, procurement and eventually recovery through the energy tariffs;
- To analyse and compare the relevant legislation, regulations and rules in the country;
- To prepare recommendations regarding the regulatory treatment and tariffs formulation based on the EU experience.

With regards to the first specific objective, the report provides a summary and overview of the EU practices in electricity and gas expanding also in the area of gas quality and the relevant impact to end users. In the area of relevant legislation our findings reveal that in terms of regulatory treatment of losses there is still work to be done in the field of definition and valuation, whereas, the areas of procurement and incentive regulations will follow in the future (as part of a potential decision of a sector reform). For the moment the technical aspects of energy systems performance remain with the Ministry of Energy. The fundamental recommendations of this study stem from the diagnosis of fundamental differences that exist between the EU (and other OECD countries) and the regulatory practices exercised in Azerbaijan. More specifically:

- **Fragmented authority, responsibilities and powers**, currently prevents the development of a centralised decision making mechanism. Knowledge on technical aspects and reporting mechanisms that support at the moment the regulatory functions exercised by the Ministry of Energy should be combined with the knowledge of economic issues that exists within the Tariff Council. In this respect INOGATE fully supports the establishment of an independent Regulatory Authority in the context of its role and responsibilities as described in the 3rd EU Energy Package.

- **Information asymmetry** is likely to exist even in the case where a fully competent and prudent independent Regulatory Authority exists in Azerbaijan. We stress however that the current disclosure of information between the regulatory bodies and the regulated companies is inadequate. We furthermore believe that increasing transparency in certain operational areas of the regulated companies (with due regard to price and tariff setting) increases both the customers and the potential investors confidence.

- **Monopolistic structure** of the industry imposes inherent efficiency limitations as per the economic theory. International experience shows that where competition and markets can work without design deficiencies, biases and imperfection, the efficiency gains surpass by far
those benefits that may result through hard regulation. This implies that incentives and completion should somehow be understood as an opportunity rather than a threat if the maximisation of consumer welfare is in stake. It is also true however that any such decision has to be made through a process of broad consultation at a national level minded the individualities and the social and economic context of the country.

2.2 Methodology and outputs
The approach involved a mixed field work and homework effort that involved to missions to Baku. The first mission was held in February 2014 and involved a series of meetings with the regulated companies in addition to a refinement and debriefing meeting with the beneficiary. The second mission of July 2014 was solely devoted to explaining to the beneficiary our preliminary findings and fine-tuning our analysis. In the period between the two missions the team has been working on collecting and analysing information and developing a study i.e. report which is envisaged to provide all the necessary background for the Tariff Council to reconsider their practices with regards to monitoring the regulated companies in the energy sector. The study is also considered useful for decision makers responsible for energy policy development within the Government of Azerbaijan and will be at the disposal of the INOGATE Country Coordinator for the purposes of consultation.

The deliverable of the assignment comprises a report presenting the EU experience in respect of losses and energy system performance for electricity and gas whereas it further elaborates on practical and theoretical aspects that the project team considered as indispensable knowledge for an energy regulatory authority. The report also involves conclusions and recommendations for the Tariff Council of the Republic of Azerbaijan in respect of the definition, valuation and procurement of losses. It also expands to areas such as incentive regulation or access to storage facilities and gas quality/combustion efficiency subjects that clearly came out from the interaction with the beneficiary and are additional to the requirements of the assignment’s ToR.

2.3 Limitations and further work
The aim of the study was to develop the necessary background for the Tariff Council to consider a revised strategy for regulating the performance of the electricity and gas sectors. The limitations in this study comprise data collection issues and content management.

On one hand the work did not involve a review on a specific methodology and a data series of recorded losses against declared electricity and/or gas systems and networks performance characteristics. It became apparent during the first mission due to the lack of detailed and reliable data it is impossible to verify declared losses as per their validity and chronological coherence.

On the other hand, this study expanded to issues that clearly surpass the requirements of the ToR. It is however not practical for the beneficiary and the relevant stakeholders to deal with several aspects of the efficiency of the electricity sector in a once-off basis. In the light of the aforementioned limitations we believe that there are simple further steps that the Tariff Council in collaboration with the Ministry of Energy and the regulated companies should proceed with:

- Establishing of a commonly agreed monitoring and reporting framework which will involve performance indicators for each important segment of the electricity/gas sector in concern i.e. upstream/generation/storage, transmission/distribution supply;
• Developing a baseline on the basis of diagnostic studies that would address the important segments as per the previous proposal. This may include for instance an efficiency study for the generation sector;
• Asking the regulated companies to distinguish and report in their regulatory accounts those investments that were implemented with a view to improve the system efficiency. Once there are enough data establish an incentive mechanism for the investments of this kind (i.e. accelerated depreciation?).

2.4 Structure of the report
The report comprises three major parts each one comprising a distinct subject namely; fundamentals of efficiency and performance, electricity, and gas sectors. Particularly, the electricity and gas sections respectively provide the EU overview of practices as an integral part which in turn is presented along with specific cases where appropriate. More specifically:
Chapter 3 is envisaged to serve as a background and presents a brief overview of theoretical concepts directly related to the economic and technical efficiency of energy systems.
Chapter 4 attempts an international overview of in the key areas related to generation performance focusing on gas-fired Combined Cycle Gas Turbine plants.
Chapter 5 provides an overview of EU Member State Countries in relation to network losses their definition, valuation and procurement. In addition it expands to efficiency gains through incentive-based regulation and provides specific case studies on the regulatory treatment of losses.
Chapter 6 discusses upstream gas sector with a focus on gas storage. The technical characteristics, access rules and eventually storage tariffs are presented for various EU counties with a view to analyse the overall performance of storages in the gas system.
Chapter 7 is devoted to gas transmission system and distribution. A summary of important information from the INOGATE’s report titled “EU Best Practices in Technologies and Methodologies for the Reduction of Losses in Gas Transmission Infrastructure” is included and enriched with a thorough EU practices review.
Finally, Chapter 8 elaborates on gas quality specifications and the impact of gas quality on end users. The focus of this additional chapter is on highlighting the dependency of combustion efficiency on a set of conditions which in turn determine gas quality.

Two appendices comprise an integral part of this report with each of them corresponding to:
3 FUNDAMENTALS

Understanding fundamental concepts and definitions is important in view of the facts and figures related to energy losses and are discussed herewith in this report. This section has deliberately included in order for the major electricity and gas sections to be able to elaborate directly on the level of knowledge on sector performance and losses that is believed to be useful for a Regulatory Authority.

3.1 The various types of efficiency

The terms efficiency and losses may denote different notions depending on the context. We consider important to briefly present some background knowledge on these terms in the context of engineering and economics which are considered relevant to the role and responsibilities of a Regulatory Authority.

3.1.1 Efficiency in the economics’ context

Economic efficiency has to do with the fundamental problem the economics have to solve; that is to allocate scarce resources. Furthermore, economic efficiency is related to the value (rather than the physical amounts) of all inputs used in producing a given output. The production of a given output is economically efficient if there are no other ways of producing the output that use a smaller total value of inputs. For example, a firm may have several alternative production methods that it could use. One may require a lot of labour but only a little capital whereas another requires a lot of capital and only a little labour. A third production method may require a lot of land but relatively little of both labour and capital. In order to maximize its profits, the firm should choose the production method that costs the least.

Beyond the broad definition of economic efficiency there are several other types of efficiencies in economics. A comprehensive and non-exhaustive list can be found in the box below:

1. **Productive efficiency**

This occurs when the maximum number of goods and services are produced with a given amount of inputs. This will occur on the production possibility frontier. On the curve it is impossible to produce more goods without producing fewer services. Productive efficiency will also occur at the lowest point on the firms average costs curve

See: [Productive Efficiency](#)

2. **Allocative efficiency**

This occurs when goods and services are distributed according to consumer preferences. An economy could be productively efficient but produce goods people don’t need this would be allocative inefficient.

A2: Allocative efficiency occurs when the price of the good = the Marginal Cost of production

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3. X inefficiency

This occurs when firms do not have incentives to cut costs, for example a monopoly which makes supernormal profits may have little incentive to get rid of surplus labour. Therefore a firm’s average cost may be higher than necessary.

See: X Inefficiency

4. Efficiency of scale

This occurs when the firm produces on the lowest point of its long run average cost and therefore benefits fully from economies of scale.

5. Dynamic efficiency

This refers to efficiency over time for example a Ford factory in 1920 would be very efficient for the time period, but by comparison would now be inefficient. Dynamic efficiency involves the introduction of new technology and working practises to reduce costs over time.

See also:

Dynamic Efficiency

Static Efficiency – efficiency at a particular point in time.

6. Social efficiency

This occurs when externalities are taken into consideration and occurs at an output where the social cost of production (SMC) equals to the social benefit (SMB).

See: Social Efficiency

7. Technical Efficiency

Optimum combination of factor inputs to produce a good: related to productive efficiency.

See: Technical Efficiency

8. Pareto Efficiency

A situation where resources are distributed in the most efficient way. It is defined as a situation where it is not possible to make one party better off without making another party worse off.

See: Pareto Efficiency

9. Distributive Efficiency

Concerned with allocating goods and services according to who needs them most. Therefore, requires an equitable distribution.
Looking into the technical efficiency as it is usually described in economics, is related to the physical amount of all factors used in the process of producing some product. A particular method of producing a given level of output is technically efficient if there are no other ways of producing the output that use less of at least one input while not using more of any others. Therefore, technical efficiency is about getting the most output from any given set of inputs, or, equivalently, about producing a given level of output using the least amount of physical inputs.

On the contrary engineering efficiency refers to the physical amount of some single key input that is used in production. It is measured by the ratio of that input to output. For example, the engineering efficiency of an engine refers to the ratio of the amount of energy in the fuel burned by the engine to the amount of usable energy produced by the engine. The difference is in friction, heat loss, and other unavoidable sources of waste. Saying that a steam engine is 40 percent efficient means that 40 percent of the energy in the fuel that is burned in the boiler is converted into work that is done by the engine, while the other 60 percent is lost. Note that engineering efficiency is expressed in terms of the use of a single input and does not involve financial considerations—it is purely about physical relationships.

Furthermore, the economists discuss the relationship between economic efficiency and the concepts of technical and engineering efficiency in order to provide a perspective on the interrelations (and differences) among the three of them.

Relationships among the concepts of Engineering, Technical and Economic Efficiency in Economics

For the definition of engineering efficiency in the economic context above, have seen that engineering efficiency measures the efficiency with which a single input is used. Although knowing the efficiency of any given gasoline, electric, or diesel engine is interesting, increasing this efficiency is not necessarily economically efficient because doing so usually requires the use of other valuable resources. For example, the engineering efficiency of a gas turbine engine can be increased by using more and stronger steel in its construction. Raising the engineering efficiency of an engine saves on fuel, but at the cost of using more of other inputs. To know whether this is worth doing, the firm must compare the value of the fuel saved with the value of the other inputs used.

Technical efficiency is desirable as long as inputs are costly to the firm in any way. If a technically inefficient process is replaced by a technically efficient process, there is a saving of resources. We do not need to put a precise value on the cost of inputs to make this judgement. All we need to know is that inputs have a positive cost to the firm, so that saving on these costs is desirable.
Usually, however, any given output may be produced in any one of many alternative technically efficient ways. Achieving technical efficiency is clearly a necessary condition for producing any output at the least cost. The existence of technical inefficiency means that costs can be reduced by reducing some inputs and not increasing any others. Achieving technical efficiency, however, is not a sufficient condition for producing at the lowest possible cost. The firm must still ask which of the many technically efficient methods it should use. This is where the concept of economic efficiency comes in. The appropriate method is the one that uses the smallest total value of inputs. This ensures that the firm spends as little as possible producing its given output; in terms of opportunity cost, the firm sacrifices the least possible value with respect to other things that it might do with those inputs.

Having discussed the concepts related to efficiency in economics it is worthwhile to be mentioned that beyond the firm’s choice, which is in turn dependent on the aforementioned efficiency concepts, it is the market structure that greatly affects the concepts of allocative efficiency and X inefficiency as described above. More specifically, the liberalisation of energy markets, introduction of competition on certain energy sector activities and ultimately the empowerment of consumer choice has its foundations in improving allocative efficiency and reducing X inefficiency. Both of them can be improved by reducing market power and gradually abolishing monopolistic structures where feasible and appropriate.

Monopoly model is characterised by setting the price at a quantity that maximises its profit. The economic theory provides that this happens on the condition that the marginal revenue is equal to the marginal cost. As it is also illustrated below, this happens at a price which is higher than the one of the equilibrium price of perfectly competitive markets.

![Figure 1: Inefficiency of the Monopoly](source:Mankiw G. Principles of Economics (2003))
Exercising market power the monopolist chooses to produce and sell the quantity of output at which the marginal-revenue and marginal-cost curves intersect; the social planner7 would choose the quantity at which the demand and marginal-cost curves intersect. The monopolist produces less than the socially efficient quantity of output.

We can also view the inefficiency of monopoly in terms of the monopolist’s price. Because the market demand curve describes a negative relationship between the price and quantity of the good, a quantity that is inefficiently low is equivalent to a price that is inefficiently high. When a monopolist charges a price above marginal cost, some potential consumers value the good at more than its marginal cost but less than the monopolist’s price. The measure by which we can measure monopoly’s inefficiency is called the deadweight loss. The economic theory suggests that the demand curve reflects the value to consumers and the marginal-cost curve reflects the costs to the monopoly producer. Thus, the area of the deadweight-loss triangle between the demand curve and the marginal-cost curve equals the total surplus lost because of monopoly pricing.

From the above it can be construed that monopolistic structures are better off avoided in the energy sector. Yet this statement comes in contrast to the general practice in liberalisation that holds certain activities i.e. networks ownership and operational control in the form of monopolies. The explanation is that networks are considered as natural monopolies. A natural monopoly exists when a single firm can supply a good or a service to an entire market at a smaller cost than could two or more firms. A natural monopoly arises when there are economies of scale over the relevant range of output. In this case, a single firm can produce any amount of output at least cost. That is, for any given amount of output, a larger number of firms leads to less output per firm and higher average total cost. An example of a natural monopoly is the distribution of electricity. To provide electricity to residents of a town, a firm must build a network throughout the town. If two or more firms were to compete in the provision of this service, each firm would have to pay the fixed cost of building a network. Thus, the average total cost of electricity is lowest if a single firm serves the entire market.

In summary, we see that economics suggest a variety of efficiencies (and inefficiencies) that reflect ultimately to the economic efficiency which in turn denotes the value of all inputs used in producing a given output. The optimal economic efficiency therefore occurs when several other efficiencies are subsequently optimised. Major issues of concern arise from the organisation of the market as it clearly affects allocative efficiency and X inefficiency. Monopolistic structures do not provide incentives for the firm to lower their average cost as they are able to control the quantity and thus the price by exercising their market power. On the contrary, there are segments of the energy sector that natural monopolies are preferable as they prevent from unnecessary costs. In this context the role of the National Regulatory Authority among others is to monitor competition conditions and competitive behaviour so that the benefits from competitive pricing are transferred to the consumers and control/incentivise natural monopolies by setting revenue/price caps or introducing incentive-based regulation in order to achieve a gradual performance (and hence cost) improvement.

From a regulatory point of view, losses, which of course by definition are responsible for lower efficiencies, can be viewed in two ways depending on the sector organisation:

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7 The government or National Regulatory Authority depending on the sectors institutional set-up
• If parts of the sector are open for competition then the competitors have genuine incentive to reduce their own costs (and hence minimise losses or equivalently maximise technical performance). In such case the NRA has to care about monitoring and incentivising efficiency improvements only on the segments that operate as natural monopolies i.e. networks.
• If the whole of the sector operates under a monopolistic structure then the NRA should ideally have knowledge on all performance characteristics i.e. generation/production facilities, network and their components, etc. We understand of course that such knowledge is difficult to be retained by the NRA due to information asymmetry – that simply denotes that the monopoly firm will always have a lot more information on their systems and operational practices compared to the NRA which also faces, time, resource and budgetary constraints.

3.1.2 Efficiency in the engineering context

3.1.2.1 General
Simply put physics (and subsequently engineering) define efficiency as a ratio (n) of useful output over input. Inputs and outputs differ from each other by the quantity of losses. It can be construed that in any engineering system losses and outputs added equal inputs. This in turn denotes that outputs are always fewer than the inputs making consistently their ratio (n) which is efficiency to be less than the unity factor (or 100% if expressed as a percentage).

The Power Industry Dictionary⁸ defines the term efficiency as:

1: Ratio of energy input to useful output. 2: The gas turbine manufacturer’s rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

The first definition is generic and easily adaptable to engineering systems comprising the infrastructure utilised in the power industry. For example the efficiency of the transmission network can easily be defined by the ratio of energy delivered to the distribution network over the energy injected to the transmission network for a given period. The difference between them is energy losses. The second definition however is more targeted on the generation sector and involves terms such as the heat rate and the heating value. It is considered important therefore to briefly discuss the concepts and definitions involved in generation plants performance.

3.1.2.2 Carnot efficiency
Before however looking at heat rate which is a term that prevails in the power industry when efficiency and performance comes into the discussion we need to revert to thermodynamics in order to recall the limitation that exists with respect to efficiency of any thermal process. Taking a look back on thermodynamic text books it is fairly easy to fall into the Carnot efficiency which characterises all heat engines and thermal machines.

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The cycle process introduced in 1824 by Carnot is shown in Figure 2. Even though not very important in practice, the Carnot cycle played a decisive role in the historical development of heat transfer theory. It consists of the following changes of state (here, the clockwise process of a power cycle):

1–2 Isothermal expansion at temperature $T$ with heat addition $Q$

2–3 Reversible adiabatic expansion from pressure $p_2$ to pressure $p_3$

3–4 Isothermal compression at temperature $T_0$ with heat removal $|Q_0|$

4–1 Reversible adiabatic compression from pressure $p_4$ to pressure $p_1$
The heat supplied is $Q = mRT \ln \frac{V_2}{V_1} = T(S_2 - S_1)$ and the heat removed is $|Q_0| = mR T_0 \ln \frac{V_3}{V_4} = T_0(S_3 - S_4) = T_0(S_2 - S_1)$. The technical work done is $-W_t = Q - |Q_0|$, and the thermal efficiency is $\eta = \frac{|W_t|}{Q} = 1 - \frac{T_0}{T}$.

Carnot cycles gained no practical importance, however, because their power related to the volume of a corresponding machine is very small. However, as an ideal, i.e., reversible process the Carnot cycle is often used for comparison in order to assess other cyclic processes. The remarkable result of Carnot’s work shows that the maximum conversion of heat into work in a heat engine operating continuously between two heat sources is limited by the ratio between the two heat sources’ temperatures. The lower the temperature ratio, the higher the Carnot efficiency. As a final remark, no 100% conversion can take place because it would require either a 0 K low temperature source, or an extremely high temperature source (mathematically, an infinite one), or both.

### 3.1.2.3 Heat rate

Moving away from the idealistic world which a Carnot cycle implies for heat engines, it is important to discuss heat rate – a term that is frequently referred to as measure of efficiency of thermal power stations. The thermal efficiency of a generating unit is a measure of the amount of electrical energy produced per unit of energy input. In the case of thermal units, the input is fuel and the means of measuring efficiency is called heat rate. Heat rate is defined as the ratio of the amount of fuel input (in BTUs)$^9$ to a generating unit to the amount of electrical energy obtained (kilowatt-hours). The resulting value is in units of BTU/kWh. For thermal units, this ratio will change as the output level of the unit is changed. In general, the efficiency of the unit will increase (i.e., the heat rate will decrease) as the output level of the unit is increased up to the normal rating of the unit.

A generating unit that is 100% efficient would use 3,412 BTUs of fuel to produce 1 kilowatt-hour of electric energy. Modern day steam units have heat rates in the 9,000–10,000 BTU/kWh range. Newer combined cycles have lower heat rates, some down to 7,000 BTU/kWh. **Dividing 3,412 by the unit’s actual heat rate and then multiplying by 100 will give the overall percentage efficiency of a unit.** When the heat rate is multiplied by the unit cost of BTUs in the fuel, the unit cost of the energy production cost ($/kilowatt hour) can be determined.

Two basic kinds of heat rates are used—average and incremental. The average heat rate simply defines the amount of fuel actually consumed for each hour that the generating unit is operating at a given level of electrical output. The incremental heat rate gives the increase in thermal input required to produce an additional increment of electrical energy, also in BTU/kWh. Changes as output decreases are sometimes called the decremental heat rates. Both the incremental heat rate and the average heat rate are given in units of BTU/kWh. Therefore, it is essential that the type of heat rate be defined when requesting or providing heat rate data.

It should be noted that average and incremental heat rates are useful for making different decisions in an electricity market. The average heat rate is generally useful for understanding the fuel consumption levels at a stable level of generation of a unit in a power station. In contrast, incremental heat rate is useful for making decisions on dispatching generation units. For instance a System dispatcher that needs an additional block of MW to cover say the next hours increased

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$^9$ A BTU is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.
demand will choose the generation unit with the lowest possible incremental variable cost. If for simplicity, we neglect O&M costs, the incremental variable cost is equal to incremental fuel cost which in turn corresponds to the incremental heat rate of the unit. Dispatchers deliberately select incremental heat rates for making their decisions without having to worry about the continuous fuel price volatility.

The following illustrative example is based on real power plant characteristics in order to provide an understanding of the process and utility of heat rates. The first step however should be to discuss the INPUT – OUTPUT curve. In the engineering world, the Input-Output Curve is the mechanism that defines the relationship between the Incremental and Average Heat Rates. It is also the data that is actually measured in the field. The Average and Incremental Heat Rates are not measured directly. The Input-Output Curve is measured and the Average and Incremental Heat Rates are constructed from it.

Consider now that we have power plants (each one comprising a single unit) of cumulative capacity 739 MW and 107 MW. The units can make available their output in five blocks each one representing a percentage of their total output. With a process of measuring fuel consumption per block the input-output curve can be derived. The incremental heat rate is calculated as the ratio of the heat rate difference over the output level difference. The average heat rate is calculated as the ratio of the fuel input over the respective output level.

In terms of efficiencies we recall that the “Dividing 3,412 by the unit’s actual heat rate and then multiplying by 100 will give the overall percentage efficiency of a unit” as mentioned above in this section.

For instance:

Power plant’s A full load efficiency should be \( \frac{3412}{8917} \times 100 = 38\% \)

Similarly:

Power plant’s B full load efficiency should be \( \frac{3412}{12598} \times 100 = 27\% \)

We can observe that different output levels imply different efficiencies. Power plant efficiencies therefore are either given at a specified output (usually the full load). We also note that the environmental conditions (temperature and altitude mostly) on which a thermal plant is required to operate have a noticeable impact on the plant output. For this reason, most frequently ISO standard performance acceptance tests are quoted together with the claimed efficiency by the equipment manufacturer. These efficiency degradation factors are in excess of the fuel quality impact which is separately discussed in section 8.2 of this report.

Table 1 below summarises the characteristics of Power plants A and B by exhibiting real data for the power blocks and respective output levels and the corresponding fuel input quantities. Both the incremental and average heat rate figures correspond to reproducible calculations as discussed above. Figure 3 presents the input-output curve, incremental and average heat rates of power plants A and B graphically and in relation to their capacity blocks.

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Table 1: Power plants A & B input-output, incremental and average heat rate summary data

<table>
<thead>
<tr>
<th></th>
<th>Output (%)</th>
<th>Input MW</th>
<th>1000 BTU/hr</th>
<th>Incremental Heat Rate BTU/kWh</th>
<th>Average Heat Rate BTU/kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Power Plant A</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Block 1</td>
<td>7%</td>
<td>52</td>
<td>997950</td>
<td>19292</td>
<td>19292</td>
</tr>
<tr>
<td>Block 2</td>
<td>25%</td>
<td>185</td>
<td>1966735</td>
<td>7283</td>
<td>10645</td>
</tr>
<tr>
<td>Block 3</td>
<td>50%</td>
<td>370</td>
<td>3429160</td>
<td>7916</td>
<td>9281</td>
</tr>
<tr>
<td>Block 4</td>
<td>80%</td>
<td>591</td>
<td>5296542</td>
<td>8423</td>
<td>8959</td>
</tr>
<tr>
<td>Block 5</td>
<td>100%</td>
<td>739</td>
<td>6589663</td>
<td>8749</td>
<td>8917</td>
</tr>
<tr>
<td><strong>Power Plant B</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Block 1</td>
<td>9%</td>
<td>10</td>
<td>210370</td>
<td>21845</td>
<td>21845</td>
</tr>
<tr>
<td>Block 2</td>
<td>25%</td>
<td>27</td>
<td>378378</td>
<td>9814</td>
<td>14145</td>
</tr>
<tr>
<td>Block 3</td>
<td>50%</td>
<td>54</td>
<td>671436</td>
<td>10955</td>
<td>12550</td>
</tr>
<tr>
<td>Block 4</td>
<td>80%</td>
<td>86</td>
<td>1063476</td>
<td>12213</td>
<td>12424</td>
</tr>
<tr>
<td>Block 5</td>
<td>100%</td>
<td>107</td>
<td>1347986</td>
<td>13295</td>
<td>12598</td>
</tr>
</tbody>
</table>

Observing the heat rate results as presented in Table 1 above, economies of scale appear with regards to the size of the generation unit. More specifically, this example shows what is often likely in power plants of the same age, technology, location, etc.. Without prejudice on individual plant characteristics it appears that certain technologies comprise multiple benefits at a particular unit size range and therefore manufacturers tend to offer this optimal size(s) as a frequent solution to the market.

Moving away from the expected fuel consumption and judging upon the incremental heat rates it appears the latter generally follow the pattern of the average heat rates although they differ substantially in terms of their values. It is worthwhile to be mentioned that incremental heat rates comprise decision variables for dispatching additional generation to the fluctuating load. For each given dispatch period the dispatcher (based on an optimisation algorithm which most frequently involves linear programming) has to select the available block (or part of it) with the lowest possible incremental heat rate. This is how the economically optimal generation mix derives from the available resources at each given system load.
Figure 3: Power plants A & B input-output, incremental and average heat rate curves
In accordance to the aforementioned methodology for deriving heat rates (average and incremental) and taking into consideration the current situation of the generation plants existing in Azerbaijan at the moment it is recommended that the generation sector is assessed in terms of its efficiency through a consolidated performance study. That would involve the following sequence of steps:

**Step 1: Stocktaking**
- Create a list of generation plants
- Match units with fuels (in case of dual fuel plants) and justify fuels energy content
- Define blocks (in terms of firm capacity) in each plant's generation unit

**Step 2: Measurements**
- Measure fuel consumption per hour for each block identified
- Develop the respective Input-Output Curves based on the measurements

**Step 3: Results**
- Calculate Average Heat Rates per block
- Use energy production figures per block in order to find out the true year-round fuel consumption of each block

### 3.2 Energy system performance

In order to provide a common understanding over the common use of terms related to performance or losses in an energy system we first need to establish some foundations as they are provided by IEA/OECD terminology. More specifically, in IEA/OECD-Eurostat-UNECE questionnaires, the term **energy commodity** is used when a statement covers both fuels and heat and power.

Energy commodity as it occurs in nature is referred to as **primary energy**. Examples of primary energy are coal, oil, natural gas and uranium as they occur in the ground. To be useful to humans, however, these forms of energy need to be extracted and transformed into **secondary energy**. Examples of secondary energy are electricity and refined petroleum products, and processed natural gas ready for use by the customer. However, even these energy forms are not really of interest to us. What we really want are end-use energy services – things like warmth, motion, mechanical power or process heat for industrial manufacturing. These are referred to as **tertiary energy** or **Final Useful Energy**. The relationships between primary, secondary and tertiary energy are summarized in Figure 4. As the figure suggests there are three general ways in which we can reduce our primary energy requirements:

- increasing the efficiency of conversion from primary to secondary energy;
- increasing the efficiency of conversion from secondary to tertiary energy;
- reducing tertiary energy demand.
In reality Sankey diagrams although generally follow the logic of Figure 4 above, they are rather more complex as they involve interrelations between the origin and use of energy commodities. A particular attribute of the Sankey diagrams is referred to as **Commodity Flow** which represents/illustrates the general pattern of the flow of a commodity from its first appearance to its final disappearance (final use) from the statistics. This is illustrated in Figure 5 below.

**Figure 5: Main commodity flows**


In addition, an energy balance – as it may be graphically illustrated – a Sankey diagram presents both the energy commodities available and the commodity flows in a manner that eventually connect to the various end-uses.
Figure 6: EU energy sector Sankey (2011)

Source: Environment Agency (EEA) (20011)
Figure 6 presents a Sankey diagram which on its left hand side presents the composition of the primary energy entering the energy system of the EU-27 in 2011. On its right hand side the diagram presents how this primary energy was used, either as consumption by specific sectors of the economy or as losses. We further distinguish conversion losses (marked by the blue circle in Figure 6 above) which effectively depend on generation efficiencies (e.g. thermal efficiencies as discussed above in sections 3.1.2.2 and 3.1.2.3) from own energy use (e.g. mining process electricity consumption or pumping at pumped storage hydro power plants) which is marked by the red circle in Figure 6 above.

3.3 Quantities and energy content

The IEA/OECD/EUROSTAT Energy Statistics Manual describes that fuels may be measured as natural units for the fuel (the term physical unit is also used). Typical examples are mass units for solid fuels (kilograms or tonnes) and volume units for liquids and gases (litres or cubic metres). Electrical energy (either as primary or as secondary or tertiary energy) is measured in an energy unit, kilowatt-hour (kWh). The most usual unit is an energy unit because the heat raising potential of the fuel is often the reason for its purchase or use. Use of energy units also permits the summing of the energy content of different fuels in different physical states. The conversion of a fuel quantity from natural units or some intermediate unit (such as mass) into energy units requires a conversion factor which expresses the heat obtained from one unit of the fuel. This conversion factor is termed as the calorific value or heating value of the fuel.

The energy content of a fuel is the thermal energy released when the fuel is burned, and is referred to as the heating value of the fuel. Heating values can be given assuming that any water vapour produced is either condensed (adding the released latent heat to the available thermal energy) or not condensed. The resulting heating values are referred to as the higher heating value (HHV)\(^{11}\) and lower heating value\(^{12}\) (LHV), respectively, or as the gross heating value and net heating value. LHVs and HHVs for a variety of fuels are given in Figure 7 below. Inasmuch as efficiencies for heating or electricity generation are given by the energy output divided by the energy content of the fuel, the efficiencies will be smaller if based on the HHV of the fuel than if based on the LHV. The difference is negligible for coal, but the HHV of natural gas is about 10 per cent greater than the LHV. In electricity generation, exhaust conditions are such that the water vapour cannot be condensed, so basing efficiencies on HHVs would make natural gas power plants appear less efficient relative to coal plants than if efficiencies were based on LHVs. However, when fuels are used for space or water heating, it is possible to condense water vapour in the exhaust by cooling the exhaust with cold water or return air, thereby preheating the water or air and capturing some of the latent heat that is released during condensation. Thus, for furnaces and boilers it is appropriate to give efficiencies in terms of the HHV. In cogeneration applications, where fuels are first used to generate electricity, and waste heat in the exhaust (and perhaps in the cooling water) is used for heating purposes, it is possible to capture the latent heat of condensation, so it would be appropriate to use HHVs in computing electricity, thermal and overall efficiencies.

\(^{11}\) Or Gross Heating/Calorific Value
\(^{12}\) Or Net Heating/Calorific Value
The calorific value of a fuel is obtained by measurement in a laboratory specialising in fuel quality determination. Major fuel producers (mining companies, refineries, etc.) will measure the calorific value and other qualities of the fuels they produce.

According to the IEA/OECD/EUROSTAT Energy Statistics Manual, the derivation of net calorific values for solid fuels is further complicated because they often contain water trapped within the fuel in addition to the water which will be formed from the hydrogen they contain. The reduction in net calorific value as a result of the additional water is uncertain because the dampness of the fuel may vary according to weather and storage conditions. In summary, the net calorific value of a fuel is the total heat produced by burning it, minus the heat needed to evaporate the water present in the fuel or produced during its combustion. Major users of solid fuels, such as power stations, should be able to provide net calorific values based on the monitoring of the electricity generation.
Part A: The Electricity sector
4 ELECTRICITY GENERATION

This section of the report presents an assessment of power generation technologies with relevance to the current generation mix in Azerbaijan. Towards this objective, and based on the fact that the dominant generation technology in Azerbaijan is gas–fuelled power plants, an overview of efficiency issues related to electricity generation from natural gas-fired units is provided in Section 4.1. An overview of the generation system of Azerbaijan as well as pertinent recommendations are presented in Section 0.

4.1 Electricity generation from natural gas-fired units: an overview

4.1.1 Efficiency

There are two main types of gas-fired power plants used for centralised electricity today: open-cycle gas turbine (OCGT) plants and combined-cycle gas turbine (CCGT) plants. OCGT plants consist of a single compressor/gas turbine that is connected to an electricity generator via a shaft. They are used to meet peak-load demand and offer moderate electrical efficiency of between 35% and 42% (lower heating value, LHV) at full load. Their efficiency is expected to reach 45% by 2020. CCGT is the dominant gas-based technology for intermediate and base-load power generation. CCGT plants have basic components the same as the OCGT plants but the heat associated to the gas turbine exhaust is used in a heat recovery steam generator (HRSG) to produce steam that drives a steam turbine and generates additional electric power. Large CCGT plants may have more than one gas turbine. Over the last few decades, impressive advancement in technology has meant a significant increase of the CCGT efficiency. The CCGT electrical efficiency is expected to increase from the current 52–60% to some 64% by 2020. In addition, CCGT plants offer flexible operation. They are designed to respond relatively quickly to changes in electricity demand and may be operated at 50% of the nominal capacity with a moderate reduction of electrical efficiency (50–52% at 50% load compared to 58–59% at full load).

While technology learning is not expected to significantly reduce the investment cost of mature technologies, technical developments in CCGT plants may still drive cost reductions from today’s €820/kWe to €720/kWe in 2020, and to €640/kWe in 203013. The annual operation and maintenance costs of CCGT plants are estimated at 4% of the investment costs per year. The generation costs of CCGT range between €46 and €56/MWh (typically, €52/MWh), of which €20–30/MWh is for the fuel14.

Unlike levelised costs for other generation technologies, levelised costs for CCGT power generation are significantly influenced by fuel costs. Figure 1 below shows that in the early 2000s fuel cost already accounted for nearly 60% of generation costs15. Furthermore, for CCGT, the share of fuel in total generation cost is predominant, around 75% or higher and levelised costs depend mainly on projected gas prices during plant lifetimes.

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13 IEA / ETSAP, Gas Fired Power 2010
14 IEA / ETSAP, Gas Fired Power, 2010
According to the IEA\textsuperscript{16}, CCGTs and OCGTs are likely to be used increasingly for mid-merit order and peak load, respectively, as well as providing a significant portion of the flexible capacity that is needed to integrate higher shares of variable wind and solar power into the electricity systems.

\textsuperscript{16} IEA, World Energy Outlook, 2012

At world level, gas is a significant fuel for electricity generation (see Figure 9 above), with significant but different trends for further increase around the world (see Figure 10 below).
Analysis from IEA (2008)\textsuperscript{17} shows that the average efficiency of natural gas-fired electricity production (over the period 2001-2005) in both public electricity-only and public CHP plants is 45% in the OECD and around 35% in non-OECD countries. Average efficiencies of natural gas plants in individual countries range from 31% in Sweden (which produces very little electricity from natural gas) to 55% in Luxembourg (Figure 11). Since 1990, the average efficiencies of natural gas-fired plants have risen significantly in many countries. As a result, the average efficiency in OECD countries has increased by almost eight percentage points, while non-OECD countries have seen a two percentage points rise.

The widespread introduction of successively more efficient combined-cycle gas turbine (CCGT) plants in OECD countries has been the main driver behind the increase in both the use of natural gas for electricity production and the average generation efficiency. The latest CCGTs can have efficiencies of about 60%. New, high efficiency, CCGT plants are also the reason behind the substantial increase in efficiency for Brazil and India (24 and 17 percentage points respectively).

\textsuperscript{17} Energy Efficiency Indicators for Public Electricity Production from Fossil Fuels, IEA Information paper, 2008
In a previous (2006) comparison of efficiencies of electricity generation technologies, similar results have been obtained: a study by ECOFYS\(^\text{18}\) shows that, for gas-fired power generation the efficiencies range from 39% for Australia to 52% for India in 2003. The average efficiency for gas is 46% and the weighted average efficiency is 45% in 2003 (Figure 12). For comparison purposes, the respective

\(^{18}\) Comparison of Efficiency in Fossil-fuel Power Generation, ECOFYS, 2006
figure for coal-fired generation is provided below (Figure 13). Since the right hand axes in the two charts below the arrow-ended line is used for a quick comparison of the 43% efficiency value which appeared to be an average efficiency achieved for gas-fired plants whereas it was not even reached by coal-fired plants in 2003 according to the ECOFYS study.

Source: ECOFYS (2006) – see footnote ref. 18

4.1.2 Gross versus net capacity (or: Auxiliary power consumption)

In general, auxiliary systems for fossil fuel power plants can be grouped under the name of ‘balance of plant’ (BoP). Starting from this level, three categories of auxiliary systems can be defined19:

- A subset of BoP that encompasses drive power components such as pumps, fans, motors and their power electronics such as variable-frequency drives. These provide drive power for fuel handling, furnace draft, and feedwater pumping. These systems and components are commonly referred to as ‘Drivepower’.
- A subset of BoP that encompasses only the electrical power system’s conversion, protection, and distribution equipment, excluding motors and variable-frequency drives. This subset includes power transformers and LV and MV equipment. These systems and components are referred to as Electrical BoP or ‘Electric Power Systems.’
- A subset of BoP that encompasses only the instruments, control, and optimisation systems. These provide boiler-turbine and other control functions. These systems and components are referred to as ‘I&C’ or simply ‘Automation’.

Table 2 below provides a summary of key technical parameters for fossil fuel power plants in the UK20. CCGTs present an average of 2.5% reduction of gross capacity due to own energy consumption (coal plants present much higher own consumption, in the order of 6.5%).

---

20 UK Electricity Generation Costs Update, Mott MacDonald, 2010
Table 2: Key technical parameters of fossil fuel power plants in UK

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Pre-dev. period (years)</th>
<th>Construction period (years)</th>
<th>Gross effic. (%)</th>
<th>Plant availability (%)</th>
<th>Aux. load (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCGT</td>
<td>2.0</td>
<td>2.5</td>
<td>59.0%</td>
<td>91.2%</td>
<td>2.3%</td>
</tr>
<tr>
<td>CCGT+CCS</td>
<td>2.0</td>
<td>3.5</td>
<td>50.0%</td>
<td>89.5%</td>
<td>10.8%</td>
</tr>
<tr>
<td>ASC coal</td>
<td>3.0</td>
<td>4.0</td>
<td>45.0%</td>
<td>90.2%</td>
<td>6.5%</td>
</tr>
<tr>
<td>ASC+CCS</td>
<td>4.0</td>
<td>4.5</td>
<td>36.0%</td>
<td>89.0%</td>
<td>15.5%</td>
</tr>
<tr>
<td>IGCC</td>
<td>4.0</td>
<td>4.0</td>
<td>45.0%</td>
<td>87.5%</td>
<td>4.5%</td>
</tr>
<tr>
<td>ICC + CCS</td>
<td>4.0</td>
<td>4.0</td>
<td>36.0%</td>
<td>87.4%</td>
<td>13.5%</td>
</tr>
<tr>
<td>Onshore wind</td>
<td>5.0</td>
<td>2.0</td>
<td>100.0%</td>
<td>97.9%</td>
<td>1.8%</td>
</tr>
<tr>
<td>Offshore wind</td>
<td>5.0</td>
<td>2.0</td>
<td>100.0%</td>
<td>95.9%</td>
<td>2.0%</td>
</tr>
<tr>
<td>Offshore R3</td>
<td>5.0</td>
<td>2.0</td>
<td>100.0%</td>
<td>95.9%</td>
<td>2.0%</td>
</tr>
<tr>
<td>3rd generation</td>
<td>4.0</td>
<td>5.0</td>
<td>100.0%</td>
<td>90.8%</td>
<td>4.5%</td>
</tr>
</tbody>
</table>

Source: Mott MacDonald, 2010 – see footnote ref. 20

4.1.3 Part load efficiency of CCGTs

The figure below shows the part load efficiency of a CCGT plant and the associated gas turbine, each relative to the 100% load case. At higher loads the part-load efficiency is good but it drops off more quickly below 50%\(^\text{21}\). The same phenomenon can be observed in the part-load efficiency of a Combined Cycle plant comprising four single-shaft blocks (GTs).

Source: R. Kehlhofer (Pennwell, 1999) – see footnote ref. 21

\(^{21}\) Combined cycle gas steam turbine power plants, by R. Kehlhofer (Pennwell, 1999)
4.2 Efficiency in electricity generation from natural gas-fired units in Azerbaijan

Electricity generation in Azerbaijan is currently entirely based on natural gas and hydro resources. The current generation mix is as follows:

- ~2,500 MW conventional steam boiler units (gas fired)
- ~3,000 MW CCGTs
- ~1,000 MW hydro

The electricity generation mix, as evolved during the last fifteen years is depicted in Figure 16 below:

![Figure 16: Electricity generation by fuel in Azerbaijan](image)


The demand for electricity in Azerbaijan is expected to double between 2012 and 2022, and to increase by almost 140% by 2025. The peak demand is also expected to double by 2022–2030.22

Further, in terms of tariffs, a medium-term tariff policy is established that incorporates a transition to full cost recovery for utility service providers with a 10% return to equity. This is expected to enable utilities to become financially self-sustainable. The Tariff Council (TC) determines the retail and wholesale tariffs as well as the gas and fuel supply prices. The regulated entities are required to provide economic substantiation of the expenses that are part of the prices (tariffs). The calculated tariffs are reviewed by the Tariff Council and published upon approval.

As regards efficiency in the electricity generation sector, according to the Energy Charter study, fuel consumption in generating units in Azerbaijan has fallen from 411 gr/kWh in 2000 to 314 gr/kWh in 2011. The target is to decrease this further to 260 g/kWh in 2015.23

The efficiency issue is currently handled by the Tariff Council through price control in the form of balancing the difference of declared CAPEX and OPEX each year (declarations include three previous

23 This should be compared with a benchmark consumption in the area of 135 gr/kWh (assuming natural gas with 9,000kcal/m³, 720 gr of natural gas / m³, and 50% efficiency for a modern CCGT plant)
years and one forecast on a rolling basis). It’s at the Tariff Council’s discretion to increase gas purchase prices for gas distributor or the generation plans without reflecting this increase to the end use prices, in order to provide incentives for efficiency. Thus, the Tariff Council can affect losses (in generation and distribution) only through the prices / tariffs mechanism. Further, with the objective of increasing transparency and availability of information, it is recommended that appropriate indicators (e.g. efficiency and availability of generating units) are calculated, submitted to the competent Ministry and published at Azerenerji’s web site.

The cost-recovery based approach, despite its merits in allowing financial viability of service providers in the energy sector of Azerbaijan, presents a certain drawback when assessed in terms of incentivizing efficient system planning and operation. Notwithstanding any issues related to availability of capital for investment in generation, the importance of upgrading the generation fleet of AZ cannot be understated.

In this context, it should be clear that competitive markets present advantages in handling technological efficiency issues. In a competitive environment for generation it would not be necessary to regulate the generation sector for efficiency, as every producer would have incentive to minimize all kinds of losses and produce with increased efficiency.

Based on the above and given the Government’s strategy to open the electricity market, it is expected that the generation sector of AZ will take advantage of the efficiency levels achieved currently for CCGT units at EU and world level, thus making steps towards reaching the government’s goals for increasing efficiency in the energy sector.

However, it is not debated that the country can improve in terms of efficiency in power generation, already under the current monopoly regime, by simply renovating or replacing the most inefficient units (a cost-benefit study would normally precede any decision related to plant refurbishment or replacement). Even in this case, the issue of adequate maintenance and overall efficient operation of the generation system remains an important parameter for minimizing overall cost of electricity generation.

4.3 Conclusions and recommendations
This Chapter discussed generation efficiency with emphasis on natural gas-fired CCGT generation which appears to be a promising option for the future of the electricity generation system of Azerbaijan.

The Tariff Council can control gas purchase prices for gas distributor or the generation plans without reflecting this increase to the end use prices, in order to provide incentives for efficiency. Thus, the Tariff Council can affect losses only through the prices / tariffs mechanism. But there is certainly an information asymmetry on the end of the regulatory as the information on fuel energy content and efficiency of the generation plants are not reported to the Tariff Council but to the Ministry of Energy. It is recommended for the sake of increasing transparency and availability of information that appropriate indicators (e.g. efficiency and availability of generating units) are calculated, submitted to the competent Ministry and published at Azerenerji’s website and of course be available to the Tariff Council for the purposes of regulatory review.

As also mentioned earlier in this report allocative efficiency may be increased by introducing competition to the generation sector. As suggested by the example for many OECD countries
including the European Union Member States generators have an apparent incentive to increase their efficiency and thereby reduce their marginal costs to the lowest possible level for this automatically makes them competitive in the market and allow for increased profits. We note however, that since the economic framework on which the aforementioned benefits arise assimilates a perfectly competitive market conditions any attempt for reform in this context, should be carefully planned and rigorously monitored by a competent regulatory authority.
5 ELECTRICITY TRANSMISSION AND DISTRIBUTION LOSSES

Purpose of this Chapter is to provide a benchmarking of electricity transmission and distribution losses in EU countries and, where possible identify reasons for differences among countries. Further, to present the current situation regarding T&D losses in Azerbaijan and provide recommendations.

5.1 Transmission losses in the EU

In general, there have been no formal attempts to harmonise the treatment of network losses at a pan-European level; analyses have been carried out within the scope of benchmarking studies of electricity transmission tariffs by the European Commission, the European Transmission System Operators (ENTSO-E) and the Council of European Energy Regulators (CEER/ERGEG).

5.1.1 Definition of losses

ERGEG reports\(^{24}\) that there is no common definition of losses within the EU. Admittedly this leads to a situation where different definitions in the Member States exist. While this broad statement is generally true considering both the losses in the Transmission and Distribution sector, it is worthwhile to be mentioned that the source of differentiation across EU jurisdictions is largely accounted to the distribution side where non-metered, non-billed and illegally off-taken energy may also be accounted as part of the general losses definition. On the other hand, in respect to the lack of harmonisation of losses definition, the boundary points of the transmission grid should be clearly defined i.e. interconnection nodes and boundary points between the transmission system assets and the transmission users’ assets. In principle, in the EU this boundary point refers to the HV bushings side of the transmission systems’ user transformer.

Having the technical (or “physical) and non-technical losses duly discriminated the former can in turn be broken down to fixed and variable components. National Grid, the UK TSO, in their “National Electricity Transmission System Seven Year Statement” defines transmission losses as:

The losses incurred on the system between the power station generating unit and the grid supply points and are made up of:

- **Variable** (\(I^2R\)) transmission heating losses in the overhead lines, underground cables and other equipment on our transmission system but excluding grid supply transformers at the Grid Supply Points (GSPs);
- ‘Fixed’ losses made up of corona losses on outdoor transmission equipment and iron losses in transformers;
- ‘Variable’ (\(I^2R\)) heating losses (copper losses) in grid supply transformers at the GSPs; and
- ‘Variable’ (\(I^2R\)) heating losses (copper losses) in generator transformers.

The above comprise a relatively robust definition of technical losses with the remark that even the “fixed” part of the losses may be subject to short variations from time to time if cases of network configuration alterations (switching on or off lines and/or transformers) or weather influence on

---

corona effect are to be accounted.

A summary of the above considerations with regards to the definition of losses as identified by ERGEG is clearly illustrated in Figure 17 below:

![Figure 17: Categorisation of T&D losses](image)

Source: ERGEG (2008) – see footnote ref. 24 above

### 5.2 Valuation of losses

Valuation refers to the ex-post procedure of calculating losses (in most cases per each voltage level). The determination of transmission losses is possible, since usually continuous metering of all consumption and generation is available at transmission level (this is not always the case in distribution level). Transmission losses are calculated by hourly energy balance (difference between injections and off-takes). ERGEG’s Position Paper (Appendix 9.1) in its Annex A2.3 provides a detailed overview of the losses valuation practices across EU member states.

#### 5.2.1 International losses’ benchmarking

Table 3 below gives information about the percentage (%) of losses in European electricity transmission and distribution networks. Depending on the countries, some values refer to 2006 and others to 2005.

<table>
<thead>
<tr>
<th>Country</th>
<th>Average % of Transmission losses</th>
<th>Average % of Distribution losses</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>1,5% of output</td>
<td>4,5% of output</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>1,5% of output</td>
<td>7% of output</td>
</tr>
<tr>
<td>Finland</td>
<td>1,6% of input</td>
<td>4,7% of input</td>
</tr>
<tr>
<td>France</td>
<td>2,3% of output</td>
<td>5,0% of output</td>
</tr>
<tr>
<td>Greece</td>
<td>2,4% of input</td>
<td>6,8% of input</td>
</tr>
<tr>
<td>Hungary</td>
<td>1,4% of input</td>
<td>9,2% of input</td>
</tr>
<tr>
<td>Norway</td>
<td>1,6% of input</td>
<td>5,0% of input</td>
</tr>
<tr>
<td>Poland</td>
<td>2,1% of input</td>
<td>11,8% of input</td>
</tr>
<tr>
<td>Portugal</td>
<td>1,1% of input</td>
<td>6,4% of input</td>
</tr>
<tr>
<td>Romania</td>
<td>2,6% of output</td>
<td>13,8% of output</td>
</tr>
<tr>
<td>Slovakia</td>
<td>1,0% of output</td>
<td>8,3% of output</td>
</tr>
</tbody>
</table>
Spain | 1.2% of input | 7.1% of input  
Sweden | 2.1% of input | 2.3% of input  
United Kingdom | 1.6% of input | < 6% of input  

Source: ERGEG (2008) – see footnote ref. 25

According to ERGEG\(^\text{25}\), the differences in the percentages of losses are mainly due to:

- The reference for the percentage. The level of the input includes the losses when the level of output does not. If the percentage of losses refers to output, it will be higher than if it refers to input (in the above table, reference to ‘output’ is grey-highlighted).
- The national definition of what voltage levels are operated by TSOs and DSOs. If the TSO operates not only the transmission grid but also the regional grids, the average percentage of losses will be higher than if the TSO operates only the transmission grid. If the DSO operates not only the distribution grids but also the regional grids, the average percentage of losses will be lower than if the DSO operates only the distribution grids.
- Values\(^\text{26}\) have been calculated with accordance to national regulatory definitions that differ from country to country.
- The level of theft on DSOs. As the DSO losses generally include theft, the higher the level of theft is, the higher the percentage.

Taking into consideration that utilities have adequate incentives to reduce network losses and that there are sufficient financing sources for the network investments to be realised, one should expect a continuously declining trend in the evolution of losses. A historical evolution of T&D losses in selected IEA countries is depicted below\(^\text{27}\):

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26 In general, values for losses vary according to the source of information (for example, the values provided by ERGEG do not always agree with values in http://www.factfish.com/statistic-country/sweden/electric%20power%20transmission%20and%20distribution%20losses%20of%20total or in http://www.keepeek.com/Digital-Asset-Management/oecd/economics/oecd-economic-surveys-mexico-2013_eco_surveys-mex-2013-en#page73)
Table 4: Evolution of transmission and distribution network losses in selected IEA countries

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Finland</td>
<td>6.2</td>
<td>4.8</td>
<td>3.6</td>
<td>3.7</td>
</tr>
<tr>
<td>Netherlands</td>
<td>4.7</td>
<td>4.2</td>
<td>4.2</td>
<td>4.2</td>
</tr>
<tr>
<td>Belgium</td>
<td>6.5</td>
<td>6.0</td>
<td>5.5</td>
<td>4.8</td>
</tr>
<tr>
<td>Germany</td>
<td>5.3</td>
<td>5.2</td>
<td>5.0</td>
<td>5.1</td>
</tr>
<tr>
<td>Italy</td>
<td>10.4</td>
<td>7.5</td>
<td>7.1</td>
<td>7.0</td>
</tr>
<tr>
<td>Denmark</td>
<td>9.3</td>
<td>8.8</td>
<td>5.9</td>
<td>7.1</td>
</tr>
<tr>
<td>United States</td>
<td>10.5</td>
<td>10.5</td>
<td>7.1</td>
<td>7.1</td>
</tr>
<tr>
<td>Switzerland</td>
<td>9.1</td>
<td>7.0</td>
<td>7.5</td>
<td>7.4</td>
</tr>
<tr>
<td>France</td>
<td>6.9</td>
<td>9.0</td>
<td>8.0</td>
<td>7.8</td>
</tr>
<tr>
<td>Austria</td>
<td>7.9</td>
<td>6.9</td>
<td>7.9</td>
<td>7.8</td>
</tr>
<tr>
<td>Sweden</td>
<td>9.8</td>
<td>7.6</td>
<td>8.4</td>
<td>9.1</td>
</tr>
<tr>
<td>Australia</td>
<td>11.6</td>
<td>8.4</td>
<td>9.2</td>
<td>9.1</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>9.2</td>
<td>8.9</td>
<td>9.2</td>
<td>9.4</td>
</tr>
<tr>
<td>Portugal</td>
<td>13.3</td>
<td>9.8</td>
<td>10.0</td>
<td>9.4</td>
</tr>
<tr>
<td>Norway</td>
<td>9.5</td>
<td>7.1</td>
<td>8.2</td>
<td>9.8</td>
</tr>
<tr>
<td>Ireland</td>
<td>12.8</td>
<td>10.9</td>
<td>9.6</td>
<td>9.9</td>
</tr>
<tr>
<td>Canada</td>
<td>10.6</td>
<td>8.2</td>
<td>9.2</td>
<td>9.9</td>
</tr>
<tr>
<td>Spain</td>
<td>11.1</td>
<td>11.1</td>
<td>11.2</td>
<td>10.6</td>
</tr>
<tr>
<td>New Zealand</td>
<td>14.4</td>
<td>13.3</td>
<td>13.1</td>
<td>11.5</td>
</tr>
<tr>
<td>Average</td>
<td>9.5</td>
<td>9.1</td>
<td>7.5</td>
<td>7.5</td>
</tr>
<tr>
<td>European Union</td>
<td>7.9</td>
<td>7.3</td>
<td>7.3</td>
<td>7.3</td>
</tr>
</tbody>
</table>

Source: OFGEM — see footnote ref. 27

The last publicly available credible data on losses for the EU are those presented in the table 3 above. In practice, losses level in electricity systems may vary from year to year due to several reasons, including:

- a change of network topology and equipment condition
- a change in demand/supply locational characteristics
- a change in operational practices of the respective network operator (i.e. dispatch or temporary network re-configuration)
- A change in transit flows

As an illustrative case we have indicatively looked at the development of losses for 6 countries 2 from Western Europe with highly meshed systems; 3 from South Eastern Europe and one from the Baltics. The latter sample was selected due to their perceived similarity in terms of planning as it was inherited from the former Soviet union.

**FRANCE**

- Transmission: The system loss rates lie between 2 and 3.5% of consumption, depending on the seasons and time of day. On average, the rate comes to 2.5%, which represents about 11.5 TWh (TeraWatt-hours) per year²⁸.
- Distribution: ERDF’s total losses represent nearly 6% of energy transmitted through the network, or 20 TWh/year²⁹.

**GREAT BRITAIN**

²⁹ [http://www.erdf.fr/Offsetting_network_losses](http://www.erdf.fr/Offsetting_network_losses)
Losses as a proportion of electricity demand in 2013, at 7.2 per cent, were down by 0.5 percentage points on 2012 (7.7 per cent). The losses item has three components:

- transmission losses (6.4 TWh) from the high voltage transmission system, which represented about 24 % of the figure in 2013;
- distribution losses (19.6 TWh), which occur between the gateways to the public supply system’s network and the customers’ meters, and accounted for about 73 % of losses;
- theft or meter fraud (1.0 TWh, around 4 per cent).

Historical losses from the UK transmission system are depicted in the table below.

**Transmission:** Historical losses from the Hellenic transmission system are depicted in the table below.

<table>
<thead>
<tr>
<th>Year</th>
<th>Tr. Losses (GWh)</th>
<th>Demand (GWh)</th>
<th>Tr. Losses (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>1.30</td>
<td>56.87</td>
<td>2.28</td>
</tr>
<tr>
<td>2009</td>
<td>1.37</td>
<td>52.82</td>
<td>2.59</td>
</tr>
<tr>
<td>2010</td>
<td>1.50</td>
<td>52.37</td>
<td>2.86</td>
</tr>
<tr>
<td>2011</td>
<td>1.29</td>
<td>51.87</td>
<td>2.49</td>
</tr>
<tr>
<td>2012</td>
<td>1.32</td>
<td>50.56</td>
<td>2.61</td>
</tr>
<tr>
<td>2013</td>
<td>1.17</td>
<td>50.72</td>
<td>2.31</td>
</tr>
<tr>
<td>2014</td>
<td>1.22</td>
<td>50.42</td>
<td>2.42</td>
</tr>
</tbody>
</table>

**Distribution:** losses during the last two years are depicted in the table below.

<table>
<thead>
<tr>
<th></th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injected energy (MWh)</td>
<td>%</td>
<td>Injected energy (MWh)</td>
</tr>
<tr>
<td>41,713,502</td>
<td>7.1</td>
<td>41,782,041</td>
</tr>
</tbody>
</table>

---

32 Source: communication with ADMIE S.A.
ROMANIA

- **Transmission**: Historical losses from the Romanian transmission system are depicted in the table below.

<table>
<thead>
<tr>
<th>Year</th>
<th>Energy injected (MWh)</th>
<th>Energy extracted (MWh)</th>
<th>losses (MWh)</th>
<th>losses based on input (%)</th>
<th>losses based on output (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>43,628,490</td>
<td>42,610,222</td>
<td>1,018,268</td>
<td>2.33</td>
<td>2.39</td>
</tr>
<tr>
<td>2013</td>
<td>40,899,399</td>
<td>39,867,664</td>
<td>1,031,735</td>
<td>2.52</td>
<td>2.59</td>
</tr>
<tr>
<td>2014</td>
<td>42,851,333</td>
<td>41,824,849</td>
<td>1,026,483</td>
<td>2.40</td>
<td>2.45</td>
</tr>
</tbody>
</table>

- **Distribution**: Historical losses from the Romanian distribution system are depicted in the table below.

<table>
<thead>
<tr>
<th>Year</th>
<th>MWh</th>
<th>%</th>
<th>MWh</th>
<th>%</th>
<th>MWh</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>6,756,192</td>
<td>12.4</td>
<td>6,720,116</td>
<td>12.7</td>
<td>6,585,066</td>
<td>12.4</td>
</tr>
</tbody>
</table>

KOSOVO

- **Transmission**: Historical losses from the Kosovo transmission system in the period 2008-2012 are depicted in the figure below.

Source: communication with Transelectrica S.A.

Source: communication with ANRE

• **Transmission**: Historical losses from the Kosovo distribution system in the period 2008-2012 are depicted in the figure below¹⁷.

![Graph of Distribution losses 2008-2012](image)

Latvia

• **Transmission and Distribution**: Historical losses from the Latvian electricity networks are depicted in the table below¹⁸.

<table>
<thead>
<tr>
<th>Losses (as a percentage of input)</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Losses</td>
<td>2.7%</td>
<td>2.8%</td>
<td>2.8%</td>
<td>2.3%</td>
<td>2.0%</td>
<td>2.1%</td>
<td>2.1%</td>
</tr>
<tr>
<td>Distribution Losses (only technical)</td>
<td>6.7%</td>
<td>6.9%</td>
<td>7.2%</td>
<td>6.9%</td>
<td>5.9%</td>
<td>5.0%</td>
<td>4.8%</td>
</tr>
<tr>
<td>Distribution Losses (only non-technical)</td>
<td>0.4%</td>
<td>0.4%</td>
<td>0.5%</td>
<td>0.2%</td>
<td>0.2%</td>
<td>0.2%</td>
<td>0.2%</td>
</tr>
</tbody>
</table>

It should be noted that losses for 2014 are included as operative data (not final) and also that non-technical losses do not refer to commercial losses (i.e. illegal offtakes, unbilled, unpaid energy) but correspond to network operators self-consumption.

Further statistics reported in the bibliography include³⁹:

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³⁸ Source: communication with Public Services Commission of Latvia
Compared to most of the INOGATE Partner Countries, Azerbaijan appears to be ranked among the top three. There was a considerable improvement during the period 2003-2008 which local and international experts justify on the respective drop of overall electricity demand at the time. We notice that as the economy recovers and the demand increases proportionally to the GDP growth rates, losses have rebounded to considerable levels.

Source: IEA (2008) – see footnote ref. 28

Figure 19: Evolution of T&D losses in several INOGATE PCs and the EU (average)

Source: IEA Statistics – Electricity Information (transmission and distribution losses, includes pilferage)
Further statistics on T&D losses for numerous countries can be retrieved by the World Bank and the Energy Information Administration (EIA). Working through the available data on losses it is worthwhile to be mentioned that the divergence of losses definitions in the national context appears to be a decisive determinant. The preceding analysis with the use of selected cases from Europe intends to illustrate that cross-country comparisons should always be made with due attention to the national losses definitions.

40 http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=2&pid=2&aid=2
5.3 Procurement of losses

Directive 2009/72/EC obliges TSOs to procure the energy they use to cover network losses according to transparent, non-discriminatory market-based procedures whenever they have this ability. As a European practice amongst TSO, two possible cases can be distinguished:

- **OPTION A**: TSOs are responsible for procurement of energy for losses (“centralised’ method”)
- **OPTION B**: Generators and/or Suppliers are mainly obliged to cover the losses (“self-procurement method”)

Under **OPTION A**, the energy required to cover transmission losses is procured:

- on the power exchanges – PEX (day ahead or longer contracts),
- bilaterally – OTC,
- by auctions/tenders (generators or traders submit price offers).

It is a common practice to use several possibilities together, for instance a combination of PEX and bilateral (longer term hedged contracts). The costs of losses, following an approval by the regulator, are used in the tariff calculation. Imbalances caused by losses are usually handled in the balancing market like any other imbalance. This option requires an ex-ante (e.g. on a yearly basis) estimation of losses and of the cost to cover the losses, so that to include the cost to the network tariff.

In several cases incentives to TSOs to reduce losses / to minimize costs are used. Of course incentive schemes apply only to option A (centralised procurement) which is used in many EU countries, e.g.:

- France, Austria, Germany
- Norway, Sweden, Finland
- Hungary, Poland, Romania, Czech Republic, Slovakia

The following table summarizes the way transmission losses are treated in six EU countries.

<table>
<thead>
<tr>
<th>Country</th>
<th>Who</th>
<th>How</th>
<th>Tariffs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Finland</td>
<td>Network operators</td>
<td>Power Exchange or</td>
<td>Paid by network tariffs</td>
</tr>
<tr>
<td>France</td>
<td></td>
<td>bilaterally</td>
<td></td>
</tr>
<tr>
<td>Norway</td>
<td></td>
<td>Annual tenders</td>
<td></td>
</tr>
<tr>
<td>Sweden</td>
<td></td>
<td>Special balancing</td>
<td>Paid by dedicated tariff</td>
</tr>
<tr>
<td>Czech Republic</td>
<td></td>
<td>group</td>
<td></td>
</tr>
<tr>
<td>Austria</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>


Under **OPTION B** (Self-procurement of transmission losses by Trading Participants), transmission losses are physically injected by the Generators. Further to the projected load demand, Suppliers actually procure the additional energy for compensation of the transmission losses related to the demand during a specific trading period. For this purpose, ex-ante calculated Transmission Loss Factors (applied also to Generators should the market design provides for) are used. The estimated transmission losses are priced at the same price as load (‘scheduled’ energy).

Further losses due to real-time imbalances are treated like any other induced or occurred imbalance, i.e. the difference between effective (ex-post) losses and estimated (ex-ante) losses is priced at the
cost of providing the extra energy on the balancing market. This option (B) is used in Ireland, Portugal, Italy and Greece.

Table 6 below summarizes the way transmission losses are treated in EU countries:
Table 6: Derivation of price for transmission losses in EU Countries

<table>
<thead>
<tr>
<th>Country</th>
<th>Price of transmission losses</th>
</tr>
</thead>
<tbody>
<tr>
<td>AT</td>
<td>The TSO buys via auctions upfront products (from 2 years in advance till day-ahead) according to the predicted required quantities in a regular process (weekly tendering). The average price of these procurements becomes the value of losses</td>
</tr>
<tr>
<td>BE</td>
<td>Calculated based on average price of yearly tenders</td>
</tr>
<tr>
<td>BG</td>
<td>Based on generators weighted average price</td>
</tr>
<tr>
<td>CZ</td>
<td>Based on costs of electricity purchased through electronic auctions, (annual, quarterly, monthly, day ahead or intraday basis) and also balancing market</td>
</tr>
<tr>
<td>DE</td>
<td>Based on average base load prices</td>
</tr>
<tr>
<td>DK</td>
<td>Based on Nasdaq Commodities OMX forward prices and contracts for difference (geographically weighted – 2 areas, 60% of the price in area 1 and 40% of the price in area 2)</td>
</tr>
<tr>
<td>EE</td>
<td>Calculated on hourly basis, using Nord Pool wholesale market prices</td>
</tr>
<tr>
<td>ES</td>
<td>Based on average wholesale market price (Day ahead market, balancing market and re-dispatching)</td>
</tr>
<tr>
<td>FI</td>
<td>Based on power exchange prices (Nord-Pool)</td>
</tr>
<tr>
<td>FR</td>
<td>Based on forward products and hourly adjustments with spot products and balancing market prices</td>
</tr>
<tr>
<td>GB</td>
<td>Based on forward market price quarterly weighted</td>
</tr>
<tr>
<td>GR</td>
<td>Equal to the hourly Day-ahead market prices</td>
</tr>
<tr>
<td>HR</td>
<td>Based on historical and signed contractual prices</td>
</tr>
<tr>
<td>HU</td>
<td>Based on the weighted average market purchase price</td>
</tr>
<tr>
<td>IE</td>
<td>Calculated using base load price (based on the average ‘Directed Contracts’ price)</td>
</tr>
<tr>
<td>IT</td>
<td>Based on the wholesale market price (Day Ahead market)</td>
</tr>
<tr>
<td>LT</td>
<td>Based on bilateral contracts prices, prices in spot market, prices from neighbouring countries mainly Nordic countries and balancing costs</td>
</tr>
<tr>
<td>LU</td>
<td>Based on yearly public tendering procedure</td>
</tr>
<tr>
<td>LV</td>
<td>Based Nord Pool Spot prices of the Latvian trading area adjusted by balancing price</td>
</tr>
<tr>
<td>NI</td>
<td>Based on the average Directed Contracts (DC) price. DC auctions are held quarterly (similar to IE)</td>
</tr>
<tr>
<td>NL</td>
<td>Based on yearly auctions results</td>
</tr>
<tr>
<td>PL</td>
<td>Based on the forward electricity prices, prices of bilateral contracts for next year and historical prices.</td>
</tr>
<tr>
<td>PT</td>
<td>Based on the hourly price for day ahead energy market (MIBEL)</td>
</tr>
<tr>
<td>RO</td>
<td>Based price established in the Centralized Market for Bilateral Contracts and Day Ahead Market</td>
</tr>
<tr>
<td>SE</td>
<td>Based on futures prices contracts procured + risk management</td>
</tr>
<tr>
<td>SI</td>
<td>Based on average peak (30%) &amp; baseload (70%) futures price from EEX</td>
</tr>
<tr>
<td>SK</td>
<td>Based on power exchange (PEX) electricity price</td>
</tr>
</tbody>
</table>

Source: own analysis on the basis of information provided by ACER’s “Report to the European Commission on the implementation of the ITC mechanism in 2013” 41

5.4 Tariffs and regulation

In the case where costs of transmission losses are recovered through tariffs, there are two options possible:

- Include cost of losses in the network tariff

Separate network tariff components for losses

Transmission tariffs, as well as any other tariff, are subject to periodical review and revision so as to reflect on the needs and changes on the industry and the financial viability of the regulated incumbent. In the following Table 7, the main characteristics of the TSO tariffs in EU for the year 2010 are depicted in comparison to those of 2013 using the standard summary table provided by ENTSO-E’s Transmission Tariffs Synthesis Report.

Transmission tariffs in the Member States reflect most of the requirements of the Regulation 714/2009 given that they are postage stamp tariff systems rather than being distance-based. In some countries a zonal tariff system (Bulgaria, Italy and Great Britain) or a nodal system (Norway) is applied. Article 4.2 of the Regulation 714/2009 foresees the provision of locational signals to producers and consumers of electricity. Some countries have introduced systems providing such locational signals (Great Britain, Norway, Sweden, Romania and Slovakia). However, the majority of the EU countries do not have locational signals that take into account the network losses.

A similar approach (Postage-stamp tariffs) is used for Distribution Network tariffs according to the EURELECTRIC Report\(^\text{42}\). Further, the report notes that:

> “The most common pricing method is the use of "postage stamps". A price system with distance-related elements in the distribution network tariff systems would appear to be inappropriate. In order to achieve a cost-reflective system, there should be regional differentiation. Other requirements for distribution network tariffs are the principles of cost covering and transparency”.

<table>
<thead>
<tr>
<th></th>
<th>Sharing of network operator charges</th>
<th>Price signal</th>
<th>Are losses included in the tariffs charged by TSO?</th>
<th>Are system services included in the tariffs charged by TSO?</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Generation</td>
<td>Load</td>
<td>Seasonal/time-of-day (1)</td>
<td>Location</td>
</tr>
<tr>
<td>Austria</td>
<td></td>
<td>15%</td>
<td>85%</td>
<td>-</td>
</tr>
<tr>
<td>Belgium</td>
<td></td>
<td>0%</td>
<td>100%</td>
<td>xxx</td>
</tr>
<tr>
<td>Bosnia and Herzegovina</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Bulgaria</td>
<td></td>
<td>0%</td>
<td>100%</td>
<td>x</td>
</tr>
<tr>
<td>Croatia</td>
<td></td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Czech Rep.</td>
<td></td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Denmark</td>
<td>2-5%</td>
<td>95-98%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Estonia</td>
<td></td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Finland</td>
<td></td>
<td>11%</td>
<td>89%</td>
<td>x</td>
</tr>
<tr>
<td>France</td>
<td></td>
<td>2%</td>
<td>98%</td>
<td>-</td>
</tr>
<tr>
<td>Germany</td>
<td></td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Great Britain</td>
<td>27%</td>
<td>73%</td>
<td>xx</td>
<td>TNUoS—locational; BSUoS—non-locational</td>
</tr>
<tr>
<td>Greece</td>
<td>0%</td>
<td>100%</td>
<td>x</td>
<td>-</td>
</tr>
<tr>
<td>Hungary</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Ireland</td>
<td>0%</td>
<td>80%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Italy</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Latvia</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Lithuania</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Luxembourg</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>FYROM</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Netherlands</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>N. Ireland</td>
<td>25%</td>
<td>75%</td>
<td>xxx</td>
<td>-</td>
</tr>
<tr>
<td>Norway</td>
<td>35%</td>
<td>65%</td>
<td>xxx</td>
<td>Location</td>
</tr>
<tr>
<td>Poland</td>
<td>0.60%</td>
<td>99.4%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Portugal</td>
<td>0%</td>
<td>100%</td>
<td>xx</td>
<td>-</td>
</tr>
<tr>
<td>Country</td>
<td>Use of system</td>
<td>Use of system</td>
<td>6G zones values</td>
<td>Tariff for ancillary services</td>
</tr>
<tr>
<td>-----------------</td>
<td>---------------</td>
<td>---------------</td>
<td>-----------------</td>
<td>-------------------------------</td>
</tr>
<tr>
<td>Romania</td>
<td>20.69%</td>
<td>79.31%</td>
<td>-</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>0%</td>
<td>100% system services</td>
<td>=6G tariffs values</td>
<td>8L zones =8L</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Serbia</td>
<td>0%</td>
<td>100%</td>
<td>x</td>
<td>Yes</td>
</tr>
<tr>
<td>Slovak Rep.</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
<td>Through a specific fee</td>
</tr>
<tr>
<td>Slovene</td>
<td>0%</td>
<td>100%</td>
<td>xx</td>
<td>Yes, Through a specific fee</td>
</tr>
<tr>
<td>Spain</td>
<td>0%</td>
<td>100%</td>
<td>xxx</td>
<td>No, recovered in the energy price</td>
</tr>
<tr>
<td>Sweden</td>
<td>28%</td>
<td>72%</td>
<td>- Location</td>
<td>Yes</td>
</tr>
<tr>
<td>Switzerland</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
<td>By a separate tariff for losses</td>
</tr>
</tbody>
</table>

Remarks:
(1) The "X" indicates time differentiation. With one "X", there is only one time differentiation ("daynight", "summer-winter" or another one). With two "X" (or more), there are two (or more) time differentiations.
(2) TNUoS: Transmission Network Use of System; BSUoS=Balancing Services Use of System

Source: ENTSO-E, Overview of transmission tariffs in Europe: Synthesis 2010
Table 8: Main characteristics of the TSO tariffs in Europe (2013)

<table>
<thead>
<tr>
<th>Sharing of network operator charges</th>
<th>Price signal</th>
<th>Are losses included in the tariffs charged by TSO?</th>
<th>Are system services included in the tariffs charged by TSO?</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Generation</td>
<td>Load</td>
<td>Seasonal/time-of-day (1)</td>
</tr>
<tr>
<td>Austria</td>
<td>20%</td>
<td>80%</td>
<td>no</td>
</tr>
<tr>
<td>Belgium</td>
<td>9%</td>
<td>91%</td>
<td>xxx</td>
</tr>
<tr>
<td>Bosnia and Herzegovina</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Croatia</td>
<td>0%</td>
<td>100%</td>
<td>x</td>
</tr>
<tr>
<td>Czech Rep.</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Denmark</td>
<td>4%</td>
<td>96%</td>
<td>x</td>
</tr>
<tr>
<td>Estonia</td>
<td>0%</td>
<td>100%</td>
<td>x</td>
</tr>
<tr>
<td>Finland</td>
<td>15%</td>
<td>85%</td>
<td>x</td>
</tr>
<tr>
<td>France</td>
<td>2%</td>
<td>98%</td>
<td>-</td>
</tr>
<tr>
<td>Germany</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Great Britain</td>
<td>27%</td>
<td>73%</td>
<td>xx</td>
</tr>
<tr>
<td>Greece</td>
<td>0%</td>
<td>100%</td>
<td>x</td>
</tr>
<tr>
<td>Hungary</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Ireland</td>
<td>25%</td>
<td>75%</td>
<td>-</td>
</tr>
<tr>
<td>Italy</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Latvia</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Lithuania</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Luxembourg</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>FYROM</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Netherlands</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>N. Ireland</td>
<td>25%</td>
<td>75%</td>
<td>load has 4 STOD rates</td>
</tr>
<tr>
<td>Norway</td>
<td>34%</td>
<td>66%</td>
<td>Via losses (3)</td>
</tr>
<tr>
<td>Poland</td>
<td>0%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Portugal</td>
<td>7%</td>
<td>93%</td>
<td>xx</td>
</tr>
</tbody>
</table>
### Remarks:

1. "X" indicates time differentiation. With one "X", there is only one time differentiation ("day-night", "summer-winter" or another one). With two "X" (or more), there are two (or more) time differentiations.
2. TNUoS: Transmission Network Use of System
3. BSUoS: Balancing Services Use of System
4. Marginal loss % per connection point

Source: ENTSO-E, Overview of transmission tariffs in Europe: Synthesis 2013

### 5.5 Regulatory and incentive mechanisms

Energy efficiency is an issue of increasing importance. Therefore, an incentive for taking measures to reduce losses should be provided to TSOs. Different approaches exist for such incentives in the various EU Member States. There is a number of external factors with significant influence on the level of losses. In particular, these include:

- the geographical size of the market, as well as
- the number and degree of dispersion of loads,

which are ultimately important driving factors that cannot be modified.

Due to its complexity, the treatment of losses is also deeply related to other regulatory and operational issues, such as the national/international energy efficiency schemes and commitments, the general process of infrastructure planning and the network reconfiguration and development, which are far beyond from the scope of this work.

Generally, it should be stated that losses are proportional to:

- the amount of energy that is delivered,
- the distance between generation and consumption, and
- inversely related to the voltage level of the network.

Consequently, any measures or actions focused on reducing or smoothing the demand for energy, (re)locating generation plants closer to demand, and upgrading the voltage level of the network, are anticipated to have definitely a positive impact on transmission losses.
Given the efficiency targets and the associated costs that losses impose on society, the reduction of network losses seems a logical instrument to increase the sector’s energy efficiency. However, these costs are currently not always relevant for grid operators. In such cases, reduction of grid losses may prove to be a low priority to network operators. To exemplify this, in a study on 41 European transmission and distribution system operators (TSOs and DSOs), only 7 seem to treat network losses as a separate cost line item in their annual financial accounts.43

In Europe, most regulators apply incentivized regulation, i.e. price or revenue cap. This scheme decouples the profits of the regulated operator from its costs by setting a price ceiling. For each regulatory period, normally between three to five years, the price cap for each year is set based on the Retail Price Index (RPI, a measure of inflation) and an efficiency factor (X). Since prices remain fixed during the period, the utility keeps or shares the achieved cost savings during that period.

Figure 20: Incentive-based regulation (single tariff review period)

Source: Regulation w.r.t. small, medium and large distribution and power transformers. Position paper, ECI, 2012

At the end of the regulatory period, a new path is set for the next three to five years.

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44 Regulation w.r.t. small, medium and large distribution and power transformers. Position paper, ICER Dec. 2012.
It is important to allow sufficient time to network operators to recover profits derived from extra-investments for efficiency. Giving enough time allows network operator to make decisions in terms of lowest life cycle cost instead of lowest investment cost.

An alternative way for regulator is to compensate upfront the extra-investments for efficiency. In this case the benefits of reduced losses can then be directly transferred to consumers (price trajectory can then be lowered).

Two main schemes can be distinguished:

- **Output based schemes**
  
  - Network operators are encouraged to reduce losses by incentives placed on a recorded reduction in their loss rate relative to a target. Such a scheme can be viewed as internalizing the benefits for the network operators of reducing their losses and often involves giving a benefit per unit that losses are reduced.
  
  - This scheme leaves the network operators to develop and decide on ways to reduce losses, making it likely that loss reductions will be achieved at minimum cost.
  
  - Revision of target losses and incentives by regulator should be adjusted to allow at least the recovery of extra-investments. Otherwise, network operator would opt for the lower investment cost equipment.

- **Input based schemes**

  - The incentive for network operators to reduce losses is placed on inputs rather than outputs. For example, by estimating the contribution to loss reduction from a particular piece of equipment compared to the one most commonly installed, operators could be given this sum upfront to encourage the installation of such equipment. All the benefits from reductions in losses are provided in the same year as the equipment is installed.
In the current practice three main options regarding the regulatory treatment of losses are used:

- The first option relates to the **responsibility for loss procurement**. In some countries (e.g. France, Germany, the Netherlands, Norway) network operators are responsible for procurement. The associated costs are typically included in the allowed revenue whereas they can be considered as controllable or non-controllable items. In other countries the suppliers have to procure the losses (e.g. Portugal, Spain, Greece) and thus the associated costs are not considered in the price control of the grid operators and the associated grid tariffs.

- The second option to consider losses in the regulation is to **include explicit loss reduction incentive schemes in the price/revenue cap** in case the grid operators are not responsible for loss procurement. This should nonetheless encourage loss reduction by the grid operators and is applied in, e.g., Portugal and Spain. These incentives link the allowed revenue with the grid operator’s performance with respect to losses. As such, the revenue is increased or decreased by the difference between the actual and the target network losses, valued at a specific price.

- A third distinction relates to the **actual treatment of costs related to losses** in the price control mechanism.
  - For OPEX related expenditures, they can either be treated as non-controllable (e.g. in Germany), which effectively makes them a cost-pass through item directly increasing or decreasing the allowed revenue, or as controllable (e.g. in Denmark) which makes them subject to the X-factor.
  - For CAPEX related expenditures, costs with respect to investments in energy efficient equipment can be part of the allowed cost (e.g. for UK DSOs) which allows earning a return on capital.

From a project perspective, the investment in loss-reducing efficiency improvements in networks typically involves a balance between increased capital expenditures and the resulting reduction in operational expenditures. In other words, the project-based assessment would involve an evaluation of the minimum lifecycle costs (LCC). For TSO/DSOs in regulated environment such trade-offs between capital and operating costs should be considered when taking investment decisions as well. In order to provide the regulated entity with incentives to make an efficient decision, the regulatory framework should embed the structure that promotes decision-making on the basis of LCC.

Incentivising schemes addressing network efficiency explicitly should induce LCC driven decision making by the regulated entities. Embedding of LCC can be accomplished through various pathways. In case of cap regulation, the scheme should allow investments in efficient equipment, while it should also allow retention of OPEX cost savings related to network loss reduction. To facilitate a reasonable payback period a gradual adjustment of the allowable losses should be considered. This induces a reasonable payback time beyond the regulation period length. To reflect the social benefits associated with energy efficient equipment, allowances for financially less attractive investment could be considered to compensate for the payback time associated with the regulation period duration. Otherwise, regulatory arrangements should include appropriate allowance on costs of losses for a sufficient time period.

In case the costs of network losses are procured by suppliers rather than network operators, incentive schemes that are based on a recorded reduction in network losses relative to a target may
Apart from financial incentives regulation may resort to non-financial incentives as well to stimulate investments in energy efficient equipment. Such non-financial incentives may comprise technical standards, certificate schemes, voluntary agreements, labelling schemes, information campaigns or R&D support.

**Some regulatory incentives exercised in the EU**

At least the following cases may be distinguished concerning regulatory incentives practices for transmission losses in the EU:

1. No regulatory or incentive mechanism (which is common among most countries);

2. Incentive-based regulatory model where the incentives for the network losses are equal to the incentives for any other costs; (e.g. Norway)

3. Allowed rate of losses to include in tariffs capped to a maximum value in %; (e.g. Austria, Czech Republic, UK)

4. Incentive mechanism allowing the network operator to be rewarded (or charged) if cost for losses lower (or above) than a reference value are achieved (e.g. Germany)

5. Upper limit (‘cap’) on acceptable amount of losses (Portugal, UK)

ERGEG’s Position Paper (Appendix 9.1) in its Annex A2.7 provides a detailed overview of the regulatory incentives to reduce losses across EU member states.
5.6 Country-specific cases (EU Member States)

5.6.1 France

In France both transmission and distribution losses are considered as non-controllable (cost of network losses is reimbursed to the network operators) as energy to compensate for losses is bought at market prices. Thus, operators are not much incentivised to reduce losses.

Transmission losses

The loss rates are included between 2 and 3.5% of consumption, depending on the seasons and time of day. On average, the rate comes to 2.5%45.

In France there is in place a voluntary Power Exchange and an OTC market. The Transmission System Operator (RTE) procures from various sources (from a yearly horizon to D-2) the volume corresponding to the forecasted losses. The challenge, therefore, is to come up with secure predictions for the quantities of these losses for the year down to 2 days. The main elements for medium and long term predictions for a week up to a year are briefly presented below.

Losses depend directly on the network configuration, and generation and consumption at each node of the transmission network. A few months ahead, none of this information is available with accuracy. However, indirectly, losses depend on temperature since, when temperature drops, consumption (and thus production) increase, which brings about an increase in losses. Losses also depend on the season, since outages of production units as well as network maintenance often take place during slack months, which influences both production plan and network configuration. Finally, consumption predictions at standard temperature are available for France for a week ahead, and prediction at forecast temperatures beyond that.

The process for yearly prediction of losses is as follows:

- Determination of the curve of hourly losses.
- Application of this curve to predicted daily volumes.
- Prediction of hourly volumes.

This process relies on the use of statistics, predictive methods (mobile averages, linear regressions, etc.) derived from experience, historical data on losses and consumption, seasonal characteristics (month, type of day, etc.) and predicted daily volumes. The method has been used since the end of 2001 and a substantial experience feedback is now available. It shows that prediction is satisfactory for the specific process. It also indicates paths for evolution of the method, namely a more diversified taking into account of forecast temperatures and the consumption structure.

System operators (TSO and DSO) buy the losses:

- on the OTC market by an auction mechanism, or directly on the PEX market, as products in the futures market (i.e. from the EPD power exchange) for the calendar, quarter and monthly products;
- on the OTC market by an auction mechanism, or directly on the PEX market, as products in the Day Ahead market (i.e. EpexSpot power exchange) for the hourly needs known the Day

Ahead;

- as products in the balancing market for the half-hourly needs, at prices accurately known 12 months after real time (calculation done at M+1 M+3 M+6 and M+12);

Each week, RTE draws up loss forecasts for the coming week. These forecasts are established on the basis of predicted consumption, generation and exchanges. The forecasts are refined two days before (D-2) according to the latest meteorological forecasts. They are then used to establish the delivery programmes sent to Suppliers with whom RTE has signed relevant contracts for supply of losses.

The sale of losses to grid operators reveals a growing share of options products, sold by a limited number of participants backed by generation facilities. Purchases by the grid operators RTE and ERDF, necessary to offset their losses, represented 33 TWh in 2008 and 17 TWh in the first half of 2009. RTE and ERDF put out tenders several times a month to buy products enabling them to cover losses on their grid. In 2008, 112 calls for tenders were put out by the two grid operators; 49 were organised in the first half of 2009. This should be compared with the 121 calls for tenders in 2007. As a result of the calls for tenders in 2008 and the first half of 2009, grid operators bought monthly products (from M+1 to M+18), quarterly products (from Q+1 to Q+5), and annual products (from Y+1 to Y+4). Since early 2009, RTE has also been covering part of its needs on the EPEX Spot (day-ahead) market.

Table 9 summarises the breakdown of energy committed contractually by sellers. Participants are selling growing volumes of options products and the share of firm products or products similar to firm products for the sellers (otherwise called premium deals) was lower in 2008 than 2007. In 2008, grid operators used 40% of options or premium deal products. In the first half of 2009, this ratio stood at 68%.

Table 9: Volume of energy sold to grid operators to make up for losses

<table>
<thead>
<tr>
<th></th>
<th>Firm Products</th>
<th>Take or Pay</th>
<th>Optional Products</th>
<th>Swap</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>22.0</td>
<td>17.0</td>
<td>18.0</td>
<td></td>
</tr>
<tr>
<td>2008</td>
<td>18.5</td>
<td>15.0</td>
<td>20.5</td>
<td></td>
</tr>
<tr>
<td>H1 2009</td>
<td>4.5</td>
<td>8.5</td>
<td>10.0</td>
<td>0.45</td>
</tr>
</tbody>
</table>

Source: RTE, ERDF; Analysis: CRE.

RTE (Réseau de transport d’électricité), the French TSO, released an article prepared by RTE staff for CIGRE in 2004 referring to losses prediction methodology. Further information on losses can be found at RTE website’s designated section.

**Distribution Losses**

Electricite Reseau Distribution France (ERDF) is the Distribution System Operator in France. ERDF is

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46 Take or pay contracts deals involve products which are paid for by the grid manager at a contractual price, but which have the possibility of not withdrawing the energy. In this case, the seller resells the energy on the spot market receives the contractual price from the grid manager and pays the spot price back to the latter. For the seller, premium deals are therefore similar to a firm product.

47 Buying and selling


49 [http://www.erdfr.fr/Offsetting_network_losses](http://www.erdfr.fr/Offsetting_network_losses)
continually offsetting its distribution network’s losses based on medium- and short-term forecasts. To ensure that enough energy is available to offset these losses, ERDF purchases electricity from both long-term and spot wholesale energy markets.

ERDF’s total losses represent nearly 6% of energy transmitted through the network, or 20 TWh/year.

ERDF evaluates energy losses using a network energy report. The report calculates the difference between ERDF’s consumption load graphs and readings from all customers. It takes into account energy waste (or loss) due to electrical phenomena in circuits and transformers.

Losses are calculated using the following equation:

\[
\text{losses} = a \cdot (\text{ERDF Network’s synchronous capacity})^2 + b \cdot \text{ERDF Network’s synchronous capacity} + c
\]

Two sets of coefficients \((a, b, c)\) are used. One applies to weekdays (denoted by subscript ‘s’), and the other to bank holidays and weekends (denoted by subscript ‘w’), as follows:

- \(a_s = 7.81 \cdot 10^{-10} \text{ kW}^{-1}\)
- \(b_s = 7.13 \cdot 10^{-2}\)
- \(c_s = 4.04 \cdot 10^5 \text{ kW}\)
- \(a_w = 4.85 \cdot 10^{-10} \text{ kW}^{-1}\)
- \(b_w = 5.58 \cdot 10^{-2}\)
- \(c_w = -1.05 \cdot 10^5 \text{ kW}\)

5.6.2 Italy

The situation in Italy concerning transmission losses may be summarized as follows. The wholesale market model includes a Power Exchange and bilateral contracts. The treatment of losses is based on the principle that “load” (i.e. end-users of electricity or the Suppliers representing them) should bear the cost for the losses. Moreover, the method followed corresponds to the “self-procurement” one. In the Day Ahead market (PX and bilateral contracts) bids and offers are adjusted to ‘ex ante’ Transmission Load Factor (TLFs) (e.g. calculated every 5 years), whilst an additional “error” factor is also applied. With respect to cost allocation:

- In the DA market, losses are priced at the energy clearing price
- The difference between the DA estimation of losses and the actual level of losses is paid by the TSO (TERNA) at the balancing price in real time and later subdivided among all network users (uplift applied to the network tariff).

In the distribution sector, an incentive for loss reduction was provided by allowing an increased rate-of-return for investments in substitution of existing transformers with low losses transformers in Medium Voltage/Low Voltage level.

5.6.3 United Kingdom

The market model in the UK is of totally decentralized nature, with energy trading based on bilateral contracts as well as trading in power exchanges (continuous trading) and the Transmission losses allocation is organised according to Option B’ (self-procurement).

Actual losses are metered as the difference between the metered quantity of energy off-taken and injected by trading participants (more specifically by the Balancing Mechanism (BM) units, which collectively can by accounted as a single trading participant). There is a locational feature (calculation of TLFs) in the allocation methodology, but currently it remains inactive (TLF is set to zero). Losses are
then allocated to “injection” at proportion of 45% and “off-take” by 55% by the so-called “BSC System Parameter a”.

In summary therefore, the UK system provides for the possibility to set nodal or zonal TLFs by calculating the latter per settlement period. Moreover, the share between generation and demand can be adjusted through the proportion parameter “a”. Settlement calculations take into account losses adjustment in:

- Scaling the payments and charges associated with accepted Bid and Offers in the Balancing Mechanism.
- Determining the System Buy and System Sell prices.
- Calculating the Balancing Services Volumes.
- Scaling the payments and charges associated with non-delivery in the Balancing Mechanism.

An incentive formula to minimize balancing costs including losses is used. The Transmission System Operator is externally incentivised in its role as the system operator for the onshore and offshore electricity transmission systems in England, Scotland and Wales by the Balancing Services Incentive Scheme (BSIS). BSIS provides a focus on key areas where National Grid is able to create value for the industry and consumers by reducing operating costs, and improving the accuracy and provision of information for use by the industry to better facilitate the market. BSIS costs can be categorised into two main groups; external costs and internal costs;

- The internal incentive scheme costs include National Grid’s internal costs for operating the transmission system. For example, staff and overheads.
- The external BSIS costs recover the external costs National Grid incurs when operating the transmission system. These costs include Balancing Mechanism (BM) charges, contracts and trading carried out to minimise the costs of actions.

These external costs are grouped in the following categories; constraints, black start, reactive power, energy related services, SO internal costs and incentive payments. External costs in their turn are part of the overall cost for balancing the system and thus in both the electricity supply industry’s interest and the TSO interest to minimise.

Yet, losses are only one of the parts comprising the TSO incentive scheme, the latter being committed to a target which is mutually agreed with the regulatory authority on an ex-ante basis and verified/adjusted regularly using the out-turn of the losses (ex-post). As also mentioned earlier in this report, losses depend on a number of network characteristics including the topology of the generators, the demand development, etc.. A steady increase of losses has been observed since the introduction of BETTA (British Electricity Trading and Transmission Arrangements) from 2005 and onwards, with which the systems of Scotland (where some large nuclear power generators are included) has incorporated to the common market and owned to this development a substantial change in power flows has been realised. Further to this change the TSO observed substantial deviations from 2007 and onwards between the forecasted losses and the actual losses, which led to a negotiation process with the regulatory authority. In the 30th of June 2008 the TSO submitted a report to the regulatory authority presenting their analyses and proposals for the forecasting of losses in the UK transmission system. The report:

- summarised the investigation (statistical & analytical) carried out;
proposed a new model for forecasting the losses; and
tested the model and produced sensitivity analyses in order to validate it and reveal any limitations.

The “Investigations into Transmission Losses on UK Electricity Transmission System, June 2008” provides a quite diversified approach as compared to that in France and it is attached to this report for a more thorough consideration (Appendix 9.2). It should be noted however that the model presented in the report is based on the established knowledge of the nature and size of transmission losses in the UK system, which takes into account a long track of previous analyses and data.

Great Britain combines input and output schemes. The current distribution price control (April 2010 to March 2015) includes an incentive mechanism to reduce losses. Target losses are set by the regulator Ofgem as a fixed loss percentage for each distribution company. The percentage is determined based on an average of performance over the last five years. The price of losses is set by Ofgem (£60/MWh pre-tax, 2010-11 prices) on the basis of the wholesale price of electricity less the EU Emissions Trading Scheme (ETS) cost of carbon plus the shadow price of carbon (as set by the Department for Environment, Food and Rural Affairs). There is cap and collar on the total incentive amount, i.e. companies are not allowed to earn or lose more than 97 basic points (pre-tax) in shareholder returns through the losses incentive. In addition, companies are provided with a pre-determined amount of upfront funding (£16m in the current price control) for low loss investments where they have made a business case using the electricity wholesale price including the Government’s shadow price of carbon. This should allow DNOs to finance these investments while ensuring that customers only pay for schemes that have a robust investment case.

5.6.4 Germany
For distribution grid operators, costs for losses can be calculated and benchmarked every year. However, the amount of losses is a fixed component for distribution grid operators without a yearly adjustment and there is no incentive to reduce the total amount. The benchmark is only intended to increase cost-efficiency and to provide incentives for grid operators to purchase energy to make up for losses in a cost-efficient way. Thus, technical efficiency in grids is not incentivised. Transmission grid operators do not have incentives to minimise losses either, since they could reach a higher revenue cap with higher cost for grid losses. As a consequence of the above, there are no incentives to invest in a more efficient grid infrastructure in Germany. To further develop the treatment of losses the German Regulatory Authority (BnetzA) has indicated recently that costs for energy losses will be fixed by the regulator, starting from the next regulatory period.

5.6.5 Spain
In Spain, transmission and distribution losses are not considered in the tariffs as the grid operators are not allowed to purchase energy to compensate losses. They are separately recovered in the energy market and charged proportionally to the demand. From this point of view transmission grid operators are not encouraged to reduce transmission losses since they are not allowed to purchase energy. On the other hand, the TSO are not incentivized to minimize capital costs, thus investments which might also reduce losses may be considered. However, the distribution grid operators’ remuneration explicitly takes a component on losses into account and sets incentives for loss

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50 Incentives to improve energy efficiency in EU Grids (ECOFYS, 2013)
51 Incentives to improve energy efficiency in EU Grids (ECOFYS, 2013)
reduction. The loss incentive scheme applies a formula that includes a loss target for each company. Depending on the actual performance of the company a price can be calculated which goes into the revenue calculation.

5.6.6 Portugal
Portugal\textsuperscript{52} uses an input scheme. An incentive mechanism to reduce network losses in the distribution networks allow the network company to be rewarded / penalized if it has achieved actual distribution losses lower than / above a target value set by the regulator for each year (see figure below):

![Incentive mechanism for distribution losses in Portugal](figure22.png)

Source: Regulation w.r.t. small, medium and large distribution and power transformers. Position paper, ECI, 2012

\textsuperscript{52} Regulation w.r.t. small, medium and large distribution and power transformers. Position paper, ECI, 2012
Conclusions and recommendations

This Chapter describes the transmission and distribution network efficiency focusing on the definition of network losses as well as their valuation and procurement as it has developed in the EU. It also touches upon the relationship of network pricing the regulation of the transmission and distribution networks with a brief mention on the manner that incentive-based regulation may induce efficiency improvement.

Similarly to our findings with regards to the generation sector an information asymmetry and lack of clarity in the relation between networks regulation and the electricity tariffs exists due to the monopolistic nature of the electricity industry of Azerbaijan and the fragmentation of regulatory powers between the Ministry of Energy and the Tariff Council.

There is just one central recommendation that can be made at this point and that is related to the future possible revision of the electricity tariff structure that the electricity customers may see in Azerbaijan. Although the absolute value of the electricity tariff may for instance remain at the existing levels of 0.06 AZN/kWh subject to the relevant decision of the Tariff Council, the electricity bill that each customer receive should clearly refer to the composition of the end use tariff. This should further be arranged by splitting the tariff into generation, transmission, distribution, and supply component. For this to be effected Azerenerji should be able to perform an accounting unbundling across the business activities generation, transmission distribution and supply and also Bakuelectricibeke should also be able to perform an accounting unbundling across its distribution and supply business activities. We stress that an accounting unbundling by no means refers to any split or other functional impact on the integrity of the companies. On the contrary, it will aid the companies understand a bit further their cost structure, define cost centres across their business activities and eventually enable an informed decision making process.

Summary of the main characteristics of country cases concerning incentives for losses reduction:

- the UK and Spanish tariff schemes include an incentive for loss reduction; the German Regulatory Authority plans to implement such an incentive in the future;
- there is a reputational driver for loss reduction in the transmission system in the UK;
- in both Spain and UK, distribution system operators are faced with clear financial incentives to reduce distribution losses;
- the UK regulation includes a combination of input and output measures;
- increased rate-of-return provided in Italy for investments in low-loss transformers

5.7 Conclusions and recommendations
Part B: The Gas sector
6 UPSTREAM GAS SECTOR: REVIEW OF THE EXPERIENCE WITH OPERATION OF UNDERGROUND GAS STORAGE IN THE EU IN RELATION PARTICULARLY TO THE “STORAGE TARIFF”

This Chapter reports on the regulatory issues related to the operation of gas storages in the EU and is divided in six distinct Sections. In the first Section a general overview on the mode of operation of storage facilities is provided and their contribution in ensuring flexibility in gas supply is discussed. Their contribution in ensuring flexibility in production, a necessity for oil and gas producing countries is also touched upon.

In the second Section, the main technical characteristics of any underground storage facility such as injection and withdrawal rates, annual cycling capability and working gas volumes are defined and typical values of the technical characteristics of storage facilities in EU member states are provided. The third Section discusses the access regimes in EU storages (full third party access, negotiated access, minor or larger facility exemption). Comprehension of the access regimes is necessary for the understanding of the level of regulatory intervention in EU storage facilities, including the determination and approval of storage tariffs and storage tariff methodology. It is shown that to a grand extend, regulatory intervention in EU storage facilities is limited and on many occasions confined to ex-post scrutiny in cases of reported abuse. However, storage facilities regardless of access regime and regulatory intervention are called to employ good practice guidelines for their operation including stringent transparency requirements. Transparency as a means to ensure efficient and non-discriminatory operation of EU storage facilities is discussed in the fourth part of this Chapter.

Sections 1 to 4 in this chapter aim to set the background for Section 5 which is the expected output according to the ToR of this AHEF as far as underground storages are concerned. It concentrates on the products offered by underground storage facilities in the EU and their tariffs. Section 5 includes an extensive review of the ratification systems of the majority of storage facilities in EU member states. Finally Section 6 discusses implications and aims to provide recommendations for the regulation of storage facilities in Azerbaijan.

6.1 Defining the context

The demand for gas in European countries (especially for households) differs throughout the year. For example during the winter time, gas demand is higher than during summer (seasonal difference), while more gas is used during business days in comparison to weekends (weekly difference). On the other hand in southern Europe, gas fired power plants peak during summer to account for the increased electricity demand due to the extensive use of air conditioning. As an example, Figure 23 and Figure 24 demonstrate the strong seasonality of gas demand in Italy, a southern EU member state with underground storage capacity and a moderate production level, for the period 2003-2012. The seasonality of gas demand in the residential and commercial sectors is dominant. A weaker seasonality is also identified in the power sector, with demand peaking twice (winter-summer) at an annual level.
Figure 23: Monthly demand (MMcm) in Italy (2003-2012) (R&C residential and commercial)

Source: The Oxford Institute for Energy Studies, June 2013

Figure 24: Monthly electricity demand (MMcm) in Italy (2008-2012)

Source: The Oxford Institute for Energy Studies, June 2013

Figure 25 confirms that the respective gas supplies to Italy, via pipeline and LNG exhibit the same seasonality, while production is almost constant with a declining trend which is common throughout Europe. The operation of storage facilities is also clearly depicted in Figure 25 with sharp maxima (withdrawals) during high demand periods and troughs during low demand periods (injections). In the absence of storage facilities (or due to their inadequacy due to technical, regulatory or commercial reasons) these extremes in demand would have to be covered by additional supply contracts or a boost to production levels provided that such an increase is feasible.

The contribution of storages to the overall supply is dependent on technical as well as regulatory and commercial restrictions and will be discussed in the next Sections due to their relation to the tariffs regime. In general, suppliers of gas have the responsibility to ensure that the amount of gas used by their customers (withdrawal from the grid) is always equal to the amount of gas that is injected into the grid. In gas terms: a supplier must balance its portfolio and to do so it needs to have access to what is known as flexibility, i.e. additional gas to account for hourly, daily, weekly etc. peaks. This additional gas may be sourced from additional supply contracts, flexibility tools available in the European market (such as flexible gas production, import contracts, line pack, swaps, interruptible contracts, scale down contracts, Liquefied Natural Gas (LNG) and hub related products) and of course storage. Storage facilities are used by market participants for different purposes. As a rule, they are currently (as in the past) used for portfolio optimisation and meeting any flexibility requirements (both peak demand and seasonal). With regard to the latter, short-term (fast cycling) storage facilities are in general used to meet daily variations in demand, while long term (seasonal) storages cover seasonal variations. In countries, where import dependency is high and diverse supply sources are lacking, storage plays a major role in securing gas supply to fulfil the contractual obligations when supplying end customers. Note that an additional form of short term storage is the so called linepack, i.e. the mostly temporary storage of gas by compression in gas transmission and distribution systems is considered to be out of the scope of the present AHEF and will not be discussed further.

Source: The Oxford Institute for Energy Studies, June 2013

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Figure 26: Schematic showing the interrelationship between demand, supply and flexibilities including the role and various forms of storage

Source: Study on natural gas storage in the EU, Draft Final report by RAMBOLL on behalf of DG TREN, 2008

Gas import generally provides less flexibility than indigenous production. In general, as the share of imported gas to a country increases, the need for storage as a seasonal balancing tool is expected to be increased so that a positive correlation between the change in net import dependency and storage capacity is supposed to exist.56

This finding (i.e. the more import dependency, the higher the storage requirements, or in opposite terms the less import dependency, the less storage) should be treated with caution within the concept to the present work. As already established, storage requirements and utilization is very much dependent on demand and in the case of a gas producing country, such as Azerbaijan, to the flexibility associated with production rates. Indeed, the 2013 UNECE Study on Underground Gas Storage in Europe and Central Asia, concludes that the recent developments in the Caspian Sea will make available significant quantities of associated gas. As stated in the report: “The supply of these gas volumes to the Azerbaijan market will require the rehabilitation and modernization of the existing underground gas storage facilities. Gas storage is an essential component of the natural gas system. The restoration of the gas storage capacity in Azerbaijan is a serious issue since:

- gas production rates will be tightly linked to those of oil production (i.e. with no or very little flexibility);
- gas consumption, driven by customers, is dependent on climatic conditions,

A storage capacity is therefore required to act as a buffer between the fairly constant production rates and the seasonal fluctuation of gas demand.” In addition, in the case of oil and associated gas

producing countries such as Azerbaijan, an efficient, in technical and commercial terms, natural gas storage facility not only serves as a supply and demand balancing tool as outlined above but can be also used to alleviate constraints on oil production. The latter are inevitably imposed in the absence of adequate storage capacity.

6.2 Technical characteristics of underground storage facilities

Typically, natural gas is stored underground under pressure in three types of facilities:

- depleted reservoirs in oil and/or gas fields as is the case of the gas storages in the Republic of Azerbaijan,
- aquifers, and
- salt cavern formations.

Other types of gas storages such as abandoned mines and rock caverns are also used but they are less common. Conversion of a field from production to storage takes advantage of existing wells, gathering systems, and pipeline connections so that depleted oil and gas reservoirs are the most common underground storage sites. Natural aquifers are suitable for gas storage if the water bearing sedimentary rock formation is overlaid with an impermeable cap rock. While the geology of aquifers is similar to depleted production fields, their use in gas storage usually requires more base (cushion) gas and greater monitoring of withdrawal and injection performance. Deliverability rates may be enhanced by the presence of an active water drive. Salt caverns provide very high withdrawal and injection rates relative to their working gas capacity. Base gas requirements are relatively low. Cavern construction is more costly than depleted field conversions when measured as the ratio of capital cost to the working gas capacity of the cavern, but the ability to perform several withdrawal and injection cycles each year reduces the per-unit cost of gas injected and withdrawn.

Evidently, each storage type has its own physical characteristics (porosity, permeability, retention capability) and economics (site preparation and maintenance costs, deliverability rates, and cycling capability), which govern its suitability to particular applications. Further, storage facilities may be classified as seasonal supply reservoirs (depleted gas/oil fields and aquifers for the most part) and high-deliverability sites (mostly salt cavern reservoirs). High deliverability can be achieved in a depleted oil or gas reservoir if the reservoir rock has high porosity and permeability (allowing a rapid flow of gas), and the reservoir has sufficient base gas pressure and a sufficient number of wells to maximize withdrawal. Additionally, it would be desirable to be able to refill a reservoir in a reasonably short time. Salt cavern storage is ideal for high deliverability, as the entire cavern is one large "pore." On average, salt storage facilities can withdraw their gas in 12 days, versus 71 days for aquifers and 64 days for depleted oil or gas reservoirs.


58 Natural gas is also stored in liquid form in above-ground tanks. A discussion on liquefied natural gas (LNG) is beyond the scope of this report.

There are several volumetric measures used to quantify the fundamental technical characteristics of an underground storage facility and the gas contained within it. For some of these, it is important to distinguish between the characteristic of a facility such as its capacity, and the characteristic of the gas within the facility such as the actual inventory level. Table 10 summarises the most common terms used to quantify the performance of an underground storage facility. Note that none of these quantification means are fixed or absolute. The rates of injection and withdrawal change as the level of gas varies within the facility. Additionally, in practice a storage facility may be able to exceed certificated total capacity in some circumstances by exceeding certain operational parameters. The facility’s total capacity can also vary, temporarily or permanently, as its defining parameters vary. Further, the measures of base gas, working gas, and working gas capacity can also change from time to time as a result of new wells, equipment, or operating practices. Also, storage facilities can withdraw base gas for supply to market during times of particularly heavy demand, although by definition, this gas is not intended for that use.

Table 10: Summary of the most common terms used to quantify the performance of an underground storage facility

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<thead>
<tr>
<th>Characteristic</th>
<th>Definition</th>
<th>Typical values in EU and Ukraine</th>
</tr>
</thead>
</table>
| **Total gas storage capacity** (TGSC) | The maximum volume of gas that can be stored in an underground storage facility in accordance with its design i.e. the physical characteristics of the reservoir, installed equipment, and operating procedures particular to the site. | 950 million m³  
Max 17 bcm                                                                                           |
| **Total gas in storage**              | The volume of storage in the underground facility at a particular time.                                                                                                                                 | See info under the term “working gas capacity” (base gas/TGSC= 1 – WGC/TGSC)                   |
| **Base gas (or cushion gas)**         | The volume of gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season.                                               | As a percentage of total UGS capacity:                                                            |
|                                       |                                                                                                                                                                                                           | • For depleted fields 16.7% - 74.6% (average 57.1%),                                             |
|                                       |                                                                                                                                                                                                           | • For aquifers: 20.0% - 57.1% (average 43.4%),                                                     |
|                                       |                                                                                                                                                                                                           | • For salt caverns: 50.0% - 88.6% (average 68.7%),                                                 |
|                                       |                                                                                                                                                                                                           | • For abandoned mines: 7% in Germany and about 50% in Belgium                                      |
| **Working gas capacity** (WGC)        | The total gas storage capacity minus base gas. The working gas can be withdrawn/injected with installed subsurface and surface facilities (wells, flow lines, etc.) subject to legal and technical limitations (pressures, velocities, etc.). Depending on local site conditions (injection/withdrawal rates, utilization hours, etc.) the working gas volume may be cycled more than once a year (see annual cycling capability). | See info under the term “withdrawal period”                                                       |
| **Annual Cycling Capability**         | Number of turn over cycles of the working gas volume, which can be achieved by withdrawal and injection in one year.                                                                                       | 18 million m³/day  
(max 250 mcm/day)                                                                                  |
<p>| <strong>Deliverability (or deliverability rate, withdrawal rate, or withdrawal capacity)</strong> | The amount of gas that can be delivered (withdrawn) from a storage facility on a daily basis. Deliverability is expressed in terms of volume or equivalent heat content of the gas withdrawn from the facility. The deliverability of a given storage facility is variable, and depends on factors such as the amount of gas in the reservoir at any particular |</p>
<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Definition</th>
<th>Typical values in EU and Ukraine</th>
</tr>
</thead>
<tbody>
<tr>
<td>time, the pressure within the reservoir, compression capability available to the reservoir, the configuration and capabilities of surface facilities associated with the reservoir, and other factors. In general, a facility's deliverability rate varies directly with the total amount of gas in the reservoir: it is at its highest when the reservoir is most full and declines as working gas is withdrawn.</td>
<td><strong>Injection capacity (or rate)</strong> The amount of gas that can be injected into a storage facility on a daily basis. As with deliverability, injection capacity is usually expressed in terms of volume or equivalent heat content of the gas withdrawn from the facility. The injection capacity of a storage facility is also variable, and is dependent on factors comparable to those that determine deliverability. By contrast, the injection rate varies inversely with the total amount of gas in storage: it is at its lowest when the reservoir is most full and increases as working gas is withdrawn.</td>
<td>9.3 million m$^3$/day (max 130 mcm/day)</td>
</tr>
<tr>
<td>For all UGS facilities averages 86 days and:</td>
<td><strong>Withdrawal period</strong> The ratio of the total working gas volume divided by the total deliverability</td>
<td></td>
</tr>
<tr>
<td>- For depleted fields: 22 - 185 days (average 132 days),</td>
<td>For depleted fields: 22 - 185 days (average 132 days),</td>
<td></td>
</tr>
<tr>
<td>- For aquifers: 23 - 144 days (average 80 days),</td>
<td>- For aquifers: 23 - 144 days (average 80 days),</td>
<td></td>
</tr>
<tr>
<td>- For salt caverns: 2 - 42 days (average 25 days),</td>
<td>- For salt caverns: 2 - 42 days (average 25 days),</td>
<td></td>
</tr>
<tr>
<td>- For abandoned mines: 4 (Germany) and 83 days (Belgium),</td>
<td>- For abandoned mines: 4 (Germany) and 83 days (Belgium),</td>
<td></td>
</tr>
<tr>
<td>This measure of full is obtained by dividing the total amount of gas in the facility by its total gas storage capacity. This indicator is rarely used, because by combining the values for base and working gas, no adequate information is provided concerning the potential gas available to the market.</td>
<td><strong>Total Gas in Storage Relative to Capacity.</strong> This measure of full is obtained by dividing the total amount of gas in the facility by its total gas storage capacity. This indicator is rarely used, because by combining the values for base and working gas, no adequate information is provided concerning the potential gas available to the market.</td>
<td></td>
</tr>
<tr>
<td>“Percent full” for a given region based on working gas capacity is obtained by dividing the sum of estimates of working gas volumes in storage by the total working gas capacity of the relevant storage facilities. This measure is based on the physical capabilities of storage facilities to hold working gas. Although working gas capacity is not measured directly, a reasonable estimate is total capacity minus base gas for the facility(ies). Hence, working gas capacity will change as its components change.</td>
<td><strong>Working Gas Relative to Working Gas Capacity</strong> “Percent full” for a given region based on working gas capacity is obtained by dividing the sum of estimates of working gas volumes in storage by the total working gas capacity of the relevant storage facilities. This measure is based on the physical capabilities of storage facilities to hold working gas. Although working gas capacity is not measured directly, a reasonable estimate is total capacity minus base gas for the facility(ies). Hence, working gas capacity will change as its components change.</td>
<td></td>
</tr>
<tr>
<td>An approach popularized by the American Gas Association (AGA) was to estimate storage &quot;percent full&quot; by comparing current inventory to the maximum amount of gas held in storage during a</td>
<td><strong>Working Gas Relative to Historical Maximums</strong> An approach popularized by the American Gas Association (AGA) was to estimate storage &quot;percent full&quot; by comparing current inventory to the maximum amount of gas held in storage during a</td>
<td></td>
</tr>
</tbody>
</table>
### Characteristic | Definition | Typical values in EU and Ukraine
--- | --- | ---
 | given time period. The regional historical maximum used by AGA for its weekly storage report (no longer published) was the sum of the largest volumes held in storage for each facility in a region at any time from 1992 to March 2000. |  |

#### 6.3 Access to underground storage facilities in the EU

The EU, though the third energy package and the Gas Directive[^60]

- Requires the regulatory authorities or Member States to define and publish criteria according to which the access regime to underground storage facilities may be determined.
- Requires Storage system operators (SSOs) to be at least legally and operationally unbundled from the vertically integrated undertaking they originally belonged too (i.e. SSOs must be at least separate in legal and functional/operational terms from the part of the original company dealing with production and supply).
- Sets legally binding standards for third-party access services, capacity allocation, congestion management, and transparency concerning storage facilities.

The term “access regime” as used above refers to the rules for making the storage facilities available to interested parties other than the owner (and operator of the infrastructure) including, but not limited to the owners’ immediate shareholders if any. The three different options for accessing an underground storage facility, as provided by the EU legislation and set by the regulators, i.e. regulated access, negotiated access and access under an exemption regime are summarized in Table 11.

As highlighted in Table 11, only in the case of a facility under a regulated third party regime, the tariff for access and the tariff methodology are set by the regulator. In negotiated access tariffs are set by the SSO (Storage System Operator) with the regulator intervening only towards the resolution of disputes.

According to the most recent update on the technical characteristics and access regime in storage gas facilities in the EU, published by GSE in June 2014, 19 out of 28 Member States have one or more storage facilities in operation.

- In just over half of the Member States (Belgium, Bulgaria, Croatia, Hungary, Italy, Latvia, Poland, Portugal, Romania and Spain), storage facilities are under fully regulated third party access regime. In terms of storage space however, fully regulated third party access accounts for just 35% of the underground storage facilities.
- In one third of the Member States (Austria, the Czech Republic, Denmark, France, Germany and Slovakia) access is negotiated. In terms of storage space, almost 60% of the storage facilities are under negotiated third party access.
- In the UK a hybrid approach has been adopted with two out seven facilities under negotiated third party access and the rest treated like as a minor facility exemption (see Table 12).
- In the Netherlands, one facility is under negotiated access, two are considered as production facilities (noted as a non-depleted production fields thereby used by the producers) and one is exclusively reserved by the TSO. The underground storage facility in Sweden is also exclusively used by the TSO.
- In Ireland, there is a single gas storage facility off Kinsale – known as South West Kinsale. The facility operates in conjunction with commercial gas production activities so that it may also be considered as used to smoothen out production swings. According to the Natural Gas

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61 GSE, June 2014, [http://www.gie.eu/download/maps/2013/GSE_STOR_DATA_JULY_2013_final.xls](http://www.gie.eu/download/maps/2013/GSE_STOR_DATA_JULY_2013_final.xls), the term hybrid refers to UK and NL, the former having adopted both nTPA and an exempted nTPA regime (minor facilities exemption) and the latter with facilities either under nTPA or facilities connected to the Groningen production site which are again considered as a production facility, no access regime applies. Ireland and Sweden where there a framework for access has not yet been established are not included in the figure.
Storage License (NGSL) obtained by the Irish Regulator in 2006, the licensee cannot contract with any party for use of over 75% of the storage facility without prior approval from the regulator. The actual access regime remains unclear.

It is worth to note, that under the Gas Directive, storage facility means “a facility used for the stocking of natural gas and owned and/or operated by a natural gas undertaking, including the part of LNG facilities used for storage but excluding the portion used for production operations, and excluding facilities reserved exclusively for transmission system operators in carrying out their functions”. So under EU regulation the term “storage” refers only to the space reserved to serve the fluctuating demand although other functions are envisaged for what is technically defined as a storage facility.

It is useful to discuss further this definition in view of the monopolistic structure of the Azeri gas sector and the ample Azeri gas reserves versus the policy goals of the European Union towards market opening and stimulation of the declining domestic gas production.

### Table 11: Available access regimes to Storage Facilities in the EU

<table>
<thead>
<tr>
<th>Storage facilities under regulated third party access (rTPA)</th>
<th>Storage facilities under negotiated third party access (nTPA)</th>
<th>Exempted facilities</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>General principles followed by the EU national energy regulators when deciding upon the access regime for storage facilities</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Storage facilities under a regulated regime are most commonly used in cases where the stored gas is important to security of supply or in the cases of congestion(^\text{63}).</td>
<td>Storage facilities under a negotiated regime are most commonly facilities with:</td>
<td>Member states have the right not to grant third party access to a storage facility. Such an exemption from third party access (regulated or negotiated) maybe provided only(^\text{64})</td>
</tr>
<tr>
<td>Storage operators can only refuse access to the facility on the basis of lack of capacity</td>
<td>- Favourable geological conditions for storage development</td>
<td>- Where the access to the facility would prevent storage operators from carrying out their Public Service Obligation (PSO), or</td>
</tr>
<tr>
<td></td>
<td>- Possibility for further consolidations of markets’ areas</td>
<td>- Where the access to the facility would cause the storage operator serious economic and financial difficulties as a result of take-or-pay contracts being in place. (The operation under a regulated regime is considered as technically/economically inefficient)</td>
</tr>
<tr>
<td></td>
<td>- Active competition between facilities</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- Impact of access regime on incentives on investments in storage</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- By only choosing nTPA (instead also rTPA) a unified legal regime will be in place for all storages</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- nTPA does best contribute to a sound investment climate for storages in a liberalised gas market</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- Storages are built for many years and investors need to have enough confidence in expected revenues over a longer period. If this is not the case, investors will not invest</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- Many storages are now (being) built on the national and surrounding countries. More flexibility is therefore much more accessible now than in the past (also via the hub)</td>
<td></td>
</tr>
</tbody>
</table>

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\(^{65}\) The term “minor facility exemption” has been introduced by the British Regulator Ofgem [https://www.ofgem.gov.uk/ofgem-publications/41204/storage-exemptions-open-letter-09-publication.pdf](https://www.ofgem.gov.uk/ofgem-publications/41204/storage-exemptions-open-letter-09-publication.pdf)
Storage operators can only refuse access to the facility on the basis of lack of capacity exemption was granted;

(c) the infrastructure must be owned by a natural or legal person which is separate at least in terms of its legal form from the system operators in whose systems that infrastructure will be built;
(d) charges must be levied on users of that infrastructure;
(e) the exemption must not be detrimental to competition or the effective functioning of the internal market in natural gas, or the efficient functioning of the regulated system to which the infrastructure is connected.

An exemption from TPA is granted by the regulator and approved by the Commission. Obtaining an exemption from regulated access under the third (and also under the second) energy package is not a trivial task, as it is preserved that the negotiated success regime. The sole example of a facility where the promoters have requested for it to be exempted from TPA is that of the proposed storage in Damborice at the Czech Republic. Their application and the favourable decision of the Czech regulator was rejected by the European Commission.66

The amount of storage capacity exempted from TPA has to be published and the reasons of exemption should OR have to be clearly explained.

For both minor and major exemptions the impact on competition from restrictive access to the storage facility is a major concern.

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Regardless of the access scheme chosen, it has to be objective, transparent and non-discriminatory.

- ‘Objective’ in this respect means that the criteria for access have to relate to the factual characteristics of the storage facilities, such as existing technical features or quality requirements. They have to be comprehensible for any third party and need to be technically justified.
- ‘Transparent’ means that all criteria have to be published ex ante, in order to allow a third party to evaluate the technical and economic consequences of TPA to storage facilities. They also have to allow insight into derivation of the criteria, i.e. the underlying technical and economic reasons for establishing them.
- ‘Non-discriminatory’ means that the SSO provides the same objective service on equal terms to all customers, whether affiliated undertakings or third parties. This non-discrimination obligation would equally cover pricing and other access conditions.

### Implications for tariffs

<table>
<thead>
<tr>
<th>Natural gas undertakings and eligible customers either inside or outside the territory covered by the interconnected system have a right to access the storage.</th>
<th>The regulatory authorities where Member States have so provided or Member States shall require storage system operators and natural gas undertakings to publish their main commercial conditions for the use of storage on an annual basis.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Access is based on published tariffs.</td>
<td>Access conditions shall be developed in consultation with system users.</td>
</tr>
<tr>
<td>The regulatory authorities develop the storage tariffs or tariff methodologies.</td>
<td>Tariff methodologies and tariffs are developed by the Storage System Operators. No regulatory intervention or approval. BUT SSOs have to ensure non-discrimination (e.g. that shall not restrict market liquidity of storage capacity, create undue barriers to market for new entrants or cross-subsidies between system users).</td>
</tr>
<tr>
<td>The right of access for eligible customers may be given by enabling them to enter into supply contracts with competing natural gas undertakings other than the owner and/or operator of the system or a related undertaking (standard contract).</td>
<td>In case of disputes, the relevant national regulatory authority shall determine appropriate arrangements.</td>
</tr>
<tr>
<td>Where regulated, the tariff structure of the SSO should:</td>
<td>The SSO shall maintain records to enable the relevant national regulatory authority to determine the conditions of access including costs and prices.</td>
</tr>
<tr>
<td>a) reflect efficiently incurred costs of access to storage facilities including a fair return on investment, both in the case of direct access</td>
<td>Minor facility exemptions, SSO decides on tariffs if any (the facility is usually used solely by the owner).</td>
</tr>
<tr>
<td></td>
<td>No obligations for publication.</td>
</tr>
</tbody>
</table>

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68 Information below is sourced from the Final ERGEG Guidelines for Good TPA Practice for Storage System Operators (GGPSSO)
<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
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</thead>
<tbody>
<tr>
<td>a)</td>
<td>to a specific storage site and access to a group of storage sites;</td>
</tr>
<tr>
<td>b)</td>
<td>reflect the geological nature of the storage facility or facilities;</td>
</tr>
<tr>
<td>c)</td>
<td>avoid cross subsidies between storage users;</td>
</tr>
<tr>
<td>d)</td>
<td>promote efficient commercialisation and use of storage;</td>
</tr>
<tr>
<td>e)</td>
<td>promote adequate and efficient investments according to users’ needs, feasibility and technical constraints;</td>
</tr>
<tr>
<td>f)</td>
<td>be clear and transparent;</td>
</tr>
<tr>
<td>g)</td>
<td>be reviewed on a regular basis taking into account developments in the market; and</td>
</tr>
<tr>
<td>h)</td>
<td>where appropriate, international benchmarking of tariffs may be taken into account and applied in a non-discriminatory manner.</td>
</tr>
</tbody>
</table>
In detail, the Gas Directive excludes from the definition those (portions of) storages that serve a function as part of production operations. Producers may need to resort to portions of storages for their exclusive use in order to smooth production swings. They may even invoke exclusive use for smoothing irregularities associated with the specific process of production fields or areas as noted above for the case of the Netherlands. Such exclusive use of storage for production operations is considered as justified if it enables or improves the production process. It is the responsibility of the Member State in which the production is located to ensure that the use of storage for production operations is not abused by producers, through the creation of de facto priority access to storages.

Irregularities caused by consumption or demand are in the realm of supply and not production operations. Consequently, it is the view of the Commission that such irregularities cannot justify exclusive reservation for production operations of certain portions of what would otherwise be considered a storage facility. In effect this means that the Commission accepts a rather lenient approach towards natural gas producers using underground storage facilities provided that their use – for production purposes- maybe justified. Presumably such a scrutiny by the regulator must take place when deciding on the access regime for the portion of a storage facility to meet demand. Indeed Italy is one example where the regulator has predetermined the portion of the storage facilities that may be allocated to local producers as equal to 10% percent of the average production rate.

A storage facility may be also used by the Storage System Operator (who often happens to be the Transmission System Operator). A TSO is responsible for operating, ensuring the maintenance of, and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transportation of gas. Among these responsibilities, only operating the transmission system can reasonably involve the use of storage. More specifically, in this sense, a TSO will need to resort to such facilities for the purpose of ensuring that the system remains physically stable and secure, i.e. ensuring that shippers’ or consumers’ behaviour does not lead to a loss in pressure that could result in impediments to the functioning of the network or in supply interruption. This means that, in addition to what is covered by the definition of a TSO, maintaining the system’s stability, including the procurement of the necessary energy for carrying out this function, should be included in the functions of a TSO. In order to fulfil its tasks related to system stability, a TSO will typically need to buy and sell certain quantities of gas, and it will need to resort to certain facilities to store such gas. Interestingly enough the Gas Directive does not foresee the exclusive reservation of only portions of a facility for TSOs in carrying out their functions. Rather, it takes an all-or-nothing approach, either reserving an entire facility exclusively for TSOs or labelling it a ‘storage facility’. To avoid having several entire facilities reserved for a TSO, the Commission suggests that this reservation can only apply to such facilities which by their function and dimension are conceptualised as tools to guarantee system stability. This will, a priori, not allow exclusive reservation of such facilities that serve mainly for seasonal purposes and facilities in general that do not respond quickly.

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enough to be able to fulfil system stability purposes. Neither will it allow exclusive reservation of facilities that are too large to serve as a system stability facility, because such withdrawal from the definition would turn the exceeding portion of the facility into something other than a ‘storage facility’. Consequently, facilities reserved exclusively for TSOs can only be those that are technically and in terms of size designed and suitable for system stability purposes. This may in particular include fast responding over ground facilities with limited capacity (as for example peak shaving liquefaction plants LNG storage tanks). Only two facilities in the EU (out of 167) are exclusively reserved by the TSO (Sweden and the Netherlands). The remainder are treated as a ‘storage facilities’ under the definition of the Directive.

Figure 28: Different uses of an underground storage facility according to the Gas Directive

Thus, strictly speaking, the European framework provides for either exclusive use by the TSO or user storage. However, it is possible for Member States to designate part of the storage for the benefit of TSOs based on grounds related to security of supply. TSO could then be given priority with regard to storage capacities to be allocated to it, whilst in the view of the Commission services the charges incurred would be those applicable to parties other than the TSO.

Further, in the view of the Commission services, the use of storage facilities for balancing purposes does not fall under the exclusive use by a TSO. Balancing is a task distinct from ensuring system stability and should be market based. The Gas Directive (with respect to gas procurement for balancing purposes by TSOs) requires that transmission system operators shall procure the energy they use for carrying out their functions according to transparent, non-discriminatory and market based procedures. Imbalance charges shall be cost-reflective to the extent possible, whilst providing appropriate incentives on network users to balance their input and off-take of gas. Storage facilities are important flexibility tools in the European gas market. However, other flexibility tools are also available (such as flexible gas production, import contracts, line pack, swaps, interruptible contracts, scale down contracts, Liquefied Natural Gas (LNG) and hub related products).

Storage facilities are used by market participants for different purposes. As a rule, they are currently (as in the past) used for portfolio optimisation and meeting any flexibility requirements (both peak demand and seasonal). With regard to the latter, fast cycling storage facilities are in general used to meet daily variations in demand, while seasonal storages cover seasonal variations of the demand. Next to that, storage facilities are unimportant tool for ensuring that any security of supply obligations (e.g. forthcoming from SoS regulation or national obligations resting on household suppliers) can always be fulfilled. In countries, where import dependency is high and diverse supply sources are lacking, storage plays a major role in securing gas supply to fulfil the contractual obligations when supplying end customers.

While the reasons above can be referred to as physical purposes, storage facilities are also used as a financial instrument. Amongst other purposes, storages enable network users to arbitrage due to short and long term differences between prices on spot and forward markets. Also, seasonal storages can provide a competitive edge by benefiting from the summer-winter spread: (lower) summer gas prices are used to meet (higher) winter demand.
### Table 12: Review of the main characteristics of storage facilities in the EU

<table>
<thead>
<tr>
<th>Country</th>
<th>Regulatory Framework(^1)</th>
<th>Provisions</th>
<th>Security of Supply obligations(^2)</th>
<th>Tariffs</th>
<th>Other or additional arrangements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>Negotiated Third Party Access (nTPA)</td>
<td>Storage is the main flexibility tool in Austria and is used for all kind of flexibility (seasonal, daily, hourly). Flexibility in import contracts and gas production is restricted. Balancing energy is mostly provided by using storage facilities. SSOs offer firm and interruptible, bundled (injection, storage, delivery) and unbundled.</td>
<td>In 2009 crisis the storage facilities were the main pillar for securing the supply. The regulator (E-Control) steps in if the charges for a storage service exceed by over 20% average charges for comparable services in the EU Member States. Tariff = Number of Units booked x unit tariff. The unit tariff varies as a function of time (duration of contract). The Number of Unit booked is equal to the withdrawal rate requested/standard withdrawal rate offered.(^3)</td>
<td></td>
<td>The Storage Operator is obliged to submit all concluded contracts to the regulator. The demand for storage capacity comes from Austrian gas wholesalers and distributors, large consumers, generating stations and local retailers. Foreign companies also use the facilities for interim storage related to transit business, and to offer flexible delivery to the Baumgarten gas hub trading point.</td>
</tr>
</tbody>
</table>

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\(^3\) [http://www.omv.com/portal/01/com/omv/OMV_Group/Products/Natural_Gas/Gas_Storage/Storage_Austria/Tariffs](http://www.omv.com/portal/01/com/omv/OMV_Group/Products/Natural_Gas/Gas_Storage/Storage_Austria/Tariffs)
<table>
<thead>
<tr>
<th>Country</th>
<th>Regulatory Framework</th>
<th>Provisions</th>
<th>Security of Supply obligations</th>
<th>Tariffs</th>
<th>Other or additional arrangements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Belgium</td>
<td>Regulated Third Party Access (rTPA)</td>
<td>Storage facilities in Belgium are only available on the H-cal gas network, there is no storage available for the L-calorific value gas network. Storage capacity is offered as a bundle of working gas volume, injection and withdrawal capacity or separately. SSOs offer firm and interruptible services until 2021. Suppliers active in distribution networks are obliged to book storage capacity. Parties who have booked storage capacity in the country (at the only storage facility available) are obliged to fill the volume which was allocated to them to at least 90% by the 1st of November of the next gas year, and to keep the storage level to at least 30% on the 15th of February of the same gas year.</td>
<td>Rates of gas storage are offered by the SSO (Fluxys) for a regulatory period of 4 years and are subject to approval by the federal regulator (CREG). At the end of the tariff period, the regulator compares actual costs with budgeted costs. The differences between income and realized and budgeted costs are included in an account of accruals and taken into account for the tariff calculation at the next tariff period. The tariff methodology is based on allowed income and comprises the following elements: (a) the regulated asset base (RAB) of all assets necessary for business storage including investment projects; (b) the rate of return on the RAB which determines remuneration (c) depreciation of these regulated assets, taking into account the investment projects; (d) the level of operating expenses. An indexation mechanism to account for inflation is included. Tariff = Space booked x unit tariff (duration is also accounted for)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bulgaria</td>
<td>Regulated Third Party Access (rTPA)</td>
<td>SSOs offer firm short and long term (&lt;1y, &gt;1y services) of bundled products. Approximately 65% of the storage capacity is reserved by the system operator.</td>
<td>2.498BGN (Lev) /1000 m³/month excluding taxes. There is no information on potential.</td>
<td></td>
<td></td>
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</tbody>
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<table>
<thead>
<tr>
<th>Country</th>
<th>Regulatory Framework</th>
<th>Provisions</th>
<th>Security of Supply obligations</th>
<th>Tariffs</th>
<th>Other or additional arrangements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Czech Republic</td>
<td>Negotiated Third Party Access (nTPA)</td>
<td>SSOs offer firm and interruptible services based on yearly/monthly/daily contracts. For new capacity SSOs can sign a special long-term contract up to 15 years. Storage capacity is offered as a bundle of working gas volume, injection and withdrawal capacity or separately.</td>
<td>which is also the Bulgarian TSO for guaranteeing “the security of supply to consumers” and “maintaining the balance between natural gas imports and consumption.”</td>
<td>variations from this value for short term/long term/firm/interruptible services. Value approved by the regulator,</td>
<td></td>
</tr>
<tr>
<td>France</td>
<td>Negotiated Third Party Access (nTPA)</td>
<td>Bundled Products sold are linked in to a specific number of injection and withdrawal dates. Injection and withdrawal rate of product varies as a function of capacity.</td>
<td>Shippers are assigned storage rights to serve domestic consumers, consumers providing services of general interest and other non-domestic consumers. Storage rights are calculated based on the “capacity goes with the customer” principle</td>
<td>Tariffs are set up by the SSO, the regulator only monitors tariffs. As an example from the webpage of Storengy, one of the largest EU SSOs, the following values are provided: Capacity, Withdrawal and injection charges separately</td>
<td>The Ministers of Economy and Energy may require operators provide all information necessary to assess the levels of access prices charged. Working gas storage</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Country</th>
<th>Regulatory Framework</th>
<th>Provisions</th>
<th>Security of Supply obligations</th>
<th>Tariffs</th>
<th>Other or additional arrangements</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(CGWC). Suppliers have the additional obligation to have in stock, on the 1\textsuperscript{st} of November each year, at least 85% of the capacities rights associated to the customer group specified above.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Product</td>
<td>Number of Nominal Injection Days</td>
<td>Number of Nominal Withdrawal Days</td>
<td>Product</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Serene Nord</td>
<td>107</td>
<td>68</td>
<td>Serene Nord</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Serene Sud</td>
<td>111</td>
<td>90</td>
<td>Serene Sud</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Sediane Nord</td>
<td>75</td>
<td>40</td>
<td>Sediane Littoral</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Sediane B</td>
<td>140</td>
<td>54</td>
<td>Sediane B</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Saline</td>
<td>107</td>
<td>18</td>
<td>Saline</td>
</tr>
</tbody>
</table>

Another example comes from TIGF\textsuperscript{78}, a storage operator in the southern of France. The annual amount invoiced to the customer under the standard offer is equal to the sum of the following components: an annual fixed term (TFA) which is independent of the number of subscribed storage units; an annual subscription term (TSA), which is proportional to the number \(n\) of subscribed storage units. It is equal to the product of the storage unit price \(PUS\) and the number \(n\); a drawn-off quantity term (TQS), equal to the product of drawn-off quantities \(Qs\) and the draw-off proportional price \(Ps\); injected quantity term (TQI), equal to the product of the injected quantities \(Qi\) and the injection proportional price \(Pi\). This capacity almost half of Germany. Second in Europe. Three storage system operators

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\textsuperscript{78} \url{http://www.tigf.fr/en/what-we-can-offer/storage/prices-and-tariffs.html}
<table>
<thead>
<tr>
<th>Country</th>
<th>Regulatory Framework</th>
<th>Provisions</th>
<th>Security of Supply obligations</th>
<th>Tariffs</th>
<th>Other or additional arrangements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Germany</td>
<td>Negotiated Third Party Access (nTPA)</td>
<td>SSOs offer a variety of products in terms of duration, un/bundled, firmness etc. Products between different SSOs still differ significantly, which makes the comparison of tariffs almost impossible.</td>
<td>No compulsory natural gas storage requirements in Germany.</td>
<td>annual amount, exclusive of additional services, is worked out as: TFA + n x PUS + Qs x Ps + Qi x Pi TIGF also offers a separate tariff if gas is to be provided specifically for balancing services (balancing injection and withdrawal from storage)</td>
<td>Germany currently has the fourth largest working gas volume (wgv) in the world. More than half of the storage facilities serve only one customer, most commonly an affiliated company. Over 20 Storage System Operators.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Product (Austora pack)</th>
<th>Bundle price (€/pack/a)</th>
<th>109.07</th>
</tr>
</thead>
<tbody>
<tr>
<td>Additional Products</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Injection capacity</td>
<td></td>
<td>5.28 €/(kWh/h)/a</td>
</tr>
<tr>
<td>Withdrawal capacity</td>
<td></td>
<td>7.86 €/(kWh/h)/a</td>
</tr>
<tr>
<td>Working gas volume</td>
<td></td>
<td>0.05 ct/kWh/y</td>
</tr>
</tbody>
</table>

80 [http://www.astora.de/speicher/speicher-rehden/speicherentgelt.html](http://www.astora.de/speicher/speicher-rehden/speicherentgelt.html)
<table>
<thead>
<tr>
<th>Country</th>
<th>Regulatory Framework&lt;sup&gt;71&lt;/sup&gt;</th>
<th>Provisions</th>
<th>Security of Supply obligations&lt;sup&gt;72&lt;/sup&gt;</th>
<th>Tariffs</th>
<th>Other or additional arrangements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hungary</td>
<td>Regulated Third Party Access (rTPA)</td>
<td>The fee for basic services provided by Hungarian Gas Storage Ltd&lt;sup&gt;81&lt;/sup&gt; is determined according to the provisions of the Tariff Decree in force (currently Decree No. 31/2009. (VI. 25.). The tariff for basic services is different for open market traders (non-USP) and eligible customers (USP). As supplementary service, Hungarian Gas Storage Ltd. also offers interruptible injection and withdrawal capacities. The pricing method of these services is again based on the formulas of the Tariff. In the case of seasonal and seasonal interruptible requests, additional charges shall be determined and applied for both market sectors in Suppliers to household customers are obliged to store 60% of their customers’ previous winter period gas consumption.</td>
<td>If the contract duration exceeds the 24 months then the tariffs are linearly reduced by a factor of 0.985 for over 24 months to 0.925 for over 72 months. Midyear bookings are possible but then the tariffs need to be multiplied by respective increasing factors. (1.05 for contract duration over 6 months, 1.1 for over 3 months, 1.2 for over a day). There are additional seasonality factors related to midyear bookings and concerning injections (1.1, April to September), withdrawals (1.2, October to March) and use of working gas volume (2, July to December)</td>
<td>According to two tariff calculators published at the site of the sole SSO&lt;sup&gt;82&lt;/sup&gt;, open market traders are charged a basic service of injection (70 days), withdrawal (133 days) and storage and an additional charge for using the peaking service which allow for faster injection and withdrawals should this is deemed necessary. Eligible consumers (non-residential) are not charged the peaking part of the service and pay a substantially lower (by 10%) injection/withdrawal charge. Injection period from April to September, Withdrawal from October to March next year. Within these periods injection for the standard product is allowed for 70 days and withdrawal for 130 days. The facility also offers a “reverse flow” product, injection and withdrawal against seasonality.</td>
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</tbody>
</table>

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<table>
<thead>
<tr>
<th>Country</th>
<th>Regulatory Framework</th>
<th>Provisions</th>
<th>Security of Supply obligations</th>
<th>Tariffs</th>
<th>Other or additional arrangements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Italy</td>
<td>Regulated Third Party Access (rTPA)</td>
<td>The regulator has defined incentives to the development of new storage capacity with the granting of additional revenues for this kind of investment; a single national tariff for storage services, and a revenues compensation mechanism among SSOs, established in order not to penalise new storage sites that for technical and economic reasons, are clearly less efficient in comparison with the existing ones.</td>
<td>Minimum and maximum level of stock that each user has to hold in storage during the injection period (1st April – 30th October) is defined by the SSO with the objective to completely fill in the storage within the end of the same period. Users that don’t comply are charged. Priority access to suppliers for vulnerable customers and consumers with consumption below 50,000 m³/y.</td>
<td>Storage is the main source of flexibility, also used by the users for balancing. The producers are obliged to publish information on semi-depleted gas fields that could be potentially converted into new storage sites with a procedure to collect interest from potential investors.</td>
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<tr>
<td>Netherlands</td>
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<tr>
<td>Portugal</td>
<td>Regulated Third Party Access (rTPA)</td>
<td>Market retailers must have and maintain security of supply reserves on behalf of domestic customers and other protected consumers as well as non-interruptible power producers.</td>
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<td></td>
<td></td>
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<tr>
<td>Slovakia</td>
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<td></td>
</tr>
<tr>
<td>Country</td>
<td>Regulatory Framework</td>
<td>Provisions</td>
<td>Security of Supply obligations</td>
<td>Tariffs</td>
<td>Other or additional arrangements</td>
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<tr>
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<td>---------------------</td>
<td>------------</td>
<td>-------------------------------</td>
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<td>----------------------------------</td>
</tr>
<tr>
<td>Spain</td>
<td>Regulated Third Party Access (rTPA)</td>
<td>shippers must keep stored at least, 20 days of their firm sales in the previous year.</td>
<td>Tariffs are derived according to the following general principles:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Remuneration of regulated activities. Access tariffs must be sufficient to recover the regulatory costs.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Fair allocation between different consumers according to their pressure category, consumption level and load factor the costs that can be attributed to each type of supply.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Incentivise consumers to make efficient use of gas in order to foster enhanced utilisation of the system.</td>
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<tr>
<td></td>
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<td></td>
<td></td>
<td>The natural gas storage fee consists in a fixed component for the contracted storage capacity (€/kWh/month), a usage charge for the energy injected (€/kWh) and a usage charge for the energy extracted (€/kWh).</td>
</tr>
<tr>
<td></td>
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<td></td>
<td>Capacity is allocated each annual period from the 1st of April of the current year to the 31st of March of the following one. This procedure directly allocates capacity to the users of underground storage according to their needs, in proportion to their supplies in the previous year, and introduces a market-based procedure for the allocation.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Country</th>
<th>Regulatory Framework</th>
<th>Provisions</th>
<th>Security of Supply obligations</th>
<th>Tariffs</th>
<th>Other or additional arrangements</th>
</tr>
</thead>
<tbody>
<tr>
<td>UK</td>
<td>Negotiated Third Party Access (nTPA) and exempted facilities</td>
<td>For negotiated third party access, a number of standard bundled products. For the storage facility at Rough Deliverability: 1 kWh/day Space 66.5934 kWh Injectability: 0.35 kWh/day Unbundled storage capacity is also on offer 30 days is the minimum service</td>
<td>No obligations on storage</td>
<td>Set by the SSO</td>
<td>of the remaining capacity, consisting of an auction mechanism.</td>
</tr>
</tbody>
</table>

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85 [http://www.centrica-sl.co.uk/index.asp?pageid=29](http://www.centrica-sl.co.uk/index.asp?pageid=29), information is provided for the storage facility at Rough.
6.4 Ensuring non-discrimination: transparency requirements

As discussed in the previous sections, the European legal framework provides considerable flexibility to storage operators as far as regulatory intervention is concerned. The reason for such a flexibility as indicated by the analysis is the fact that underground storages, under certain circumstances are not unique infrastructures, i.e. they do not represent natural monopolies, as is for example the case for transmission and distribution networks. As demonstrated in Figure 27, in over a third of the Member States, storage facilities are under a negotiated access regime with only ex-post regulatory intervention, solely to resolve disputes. Nevertheless, to ensure that the core requirement of non-discrimination is preserved and that a SSO or one or more of the users of a negotiated access facility do not acquire a dominant position over potential interested parties, considerable effort goes into ensuring that sufficient transparency requirements are in place.

In 2011, ERGEG\textsuperscript{86}, the European Commission’s advisory group on internal energy market issues and a forerunner of ACER\textsuperscript{87} issued Guidelines for Good Practice for storage facilities\textsuperscript{88}. The GGPSSO intend to give a minimum set of rules required for the organisation of the market for storage capacity. They are forward looking and should be flexible enough to account for developments in market arrangements. The GGPSSO are addressed to all Storage System Operators (SSOs) as well as the storage users of storage facilities under both a regulated and a negotiated access regime. The purpose of these GGPSSO is to ensure that SSOs provide the services needed by storage users on a fair and non-discriminatory basis.

Although the GGPSSO are not legally binding, the transparency requirements proposed by the GGPSSO have been accepted by Gas Storage Europe (GSE), an umbrella organisation representing storage operators towards the European Institutions and regulators as well as the European bodies of regulators and have been implemented by most SSOs. The relevant national regulatory authority is called to check that results of the application of the GGPSSOs independent of the access regime (nTPA and rTPA) in terms of non-discrimination, transparency and competition. Transparency is an important tool to develop market awareness and thus to ensure that the other two components, non-discrimination and competition are in place. The following paragraphs outline ERGEGs guidelines on the publication requirements:

- \textit{Allocation of storage capacity shall be made transparent by detailed publication of timing, organisation (schedule) and aggregated results of applied allocation mechanisms on the internet in the local language as well as in English. If requested by users, English should also be used by the SSOs when communicating with (potential) storage users.}
- \textit{In order to reach maximal market awareness and to ensure the principle of non-discrimination, SSOs shall publish at least on their website (and common marketing/trading

\textsuperscript{86} The European Regulators’ Group for Electricity and Gas. ERGEG was set up by the European Commission to assist the Commission in consolidating a single EU market for electricity and gas. ERGEG’s members were the heads of the national energy regulatory authorities in the EU’s 27 Member State.

\textsuperscript{87} The Agency of the Cooperation of Energy Regulators founded within the third energy package.

platform(s)) in English and the local language the actual design of the capacity allocation mechanism, including a schedule for regularly applied allocations, the actual procedure and its timing as well as further conditions that may apply and the aggregated results of the process.

- In order to facilitate transparency, SSOs should provide, for example, the following information, for which the extensiveness depends on cost-benefit analysis/user consultations to find out user needs:
  - Working gas volumes, firm and interruptible withdrawal and injection capacity for each storage facility on a daily and longer term basis (technical, commercialised, subscribed/booked, and available capacity);
  - Historical interruption data/Historical flows/levels of utilisation at each storage facility;
  - Planned maintenance operations as far ahead as possible;
  - Nomination lead times for different capacity products (yearly, monthly, daily);
  - Clear description of CAM and CMP in the contract terms, so that users are fully aware of their storage access rights and obligations;
  - Calculation of tariffs;
  - Contact details;
  - Nomination lead times;
  - Ancillary services offered;
  - Clear information on the applied mechanisms, procedures and necessary steps to request storage capacity or trade capacity on secondary market;
  - Methods and timing for allocating storage capacity, if under a “storage rights envelope” giving access to available capacity;
  - Overview of relevant regulations;
  - Characteristics of storage groups;
  - Detailed information provided to storage users in case of unplanned outages (affecting injection and withdrawal rate, impact on storage operation, duration of disruption...);

These transparency requirements have been implemented under the collective name “GSE Transparency Template” which includes the information put forward by the ERGEG GGPSSOs and summarized in Figure 29.

As discussed above and will be further analysed in the conclusion of this section, transparency is a central pillar to any effort towards efficient and non-discriminatory operation and is strongly recommended as a first step towards the modernization of the Azeri natural gas facilities as identified by the 2013 UNECE report.
### Figure 29: GSE transparency template

<table>
<thead>
<tr>
<th>Macro Area</th>
<th>Submenu</th>
</tr>
</thead>
<tbody>
<tr>
<td>1     Contact</td>
<td>Contact</td>
</tr>
<tr>
<td>2     Services and facilities</td>
<td>Technical characteristics</td>
</tr>
<tr>
<td></td>
<td>Products and services</td>
</tr>
<tr>
<td>3     How to become a customer/user</td>
<td>How to book capacity</td>
</tr>
<tr>
<td></td>
<td>Contract Information</td>
</tr>
<tr>
<td></td>
<td>TSO Information</td>
</tr>
<tr>
<td>4     Capacities</td>
<td>Primary market</td>
</tr>
<tr>
<td></td>
<td>Secondary market</td>
</tr>
<tr>
<td>5     Tariffs and pricing</td>
<td>Pricing/Tariff information</td>
</tr>
<tr>
<td></td>
<td>Fee/Tariff calculator</td>
</tr>
<tr>
<td>6     Legal documentation</td>
<td>Storage codes</td>
</tr>
<tr>
<td></td>
<td>Regulation and legislation</td>
</tr>
<tr>
<td>7     Operational information</td>
<td>Maintenance</td>
</tr>
<tr>
<td></td>
<td>Operational data</td>
</tr>
<tr>
<td>8     Miscellaneous</td>
<td>Projects</td>
</tr>
</tbody>
</table>

Source: GSE\(^{89}\).  

Further to the transparency information listed above, GSE provides on-line information on the level of gas in storage, injection and withdrawal rates\(^ {90}\) for each storage facility in the EU and Ukraine on daily and even on hourly level.

### 6.5 Storage tariffs

One of the goals of the present AHEF assignment is to provide information on the “storage tariff”, i.e. the compensation received by the Storage System Operator for the provision of a service. It is clear that depending on the utilisation of the storage facility a number of different compensations may be considered under the very general term of a “storage tariff” as illustrated in Figure 30. To simplify, it is useful again to distinguish the services provided to a third party, commonly a gas supplier and the services provided by the TSO. It is self-evident, that the former, i.e. third party services are charged in terms of the “storage product” on offer, regardless of how the gas may be used by the third party after it has been injected into the transmission system (supply/demand swings, balancing, and additional gas to account for system losses).

\(^{90}\) [http://transparency.gie.eu/](http://transparency.gie.eu/)
Figure 30: Types of services included under the general term of a “storage tariff”

The storage products offered by EU SSOs are similar in their basic design regardless of the access regime (i.e. rTPA-full regulatory intervention or nTPA-only ex-post regulatory intervention, in case of disputes). The design of storage products is based again on the proposals included in the ERGEG GGPSSO document. The following paragraphs outline ERGEGs guidelines on storage products on offer:

- The SSO shall offer to storage users the storage capacity in a way that facilitates competitive, non-discriminatory, and efficient access to best meet storage user needs and that facilitates trade in storage services in secondary markets. Specifically the SSO shall offer in the primary market, pursuant to its responsibilities a menu of services, including the following:
  
  o bundled services (SBU) of space and injectability/deliverability with determined technical ratios and with an appropriate size;
  o unbundled services supplementing SBUs at least for available storage capacity at the beginning of the storage year;
  o long-term (≥ 1 year) and short-term services (<1 year) down to a minimum period of one day;
  o both firm and interruptible storage services. The price of interruptible services may reflect the probability of interruption
As summarized in Figure 31 and extensively reviewed in Table 12, products offered by the system operator to the potential user of a storage facility are both bundled (the user reserves multiples of predetermined injection and withdrawal rates and slices of storage space) and unbundled. On top of these bundled products reservations for additional injection rate and/or additional storage space and/or additional withdrawal capacity maybe made. Depending on the period of time each of the bundled or unbundled products are reserved, users are charged differently. Such an approach could be applicable to Azerbaijan on occasions that the storage facilities are used by producers, other than the System Operator, or by Azeri gas to store gas to meet seasonal demand of the distribution system customers.

**Figure 31: Types of services**

The tariff for the use of the storage facility (or tariffs corresponding to the different products on offer) are determined by methods similar to the determination of the tariffs in the gas transmission system. In detail, the tariff methodology is based on allowed income and comprises the following elements:

a) The regulated asset base (RAB) of all assets necessary for business storage including investment projects.

b) The rate of return on the RAB which determines remuneration.

c) The depreciation of these regulated assets, taking into account the investment projects.

d) The level of operating expenses.

e) The duration of the regulatory period.

f) A potential premium to incentivize new investments.

g) Specific treatment for fuel gas and losses (cost pass through or cap and incentives).
h) An assumption of asset life; different depending on type of asset. Indicatively, the following asset life of individual storage components is assumed by the Italian Storage operator STOGIT:\(^{91}\):

<table>
<thead>
<tr>
<th>Asset</th>
<th>Life Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wells</td>
<td>60</td>
</tr>
<tr>
<td>Pipes</td>
<td>50</td>
</tr>
<tr>
<td>Buildings</td>
<td>40</td>
</tr>
<tr>
<td>Treatment</td>
<td>25</td>
</tr>
<tr>
<td>Compressor Stations</td>
<td>20</td>
</tr>
<tr>
<td>Other</td>
<td>10</td>
</tr>
<tr>
<td>ICT</td>
<td>5</td>
</tr>
</tbody>
</table>

i) An indexation mechanism to account for inflation is included. Clearly the challenging part in the process is the determination of the “allowed income” particularly in the absence of competition.

j) An assumption on the distribution of revenues from the various storage products available.

Source: Study on natural gas storage in the EU, Draft Final report by RAMBOLL on behalf of DG TREN, 2008\(^{92}\).

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91 STOGIT Storage Business - Regulatory framework for 2011-2014 period

As part of the implementation of the third energy package, European National Regulators, the Agency for the Cooperation of Energy Regulators, the European Transmission System Operators for Gas, the Transmission System Operators and other stakeholders are deeply involved to the development of a pan-European tariff network code, i.e. a set of rules for tariff setting applicable to all Member States. Although the tariff code is still in draft form, subject to consultations amongst the parties involved and at a next stage also subject to consultation with the Commission and the European Council and thus subject to changes it is worth noting the special provisions included for the determination of the transmission tariff for the transportation of gas to and from storages as follows:

«When the national regulatory authority sets or approves the transmission tariffs for the storage facilities, the following shall be taken into consideration:\n
- The net benefits that the storage facilities may provide to the transmission system;
- The need to promote efficient investment in the transmission system;
- The need to minimise detrimental effects on cross-border trade.»

Thus the forthcoming provisions at EU level inherently relate to the tariff system of at least the transmission tariff to and from storages to (a) their role (e.g. national security of supply), (b) potential investments in the transmission system but also to the need not to impose barriers to gas imports/exports and any gas trading out of the national boundary.

Note that as far for the particular issue of gas losses (in the form of known or unknown leaks from equipment, egg compressors, dehydrators) in underground storage facilities, there is only limited information available as far as European UGSs are concerned. To a grand extend this lack of information is due to the access regime (negotiated TPA, exempted facility) to many storages so that regulatory intervention is limited. Nevertheless, as will be shown in the next Section, where published losses at storage facilities are limited (of the order of 0.5-1% of gas injected at most). Losses in storage facilities are treated in a similar manner to transmission and distribution are concerned, that is as discussed in the next session losses are either accounted for in-kind by the facility users or are paid for through the storage tariffs.

### 6.6 Conclusions and recommendations

Figure 33 summarises the role of storages in the European Union. Storages are used:

- by producers to smoothen out production swings,
- by suppliers to meet daily and seasonal variations in demand and also for strategic storage, particularly in order to ensure uninterruptible service to residential and commercial consumers. To this end suppliers (or vertically integrated distribution companies) have to meet special requirements set by national legislation and concerning a minimum level of gas supplies to be kept in underground storage facilities. In the liberalised markets of mostly central-north-western EU, storages are also used for arbitrage with suppliers storing low

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priced gas in UGS facilities to make it available at latter periods when high demand would have led to increased prices.

- by System Operators again for the reason of keeping strategic storages, provided that such an obligation has been assigned to a system operator, also for storing balancing gas, gas necessary to meet fuel consumption and fuel losses.

Figure 33: Role of storages in the EU

Storages are clearly to play an even more important role for Europe in the future, given the EUs declining production, the European dependence to Russian gas at least until the realization of the Southern Corridor through the construction and operation of TANAP and TAP, and also due to the EU’s increasing dependence on renewable energy sources which in turn call for flexible but costly natural gas fired power production and thus for flexibility in gas supply patterns.

Storages are not by default “unique infrastructures”. They are not natural monopolies as is the case of transmission and, many EU, distribution networks. On many occasions, storages are competitive infrastructures serving the same countries or regions so that it is competition and market rules that shape the operational rules of storage facilities rather than legislation and regulatory intervention. As a consequence, EU legislation includes provisions for the divergence from strict third party access rules for storage facilities and regulatory intervention is often only ex-post, limited to cases of disputes.

Regardless of the access regime, transparency is key to ensure (a) the most efficient operation of storages, (b) access of all interested parties under non-discriminatory conditions and (c) that security of supply obligations are respected. Transparency is inherently linked to regulatory monitoring which in turn safeguards both competition and consumer interests.

The Republic of Azerbaijan is amongst the ten countries in the world with the largest underground storage facilities, in terms of volume of working gas. It is also known that the role of Azerbaijan as an exporter of natural gas to Europe is bound to increase in less than a decade. It is valid to assume

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that Azeri UGS facilities will be receiving increasing attention in the years to come for their potential role to meet swings in the production of both oil and gas as well as to serve national demand. If such would be the case, it would be important to distinguish the part of the UGSs to be used to meet production demand, the part to accommodate natural gas exporters and the part for strategic storage for the benefit of national residential and commercial natural gas consumers, or other categories of consumers if that would be the case.

Transparency in the available injection and withdrawal rates, available working gas volume, gas in storage (with a distinction concerning strategic gas reserves) and storage tariffs is essential to ensure efficient operation of the facilities. Further adjustments in the products offered by the Azeri storage facilities (e.g. long term, short term, bundled and unbundled) could further contribute to the efficient use of the facilities.
7 GAS TRANSMISSION AND DISTRIBUTION LOSSES

The purpose of this Chapter is to discuss transmission and distribution losses with emphasis on European Networks. Some additional references on both Russia and the US are also provided. Note that there have been no formal attempts to harmonise the treatment of network losses at a pan-European level. Further, no analyses have been carried out within the scope of benchmarking studies of gas transmission tariffs by the European Commission, the European Transmission System Operators (ENTSO-G), the Council of European Energy Regulators (CEER) or the Agency for the cooperation of Energy Regulators (ACER, formerly ERGEG) as has been the case with electricity. A study on the gas sector losses is due to start only at the second half of 2014. In the absence of a complete study on European gas transmission and distribution losses, data on the actual values of losses are scarce and have been retrieved from multiple sources.

This Chapter is organized as follows. In section 7.1, the basic elements of a gas transmission network and the sources of losses are discussed. The purpose of this Section is to introduce the basic terminology related to gas losses, to highlight the distinction between fugitive losses and major leaks, the latter with a reducing trend at European networks and to identify the components of a transmission network that are more susceptible to fugitive losses. Methods to identify, quantify and reduce natural gas losses in transmission networks, together with associated costs are discussed in Section 7.2.

Natural gas comprises circa 90% methane. Thus any natural gas leak from a transmission, or a distribution, pipeline to the atmosphere is inherently related to the release of methane. In turn methane is a greenhouse gas, co-responsible for climate change. As such, methane emissions including fugitive methane emissions from pipeline systems, are monitored both by the European Environmental Agency (EEA) and the United Nations Framework Convention on Climate Change (UNFCCC). The methodology for estimating fugitive methane emissions from transmission and distribution networks is well established, it can serve well as a yardstick to determine natural gas emissions and as such is presented in Section 7.3 together with the historical emissions from 1990 to 2012 of EU member states. These have been submitted to the EEA and the UNFCCC for both transmission and distribution networks. Under the UNFCCC, initiatives and methodologies for the reduction of natural gas losses have been established in the context of projects proposed and developed under the so called “Clean Development Mechanism” (CDM) proposed in the Kyoto Protocol. As Azerbaijan can be a host country to CDM projects, these methodologies are applicable and are also presented in Section 3 together with examples of ongoing projects which have shown quantifiable results of considerable reductions of natural gas losses in networks.

Section 7.4 focuses on distribution losses. Sources of distribution losses are presented and discussed and the EU Member States reports to Eurostat on the level of distribution losses from 1990 to 2012 are analysed.

Do energy regulators regulate losses, by what means and methodologies and to what extend? As indicated in the beginning of this Chapter, there is no harmonized treatment of losses in the European Union. Further there is no specific obligation for the transmission system operator to procure the energy required for losses as is the case in electricity. Such being the case, gas lost in transmission networks is provided by either the network users (i.e. the gas suppliers) or the operators, or by both depending on the mode agreed between the regulator, the operators and the
stakeholders. Similar is the situation for gas storages whereas in distribution networks most commonly gas to account for gas lost is provided by the system operator. Section 7.5 reviews the regulatory treatment of losses and the potential effect of losses on storage, transmission and distribution tariffs.

Transparency in all aspects of energy related operations is central to oversight. The transparency requirements imposed by the British regulator are analysed in Sections 7.6 and 7.7 as a best practice example of ensuring publication and adequate analysis of gas losses which has led to their reduction. Transparency also raises customer awareness and to that it is even a more valuable tool towards the achieving the regulatory goals.

Main findings of the analysis highlighted above and recommendations for the Azeri gas sector are included in Section 7.8.

7.1 Elements of a gas transmission network

A gas transmission network comprises\(^95\):

- **Transmission pipelines** – large diameter pipelines that deliver gas at high pressures from field production and processing areas to distribution systems;
- **Compressor stations** situated along the length of the transmission pipeline with natural gas driven compressors (reciprocating or centrifugal) to boost gas pressure for transport. In addition to compressors, the stations also include equipment, such as scrubbers, glycol dehydrators, and storage tanks, to remove and store water vapour, condensate and other impurities.
- **Valve stations** – isolation valves situated along the transmission pipeline that can shut in segments of pipe for maintenance; and
- **Distribution gate stations** receiving high pressure gas from the transmission line. They reduce the pressure, meter the flow, and deliver gas to the customers.
- **Metering stations** – they meter gas for delivery to distribution stations and/or final customers, commonly industrial, that are connected to the transmission pipelines.

Figure 34 presents in a schematic illustrating the sources of potential losses in a gas transmission network. A recent technical document\(^96\) by the US Environmental Protection Agency provides a thorough description of sources of leaks in the gas sector as follows. «Potential sources of leak emissions include agitator seals, compressors seals, connectors, pump diaphragms, flanges, hatches, instruments, meters, open-ended lines, pressure relief devices, pump seals and valves. Leak emissions occur through many types of connection points (e.g., flanges, seals, threaded fittings) or through moving parts of valves, pumps, compressors, and other types of process equipment. Changes in pressure, temperature and mechanical stresses on equipment may eventually cause them to leak. Leak emissions can also occur when connection points are not fitted properly, which causes leaks from points that are not in good contact. Other leaks can occur due to normal operation of

\(^{95}\) A significant part of section and the next section has been sourced from “EU Best Practices in Technologies and Methodologies for the Reduction of Losses in Gas Transmission Infrastructure”, Contract No 2011/278827, INOGATE Programme, February 2014.

\(^{96}\) Oil and Natural Gas Sector Leaks, Prepared by the U.S. EPA Office of Air Quality Planning and Standards, April 2014, [http://www.epa.gov/airquality/oilandgas/pdfs/20140415leaks.pdf](http://www.epa.gov/airquality/oilandgas/pdfs/20140415leaks.pdf)
equipment, which over time can cause seals and gaskets to wear. Weather conditions can also affect
the performance of seals and gaskets that are intended to prevent leaks. Lastly, leak emissions can
occur from equipment that is not operating correctly, such as storage vessel thief hatches that are left
open or separator dump valves that are stuck open.

Figure 34: Transmission sector losses

Figure 35 below, presents results from a measurement study of losses in the Russian transmission
system before 2007. Almost 60% of natural gas losses were due to fugitive leaks within compressor
stations with an additional 10% from pipelines which were typically subject to significant pressure,
thermal and mechanical stresses. The remainder of losses (close to 30%) were due to vented
emissions during maintenance and repair activities on pipelines and compressor stations, and during
compressor start-up/shutdown operations.

It is worth comparing the data in Figure 35 to Figure 36 which shows the major sources of gas losses
in transmission networks in the US in 2011, i.e. at least four years later than the study on the Russian
network. As it can be seen fugitive compressor emissions remain the major source of gas losses in
transmission networks.

A more granular assessment of leakage (fugitive) losses identifies the following key sources:

- **Compressor seals** on the piston (reciprocating) or rotating (centrifugal) shafts that prevent
  compressed natural gas from escaping the compressor casing
- **Unit valves** that isolate each compressor when it is depressurised
- **Blowdown valves**, which are used to depressurise the compressor
- **Pneumatic devices** are control devices that automatically operate valves and control
  pressure, flow, temperature or liquid levels. The vast majority of these devices are powered
  by pressurized natural gas
- **Standard components** that include valves, such as gate, ball, plug valves, threaded connectors; and flanges

Figure 35: Sources of natural gas emissions within a transmission system in Russia

![Diagram showing sources of natural gas emissions in Russia](http://www.sciencedirect.com/science/article/pii/S1750583607000898)


Figure 36: Sources of natural gas emissions within a transmission system in the US

![Diagram showing sources of natural gas emissions in the US](http://www.epa.gov/gasstar/images/charts/transmission-emissions.gif)

Source: US Environmental Protection Agency, 2011

The majority of these leakages result from wear and tear, brought on by normal operation and the high thermal and mechanical stresses experienced during compression. Vented emissions are

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primarily the result of controlled discharges to atmosphere for safety reasons. The primary sources of vented emissions include:

- **Pipeline repairs** typically require operators to close a section of the pipeline and depressurize it by venting the gas to the atmosphere, thus ensuring safe working conditions.
- **Station repairs** or **emergency shutdown testing** may require compressors or other equipment to be periodically taken off-line. Consequently, compressors and associated piping/equipment between isolation valves are depressurised, with the natural gas released to the atmosphere.
- **Compressor start-ups** use pressurized natural gas to expand across the starter turbine and spin the engine. The gas used to turn the starter turbine is vented to atmosphere. Since the compressor discharge header needs to be unloaded before start-up, it is also vented to the atmosphere.

In addition to fugitive leaks as outlined above, there can be major natural gas losses occurring from specific incidents that have resulted in pipeline cracks or rupture and ultimately pipeline failures thus leading to considerable losses of gas. EGIG, the European Gas pipeline Incident data Group, is a co-operation of fifteen major gas transmission system operators in Western Europe\(^\text{99}\). EGIG owns and maintains an extensive gas pipeline-incident database dating from 1970 onwards which includes pipeline incidents on onshore gas transmission steel pipelines of design pressure over 15 bar installed outside installation fences and excluding associated equipment (e.g. valves, compressors) or parts other than the pipeline itself.

Figure 37: Number of incidents in Western European pipelines from 1980 to 2010

Figure 37 above illustrates the reducing failure frequency over the years as reported in the latest EGIG report\textsuperscript{100}. This has been due to technological developments such as welding, inspection, condition monitoring using in-line inspection and improved procedures for damage prevention and detection.

As far as the cause of external interference is concerned, its associated failure frequency over the period 1970-2010 decreased to 0.17 per 1000 [km y] while the 5-years moving average has levelled off at around 0.1 per 1,000 [km y] since 1997. From 2003 the 5-years moving average of the external interference is gradually decreasing from 0.1 to 0.06. However external interference remains the main cause of incidents, but the differences with incidents of other causes, especially corrosion and construction defects/material failures are small.

Improvements in the prevention of external interference incidents are obtained through a more stringent enforcement of land use planning, the application of one-call systems for the digging activities of external parties (in several EU countries there is a legal requirement to report digging activities) with the adoption of appropriate actions by the gas companies such as supervision or marking of the pipeline in the direct neighbourhood of the digging activities.

Through further analysis of the failure data, EGIG concluded that small diameter (e.g. diameters less than 17 inches) are more vulnerable to external interferences than bigger diameter pipelines. This can be explained by the fact that small diameter pipelines can be more easily hooked up during ground works than bigger pipelines. Further on their resistance is often lower due to thinner wall thickness. Depth of cover is one leading indicator for the failure frequency of pipelines, the general rule being that pipelines with a larger depth cover will have a lower failure frequency.

Corrosion has been identified as the third cause of failure. Corrosion is a phenomenon of deterioration of the pipelines, is independent of pipeline thickness but inherently related to the aging pipelines.

### 7.2 Methodologies for Estimating Natural Gas Emissions

There are several methods for estimating natural gas leaks from pipelines and compressor stations. A summary of the available options is provided in Table 13. In addition to the options listed in the Table, natural gas leaks can also be estimated through the approach of Section 0.

It is important to note that essentially, in their majority estimation methods are based on the use of the so called emission factors which in their simplest approach involve the multiplication of a predetermined factor with the gas put through a transmission or a distribution system. In more complex approximations, emissions are calculated on a component level (compressor, valve etc.). Again emissions are calculated as the product of a predetermined emission factor by the so called activity data which can be length of transmission and distribution network, number of valves etc.

\textsuperscript{100} 8\textsuperscript{th} EGIG Report, December 2011, \url{http://www.egig.eu/uploads/bestanden/96652994-c9af-4612-8467-9bc6c2ed3fb3}
Emission factors at component level are included in the U.S. EPA Office of Air Quality Planning and Standards recent white papers\(^{101}\) and also at “EU Best Practices in Technologies and Methodologies for the Reduction of Losses in Gas Transmission Infrastructure”, also prepared under INOGATE.

Table 14 lists several approaches that can be employed to achieve emission reductions and their approximate cost for particular payback periods (0-1 year, 1-3 years, 3+ years).

In addition to the approaches of Table 14, the introduction of SCADA and PIMS systems for transmission networks can significantly contribute to the reduction of natural gas losses.

- The installation of an integrated Supervisory Control And Data Acquisition (SCADA) system for the remote supervision and control of all metering and/or regulating stations, line valve stations and remote communication stations for the gas control and dispatching centres is of primary importance to ensure not only that the transmission system will supply the natural gas market with sufficient quantities in all foreseeable conditions, normal and abnormal but also for the reduction of losses.

SCADA tools and related software can be used in order to evaluate the transmission system’s operation. Many failures can be predicted and avoided when previous abnormal situations have been recorded, and when the supervisory system monitors and combines in real time the signals, of the network. Simulation software programmes have been developed to calculate pipeline pressure and flow data and identify potential leakage.

For pipeline rupture, there are tools which help predict and avoid it (i.e., risk analysis, inspections). However, when it happens, there is a whole mechanism of on-call and emergency personnel mobilised in order to minimise its effects. The time needed to start actions is usually between a half and one hour. To minimise this time even more, Motor-Operated Valves (MOV) can be installed in many valve stations, especially in those supplying gas to branches. As a result, the SCADA operators can immediately minimise environmental issues, after a pipeline rupture.

- Pipeline Integrity Management is a process for assessing and mitigating pipeline risks in an effort to reduce both the likelihood and consequences of incidents. Transmission companies with extended networks to all areas residential and rural, congested and remote, deploy a system for the integrity management of their installations.

This system assesses the quality of the pipeline network, identifies risky areas, and records any incidents that have happened in the past and the corrective actions taken. It schedules the preventive and predictive maintenance and produces reports for the operator and the regulatory authorities.

The PIMS takes data from all sources related to the pipelines: GIS, document management system, Inspection and Assessment reports, SCADA and LDAR systems and presents them in a single integrated user interface, giving the operator all the important information in one

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\(^{101}\) Reference is made to the following two documents “Oil and Natural Gas Sector Leaks” and “Oil and Natural Gas Sector Compressors”, Prepared by the U.S. EPA Office of Air Quality Planning and Standards, April 2014, [http://www.epa.gov/airquality/oilandgas/pdfs/20140415leaks.pdf](http://www.epa.gov/airquality/oilandgas/pdfs/20140415leaks.pdf) and [http://www.epa.gov/airquality/oilandgas/pdfs/20140415compressors.pdf](http://www.epa.gov/airquality/oilandgas/pdfs/20140415compressors.pdf)
place. The continuous monitoring, auditing of the pipeline network, the recording of incidents and the planning of predictive, proactive and corrective maintenance minimizes the fugitive gas emissions, and provides full control of any leakage.

For new pipelines systems, the functional requirements for integrity management should be incorporated into the planning, design, material selection, and construction of the system. However, for pipelines which are already in operation, the integrity management plan is drawn after baseline assessments and data integration.102

The implementation of PIMS is much more than the installation of new software or a database. It embraces the operator management structure and work processes, and provides a new approach to risk management103. Additionally, the PIM system must comply with, and extend recent codes, such as ASME B31.8, API 1160, BS PD 8010, DNV RP 116 and CEN 15174.104 The reader is referred to “EU Best Practices in Technologies and Methodologies for the Reduction of Losses in Gas Transmission Infrastructure”, Contract No 2011/278827, INOGATE Programme, February 2014 for more information on SCADA and PIMS systems.

102 An innovative approach to managing the integrity of oil and gas pipelines; Petroleum & Coal, 2012; M.A.Usman and S.E. Ngeme; http://www.vurup.sk/sites/default/files/downloads/pc_1_2012_usman_152.pdf
103 Bureau Veritas Pipeline Integrity management http://www.bureauveritas.com/wps/wcm/connect/bv_com/group/services+sheet/pipeline-integrity-management_941
104 Penspen Pipeline Integrity; http://www.penspenintegrity.com/services/pims
Table 13: Summary of the approaches for estimating natural gas losses

<table>
<thead>
<tr>
<th>Approach</th>
<th>Information requirements</th>
<th>Advantages</th>
<th>Disadvantages</th>
<th>Accuracy</th>
<th>Details</th>
</tr>
</thead>
</table>
| Emission factors: Facility-level | Length of pipelines                      | Simple; very low effort and cost                         | Very poor accuracy; mitigation efforts are not accounted | Low      | This method is similar to Tier 1 of Table 10. In its simplest form, fugitive and vented methane emissions can be estimated using the following equation:  
   \[ Emissions = \sum \text{Activity data} \times \text{Emission factor} \]  
   The accuracy of emissions estimated can increase based on the granularity of the activity data available:  
   - Facility-level: Length of pipelines in the transmission system;  
   - Equipment-level: Number of compressor stations, or reciprocating and centrifugal compressors in the transmission system; and  
   - Component-level: Number of valves, flanges, connectors, reciprocating/centrifugal compressor seals, etc., in the transmission system. While this approach provides a relatively quick and easy method to estimate fugitive and vented emissions, the estimates will be highly uncertain as they will be a function of the data set used to develop the emission factors and, thus, may not be representative of actual field conditions, including age/type of equipment (compressors, components), operational and maintenance norms, weather, and pipeline pressure. |
| Emission factors: Equipment-level | Number of compressor stations, or reciprocating and centrifugal compressors | Simple; low effort and cost                              | Very poor accuracy; mitigation efforts are not accounted | Low      | With the screening approach, components are checked using a leak detector, such as an organic vapour analyzer (OVA). A component is designated as leaking if its concentration is above a specific threshold, which is typically defined by local regulations (e.g., 10,000 parts per million by volume (ppmv)). Alternately, if the component’s concentration is below this threshold, it is designated as non-leaking. Based on this categorisation, emission factors are applied and an emissions inventory built up using the following equation:  
   \[ Emissions_{\text{TOC}} = \sum N_g \times EF_g + N_L \times EF_L \]  
   where, |
| Emission factors: Component-level | Number of valves, flanges, connectors, compressor seals, etc. | Simple; minor one-time effort to establish component inventory | Poor accuracy; mitigation efforts are not accounted | Low      |                                                                                                                                                                       |
| Screening approach            | Number of components                      | Leaking components identified; repairs reflected in results | Labour intensive; moderate annual costs; poor accuracy as actual leak rate not calculated | Low      |                                                                                                                                                                       |

105 A significant part of section has been sourced from “EU Best Practices in Technologies and Methodologies for the Reduction of Losses in Gas Transmission Infrastructure”, Contract No 2011/278827, Inogate Programme, February 2014. The reader is referred to the original document for more information and details.
<table>
<thead>
<tr>
<th>Approach</th>
<th>Information requirements</th>
<th>Advantages</th>
<th>Disadvantages</th>
<th>Accuracy</th>
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<td>Total Organic Compound (TOC) rate from all components</td>
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<td><strong>Emissions</strong>$_{TOC}$</td>
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<td></td>
<td>Emission factor for components with screening values greater than or equal to threshold</td>
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<td><strong>EF$_G$</strong></td>
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<td>Number of components with screening values greater than or equal to threshold;</td>
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<td><strong>N$_G$</strong></td>
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<td>Emission factor for components with screening values less than the threshold;</td>
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<td></td>
<td><strong>EF$_L$</strong></td>
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<td></td>
<td>Number of components with screening values less than the threshold.</td>
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<td><strong>N$_L$</strong></td>
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<td>Approach</td>
<td>Information requirements</td>
<td>Advantages</td>
<td>Disadvantages</td>
<td>Accuracy</td>
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</table>
| Correlation approach| Leak survey: leak/ no leak identified; repairs reflected in results | Leaking components identified; repairs reflected in results | Labour intensive; moderate annual costs; accuracy still limited, data insufficient for accurate repair cost benefit analysis | Accuracy | The correlation approach takes the screening approach a step further, and estimates the emissions for all components in a facility using each component's screened concentration. The concentration is then correlated to a mass emission rate for a particular component type using the following equation:  
\[ Emissions_{TOC} = A \times SV^B \]  
where,  
- \( Emissions_{TOC} \): TOC emission rate from all components;  
- \( A \) and \( B \): correlation constants (specific to the component);  
- \( SV \): screening concentration (e.g., ppmv)  
This approach is common for regulatory-based LDAR programmes that mandate reductions in VOC and TOC emissions. As such, while this is common for refineries, gas processing plants, it is not something that is typically required for transmission compressor stations. Thus, for it to be practical the compressor stations must develop a specialised database that records LDAR activities and calculates the emission rates. If screening data and the means to make the correlation calculations on an individual component basis are available, the correlation approach can provide an estimate of equipment leak emissions. However, leaks above the regulatory threshold (e.g., >10,000 ppmv) are those that contribute most to the facility emissions and losses. These approaches fail to distinguish between leaks above threshold, and because of their inaccuracy, screening measurements cannot be used to determine which leaks should be fixed first or what leak reduction would result.  
Additionally, both the screening and correlation approach have a major drawback, which adds to the uncertainty of the estimates. That is, screening concentrations and correlation equations are unable to accurately characterize leaks that are beyond the scale of flame ionisation detectors, which are the most common instrument used when correlations are applied. The sampling flow rate of these instruments are very low, approximately 1000 ml/min, so if as little as 10 ml/min of methane is captured, the resulting concentration will be 10,000 ppm (1%), which is the upper limit of the instrument. Wind speed, distance of the probe from the leak, and characteristics of the leak such as exit velocity affect how much of the leak actually is captured by the sample probe. These uncertainties explain the large scatter in estimating leak rates using...
<table>
<thead>
<tr>
<th>Approach</th>
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<th>Advantages</th>
<th>Disadvantages</th>
<th>Accuracy</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engineering calculations</td>
<td>Leak survey: leak concentration data (parts per million)</td>
<td>Simple; low effort and cost; accurate if detailed specifications available</td>
<td>Need to track events; detailed design specification requirements</td>
<td></td>
<td>For large scale vented emissions (incidents), the volume of gas released is typically estimated based on design specifications. However, if the blowdown only incorporates a partial section of the equipment or pipeline then more precise engineering calculations will be required.</td>
</tr>
</tbody>
</table>
| Measurements: Hi-Flow® sampler; calibrated bag | Number of events (e.g., blowdowns); pipeline/equipment specifications | Leaking components identified; high accuracy (±10%); repair cost benefit analysis can be conducted | Labour intensive; costs moderate to high | High     | Fugitive emissions at compressor stations, distribution gate stations, and valve stations may be quantified through high volume samplers and calibrated bags. The Hi-Flow® sampler is a portable measurement instrument that completely captures an emission’s source for measurement. A high volume sampler consists of a fixed rate induced flow sampling system to capture the fugitive emission and measure its volume. The sampler captures emissions through a flexible hose which has different attachments to accommodate different component types while preventing interference from other nearby emissions sources. A dual-element hydrocarbon detector (catalytic-oxidation/thermal-conductivity) measures hydrocarbon concentrations in the captured stream ranging from 0.01 to 100 percent. A background sample-collection line and hydrocarbon detector allows the sample readings to be corrected for ambient gas concentrations. Hi-Flow® samplers can measure leaks up to 17 m³/hour (0.3 m³/min), which is sufficient for most leaks encountered at compressor stations, though larger leaks must be quantified by other means. Components that are likely to have fugitive emissions which can be measured using the Hi-Flow® sampler include pipe fittings, valve packings, open-ended lines, pump seals, connectors, and compressor seals. The accuracy of the flow rate calculated is ±5 % of the reading. The cost of a Hi-Flow sampler is approximately €14,000. **Calibrated bags** are used to measure leaks from large sources that may be beyond the range of the Hi-Flow® sampler. Calibrated bagging uses bags of known volume (e.g., 0.2 m³), made from antistatic plastic with a neck shaped for easy placement around a vent stack or open ended line. Measurement is made by timing the bag expansion to full capacity. The temperature of the gas is measured to correct the volume to standard }
<table>
<thead>
<tr>
<th>Approach</th>
<th>Information requirements</th>
<th>Advantages</th>
<th>Disadvantages</th>
<th>Accuracy</th>
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</tr>
</tbody>
</table>

Approach:

Calibrated bags:

- Conditions: Additional, gas composition is measured to adjust for methane content.
- Accuracy: Accuracy of leak rate measurement using calibrated bags depends on precise operation of the stopwatch and the bag placement technique to capture all emissions and remove the bag at the maximum point of inflation; however, measurements are generally accurate to within ±10 percent. Typically several measurements are taken of one leak to provide a sense of repeatability. Calibrated bag costs are minimal at about €50 each, with labour being a primary component of the measurement cost.

Rotameters:

- Use a tapered calibrated tube and float bob to measure emissions. The rotameter tube is connected to the emissions source, and leaking gas lifts the float bob in the tube to give a reading, which corresponds to a flow rate calibrated for the specific meter, float, and gas. Rotameters are appropriate when they can be connected to the emitting component to completely capture the leak, such as a vent or open ended line. They can measure leak rates over 50 m³/hour; however, measurements of this size could exert a back pressure on the process, which can lead to incomplete capture and be a safety issue. A typical rotameter has an accuracy of ± 5 percent at a point within its measurement range. Rotameters typically cost less than €1,000.
Table 14: Summary of the approaches to reduce natural gas losses in transmission and distribution networks

<table>
<thead>
<tr>
<th>Category</th>
<th>Component</th>
<th>Estimated Payback(^{106})</th>
<th>Capital Cost [US$]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Compressors/Engines</td>
<td>Wet Seal Degassing Recovery System for Centrifugal Compressors</td>
<td>0-1 year</td>
<td>$33,000</td>
</tr>
<tr>
<td>Compressors/Engines</td>
<td>Replace Gas Starters with Air or Nitrogen</td>
<td>0-1 year</td>
<td>&lt; $1,000</td>
</tr>
<tr>
<td>Compressors/Engines</td>
<td>Reduce Natural Gas Venting with Fewer Compressor Engine Start-ups and Improved Engine Ignition</td>
<td>0-1 year</td>
<td>&lt; $1,000</td>
</tr>
<tr>
<td>Compressors/Engines</td>
<td>Reducing Methane Emissions from Compressor Rod Packing Systems</td>
<td>0-1 year</td>
<td>&lt; $1,000</td>
</tr>
<tr>
<td>Compressors/Engines</td>
<td>Test and Repair Pressure Safety Valves</td>
<td>0-1 year</td>
<td>&lt; $1,000</td>
</tr>
<tr>
<td>Compressors/Engines</td>
<td>Reducing Emissions when Taking Compressors Off-Line</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Compressors/Engines</td>
<td>Eliminate Unnecessary Equipment and/or Systems</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Compressors/Engines</td>
<td>Install Automated Air/Fuel Ratio Controls</td>
<td>0-1 year</td>
<td>&gt; $50,000</td>
</tr>
<tr>
<td>Compressors/Engines</td>
<td>Install Electric Motor Starters</td>
<td>1-3 years</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Compressors/Engines</td>
<td>Inject Blowdown Gas into Low Pressure Mains or Fuel Gas System</td>
<td>1-3 years</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Compressors/Engines</td>
<td>Replace Compressor Cylinder Unloaders</td>
<td>1-3 years</td>
<td>$10,000-$50,000</td>
</tr>
<tr>
<td>Compressors/Engines</td>
<td>Install Electric Compressors</td>
<td>1-3 years</td>
<td>&gt; $50,000</td>
</tr>
<tr>
<td>Compressors/Engines</td>
<td>Replacing Wet Seals with Dry Seals in Centrifugal Compressors</td>
<td>1-3 years</td>
<td>&gt; $50,000</td>
</tr>
<tr>
<td>Dehydrators</td>
<td>Reroute Glycol Skimmer Gas</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Dehydrators</td>
<td>Pipe Glycol Dehydrator to Vapour Recovery Unit</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Dehydrators</td>
<td>Replace Glycol Dehydration Units with Methanol Injection</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Dehydrators</td>
<td>Eliminate Unnecessary Equipment and/or Systems</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Dehydrators</td>
<td>Zero Emissions Dehydrators</td>
<td>0-1 year</td>
<td>$10,000-$50,000</td>
</tr>
<tr>
<td>Dehydrators</td>
<td>Convert Natural Gas-</td>
<td>1-3 years</td>
<td>$1,000-$10,000</td>
</tr>
</tbody>
</table>


\(^{107}\) Economic payback based on a natural gas value of $5/Mcf.
<table>
<thead>
<tr>
<th>Category</th>
<th>Component</th>
<th>Estimated Payback</th>
<th>Capital Cost [US$]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dehydrators</td>
<td>Convert Pneumatics to Mechanical Controls</td>
<td>1-3 years</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Directed Inspection and Maintenance</td>
<td>Conduct Directed Inspection and Maintenance at Remote Sites</td>
<td>0-1 year</td>
<td>&lt; $1,000</td>
</tr>
<tr>
<td>Directed Inspection and Maintenance</td>
<td>Test and Repair Pressure Safety Valves</td>
<td>0-1 year</td>
<td>&lt; $1,000</td>
</tr>
<tr>
<td>Directed Inspection and Maintenance</td>
<td>Directed Inspection and Maintenance at Gate Stations and Surface Facilities</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Directed Inspection and Maintenance</td>
<td>Directed Inspection and Maintenance at Compressor Stations</td>
<td>0-1 year</td>
<td>$10,000-$50,000</td>
</tr>
<tr>
<td>Pipelines</td>
<td>Test and Repair Pressure Safety Valves</td>
<td>0-1 year</td>
<td>&lt; $1,000</td>
</tr>
<tr>
<td>Pipelines</td>
<td>Insert Gas Main Flexible Liners</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Pipelines</td>
<td>Composite Wrap for Non-Leaking Pipeline Defects</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Pipelines</td>
<td>Perform Valve Leak Repair During Pipeline Replacement</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Pipelines</td>
<td>Using Hot Taps for In Service Pipeline Connections</td>
<td>0-1 year</td>
<td>$10,000-$50,000</td>
</tr>
<tr>
<td>Pipelines</td>
<td>Recover Gas from Pipeline Pigging Operations</td>
<td>0-1 year</td>
<td>$10,000-$50,000</td>
</tr>
<tr>
<td>Pipelines</td>
<td>Using Pipeline Pump-Down Techniques to Lower Gas Line Pressure before Maintenance</td>
<td>0-1 year</td>
<td>&gt;$50,000</td>
</tr>
<tr>
<td>Pipelines</td>
<td>Use Inert Gases and Pigs to Perform Pipeline Purges</td>
<td>1-3 years</td>
<td>na</td>
</tr>
<tr>
<td>Pipelines</td>
<td>Convert Natural Gas-Driven Chemical Pumps</td>
<td>1-3 years</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Pipelines</td>
<td>Inject Blowdown Gas into Low Pressure Mains or Fuel Gas System</td>
<td>1-3 years</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Pneumatics/Controls</td>
<td>Convert Gas Pneumatic Controls to Instrument Air</td>
<td>0-1 year</td>
<td>&gt;$50,000</td>
</tr>
<tr>
<td>Pneumatics/Controls</td>
<td>Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry</td>
<td>0-1 year</td>
<td>&lt; $1,000</td>
</tr>
<tr>
<td>Pneumatics/Controls</td>
<td>Convert Pneumatics to</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Category</td>
<td>Component</td>
<td>Estimated Payback</td>
<td>Capital Cost [US$]</td>
</tr>
<tr>
<td>---------------------</td>
<td>---------------------------------------------------------------------------</td>
<td>-------------------</td>
<td>--------------------</td>
</tr>
<tr>
<td>Pneumatics/Controls</td>
<td>Convert Natural Gas-Driven Chemical Pumps</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Pneumatics/Controls</td>
<td>Eliminate Unnecessary Equipment and/or Systems</td>
<td>1-3 years</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Pneumatics/Controls</td>
<td>Recover Gas from Pipeline Pigging Operations</td>
<td>1-3 years</td>
<td>$10,000-$50,000</td>
</tr>
<tr>
<td>Valves</td>
<td>Test and Repair Pressure Safety Valves</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Valves</td>
<td>Perform Valve Leak Repair During Pipeline Replacement</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Valves</td>
<td>Replace Burst Plates with Secondary Relief Valves</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Valves</td>
<td>Install Excess Flow Valves (distribution only)</td>
<td>3-10 years</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td>Other</td>
<td>Increase Frequency of Replacing Modules in Turbine Meters</td>
<td>0-1 year</td>
<td>na</td>
</tr>
<tr>
<td>Other</td>
<td>Redesign Blowdown Systems and Alter ESD Practices</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td></td>
<td>Eliminate Unnecessary Equipment and/or Systems</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td></td>
<td>Establish a Walking Survey system and increase frequency of walking inspections</td>
<td>0-1 year</td>
<td>$1,000-$10,000</td>
</tr>
<tr>
<td></td>
<td>Replace Bi-Directional Orifice Metering with Ultrasonic Meters</td>
<td>0-1 year</td>
<td>&gt; $50,000</td>
</tr>
</tbody>
</table>

### 7.3 Green House Gas (GHG) Emission Monitoring Programmes: a method to estimate losses in the gas transmission system.

#### 7.3.1 Estimation of gas losses in the context of GHG monitoring

Information on statistical and benchmarking values of losses from gas transmission and distribution networks can sourced indirectly from data on fugitive methane emissions maintained at the United Nations Convention on Climate Change (UNFCCC)\(^\text{108}\), the European Environment Agency and more specifically from the annual reports submitted by the parties with reporting obligations under the

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\(^\text{108}\) [www.unfccc.int](http://www.unfccc.int)
UNFCCC\textsuperscript{109}. As shown in Figure 38 natural gas comprises circa 90% of methane. Thus any leak of natural gas from a transmission or a distribution pipeline to the atmosphere is inherently related to the release of methane.

Figure 38: Gas composition of a typical natural gas

![Gas composition of a typical natural gas](image)

Source: BP in association the International Gas Union\textsuperscript{110}

Methane is one of the six long term greenhouse gases (GHG). When released into the atmosphere, methane absorbs and re-emits infrared radiation so is thus co-responsible for global warming. Methane is chemically stable and it can persist in the atmosphere over time scales of a decade to centuries or even longer, so that its emission can have a long-term influence on climate. With a Global warming potential (GWP) of 21, a unit mass of methane contributes to global warming, over a hundred year period, twenty one times more that the same mass of CO2.

Due to methane’s potential impact on global climate change, countries that have ratified the UNFCCC, amongst other reporting obligations, they have to report separately the so called “fugitive methane emissions” from natural gas transmission and distribution systems i.e. methane (and therefore natural gas) emissions due to leaks.

The value included under the “fugitive methane emissions from natural gas transmission systems” includes also emissions from storages. Note however that the term “fugitive emissions” from networks as outlined above does not include contributions from fuel combustion. Methane emissions due to incomplete combustion in compressor stations, methane consumption as a fuel and

\textsuperscript{109} UNFCCC: the United Nations Convention on Climate Change signed in 1992 and entered into force in 1994. The UNFCCC provides a framework and process for further negotiation towards the ultimate objective of the “stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system (...) within a time frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner”. The UNFCCC however did not set a specific binding target for green house gas emissions reductions. As indicated above, it only sets the general framework for further negotiations and reporting obligations. The UNFCCC has been ratified by 195 parties -all United Nations members including US - (except South Sudan).

\textsuperscript{110} Guidebook to gas interchangeability and gas quality, published by BP in association the International Gas Union,
consequently the portion of natural gas used to drive compression stations, as far as reporting for GHG is concerned are under the combustion systems category where however only aggregate values of the overall combustion systems of a country are shown and is thus impossible to identify the contribution of natural gas compressors.

Figure 39, Figure 40, Table 15 and Table 16 show that fugitive methane emissions in gas transmission and distribution networks in EU-15 are below 0.6 and 1% respectively\textsuperscript{111}. The values of Figure 39, Figure 40, Table 15 and Table 16 should be treated with caution bearing in mind that there are indeed uncertainties associated with these estimates so that the total level of accounted and unaccounted losses in networks can be as large as twice the values of these figures\textsuperscript{112}. However even by assuming an uncertainty factor of two applicable to all values in the figures, losses remain below 1.2 and 2% for transmission and distribution networks respectively. Indeed, as confirmed by Table 15 and Figure 45, losses from distribution networks (where data are available from Eurostat) lie below 2% for EU-28 with the exception of the Czech Republic and Romania.

7.3.2 The IPCC methodology for the estimation of fugitive emissions

It is useful to comprehend the methodology to estimate fugitive methane emissions under the UNFCCC Green House Gas reporting obligations, as this is a well-established approach with a global consensus. In this sense it is largely indisputable and can serve well as a means to provide benchmarking values for transmission and distribution systems in Azerbaijan.

\textsuperscript{111} These values should be increased by 10% for natural gas instead of methane.

\textsuperscript{112} for example data from 136 distribution companies in the US indicate that known losses from leaks are almost equal to unaccounted for gas, http://www.narummeetings.org/Presentations/LAUF_AG.pdf. Taking into account both sources however values remain below 1.2%.
Table 15: Fugitive CH₄ emissions from natural gas transmission networks in EU-15

<table>
<thead>
<tr>
<th>Country</th>
<th>Parameter for calculation</th>
<th>Unit</th>
<th>1990</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Value</td>
<td>Implied emission factor [kg/Unit]</td>
<td>CH₄ emissions [Gg]</td>
<td>gas consumption [bcma]</td>
</tr>
<tr>
<td>Austria</td>
<td>length of pipelines</td>
<td>[km]</td>
<td>3628</td>
<td>494.56</td>
</tr>
<tr>
<td>Belgium</td>
<td>gas consumed</td>
<td>[PJ]</td>
<td>341</td>
<td>5979.11</td>
</tr>
<tr>
<td>Denmark</td>
<td>volume</td>
<td>[mil. m³]</td>
<td>2739</td>
<td>69.45</td>
</tr>
<tr>
<td>Finland</td>
<td>gas consumed</td>
<td>[PJ]</td>
<td>92</td>
<td>1855.49</td>
</tr>
<tr>
<td>France</td>
<td>gas consumed</td>
<td>[PJ]</td>
<td>1055</td>
<td>14663.89</td>
</tr>
<tr>
<td>Germany</td>
<td>length of pipelines</td>
<td>[km]</td>
<td>36760</td>
<td>231.72</td>
</tr>
<tr>
<td>Greece</td>
<td>length of pipelines</td>
<td>[km]</td>
<td>NAP</td>
<td>NAP</td>
</tr>
<tr>
<td>Ireland</td>
<td>gas consumed</td>
<td>[PJ]</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>Italy</td>
<td>gas consumed</td>
<td>[PJ]</td>
<td>45684</td>
<td>822.12</td>
</tr>
<tr>
<td>Luxemburg</td>
<td>gas consumed</td>
<td>[PJ]</td>
<td>18</td>
<td>1320.17</td>
</tr>
<tr>
<td>Netherlands</td>
<td>gas transported</td>
<td>[PJ]</td>
<td>2648</td>
<td>2137.02</td>
</tr>
</tbody>
</table>

European Environment Agency, Annual European Union greenhouse gas inventory 1990–2012 and inventory report 2014, Submission to the UNFCCC Secretariat, May 2014, Only EU-15 report this Category (Category 1.B.2.biii.4), Data on gas consumption from BP Statistical Review of the World, 2014. A density of 0.717 kg/Nm³ has been assumed to change the mass of methane to volume for the computation of the [CH₄ emissions as [%] of consumption] indicator.
<table>
<thead>
<tr>
<th>Country</th>
<th>gas consumed</th>
<th>[Gg]</th>
<th>NAP</th>
<th>NAP</th>
<th>NAP</th>
<th>NAP</th>
<th>NAP</th>
<th>5264</th>
<th>3193</th>
<th>16.81</th>
<th>4.50</th>
<th>0.52%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Portugal</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Spain</td>
<td>NA</td>
<td>198</td>
<td>837.17</td>
<td>0.17</td>
<td>5.60</td>
<td>0.00%</td>
<td>1183</td>
<td>496.43</td>
<td>0.59</td>
<td>31.30</td>
<td>0.00%</td>
<td></td>
</tr>
<tr>
<td>Sweden</td>
<td>length of pipelines</td>
<td>320</td>
<td>6.74</td>
<td>0.00</td>
<td>0.70</td>
<td>0.00%</td>
<td>620</td>
<td>40.54</td>
<td>0.03</td>
<td>1.10</td>
<td>0.00%</td>
<td></td>
</tr>
<tr>
<td>UK</td>
<td>NA</td>
<td>1395830</td>
<td>6.55</td>
<td>9.14</td>
<td>52.40</td>
<td>0.02%</td>
<td>1992125</td>
<td>3.47</td>
<td>6.91</td>
<td>73.70</td>
<td>0.01%</td>
<td></td>
</tr>
</tbody>
</table>
Table 16: Fugitive CH₄ emissions from natural gas distribution networks in EU-15

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Value</td>
<td>Value</td>
<td>Value</td>
<td>Value</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Implied emission factor</td>
<td>CH₄ emissions</td>
<td>Gas consumption</td>
<td>CH₄ emissions as [%] of consumption</td>
</tr>
<tr>
<td>Austria</td>
<td>length of pipelines</td>
<td>[km]</td>
<td>11672</td>
<td>239.81</td>
<td>6.40</td>
<td>0.06%</td>
</tr>
<tr>
<td>Belgium</td>
<td>gas consumed</td>
<td>[PJ]</td>
<td>341</td>
<td>66474.61</td>
<td>22.67</td>
<td>9.10</td>
</tr>
<tr>
<td>Denmark</td>
<td>volume</td>
<td>[mil. m³]</td>
<td>1749</td>
<td>147.44</td>
<td>0.26</td>
<td>2.00</td>
</tr>
<tr>
<td>Finland</td>
<td>gas consumed</td>
<td>[PJ]</td>
<td>5</td>
<td>NA</td>
<td>NA</td>
<td>2.50</td>
</tr>
<tr>
<td>France</td>
<td>gas consumed</td>
<td>[PJ]</td>
<td>1055</td>
<td>14663.89</td>
<td>15.47</td>
<td>29.30</td>
</tr>
<tr>
<td>Germany</td>
<td>length of pipelines</td>
<td>[km]</td>
<td>245852</td>
<td>813.26</td>
<td>199.94</td>
<td>59.90</td>
</tr>
<tr>
<td>Greece</td>
<td>length of pipelines</td>
<td>[km]</td>
<td>NAP</td>
<td>NAP</td>
<td>NAP</td>
<td>NAP</td>
</tr>
<tr>
<td>Ireland</td>
<td>gas consumed</td>
<td>[PJ]</td>
<td>24</td>
<td>214519.35</td>
<td>5.12</td>
<td>2.10</td>
</tr>
<tr>
<td>Italy</td>
<td>gas consumed</td>
<td>[PJ]</td>
<td>20632</td>
<td>12049.8</td>
<td>248.61</td>
<td>43.30</td>
</tr>
<tr>
<td>Luxemburg</td>
<td>gas consumed</td>
<td>[PJ]</td>
<td>17933</td>
<td>30.07</td>
<td>0.54</td>
<td>NA</td>
</tr>
<tr>
<td>Netherlands</td>
<td>length of pipelines</td>
<td>[10³ km]</td>
<td>100</td>
<td>121283.21</td>
<td>12.13</td>
<td>34.60</td>
</tr>
<tr>
<td>Portugal</td>
<td>gas consumed</td>
<td>[Gg]</td>
<td>NAP</td>
<td>NAP</td>
<td>NAP</td>
<td>NAP</td>
</tr>
<tr>
<td>Spain</td>
<td>NA</td>
<td>[PJ]</td>
<td>206</td>
<td>78856.89</td>
<td>16.24</td>
<td>5.60</td>
</tr>
<tr>
<td>Sweden</td>
<td>length of pipelines</td>
<td>[km]</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>0.70</td>
</tr>
<tr>
<td>UK</td>
<td>gas consumed</td>
<td>[GWh]</td>
<td>1396</td>
<td>264819.47</td>
<td>369.69</td>
<td>52.40</td>
</tr>
</tbody>
</table>

¹¹⁴ European Environment Agency, Annual European Union greenhouse gas inventory 1990–2012 and inventory report 2014, Submission to the UNFCCC Secretariat, May 2014, Only EU-15 report this Category (Category 1.B.2.biii.5), Data on gas consumption from BP Statistical Review of the World, 2014. A density of 0.717 kg/Nm³ has been assumed to change the mass of methane to volume for the computation of the [CH₄ emissions as [%] of consumption] indicator.
Figure 39: Fugitive CH4 emissions from gas transmission networks EU-15\textsuperscript{115} including storages

![Graph showing fugitive CH4 emissions from gas transmission networks EU-15 including storages.]

Figure 40: Fugitive CH4 emissions from gas distribution networks EU-15\textsuperscript{116}

![Graph showing fugitive CH4 emissions from gas distribution networks EU-15.]

\textsuperscript{115} Data from Table 15.

\textsuperscript{116} Data from Table 16.
7.3.3 Emission reduction methodologies in the context of GHG reduction policies

Figure 41: Methodology for the estimation of fugitive methane emissions according to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories

The methodology stems from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories and foresees three approaches “tiers”. The basic decision process is outlined in Figure 41 and is as follows:

- Check if the detailed data needed to apply a Tier 3 approach are readily available, and if so, then apply a Tier 3 approach, otherwise, if these data are not readily available:
  - Check if the detailed data needed to apply a Tier 2 approach are readily available, and if so, then apply a Tier 2 approach, otherwise, if these data are not readily available:
  - Check to see if the category is key and the specific subcategory being considered is significantly based on the IPCC definitions of key and significant, and if so, go back and...
gather the data needed to apply a Tier 3 or Tier 2 approach, otherwise, if the subcategory is not significant:

- Apply a Tier 1 approach.

Methods and details for the calculation of CH4 emissions are included on Table 17 below:

<table>
<thead>
<tr>
<th>Tier</th>
<th>Description and applicability</th>
<th>Details</th>
</tr>
</thead>
</table>
| Tier 1 | Tier 1 comprises the application of appropriate default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subcategory of a country’s oil and natural gas industry and should only be used for non-key sources. A Tier 1 approach is the simplest method to apply but is susceptible to substantial uncertainties and may easily be in error by an order-of-magnitude or more. For this reason, it should only be used as a last resort option. | The application of Tier 1 is done through the following equations:

\[
E_{gas,industry \ segment} = A_{industry \ segment} \times EF_{gas,industry \ segment}
\]

\[
E_{gas} = \sum_{industry \ segments} E_{gas,industry \ segment}
\]

Where

- \(E_{gas,industry \ segment}\): Annual Emissions [Gg]
- \(A_{industry \ segment}\): Activity value [units of activity]
- \(EF_{gas,industry \ segment}\): Reference directly from national statistics using the value reported for total net supply of natural gas. This is the sum of imports plus total net gas receipts from gas fields and processing or reprocessing plants after all upstream uses, losses - injection volumes have been deducted.
- \(E_{gas}\): Total fugitive emissions from all industry segments.

| Tier 2 | Tier 2 consists of using Tier 1 equations with country-specific, instead of default, emission factors. It should be applied to key categories where the use of a Tier 3 approach is not practicable. The country specific values may be developed from studies and measurement programmes, or be derived by initially applying a Tier 3 approach and then back-calculating Tier 2 emission factors. For example, some countries have been applying Tier 3 approaches for particular years and have then used these results to develop Tier 2 factors for use in subsequent years until the next Tier 3 assessment is performed. In general, all emission factors (including Tier 1 and Tier 2 values) should be periodically re-affirmed or updated. The frequency at which such updates are performed should be commensurate with the rates at... |

A key category is one that is prioritised within the national inventory system because its estimate has a significant influence on a country’s total inventory of greenhouse gases in terms of the absolute level, the trend, or the uncertainty in emissions and removals. [http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/1_Volume1/V1_4_Ch4_MethodChoice.pdf](http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/1_Volume1/V1_4_Ch4_MethodChoice.pdf), Volume 1.
which new technologies, practices, standards and other relevant factors. Since new emission factors developed in this manner account for real changes within the industry, they should not be applied backwards through the time series.

**Tier 3**

The ability to use a Tier 3 approach will depend on the availability of detailed production statistics and infrastructure data (e.g., information regarding the numbers and types of facilities and the amount and type of equipment used at each site), and it may not be possible to apply it under all circumstances.

Tier 3 comprises the application of a rigorous bottom-up assessment by primary type of source (e.g., venting, flaring, fugitive equipment leaks, evaporation losses and accidental releases) at the individual facility level. It should be used for key categories where the necessary activity and infrastructure data are readily available or are reasonable to obtain. Tier 3 should also be used to estimate emissions from surface facilities where:

The key types of data that would be utilized in a Tier 3 assessment would include the following:

- Facility inventory, including an assessment of the type and amount of equipment or process units at each facility, and major emission controls.
- Country-specific emission factors for fugitive equipment leaks.

Emission factors for conducting Tier 3 assessments are not provided in the IPCC Guidelines due to the large amount of such information and the fact these data are continually being updated to include additional measurement results and to reflect development and penetration of new control technologies and requirements.

Rather, the IPCC has developed an Emission Factor Database (EFDB) which will be periodically updated and is available through the Internet at www.ipcc-nggip.iges.or.jp/EFDB/main.php. Unfortunately no specific transmission and distribution emission factors, other than Table 11 are included in EFDB.

Activity data under this tier are the following:

<table>
<thead>
<tr>
<th>Equipment Leaks</th>
<th>Facility/Installation Counts by Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Processes Used at Each Facility Equipment Component Schedules by Type of Process Unit Gas/Vapour Compositions</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Gas-Operated Devices</th>
<th>Schedule of Gas-operated Devices by Type of Process Unit Gas Consumption Factors of Supply Medium Gas Composition</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Accidental Releases &amp; Third-Party Damages</th>
<th>Incident Reports/Summaries</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Pipeline Leaks Type of Piping Material</th>
<th>Length of Pipeline</th>
</tr>
</thead>
</table>
7.4 Distribution losses in the EU

7.4.1 Sources of losses in distribution networks

Leakage represents the largest component of losses in distribution networks. For the purpose of analysis, leakage is split into three categories which are:

- Distribution Mains (including service pipes)
- Above Ground Installations (AGI’s) and,
- Other losses including metering errors, meter bypass and theft of gas and own use

Figure 42: Sources of natural gas losses within a distribution system in the US\(^\text{120}\)

Distribution mains and service leakage is a feature of normal system operation. AGI leakage includes the routine venting of control equipment. Other losses include the amount of gas lost as a result of interference damage and broken mains. These losses are not continuous but are caused by specific events.

Studies in distribution networks in the US, Figure 43 and Figure 44, identify corrosion (due to the lack of replacement of aging cast iron pipelines) as the most common source of pipeline leaks. One study\(^\text{121}\) suggests replacement of cast iron pipelines ultimately by polyethylene as is considered to have the lowest risk of serious incidents due to its extreme resistance to joint leakage, fracture and corrosion. A replacement policy is suggested based on MRP (Mains Replacement Planning) module, a decision support tool comprising risk based methodology to prioritise which mains to replace and can be used with either its own inbuilt mains condition models or models tailored to meet a customer’s specific requirements.

\(^{120}\) http://www.epa.gov/gasstar/images/charts/transmission-emissions.gif

\(^{121}\) see for example http://www.dnv.com/services/software/products/uptime/mrp.asp
Figure 43: Causes of leaks from several distribution companies in the US (data 2004-2006). Category “other” stands for any cause additional to the ones already included such as exceedance of life time.

Figure 44: Number of leaks per 100 miles as reported from several distribution companies in the US (data 2004-2006).

122 Benchmarking Analysis, Risk Analysis, Model Replacement Analysis and Computerized Main Prioritization and Ranking Program, prepared on behalf of Philadelphia Gas Works by the company Advantica, 2008, available on line.

123 Leak classification from http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=a7c6ca170a574110VgnVCM1000009ed07898RCRD&vgnextchannel=67027e2cd44d3110VgnVCM1000009ed07898RCRD

124 Benchmarking Analysis, Risk Analysis, Model Replacement Analysis and Computerized Main Prioritization and Ranking Program, prepared on behalf of Philadelphia Gas Works by the company Advantica, 2008, available on line.
The second largest cause of losses in distribution networks is metering errors. Metering accuracy—caused by physical accuracy of meters, timing mismatch and administrative process error. Uncertainty in the measurement of volume, temperature, pressure and heating value will influence metering accuracy.125

7.4.2 Losses in distribution networks
EU Member States report to the European Statistics Database, Eurostat, losses from distribution networks. Table 18 and Figure 45 are in line with the UNFCCC reported data of Figure 40 and Table 16 with gas distribution losses lying for the majority of the Member States well below 1%. According to the definition of distribution losses provided by Eurostat this category also includes losses incurred not only in the distribution but also in the transmission networks. Indeed the Energy Statistics Manual compiled by OECD, the International Energy Agency and Eurostat which provides instructions to EU Member States on energy statistics reporting126 clearly states the following «As natural gas is often piped over long distances, some losses may occur. When referring to transport and distribution losses, it is usually understood that transport losses are those that occur during the transmission of gas over a long distance, while distribution losses are those that happen in the gas supply chain through the local distribution network. These losses may be due to differences in measurement, such as differences in metre calibrations of the flows or differences in temperature and pressure at the moment of measurement. Moreover, there may be smaller or larger leaks in pipelines. All these differences can be classified as losses during the transport and distribution of the natural gas from production to consumption point, or transport and distribution losses. For information, those losses account for less than 1% in global gas supply, although the percentage can obviously vary substantially between countries. The category Distribution Losses should include all losses which occur during transport and distribution of gas, including pipeline losses.” Gas used by pipeline compressors to transport the gas in the pipeline is not included in the distribution losses.

Only fragmented information on gas consumption by pipeline compressors can be found. As a rough estimate fuel gas for compressing power does not exceed at most 1-1.5% of gas transported. The actual value depending upon the number of compressors in use, their mode of operation, the suction pressure and pressure drops in the network, seasonal conditions etc.. Currently there are several software packages capable of optimising the use of a compressor.

Figure 45: Gas distribution losses in the European Union in the period 1990-2012. Data from Table 18

Table 18: Gas distribution losses in the European Union in the period 1990-2012. Data have been normalised by the sum of imports and domestic production, source Eurostat 127

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>EU-28</td>
<td>0.91%</td>
<td>0.95%</td>
<td>0.94%</td>
<td>0.70%</td>
<td>0.65%</td>
<td>0.55%</td>
<td>0.57%</td>
</tr>
<tr>
<td>EU-15</td>
<td>0.92%</td>
<td>0.57%</td>
<td>0.72%</td>
<td>0.51%</td>
<td>0.55%</td>
<td>0.46%</td>
<td>0.47%</td>
</tr>
<tr>
<td>Euro area</td>
<td>0.47%</td>
<td>0.42%</td>
<td>0.46%</td>
<td>0.41%</td>
<td>0.30%</td>
<td>0.25%</td>
<td>0.30%</td>
</tr>
<tr>
<td>Austria</td>
<td>0.15%</td>
<td>0.08%</td>
<td>0.03%</td>
<td>0.02%</td>
<td>0.02%</td>
<td>0.02%</td>
<td>0.02%</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>1.24%</td>
<td>1.81%</td>
<td>1.38%</td>
<td>1.77%</td>
<td>0.59%</td>
<td>0.29%</td>
<td>0.44%</td>
</tr>
<tr>
<td>Czech Rep.</td>
<td>0.00%</td>
<td>4.29%</td>
<td>2.87%</td>
<td>1.21%</td>
<td>1.87%</td>
<td>1.62%</td>
<td>2.12%</td>
</tr>
<tr>
<td>Croatia</td>
<td>1.39%</td>
<td>1.48%</td>
<td>2.57%</td>
<td>1.79%</td>
<td>1.60%</td>
<td>1.79%</td>
<td>1.57%</td>
</tr>
<tr>
<td>Denmark</td>
<td>0.10%</td>
<td>0.06%</td>
<td>0.04%</td>
<td>0.03%</td>
<td>0.04%</td>
<td>0.04%</td>
<td>0.05%</td>
</tr>
<tr>
<td>Estonia</td>
<td>0.11%</td>
<td>0.10%</td>
<td>0.00%</td>
<td>0.00%</td>
<td>0.00%</td>
<td>0.00%</td>
<td>0.00%</td>
</tr>
<tr>
<td>France</td>
<td>0.18%</td>
<td>0.16%</td>
<td>0.79%</td>
<td>1.62%</td>
<td>0.84%</td>
<td>0.74%</td>
<td>0.75%</td>
</tr>
<tr>
<td>Germany</td>
<td>1.20%</td>
<td>0.74%</td>
<td>0.56%</td>
<td>0.00%</td>
<td>0.00%</td>
<td>0.00%</td>
<td>0.00%</td>
</tr>
<tr>
<td>Greece</td>
<td>0.00%</td>
<td>0.00%</td>
<td>0.70%</td>
<td>0.30%</td>
<td>0.54%</td>
<td>0.40%</td>
<td>0.52%</td>
</tr>
<tr>
<td>Hungary</td>
<td>2.76%</td>
<td>3.80%</td>
<td>3.18%</td>
<td>2.88%</td>
<td>1.67%</td>
<td>1.86%</td>
<td>1.52%</td>
</tr>
<tr>
<td>Ireland</td>
<td>1.76%</td>
<td>2.38%</td>
<td>0.82%</td>
<td>1.92%</td>
<td>1.50%</td>
<td>1.59%</td>
<td>1.51%</td>
</tr>
<tr>
<td>Italy</td>
<td>0.30%</td>
<td>0.31%</td>
<td>0.45%</td>
<td>0.70%</td>
<td>0.71%</td>
<td>0.53%</td>
<td>0.70%</td>
</tr>
<tr>
<td>Latvia</td>
<td>0.12%</td>
<td>2.33%</td>
<td>1.45%</td>
<td>0.28%</td>
<td>0.71%</td>
<td>0.86%</td>
<td>0.87%</td>
</tr>
<tr>
<td>Lithuania</td>
<td>0.84%</td>
<td>2.28%</td>
<td>1.27%</td>
<td>0.40%</td>
<td>0.00%</td>
<td>0.00%</td>
<td>0.00%</td>
</tr>
<tr>
<td>Poland</td>
<td>2.27%</td>
<td>2.93%</td>
<td>3.42%</td>
<td>1.23%</td>
<td>1.23%</td>
<td>0.22%</td>
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</tr>
<tr>
<td>Portugal</td>
<td>0.00%</td>
<td>0.00%</td>
<td>0.13%</td>
<td>0.45%</td>
<td>0.63%</td>
<td>0.10%</td>
<td>0.47%</td>
</tr>
</tbody>
</table>

7.5 Regulating gas losses

The previous sections dealt with mostly the technical aspects of losses in transmission and distribution network and their treatment. Values of natural gas losses in Member States from 1990 to 2012 were presented in an effort to enhance understanding of the magnitude and relative significance of gas losses in European networks. As shown in the previous Sections, losses in EU Member States are low less than 1% in the majority of MS. The relative significance of such a low value of losses however should not be underestimated. Taking into account that gas consumption in EU-28 in 2013 exceed 400 billion Nm³ with average gas prices of 10.6 €/mmBTU\textsuperscript{128}, a gas loss of 1% gives rise to a cost of over 1.2 billion € or approximately 10 € per annum per household\textsuperscript{129}. Adding an additional 1% to account for compressing power just over 20€ per annum per household are paid in EU Member States for gas imported or produced but never consumed by the end users. Clearly larger values of losses can render significant financial implications.

This section will go a step further to discuss the treatment of losses from the point of view of an energy regulator. As the way that losses are viewed from a technical perspective is not identical to the perspective of an energy regulator, a brief introduction of the regulatory definition of losses is included in the first part of this section before proceeding to aspects of regulatory concern.

In a very simplistic approach, a “LOSS” occurs whenever the physical inputs are greater than the physical outputs of a pipeline system. By analogy, a “GAIN” occurs whenever the physical outputs are greater than inputs of the pipeline system.
Figure 46: Simplistic representation of a transmission or a distribution gas system with losses.

1. Compressor Fuel Use (CFU), which is the total energy used by the compressors which help to maintain pressure and flow in the NTS. CFU is made up of fuel gas used for the gas turbine powered compressors (Own use Gas, or OUG) and energy used by the electric driven compressors;

2. Known losses of gas, which is gas released from the pipeworks e.g. during maintenance in quantities that can be estimated;

To enhance understanding into the concept of linepack the following explanation is provided. Consider that a 50-mile section of a 42-inch transmission line operating at a pressure of about 68 bars of pressure contains about 5 mil Nm³ of gas -- enough to power a kitchen range for more than 2,000 years. The amount of gas in the pipe is called the "linepack." By raising and lowering the pressure on any pipeline segment, a pipeline company can use the segment to store gas during periods when there is less demand at the end of the pipeline. Using linepack in this way allows pipeline operators to handle hourly fluctuations in demand very efficiently.

3. Unbilled Energy, normally referred to as Calorific Value Shrinkage (CVS), which is the difference between delivered and billed energy; and

4. Unaccounted for Gas (UfG), which is the gas which is lost or otherwise not accounted for as offtaken from a transmission or a distribution system. UfG is considered to be the consequence of data and/or meter error and is thus a relatively complex component of shrinkage, involving not only the mechanical behaviour of high pressure metering systems but statistical variations in their operation.

Figure 47: Summary of gas losses under the general term of Unaccounted for Gas

The American Gas Association defines UfG (referred to as Loss and Unaccounted gas – LAUF Gas) as the difference between the total gas available from all sources, and the total gas accounted for as sales, net interchange, and company use. For distribution systems in particular, AGA defines UfG as «The difference between the city-gate measurement and the volume of gas sold to the customer». UfG is the inevitable imbalance that exists at any given time between the measured gas coming into a distribution system and the measured gas going out. UfG includes leakage, theft, operational use of gas, metering errors, data transfer errors, database system errors and all inaccuracies of the billing methodology. Under this definition UfG also includes Unbilled Energy of paragraph (3) above and as schematically shown by Figure 46, it is essentially a black box. Note that on a number of Member States the term Shrinkage is also used interchangeably with UfG.

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131 Line Losses (leaks) that cannot be estimated or the part of the line losses that is not included in the estimates is also considered as UfG

132 [http://www.narucmeetings.org/Presentations/LAUF_AGA.pdf](http://www.narucmeetings.org/Presentations/LAUF_AGA.pdf)
Figure 48: Regulatory treatment of lost gas

Table 18

Figure 48 presents the regulatory treatment of lost gas when the responsibility for providing the lost gas remains with the operator. The least condition to be imposed is that the operator remains cash neutral as far as losses are concerned. Depending on the regulatory approach adopted, the system operator could also be incentivized to reduce losses and thus benefit from reductions or penalized for not acting as a prudent and efficient operator.

UfG is a term defined strictly for regulatory and accounting purposes. Regulators build a form of reimbursement for unaccounted for gas into the utility’s rate structure. This reimbursement can cover the full cost of losses, partial cost of losses or provide incentives for a reduction of losses.

In more detail, in order to meet demand in European networks, the amount of gas lost (here the term used to include the sum of items [1] to [4] above) has to be replaced by additional gas provided by either the supplier or the system operator, Figure 48. Table 19 presents the regulatory treatment of gas losses in selected member states as far as transmission is concerned. It can be seen that in most cases, it is indeed the system operator (rather than the supplier) the one that has to provide for
the gas lost most commonly according to the procedure of Figure 48\textsuperscript{133} and is reimbursed through the transmission tariffs.

Indeed the level of losses to be recovered through tariffs are on many occasions pre-approved by the regulator and may be set at such values that the operator does not necessarily recover the full cost. Such is the case of UK and Belgium in Table 19. In UK, the regulator preapproves a certain fiscal amount as TSO expenses towards losses, however should the cost of losses be found less or above the preapproved amount the cost/gain is split between the operator and the users. In Belgium and in other Member States where the users rather than the operator have the obligation to provide the lost gas, the regulator indeed approves the value of losses, users provide additional gas according to the preapproved value and should the losses turn out to be higher than the preapproved amount the cost is borne by the operator. On other occasions such as Ireland and Greece, as the operator procures gas from the market to cover own consumption and UfG it is considered that this gas is received at competitive prices, users are charged the full amount of gas bought and the operator remains cash neutral to the transaction. Regardless of the method adopted however there are two things to be taken into account and are crucial to the overall process towards reduction of losses. One is the maximum amount of losses that may be tolerated by the regulator or any other tariff setting authority that can be passed from the system operator (who bears the responsibility of the losses) to the system users and final consumers. The second item is transparency of the level of losses, the cause of these losses and finally the cost of these losses to the final consumers. The latter as a means not only to enhance regulatory oversight towards establishing criteria for the quantification of an efficient or inefficient network operation but also as a means to raise customer awareness.

Table 20 relates actions undertaken by system operators towards the reduction of losses with reporting obligations imposed by the regulators for the sake of transparency. As shown in the table it is important that:

- Reporting is done at regional/town level for better identification of actions towards loss reduction. The operator should inform the regulator on damages and cost of repairs and replacements per item replaced. Itemised rather than bulk reporting (e.g. the cost of all items replaced over a year) is important for benchmarking of individual costs.
- The operator provides both forecasts of lost gas at least at monthly levels and reports on actual gas lost. The calculation of lost gas must be at such a level of detail that would allow the regulator to reproduce.
- Estimates for monthly billing purposes should reconcile the accounts at the end of the “UfG-year”.
- Meter reading frequency is increased (monthly level or every two months if such a practice does not exist already).

\textsuperscript{133} It should be noted that under the liberalisation requirements out forward by the second and third European energy packages, the transmission operator and the supplier belonging to an originally vertically integrated incumbent have undergone at least legal and functional unbundling. As a result, the value of lost gas is registered in the financial sheets of either the supplier and most commonly the transmission (and the distribution system operator).
## Table 19: Regulatory treatment of losses in selected EU Member States

<table>
<thead>
<tr>
<th>Country</th>
<th>Approach</th>
<th>Approved values of losses of gas transported</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>Gas provided by</td>
<td>System Losses: 0.2% for transmission network. For storage: 0.5 of the injected quantities and 0.5% of the withdrawn quantities. The users need to provide these quantities. For any additional value risk is borne by the operator.</td>
</tr>
<tr>
<td></td>
<td>the operator</td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td>Gas provided in</td>
<td>System Losses: 0.2% for transmission network. For storage: 0.5 of the injected quantities and 0.5% of the withdrawn quantities. The users need to provide these quantities. For any additional value risk is borne by the operator.</td>
</tr>
<tr>
<td>(Fluxys)</td>
<td>kind by system</td>
<td></td>
</tr>
<tr>
<td></td>
<td>users</td>
<td></td>
</tr>
<tr>
<td>Greece</td>
<td>Gas provided by</td>
<td>System Losses: The regulator approves a maximum amount of operational gas (for user as fuel gas and UfG). Gas is procured and users are charged the full amount. The transporter is Cash Neutral in respect to the provision of the operational gas.</td>
</tr>
<tr>
<td></td>
<td>the operator</td>
<td></td>
</tr>
<tr>
<td>France (GRT)</td>
<td>Transmission</td>
<td>System Losses: —</td>
</tr>
<tr>
<td></td>
<td>tariffs</td>
<td></td>
</tr>
<tr>
<td>Ireland (Bord</td>
<td>Gas provided by</td>
<td>System Losses: Shrinkage charges billed to customers at cost. There is no actual percentage covering all volumes and load factors. Shrinkage gas is procured on the basis of a competitive tender therefore it is more a market related cost than a cost related to the transmission tariffs. The Transporter is Cash Neutral in respect to the provision of Shrinkage Gas and accordingly, all costs associated with purchasing Shrinkage Gas is recoverable by the Transporter.</td>
</tr>
<tr>
<td>Gais)</td>
<td>the operator</td>
<td></td>
</tr>
<tr>
<td>Italy (Snam</td>
<td>Transmission</td>
<td>System Losses:</td>
</tr>
<tr>
<td>Rete Gas)</td>
<td>tariffs</td>
<td></td>
</tr>
<tr>
<td>Netherlands (</td>
<td>In kind</td>
<td>System Losses: No additional provisions. The supplier provides the gas and bears the risk.</td>
</tr>
<tr>
<td>GTS)</td>
<td>In kind</td>
<td></td>
</tr>
<tr>
<td>Romania</td>
<td>Gas provided by</td>
<td>System Losses: Between 1% and 2% from the total amount of gas delivered to the final customers. The percentage is agreed with the operator. 0.5% for storage.</td>
</tr>
<tr>
<td></td>
<td>the operator</td>
<td></td>
</tr>
</tbody>
</table>

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135 [http://www.desfa.gr/files/PR/N.%20KATSIS/%CE%95%CE%9B%CE%97%CE%9D%CE%9A%CE%97%20%CE%9D%CE%9F%CE%9C%CE%9F%CE%98%CE%95%CE%A3%CE%99%CE%91/Microsoft%20Word%20-%20Unofficial%20Translation%20of%20the%20Network%20Code%20for%20the%20Regulation%20of%20the%20National%20Gas%20System%202_.pdf](http://www.desfa.gr/files/PR/N.%20KATSIS/%CE%95%CE%9B%CE%97%CE%9D%CE%9A%CE%97%20%CE%9D%CE%9F%CE%9C%CE%9F%CE%98%CE%95%CE%A3%CE%99%CE%91/Microsoft%20Word%20-%20Unofficial%20Translation%20of%20the%20Network%20Code%20for%20the%20Regulation%20of%20the%20National%20Gas%20System%202_.pdf)

136 West European Gas Transmission Tariff comparisons, Arthur D. Little, 2012

137 Gaslink consolidated code, April 2013, Part E

Spain (Enagas) | in kind | in kind | Losses underground storage: 0% of gas injected\(^a\).
Losses primary transport: 0.2% of total gas supplied to network (from international connections, storages, plants regasification or other points of entry from outside the gas system).
Shrinkage pressure distribution equal to or less than 4 bar: 1%.
Shrinkage pressure distribution equal to or less than 4 bar, for networks fed from satellite plant: 2%.
Losses distribution equal to or less than 4 bar: 0.39%.
No decline in pipelines of maximum pressure exceeding 16 bars.

UK (National Grid) | Shared between operator and the shippers (shared risk/reward) | The target cost of losses for each year is calculated to include the product of an annual target volume multiplied by a gas cost reference price. The volumes for each of the five years of the formula period have been pre-determined. The target cost also includes an allowance of £0.5m per annum for electric compression costs. The performance measure is the actual annual cost of the provision of NTS Shrinkage plus the costs for electric compression. This is then compared with the target and the difference is shared between shippers and National Grid subject to sharing factors and an annual cap and collar. The allowed revenue is then the actual cost incurred plus this incentive “revenue” (which may be positive or negative).

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\(^a\) [http://www.enagas.es/stfls/EnagasImport/Ficheros/191/101/7%20orden%20IET%202459-04%20%20boe%2031%20-12%20-13.0.pdf](http://www.enagas.es/stfls/EnagasImport/Ficheros/191/101/7%20orden%20IET%202459-04%20%20boe%2031%20-12%20-13.0.pdf)
Table 20: Sources of lost gas and mitigate actions for the system operator and the regulator

<table>
<thead>
<tr>
<th>Source</th>
<th>Problem</th>
<th>Mitigation Action</th>
<th>Actions for the regulator</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipe leaks</td>
<td>High levels or dramatic change in LAUF gas which might indicate a safety threat</td>
<td>Continuous monitoring of leaks. Detailed leak surveys. Repair or replace at-risk pipelines in timely fashion.</td>
<td>Impose monitoring programme and reporting obligations on system operator. Reporting should be done at regional/town level for better identification of actions.</td>
</tr>
<tr>
<td>Measurement error, temperature and pressure differences, heat value conversion, meter inaccuracies</td>
<td>Inaccurate gas volumes at customer meters</td>
<td>Testing and calibration meter accuracy. Replacement or maintenance of malfunctioning devices. Installation of automated metering devices.</td>
<td>Imposed as part of monitoring and reporting programme. The operator to inform the regulator on meter/pipeline replacements per region so that a database on regional gas losses versus pipeline meter replacement can be built. Such a database can support the selection of particular benchmarked values for losses.</td>
</tr>
<tr>
<td>Accounting Error</td>
<td>Inaccurate calculations and misinterpretation of metering data. Improper accounting of gas receipts and deliveries</td>
<td>Periodic internal audits. Staff training. Well defined standard practices.</td>
<td>Imposed as part of monitoring and reporting programme. See above. In general, the UFG calculation must be auditable, estimates for monthly billing purposes shall reconcile the accounts at the end of the “UFG-year”. Disclosure at regional level should be sought.</td>
</tr>
<tr>
<td>Third party damage</td>
<td>All customers paying for gas losses and repairs. Safety threats leading to accidents</td>
<td>Proactive programme informing public on the dangers of digging. Strict penalties for guilty party plus charges for gas losses and repairs</td>
<td>The operator should at least inform the regulator on damages and cost of repairs.</td>
</tr>
<tr>
<td>Cycle billing</td>
<td>Timing mismatch between gas receipts and deliveries</td>
<td>More frequent meter reads (e.g. monthly) to ensure less accounting lag.</td>
<td>Increase of meter reading frequency (monthly level or every two months if such a practice does not exist.</td>
</tr>
<tr>
<td>Stolen gas</td>
<td>All customers subsidizing delinquent customers. Safety threat for local community</td>
<td>Inspection of meters for sign of tampering. Follow up investigations. Strict penalties.</td>
<td>As part of the monitoring programme, stolen gas to be reported at regional level.</td>
</tr>
<tr>
<td>Blowdown</td>
<td>Release of gas during inspections, maintenance or emergency procedures</td>
<td>Inject gas into low pressure main.</td>
<td>As part of the monitoring programme, obligation to report on actions.</td>
</tr>
</tbody>
</table>

7.6 Monitoring lost gas: transparency requirements

As is the case in all aspects of energy regulation, transparency and monitoring is always an essential towards reducing UfG. In this context, the example of the British regulator Ofgem should be noted. Ofgem, amongst other tasks, is the authority responsible for licensing Transmission System Operators and thus sets the terms and conditions upon which any license is granted. On February 2012, Ofgem decided towards a modification\(^\text{141}\) in the license of National Grid, the sole owner and operator of gas transmission infrastructure in the UK, to include provisions that:

- The licensee shall use reasonable endeavours to undertake the UfG Projects as specified in this condition for the purposes of investigating the causes of UfG.
- UfG projects include validation of measuring equipment at gas Entry Points and Supply Meter Installations at Exit Points as well as data analysis in an effort to determine the causes of UfG and potentially a pilot project to determine measurement uncertainty.
- The licensee shall publish UfG Reports on its website and provide a copy of the UfG Reports to the Authority. The reports should be published quarterly, semi-annually or even annually on dates agreed and included in the license.
- All data related to the report should be also published on the website of the TSO within a month from the publication of the report.

As a result of this term in the TSO license, National Grid has set up a Data Assurance and Quality Team which has undertaken the task of monitoring UfG. The list below summarises the lessons learned by National Grid from site visits (to meters) over a two year period\(^\text{142}\).

<table>
<thead>
<tr>
<th>Lessons learned and points noted by National Grid technical staff in their site visits</th>
</tr>
</thead>
</table>
| - It has been observed that the quality of some site billing data can be degraded as a result of telemetry problems despite the metering installation operating normally. Additional checks and confirmation procedures have been adopted in some instances to ensure accurate billing data is adopted.  
- Additional telemetry tests have been introduced to ensure that volume and energy integrator signals are connected correctly. Several wiring faults have been identified and rectified since May 2013 report.  
- During site visits we verify that Ultra-Sonic Meters (USMs) connected to measure gas in or out of the National Transmission System are calibrated using high pressure gas, that the calibration range is appropriate for the site operational range, that the calibrated profile is linearised correctly and that the meters comply with the uncertainty calculations for the meter system. We have noted that this best practice is not always followed.  
- We have observed that occasionally, orifice plate inspection/replacement intervals exceed the recommended 12 month period. This can be as a result of deferred maintenance, a change to maintenance regime or resource limitations. Where this is the case we prioritise these locations for their next site visit to ensure any significant performance change is captured. |

\(^{142}\) http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/balancing/unaccounted-for-gas/ , October 2013 UAG Report

144
We have seen several instances of metering faults resulting from the failure of electrical connections on temperature probes. These units have very fine 4-20mA loop wires which can be easily damaged when disconnecting/reconnecting for testing purposes. We have shared this information with the asset owners and are engaging with them to prevent issues occurring.

We have identified through our site visits that some turbine meters with manual lubrication systems do not have their operation checked in routine site maintenance procedures and it would be necessary to do so to adhere with best practice.

Daily UAG data has been published on the National Grid website since October 2012. Weekly updates are made to this information and cover the period from 1 March 2007 up to 7 days previous.

The selection of the sites is based on the following criteria:

- Sites with a history of errors
- Sites with a history of validation issues (including no reports received)
- Those yet to be selected for the audit programme
- Those with a history of meter failures
- Those operating close to the extremities of their metering ranges.
- Those identified by the data centred techniques.

As part of the effort towards the identification of UfG sources, National Grid also performs an extensive data analysis. They have created a “tool box” of a number of data processing techniques that they use to identify problems. The reader is referred to the original documents published by National Grid for a more detailed description of these techniques, their advantages and disadvantages.

To add confidence in the results by ignoring spurious events, a meter error or UfG is considered valid if:

- 2 or more of the methods find an event for similar dates, or
- The data mining tool identifies a very strong correlation between UAG and a facility

Having identified potential events at Offtakes in the previous point, processes have also been developed to allow effective investigations as to whether these are issues which are known to the business (albeit to other teams/companies) in which case there would be little value in investigating them further. Briefly, potential issues are investigated by checking against:

- Review whether issue coincides with site validation – did problem occur within 2 weeks? If so there could be an issue with hardware removed/installled on site or with human oversight.
- Check whether the records show there were flow computer integrator issues.
- Check whether the records show there were telemetry issues at the facility.
- Check whether the records show there were known site issues recorded in control room logs.
- Check whether the records show there were Non Routine Operations (NROs) undertaken which may result in non-standard site flow patterns.

The reader should refer to the April 2014 UAG Report.
f) Investigate whether the observed issues were due to flow swaps between Offtakess, i.e. standard but infrequent flow pattern.

g) Review the compiled database of operational intelligence gathered from other teams and internal National Grid documentation.

One method computes the efficiency of gas fired power plants as the ratio of electricity produced during a specific time interval to the quantity of natural gas consumed. The former needs to be provided to the Transmission System Operator by for example the electricity market operator, or the transmission system operator. The latter is drawn from the gas meters. Taking into account that power stations utilising gas turbines are expected to operate in a relatively narrow efficiency band for a given mode of operation, any apparent increases in efficiency are likely to be due to under measurement of gas flow, while any decreases in efficiency could be over measurement of the gas flow. These gas flow issues may indicate an event worthy of investigation. The following shows the standard times series data for gas fuel flow and generated power for a power station. Specific occasions that may be due to metering or other errors are identified. This method may not be suitable for all power stations as for example, some have their gas fuel metered a significant distance from the gas turbine and some blend NTS gas with offshore gas but it is expected that the majority of directly connected power stations can be accommodated by this method. Special care is required to distinguish between open and closed cycle (CC) gas turbines or any other steam requirements.

![Figure 49: Example of time series for power station gas fuel and generated power](http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/balancing/unaccounted-for-gas/)

Striking results towards the identification of potential causes of UfG were also obtained with the so called «Six year trending». This method involves producing a number of time series plots for the NTS Offtakess then reviewing the demand patterns looking for deviations from normal. Some Offtakess (single feed work the best) or groups of Offtakess have cyclic and repeatable demand pattern hence when this pattern deviates from normal it may indicate an event that should be investigated. The following figure shows a significant metering error at a particular offtake point. Unfortunately this method requires very long time series to ensure to detect operational extremes so that it is suitable only for very large errors.

144 [http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/balancing/unaccounted-for-gas/](http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/balancing/unaccounted-for-gas/) Figure B.4, October 2013 UAG Report
Another method is the Composite Weather Variable (CWV). This technique creates a model which predicts flow through a meter or set of meters based on weather data then compares the difference between forecast and actual flows. This sort of model is applicable distribution networks where demand is primarily temperature sensitive. According to the report published by National Grid on this technique has been tested on the gas flows in the city of Aberdeen over a period of time and a significant meter error has been found to detect on its very start. It can be seen that CWV is typically the mirror image of demand and when this relationship alters, an investigation would be conducted.

145 http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/balancing/unaccounted-for-gas/ Figure B.7, October 2013 UAG Report
146 http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/balancing/unaccounted-for-gas/ Figure B.7, October 2013 UAG Report
7.7 Unbilled Energy – Calorific Value Shrinkage (CVS)

Gas consumption in Europe is billed in energy rather than in volume units. From the discussions of the project team with the Tariff (price) Council of the Republic of Azerbaijan it has been understood that gas in Azerbaijan is priced at volume rather than energy units so that gas lost due to errors in calorific value measurements is not an issue for Azeri systems. Nevertheless for the sake of completeness a short section in this report is also devoted to the issue of losses due to unbilled energy resulting from erroneous determination of the gas calorific value.

Indeed, in European systems the requirement of billing gas consumption in energy units calls for a determination of the Gross Calorific value (GCV) at both entry and exit points in a transmission network simultaneously with volumetric measurements. Installation of calibrated gas chromatographers (GC) operating according to international standards (e.g. ISO 6974, ISO 6976) and measuring gas quality simultaneously with any other metering equipment quantifying gas volume is common practice at entry points of European transmission networks, exit points to large industrial plants and power plants as well as city gates. Equally however there are indeed examples of exit points operating in the absence of a gas chromatographer. In such cases, the GCV is most commonly estimated from the value measured at the closest exit point equipped with a GC. Inevitably such assumptions introduce an error in the billing of the non GC equipped customer. If the gas delivered to that particular customer is of higher calorific value, then inevitably some energy that has been delivered has not been billed for. The reverse of course may also be true.

The magnitude of such errors is very much dependent on the corresponding magnitude in the variation of the GCV. If gas is coming from multiple sources (e.g. domestic production, imports and LNG) the GCV variation is likely to be larger than when derived from a single source.

Further, Calorific Value Shrinkage is indeed an issue with distribution networks, where gas quality is metered at city gates but certainly not at customer deliveries. Indeed, the term Calorific Value Shrinkage has been introduced by the British transmission system operator, National Grid, to describe exactly the interactions from the following factors:

- Gas from different sources have significantly different GCV values.
- Gas from different sources is delivered to the same distribution zone from different distribution entry points.
- The geographic locations of different distribution entry points.

In such cases, as is the case of a consumption point on the transmission some assumption is made concerning the energy reaching the final customer. In the UK, when energy is billed the GCV is capped at 1 MJ/m³ above the lowest calorific value measured at city gates. In Greek and Italian distribution systems, the mass weighted average of the GCV measured at city gates is used. The amount of energy delivered but not used is termed as CV Shrinkage.

Further to the uncertainties introduced in the determination of the GCV in the absence of a gas chromatographer at an exit (or entry point, although the latter is fairly unlikely in European systems),

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147 The latter obligation also stems from environmental legislation on large combustion power plants, Directive 2010/75/EC
there are occasions where a GC is not functioning properly or on extreme cases not functioning at all. To this end, the Dutch operator Gasuni has been obliged by the regulator to publish on the company website a specific report highlighting the occasions of GCs malfunctions.¹⁴⁸

Figure 52: Daily CVS values from 1 March 2007 as published by National Grid¹⁴⁹ (values have been normalized by the 2007 average CVS value)

7.8 Conclusions and recommendations

This Chapter discussed transmission and distribution losses with emphasis on European Networks. The sources of losses were discussed and methods to identify, quantify and reduce natural gas losses in transmission networks, together with associated costs were presented. It has been shown that even simple methodologies, based on the multiplication of gas throughput or pipeline length with the so called “respective emission factor” can provide a yardstick towards the expected level of emissions from gas networks. Such calculations, taking into account the associated uncertainties, are useful for any regulator when assessing the information provided by the system operator(s) and can ultimately define a target to be achieved.

As natural gas comprises circa 90% methane – a greenhouse gas, natural gas leaks from pipeworks have received increased attention as part of the global initiatives to combat climate change. Methodologies for the estimation of methane emissions are also widely acknowledged as they constitute the base for the countries reporting to the United Nations Framework Convention on Climate Change (UNFCCC) and can thus be also used by the regulator to determine a gas loss reduction policy.

Azerbaijan can be a host country to projects developed under the Clean Development Mechanism (CDM). Such projects can also include gas loss reductions. Existing CDM projects currently in progress in other host countries have demonstrated notable results which should be at least become the topic of further investigation.

¹⁴⁸
¹⁴⁹ Own processing, data from http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=34062
EU Member States report extremely low values of losses that do not exceed in their majority an upper level of 1%, if only fugitive emissions are considered. Considering own use of gas (e.g. for powering compressors), gas losses in Europe could at most reach 2% of total gas demand although in many Member States the values are considerably lower. These values have been achieved through continuous improvements in networks over the last fifteen-twenty years.

As far as the energy regulator’s involvement in the treatment of losses is concerned, there is no harmonized approach in the European Union and there is no specific obligation for transmission system operators to procure the energy required for losses as is the case in electricity. Such being the case, gas lost in transmission networks is provided by either the network users (i.e. the gas suppliers) or the operators, or by both, depending on the mode agreed between the regulator, the operators and the stakeholders. Similar is the situation for gas storages whereas in distribution networks most commonly gas to account for gas lost is provided by the system operator. However when lost gas is provided by the system operator this is indeed procured and obtained at market prices. Transparency requirements for the whole process are imposed by the regulators.

The part of lost gas that is mostly a cause of concern for European, and also the US and Australian regulators is the so called Unaccounted for Gas. UfG is a term defined strictly for regulatory and accounting purposes. UfG is the gas which is lost or otherwise not accounted for as offtaken from a transmission or a distribution system. UfG is considered to be the consequence of data and/or meter error and is thus a relatively complex component of shrinkage, involving not only the mechanical behaviour of high pressure metering systems but statistical variations in their operation.

Regulators build a form of reimbursement for unaccounted for gas into the system operator’s rate structure. This reimbursement can cover the full cost of losses, partial cost of losses or provide incentives for a reduction of losses. Indeed the level of losses to be recovered through tariffs is on many occasions pre-approved by the regulator and may be set at such values that the operator does not necessarily recover the full cost. It is essential to ensure that the system operator is at least cash neutral to losses recovery and at most properly incentivised to act as a prudent and efficient operator towards the timely reduction of losses. Two things need to be taken into account and are crucial to the overall process towards reduction of losses. One is the maximum amount of losses that may be tolerated by the regulator or any other tariff setting authority and passed from the system operator (who bears the responsibility of the losses) to the system users and final consumers. To this end, the values and methodologies provided in this Chapter can provide guidance. The second item is transparency of the level of losses, the cause of those losses and finally the cost of those losses to the final consumers. Transparency in all aspects of energy related operations is key to oversight. Transparency also raises customer awareness and to that it is even a more valuable tool towards achieving the regulatory goals. Specific steps towards establishing a transparent system for monitoring gas losses have also been suggested as part of this present work.
8 QUALITY OF GAS & THE IMPACT ON END-USERS

This Chapter aims to provide a short note on the effect of natural gas quality in general, and of the natural gas calorific value in particular, to the overall performance of electricity and gas systems. The analysis is carried out in the spectrum of gas quality and heat content and also in relation to the electricity generation heat rate. It aims to add to the analysis of the electricity parts of this report. A considerable portion of this chapter has been sourced from the publication of BP in association with the International Gas Union (IGU) entitled «Guidebook to Gas Interchangeability and Gas Quality» as well as from publications from gas turbine manufacturers.

Natural gas is a generic term to define a mixture which varies in composition or quality as a result of different sources, extraction and processing. Even gas from the same region or even from the same production site can exhibit some variations in composition. One concept to be borne in mind when dealing with gas quality issues is that of interchangeability, defined as the ability to substitute one gaseous fuel for another in a combustion application without materially changing the operational performance of the application (safety, efficiency or emissions).

Limits on a range of gas quality specifications are included in national standards to protect network integrity and ensure downstream combustion safety. For example, the concentrations of water and hydrocarbon are controlled to prevent pipeline and valve blockages, toxic components such as hydrogen sulphide and mercury are controlled on health and safety grounds, whilst hydrocarbons and liquid contaminants are managed to ensure equipment performance and safety.

This Chapter includes three sections. The first section presents the basic parameters determining gas quality. The second section discusses the effect of gas quality on output power and efficiency on gas fired appliances with emphasis on gas turbines. Main points of the analysis are included in the third section.

Figure 53: Wobbe Number limits in EU

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Figure 54: Example of natural gas specifications\(^\text{151}\)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
<th>Units</th>
<th>Minimum</th>
<th>Maximum</th>
<th>Recommended implementation date</th>
</tr>
</thead>
<tbody>
<tr>
<td>WI</td>
<td>(Superior) Wobbe Index</td>
<td>kWh/m(^3)</td>
<td>13.60</td>
<td>15.81</td>
<td>01/10/2010</td>
</tr>
<tr>
<td>D</td>
<td>Relative density</td>
<td>m(^3)/kg</td>
<td>0.555</td>
<td>0.700</td>
<td>01/10/2010</td>
</tr>
<tr>
<td>S</td>
<td>Total sulphur</td>
<td>mg/m(^3)</td>
<td>-</td>
<td>30</td>
<td>01/10/2006</td>
</tr>
<tr>
<td>H(_2)S + COS</td>
<td>Hydrogen sulphide + carbonyl sulphide</td>
<td>mg/m(^3)</td>
<td>-</td>
<td>5</td>
<td>01/10/2006</td>
</tr>
<tr>
<td>RSH</td>
<td>Mercaptans</td>
<td>mg/m(^3)</td>
<td>-</td>
<td>6</td>
<td>01/10/2006</td>
</tr>
<tr>
<td>O(_2)</td>
<td>Oxygen</td>
<td>mol %</td>
<td>-</td>
<td>0.001*</td>
<td>01/10/2010</td>
</tr>
<tr>
<td>CO(_2)</td>
<td>Carbon dioxide</td>
<td>mol %</td>
<td>-</td>
<td>2.5</td>
<td>01/10/2006</td>
</tr>
<tr>
<td>H(_2)O DP</td>
<td>Water dew point</td>
<td>°C at 7000 kPa(a)</td>
<td>-</td>
<td>-8</td>
<td>See note **</td>
</tr>
<tr>
<td>HC DP</td>
<td>Hydrocarbon dew point</td>
<td>°C at 1 - 7000 kPa(a)</td>
<td>-</td>
<td>-2</td>
<td>01/10/2006</td>
</tr>
</tbody>
</table>

*Limit is <0.001 mol%, daily average. However, cross border point daily average levels up to 0.01 mol% will be accepted if these are the result of the prudent operation of UGS's existing in 2006, which use oxygen for desulphurisation purposes. (Based on the full CBP Wobbe range).

**At certain cross border points, less stringent values are used than defined in this CBP. For these cross border points, these values can be maintained and the relevant producers, shippers and transporters should examine together how the CBP value can be met in the long run. At all other cross border points, this value can be adopted by 1st October 2006.

Note: The reference temperature for combustion is 25°C. The reference temperature and pressure for volume measurement are 0°C and 101.325kPa.

### 8.1 Gas quality specifications and implications

Gas quality has two major technical aspects:

(a) The “pipeline specification” in which stringent specifications for water and hydrocarbon dewpoints are stated along with limits of contaminants such as sulphur. The objective here is to ensure pipeline material integrity for reliable gas transportation purposes.

(b) The “interchangeability specification” to ensure satisfactory performance of end-use equipment.

Thus, gas quality specifications may include limits for:

- The Wobbe Index
- Other interchangeability indicators such as the Weaver flame speed and other Weaver indices, AGA indices, the Incomplete Combustion Factor (ICF), the Lift index (LI), the Soot Index, the Methane number etc.
- Hydrocarbon and water dewpoint
- Solid and liquid contaminants
- Hydrogen Sulphide and total sulphur
- Carbon dioxide, nitrogen and total inerts

• Oxygen and hydrogen
• Concentration for specified hydrocarbons
• Contaminants: mercury, arsenic, helium, argon, chlorides, metals
• Odour

An example of the parameters commonly used to specify the quality of natural gas are shown in Figure 54 with the effect of each parameter on combustion efficiency and pipeline material integrity shown in Table 21. With the exception of the Wobbe Index which is discussed in the core part of this section, the definitions of the remaining interchangeability indices are provided in Table 22.

As far as EU Member States are concerned, different gas qualities have resulted in different specifications for acceptable natural gas, typically based on the historical or indigenous supply for each European country, and around the world. *Utilisation is thus indeed optimised for a particular gas quality.*

As shown in Figure 54, one of the parameters determining gas quality is the so called Wobbe Index defined as the ratio of the Gross Calorific Value to the square root of the gas density.

\[ WI = \frac{GCV}{\sqrt{\text{density}}} \]  \hspace{1cm} (1)

The Wobbe Index represents the amount of fuel energy flowing through an orifice to combustion equipment. The WI is a more useful indicator than calorific value alone in that it accounts for the impact of gas density on the fuel flow through a nozzle or orifice. It can be considered as a corrected calorific value, accounting for the impact of density differences between different fuel gases on the actual heating performance.

Figure 53 shows the Wobbe Index limits in the EU. Large variations between Member States can be detected. Currently Member States are involved into a lengthy, but as yet inconclusive discussion, regarding the harmonisation of gas quality specifications and the potential and implications for adopting one sole accepted gas specification throughout EU. The proposed specification is one of Figure 54, shown as far as the Wobbe Index is concerned at the rightmost part of Figure 53.

The Project Team of this AHEF assignment does not have enough information to assess the potential variations in gas quality in Azerbaijan. Such an analysis would at least require time series of the composition and calorific value of gas injected in the Azeri network on a daily basis. However, as Azerbaijan is relying on indigenous sources -with only a small part of gas sourced from Iran and injected to a comparably isolated network- it may be postulated that variations in gas composition will be minor, larger ones, if any, occurring on the case of faults in the gas processing equipment. Gas pipelines operate at pressures above atmospheric so entry of ambient air in the gas network in the case of leaks is rather improbable.

Another useful parameter to quantify gas quality is the Modified Wobbe Index defined as:

\[ MWI = \frac{GCV}{\sqrt{\text{density} \times \text{temperature}}} \]  \hspace{1cm} (2)

Gas turbines typically use fuel heating to ensure that there are no problems associated with dew-point liquid drop out. Also heating the fuel gas provides a method of control of the combustion characteristics of the fuel by altering the fuel density. Inclusion of the fuel temperature in the Wobbe Index highlights the importance of initial temperature in the combustion process.
Table 21: Various interchangeability indicators

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Definition</th>
<th>Utilisation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weaver flame speed and other weaver indices</td>
<td>Developed by Weaver in the US in the 1950s mostly however for town gas mixtures. Natural gas is generally hydrogen free with a constant Weaver Flame Speed factor of 14.</td>
<td></td>
</tr>
<tr>
<td>AGA indices</td>
<td>Developed by the American Gas Association and published in 1940. Represent a collection of several indices for flame lifting, flashback and yellow tip. Not appropriate for the high efficiency low emissions burner technology of today. Currently under review and update.</td>
<td></td>
</tr>
<tr>
<td>ICF-Incomplete Combustion Factor</td>
<td>$ICF = \frac{WI - 50.73 + 0.03 PN}{1.56}$ &lt;br&gt;PN: sum by volume propane and nitrogen. Used in the UK specification with limiting value less than 0.48.</td>
<td>Most important for instantaneous water heaters, which may have short periods of operations under cold start-up conditions and therefore susceptible to peaks of high emissions.</td>
</tr>
<tr>
<td>LI-Lift Index</td>
<td>$LI = 3.25 - 2.41 \tan^{-1}\left{\frac{0.122 + 0.0009H_2}{-36.8 - 0.0119PN + 0.775 - 0.118PN^{1/3}H_2}\right}$ &lt;br&gt;PN: the sum of % of nitrogen and propane. LI equal to 0 denotes no visible detachment. LI of 6 denotes complete detachment in over 50% of the flames.</td>
<td>Identified for cooker hobs which require flame stability under controlled turndown.</td>
</tr>
<tr>
<td>SI-Soot Index</td>
<td>$SI = 0.896 \tan^{-1}(0.0255C_3H_8 - 0.0233N_2 + 0.617)$ &lt;br&gt;$C_3H_8$ and $N_2$ in % by volume. This index is limited in application to the UK with an SI limit of lower than 0.6.</td>
<td>Most relevant for radiant fires with white ceramic radiant where sooting would be undesirable not for safety but for aesthetic reasons.</td>
</tr>
<tr>
<td>MN-Methane Number</td>
<td>$MON = -406.14 + 508.04\left(\frac{H}{C}\right) - 1733.55\left(\frac{H}{C}\right)^2 + 20.17\left(\frac{H}{C}\right)^3$ &lt;br&gt;$MN = 1.624 \times MON - 119.1$ &lt;br&gt;If a gas mixture has a Methane Number of 70, its knock resistance is equivalent to that of a gas mixture of 70% methane and 30% hydrogen.</td>
<td>The main parameter for rating the knock resistance of gaseous fuel when burned in a diesel engine. Analogous to the Octane Number for gasoline. The Methane number must be at least equal to the Methane Number of the Gas Engine.</td>
</tr>
</tbody>
</table>

Table 22: Gas specification parameters and operational issues

152 Unless otherwise specified, information in the table has been sourced from the BP Guidebook to Gas Interchangeability and Gas Quality
<table>
<thead>
<tr>
<th>Gas Constituent</th>
<th>Description</th>
<th>Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Hydrocarbons</strong></td>
<td><strong>Issues</strong>&lt;br&gt;• Provide the gas calorific value when it is burnt.&lt;br&gt;• The most abundant is methane but other hydrocarbons are found in reducing concentrations while the number of carbon in the atom increases.&lt;br&gt;• Hydrocarbon liquids, a hydrocarbon-rich liquid phase, form via concentration from the gas phase.&lt;br&gt;• Heavier hydrocarbons could form liquid phases in the network causing blockage problems.&lt;br&gt;• The control of the hydrocarbon dew point is the preferred method for controlling liquid formation. The specification normally reflects the expected ambient temperature and hence risk of hydrocarbon drop out occurring.</td>
<td></td>
</tr>
<tr>
<td><strong>Diluents or Inert Gases</strong></td>
<td><strong>Issues</strong>&lt;br&gt;• Typical inert gases are carbon dioxide, nitrogen, helium and argon&lt;br&gt;• They are non-combustible and are present in small amounts. Both CO$_2$ and N$_2$ can be used to lower the calorific value.&lt;br&gt;• Very low Wobbe index if large amount of inert gases are present, lowering combustion efficiency.</td>
<td></td>
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<tr>
<td><strong>Contaminants</strong></td>
<td><strong>Issues</strong>&lt;br&gt;• Usually present in very small concentrations but they may affect downstream operations.&lt;br&gt;• Health and safety implications if the public are exposed to either their contaminants or their combustion products.&lt;br&gt;• May cause corrosion of the pipeline network and restrict gas flow&lt;br&gt;• Turbines are particularly sensitive to impurities as the gas is burned at particularly high temperatures. Under these conditions, metal impurities such as mercury may form amalgamates with the engine components, causing embrittlement, cracking and permanent failure.</td>
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<tr>
<td><strong>Water</strong></td>
<td><strong>Issues</strong>&lt;br&gt;• The amount of water in the gas may be expressed either on a molar basis or, more usefully, as a dew temperature at which a water-rich liquid phase forms.&lt;br&gt;• Hydrates are ice-like solids containing hydrocarbons and can form if the temperature of the gas decreases (at a pressure-reduction station for example).&lt;br&gt;• The temperature, pressure and composition of natural gas in the transmission pipeline are controlled to prevent the formation of water droplets and hydrates.&lt;br&gt;• The presence of excessive water in natural gas can cause corrosion of the pipeline.&lt;br&gt;• Hydrate formation can block valves and, in extreme cases, the pipeline itself.</td>
<td></td>
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<tr>
<td><strong>Oxygen</strong></td>
<td><strong>Issues</strong>&lt;br&gt;• Oxygen is strictly controlled in the UK to protect molecular sieves at LNG storage sites.&lt;br&gt;• The allowable oxygen concentration in natural gas limits the usage of air ballasting for gas quality enrichment. Compared to membrane separation, can promote pipeline corrosion in the presence of water and sulphur.&lt;br&gt;• In underground storage sites oxygen promotes bacterial activity which produces hydrogen sulphide.</td>
<td></td>
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</tbody>
</table>

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153 Table from the BP Guidebook to Gas Interchangeability and Gas Quality
<table>
<thead>
<tr>
<th>Gas Constituent</th>
<th>Description</th>
<th>Issues</th>
</tr>
</thead>
</table>
| **cryogenic separation** | is often preferred to produce high purity nitrogen for ballasting to avoid excess oxygen in ballasted gas.  
  - Conversely, in those countries that have biogas entry points, for example Germany, a high limit of typically 3% is specified. | |
| **Hydrogen** |  
  - Hydrogen is flammable and in the UK can be tolerated by most domestic appliances up to about 4mol%. |  
  - Associated with stress corrosion cracking of steel pipelines. |
| **Hydrogen sulphide** |  
  - Hydrogen sulphide is toxic and it is controlled on health and safety grounds.  
  - Iron sulphide occurs as a result of the reaction of hydrogen sulphide with iron oxide, created by the corrosion of ferrous metals. The solid, often black in colour, can spontaneously ignite when exposed to air. |  
  - Hydrogen sulphide reacts with copper piping commonly used in domestic systems to form copper sulphide flakes which form a black dust and may cause blockage of filters and burner jets if allowed to accumulate. |
| **Organic sulphur species** |  
  - Organic sulphur compounds are mercaptans (also known as thiols) and sulphides that may be present naturally in the gas |  
  - Limited due to highly unpleasant odour.  
  - Also to reduce the possible mosking effect they may have odorants added to the gas to aid public detection of gas leaks. |
| **Solids or Liquids** |  
  - Generally only introduced into the network by operational failures.  
  - Most regulations state that the natural gas must be commercially free of materials or dust or other solid and liquid matter so as not to interfere with the integrity or operation of the network or gas-burning appliances. |  
  - Can cause corosions, stress or abrasion damage on pipeline and restrict the gas flow.  
  - Have the potential to cause severe damage to turbine blades.  
  - Liquids can block filters and the impulse lines of pressure measuring equipment. Build-up of liquids on either side of an orifice –plate meter will cause under-resignation of the metered value. |
8.2 Impact of gas quality on end users

Gas-fired equipment demonstrates different levels of tolerance to the variation of gas composition depending on the sensitivity and design tolerance to output parameters such as emissions and combustion efficiency. Rapid or transient changes in gas composition are particularly problematic for some combustors, especially gas turbines. The analysis of this section will indeed focus on gas turbines as according to the Terms of Reference of the present AHEF, fuel quality issues should be discussed in association to efficiency for electricity generation\textsuperscript{154}.

8.2.1 Basic principles of gas turbine efficiency and combustion

The thermodynamic cycle upon which all gas turbines operate is the Brayton cycle. Two parameters are critical for gas turbine performance; the pressure ratio (between the compressor discharge pressure and the inlet pressure taking into account the pressure losses in the combustion chamber) and the firing temperature\textsuperscript{156}.

\textsuperscript{154} Additional information on the effect on fuel quality on appliances can be sourced indicatively from the BP Guidebook to Gas Interchangeability and Gas Quality available on line, from the “Study on Interoperability -Gas Quality Harmonisation -Cost Benefit Analysis”, Report prepared for the European Commission by GL Noble Denton and Pöyry Management Consulting, July 2011 and from the European Commission site on gas quality.

\textsuperscript{155} Figure and a significant part of this section have been sourced from Brooks, F.J. GE Gas Turbine Performance Characteristics, GE Power Systems (document GER-3567H, available on line).

\textsuperscript{156} ISO document 2314, “Gas Turbines – Acceptance Tests.” The firing temperature here is a reference turbine inlet temperature and is not generally a temperature that exists in a gas turbine cycle; it is calculated from a heat balance on the combustion system, using parameters obtained in a field test.
Figure 56 shows a plot of output and efficiency for different firing temperatures and various pressure ratios. Output per unit of mass of airflow is important since the higher this value, the smaller the gas turbine required for the same output power. Thermal efficiency is important because it directly affects the operating fuel costs. Figure 56 illustrates a number of significant points:\(^{157}\)

- **In simple-cycle applications** (the top graph of Figure 56), pressure ratio increases translate into efficiency gains at a given firing temperature. The higher the pressure ratio, the greater the benefits from increased firing temperature. Increases in firing temperature provide power increases at a given pressure ratio, although there is a sacrifice of efficiency due to the increase in cooling air losses required to maintain parts lives.

- **In combined-cycle applications** (as shown in the lower graph of Figure 56), pressure ratio increases have a less pronounced effect on efficiency. Note also that as the pressure ratio increases, the specific power decreases. Increases in firing temperature result in increased thermal efficiency. The significant differences in the slope of the two curves indicate that the optimum cycle parameters are not the same for simple and combined cycles.

Since the gas turbine is an air-breathing engine, its performance is changed by anything that affects the density and/or mass flow of the air intake to the compressor. Ambient weather conditions (temperature and humidity) are the most obvious parameters affecting output. Altitude affects the compressor inlet pressure and thus also gas turbine performance.\(^{159}\)

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\(^{158}\) Figure and a significant part of this section have been sourced from Brooks, F.J. GE Gas Turbine Performance Characteristics, GE Power Systems (document GER-3567H, available on line).

\(^{159}\) Further information on the effect of altitude, steam addition and other parameters affecting output and efficiency is also included in the paper by Brooks.
Work from a gas turbine can be defined as the product of mass flow, the product heat energy in the combusted gas \( (C_p) \), and temperature differential across the turbine. The mass flow in this equation is the sum of compressor airflow and fuel flow. The heat energy is a function of the elements in the fuel and the products of combustion. Natural gas (methane) produces nearly 2% more output than distillate oil. This is due to the higher specific heat in the combustion products of natural gas, resulting from the higher water vapour content produced by the higher hydrogen/carbon ratio of methane. This effect is noted even though the mass flow of methane is lower than the mass flow of distillate fuel. The effects of specific heat are greater than, and in opposition to, the effects of mass flow.

Figure 56 shows the effect of various fuels on turbine output. Although there is no clear relationship between fuel calorific value and output, it is possible to make some general assumptions. If the fuel consists only of hydrocarbons with no inert gases and no oxygen atoms, output increases as the lower calorific value (LHV) increases. Here the effects of \( C_p \) are greater than the effects of mass flow. Also, as the amount of inert gases is increased, the decrease in LHV will provide an increase in the output. This is the major impact of IGCC type fuels\(^{160}\) that have large amounts of inert gas in the fuel. This mass flow addition, which is not compressed by the gas turbine’s compressor, increases the turbine output. As a very general rule, in most cases of operation with lower heating value fuels it can be assumed that output and efficiency will be equal to or higher than that obtained in natural gas. In the case of higher heating values such as refinery gases, output and efficiency may be equal to or lower than that obtained on natural gas.

8.2.2 Dry Low NOx Combustion Systems

The regulatory requirements for low emissions from gas turbine power plants have increased during the past 20 years. Environmental agencies throughout the world are now requiring even lower rates of emissions of nitrogen oxides (NOx) and other pollutants from both new and existing gas turbines. Nitrogen oxides\(^{161}\) are a by-product of all combustion processes with quantities increasing dramatically as a function of combustion temperature, the latter strongly linked to the fuel-to-air ratio in the combustor. The leaner the fuel-air mixture, the lower the temperature, thus the lower the NOx production as shown in Figure 57.

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\(^{160}\) IGCC, Integrated Gasification Combined Cycle, comprising of a Gasification unit where a solid fuel of low calorific value is gasified to create syngas, a mixture of hydrogen and CO, a gas treatment unit and a combined-cycle power block for power generation.

\(^{161}\) The term nitrogen oxides is used to refer to the sum of NO and NO\(_2\), with the former predominantly generated during the combustion process (referred to as thermal NO) and the latter formed further downstream.
Figure 57: Relation between equivalence ratio and the formation of various pollutants including NOx

Note: The yellow zone denotes the region of operation of modern gas turbines operating on a lean premixed mode.

Traditional methods of reducing NOx emissions from combustion turbines include water and steam injection which again aims at reducing the flame temperature. However these methods are limited in their ability to reach the extremely low levels required in many regulations. On the other hand, operation of the turbine at the so called “lean premixed regime”, close to the lean flammability limit (referred to as blow out in Figure 57.), can achieve very low levels of NOx. This operation mode however is at the expense of flame stability so that low premixed systems most commonly operate at loads of over 50% of the full turbine power and requires consistency in the variables that affect combustor operation, including fuel properties. Small variations in the fuel concentration (i.e. in the natural gas composition) can lead to autoignition, flame flashback or self-induced combustion oscillations. To avoid such phenomena gas turbines are designed to operate within a narrow range of the Wobbe Index. A schematic of a dry low NOx combustor is shown in Figure 58 below:

Figure 58: Fuel-staged Dry Low NOx combustor

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162 Figure from Davis, L.B. & Black, S.H. Dry Low NOx Combustion Systems for GE Heavy-Duty Gas Turbines, GE Power Systems (document GER-3568G, available on line).
Figure 59 presents the typical operation modes of Dry Low NOx (DLN) gas turbine manufactured by GE power systems. As shown in the figure, depending on the load of the turbine four operational modes can be distinguished:

- **Primary – Fuel to the primary nozzles only.** Flame is in the primary stage only. This mode of operation is used to ignite, accelerate and operate the machine over low- to mid-loads, up to a pre-selected combustion reference temperature. Commonly, at this stage only fuel is injected from the primary nozzles mixing with the surrounding air while combusting so that the fuel to air ratio is close to unity (diffusion flame).

- **Lean-Lean – Fuel to both the primary and secondary nozzles.** Flame is in both the primary and secondary stages. This mode of operation is used for intermediate loads between two pre-selected combustion reference temperatures.

- **Secondary – Fuel to the secondary nozzle only.** Flame is in the secondary zone only. This mode is a transition state between lean-lean and premix modes. This mode is necessary to extinguish the flame in the primary zone, before fuel is reintroduced into what becomes the primary premixing zone.

- **Premix – Fuel to both primary and secondary nozzles.** Flame is in the secondary stage only. This mode of operation is achieved at the combustion reference temperature design point. Optimum emissions are generated in premix mode. The load range associated with these modes varies depending on the design of the combustor.

Evidently, the design may vary depending on the manufacturer and the turbine model, however the general principles remain i.e. at lower loads combustion is at equivalence ratios of close to unity and reducing to leaner mixtures with increasing loads. The effect of this mode of operation on the nitrous oxide emissions is shown in Figure 60 below:

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163 Figure from Davis. L.B. & Black, S.H. Dry Low NOx Combustion Systems for GE Heavy-Duty Gas Turbines, GE Power Systems (document GER-3568G, available on line).
Premixed combustion systems can be vulnerable to contaminants in the fuel. Large amounts (e.g., 25%) of diluents such as CO₂ or N₂, and trace amounts of higher hydrocarbons (beyond hexane) have no effect on the heating value of the fuel but can lead to autoignition at much lower temperatures than would be expected, can give rise to flame stability issues and flashback.

Combustion pressure oscillations—often referred to as combustion dynamics—can be generated during lean premixed combustion. The fuel delivery system, the compressor discharge plenum, the pre-mixers, and the combustor down into the sonic region of the turbine act as coupled acoustic cavities with characteristic resonances. The dependence of heat release on (1) unsteady large-scale structures in the flow and (2) variations in fuel/air ratio may lead to self-sustaining oscillations and ultimately cause severe damage to the turbine. Passive and active control systems are currently incorporated in all modern gas turbines to limit such effects. As already stated, since the Azeri gas demand is to a grand extend met by indigenous production, to the knowledge of the project team, variations in gas quality should be also minor so that such phenomena should be extremely limited and due to extreme situations (e.g. fault in a gas processing plant).

8.3 Conclusions
This Chapter provided a short note on the effect of natural gas quality in general, and of the natural gas calorific value in particular, to the overall performance of electricity and gas systems. The analysis was carried out in the spectrum of gas quality and heat content and also in relation to the electricity generation heat rate as described in the Terms of Reference in the present AHEF.

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Natural gas is a generic term to define a mixture which varies in composition or quality as a result of different sources, extraction and processing. Even gas from the same region or even from the same production site can exhibit some variations in composition.

Gas quality has two major technical aspects:

a) The “pipeline specification” in which stringent specifications for water and hydrocarbon dewpoints are stated along with limits of contaminants such as sulphur. The objective here is to ensure pipeline material integrity for reliable gas transportation purposes.

b) The “interchangeability specification” to ensure satisfactory performance of end-use equipment. Interchangeability is defined as the ability to substitute one gaseous fuel for another in a combustion application without materially changing the operational performance of the application (safety, efficiency or emissions). A detailed description on the calculation and use of an extensive list of interoperability indicators has been provided in this chapter.

Gas-fired equipment demonstrates different levels of tolerance to the variation of gas composition depending on the sensitivity and design tolerance to output parameters such as emissions and combustion efficiency. Rapid or transient changes in gas composition are particularly problematic for some combustors, especially gas turbines. The analysis of this section focused on gas turbines as according to the Terms of Reference of the present AHEF, fuel quality issues should be discussed in association to efficiency for electricity generation. Based on data published by gas turbine manufacturers, the analysis in this section showed that although there is no clear relationship between fuel calorific value and output, it is possible to make some general assumptions.

- If the fuel consists only of hydrocarbons with no inert gases and no oxygen atoms, output increases as the lower calorific value (LHV) increases. Here the effects of Cp are greater than the effects of mass flow.
- As the amount of inert gases is increased, there can be an increase in output despite the decreasing calorific value. Large amounts of inert gas in the fuel act as a mass flow addition, which if not compressed by the gas turbine’s compressor, increases the turbine output.
- As a very general rule, in most cases of operation with lower heating value fuels it can be postulated that output and efficiency will be equal to or higher than that obtained in natural gas. In the case of higher heating values such as refinery gases, output and efficiency may be equal to or lower than that obtained on natural gas.

The regulatory requirements for low emissions from gas turbine power plants have increased during the past 20 years. Environmental agencies throughout the world are now requiring even lower rates of emissions of nitrogen oxides (NOx) and other pollutants from both new and existing gas turbines. Nitrogen oxides are a by-product of all combustion processes with quantities increasing dramatically as a function of combustion temperature, the latter strongly linked to the fuel-to-air ratio in the combustor. Operation of the turbine at the so called “lean premixed regime” where the air and fuel have already been mixed in a uniform fuel poor mixture can achieve very low levels of

\[ \text{The term nitrogen oxide is used to refer to the sum of NO and NO}_2, \text{ with the former predominantly generated during the combustion process (referred to as thermal NO) and the latter formed further downstream.} \]
NOx. This operation mode however is at the expense of flame stability and requires consistency in the variables that affect combustor operation, including fuel properties. Small variations in the fuel concentration (i.e. in the natural gas composition) can lead to autoignition, flame flashback or self-induced combustion oscillations. To avoid such phenomena gas turbines are designed to operate within a narrow range of the Wobbe Index.

The Project Team of this AHEF does not have enough information to assess the potential variations in gas quality in Azerbaijan. Such an analysis would at least require time series of the composition and calorific value of gas injected in the Azeri network on a daily basis. However, as Azerbaijan is relying on indigenous sources -with only a small part of gas sourced from Iran and injected to a comparably isolated network- it may be postulated that variations in gas composition will be minor, larger ones, if any, occurring on the case of faults in the gas processing equipment.
9 APPENDICES


10 BIBLIOGRAPHY


