STUDY ON WORLD GAS PRICING REGULATION AND LESSONS FOR THE ISRAELI MARKET.

Final Report

Prepared by NEWES, New Energy Solutions

for the Public Utilities Authority (Electricity)

of the State of Israel

28 September 2014

Contents

EXECUTIVE SUMMARY

This Report represents a follow-up and update of the “Examination of the Natural Gas Agreements with the Tamar Reserve for 2013 and Thereafter” that was prepared by NEWES (New Energy Solutions) for the Public Utilities Authority (Electricity) of the State of Israel in 2012. It aims at providing a Survey of pricing practices for the domestic markets of natural gas in the world, with a particular focus on electricity generation, and with consideration of the main contractual conditions that accompany pricing. The Survey is then used as a source ofdraw lessons and suggestions for Israel’s case, in the wake of the evolution of the Israeli gas markets in the last two years.

Wholesale gas market regulatory experiences in the world.

Several case studies have been examined, with the analysis following as far as possible a common scheme for all countries, investigating the regulatory framework, the nature of the Regulator, the scope, methodology ad main parameters of the regulation of prices and ancillary conditions, and the prevailing price levels. The Study has considered these countries: U.S.A; Brazil; Argentina; Europe (overview and selected Member States: Italy, France, Netherlands); Algeria; Nigeria; Egypt; Russian Federation; China; India; New Zealand.

There is a world tendency towards deregulation of gas prices, starting from the wholesale level and from larger customers. However, most countries retain some form of regulation for residential and other small customers (mostly the commercial sector and public services) and in many cases even wholesale markets are not open and wholesale prices are also regulated..

The most advanced economies (OECD Members) have generally open wholesale markets and phased out their gas price regulation, even though they generally maintain the regulation of network services like transmission, distribution and (in some cases) also storage and LNG regasification.

For retail, several **OECD** countries (like **U.S., France, Italy**) still keep some type of price control, particularly for smaller customers. In other cases, there is no control even for retail prices, and prices are only subject to ex-post control from Competition regulators. These regulated retail prices are increasingly linked to gas hub prices rather than to competing fuels.

In a few cases, if there is a specialised regulator, it retains a market monitoring and advisory role towards the government or the Competition regulator.

In the past, in the **Netherlands** – as well as in most Western European countries – prices of natural gas were related to those of competing fuels, notably oil derivatives, with some margins aimed at maintaining some competitiveness for gas. Lately, the Dutch market is fully liberalized, with no wholesale price regulation, and integrated to those of neighbouring countries of North-Western and Central Europe, with prices defined mostly in market hubs.

The **US** have phased out wellhead and wholesale price wholesale regulation since the early 1980s. It was a complex and burdensome practice, which had been lasting for several decades and has been widely seen as partly liable for the shortage that affected America's gas industry in the 1970s.

Russia retains some (rather opaque) cost based regulation of upstream facilities, but its prices are mostly either liberalized (as is in fact the case of most of the power generation market), or linked to those of competing fuels. For the wholesale market, and particularly for the dominant operator, prices have been slowly increased with a view to bring them in line with netbacks to export markets (export parity) but this objective has not been fully achieved yet.

Both **China** and **India** have various and complex regulatory regimes, mixing cost based cases with market-oriented ones. In both cases, official policies aim to bring prices in line with market levels, notably with oil derivatives in China and with import prices in India. Yet implementation is slow, particularly in India.

In **Brazil**, prices are generally driven by interfuel competition, but some special programs reduce the price for power generation. Regulatory criteria are cost based for network services but less clear for the commodity price, which is generally in line with import costs.

In **Argentina**, a prolonged price freeze after the country's 2001 default and high inflation has led to stagnation of upstream investments, production decline since 2005 and a shortage that is now covered by costly LNG imports. Price levels are well below any cost definition. However, some supplies have lately been made available at market prices.

The 3 large African gas producers (**Algeria**, **Egypt** and **Nigeria**) all have a dominant national company, and use "single buyer" models so that gas is purchased from producing joint-ventures at various conditions, often hard to detect, but with rates of return usually in the 12-15% range. Gas is then re-sold to consumers at regulated prices, which may be related to political priorities rather than cost. However, this model is being revised, at least in Egypt, where production stagnation and fast demand increase is about to turn the country into a net importer and huge subsidies have become unsustainable for public finances. Nigeria has also increased its prices for power generation, bringing them almost in line with production cost, with a view to fix its power generation deficit.

Finally, **New Zealand**, now a fully liberalized market in spite of its small size, has also undergone a period of regulated prices, indexed to inflation, which were introduced between 1996-2002 as a remedy against the market dominance by a single gas field. However, the price control has led to reduced exploration and development and a demand supply imbalance, followed by a sharp production decline. Ensuing price increases and liberalization – allowed by a much less concentrated supply – have restored the equilibrium.

Full cost transparency of the kind usually delivered by modern electricity and gas regulation is rarely found in the upstream gas regulatory regimes, which are often administered by Ministries, with a strong influence of large state owned companies. Furthermore, there some logical flaws that hamper a proper definition of some cost items, like depreciation, by the usual accounting criteria, as the value of mineral resources is essentially related to forward looking market conditions rather than at cost.

On the other hand, criteria for regulated price update, where applicable, are mostly transparent and well known, both in terms of indicators and frequency. They are related to oil derivatives (Russia, China,) or to gas markets (U.S., Italy), or to a mix of both (France). Update feequency varies between quarterly and yearly.

Price levels in the world are very variable, as LNG trade is still too limited and costly to bring about their alignment. Exporting countries and integrated markets (including North America as a whole) have domestic lower prices, usually below $5/MMbtu, whereas net importing areas (including the EU as a whole) usually have higher prices, above $6/MMbtu and up to 15 and more for Japan and other consumers relying mostly on LNG imports. Currently isolated countries like Israel and New Zealand lie in between, around 5-6$.

Israeli conditions and regulatory perspectives

Israel is on the eve of expanding its gas use, thanks to the full exploitation of the Tamar reservoir and to the likely development of Leviathan and smaller fields. Up to 40% of reserves may be exported, with the latest expectations focusing on neighboring areas and on the Egyptian terminals that are currently short of natural gas. This policy and recent (though non-binding) Memorandums of Understanding for the sale of Tamar gas to neighboring markets point to the likely interconnection of the main reservoirs. This is favourable for security of supply of supply and market development.

As for pricing, the main relevant options that are examined in the Report are: (i) keeping the existing arrangements; (ii) setting prices in line with the netbacks of end products; (iii) regulating in line with costs; (iv) regulating in line with competing fuels; and (v) regulating in line with international gas markets.

Competing fuels are hardly relevant in the country, as little interfuel competition is feasible, notably for environmental and logistic reasons. Netbacks from end products of gas use could be feasible for methanol or fertilizers, but not for electricity, due to the lack of a competitive market of the latter.

Existing Tamar contracts are found to price gas well any reasonable estimation of costs, leading to very high rates of return. Moreover, their indexation is not in line with most of the international experience of both regulated and unregulated gas supplies, as it shifts all risks onto consumers.

On the other hand, cost-based regulation of gas fields has not proven appropriate in the past. As the U.S. and New Zealand experiences show, such regulation is poorly rooted in economic theory, riddled with uncertainties which are sources of controversies, and has often delivered shortages. Markets in countries like Algeria, Argentina, Egypt and Nigeria have also suffered from pricing practices that have not adequately encouraged exploration and development of new resources, and this risk is serious for Israel as well, as most newly found reserves have not been developed yet. Other countries which have partially adopted cost based regulation of gas fields, , like Russia, China and India, are also moving away from it and towards market based approaches, whereas other countries like the Netherlands have refrained from it altogether.

The Report recommends that a market based approach should be adopted. In the current global market environment, this should preferably be based on indices of competitive gas markets, choosing among the most liquid, transparent and representative ones, and selecting them in a way to approximately represent the likely outcome of Israeli exports. Markets in Europe and East Asia may fit the purpose. The domestic price could then be set at the export parity level, namely the average level of export market prices minus transportation costs to then, including those of the LNG chain where applicable.

Since such prices may be swinging, it may be in the interest of both suppliers and consumers to agree on a floor and ceiling approach, where a lower and an upper limit to fluctuations would be defined. The lower limit could be defined as a conservative estimate of production costs for the relevant fields, and the ceiling could be based on existing contracts. This approach is well suited to strike the balance between consumers' and producers' interests, avoiding producer flights and delivering to consumers the most precise information about the value of the resource that they are using. Thus, this approach would not guarantee any specific price level, but it would reassure that development costs are covered, and that prices are paid in line with the market value of the resources. It is also in line with the regulatory practice of net exporting countries from advanced economies, like Australia and Canada.

The following Table shows which prices would prevail, under specific assumptions. These prices reflect the average of Tamar sales, including those to industry and other sectors, which are priced at a discount to the energy equivalent price of competing fuels.

Prices should be adjusted to take into account delivery conditions. For example, higher flexibility rates, as allowed by a lower take or pay or higher permitted swing factors, would entail slightly higher costs. However, availability of storage facilities or connection to wider markets can help reducing the costs of flexibility, and an embryonic balancing market within the country, possibly operated by a central entity, may also help.

The international Survey has not found much information about ancillary contractual conditions, which are normally negotiated between the parties rather than regulated. Any regulation is related to specific features of the producing areas and their connected infrastructure and cannot be generalized..

Results of the simulations for the main applicable pricing options, based on sales between 2013 and 2030.

	Average consumer price ($/MMbtu)	Tamar internal rate of return	Total tax revenue ($ billion)
Option 1a – Current prices	7.22	24.1%	47.89
Option 1b – Current prices with price reviews	5.64	19.6%	34.24
Option 3 – Cost reflective regulation	1.73	8.1%	9.89
Option 3 – Cost reflective regulation (12% return)	2.60	12.0%	15.93
Option 5 – Export parity*	4.24	17.9%	26.89
Suggested option – bounded export parity*	4.33	18.2%	27.96

(*) based on the hub prices that have prevailed between July 2008 – June 2014

1. OUTLINE OF THE REPORT

This Report represents a follow-up and update of the “Examination of the Natural Gas Agreements with the Tamar Reserve for 2013 and Thereafter” that was prepared by NEWES (New Energy Solutions) for the Public Utilities Authority (Electricity) of the State of Israel. It aims at providing a Survey of pricing practices for the domestic markets of natural gas in the world, with a particular focus on electricity generation, and with consideration of the main contractual conditions that accompany pricing, with a view to draw lessons and suggestions for Israel’s case.

In Chapter 2, several case studies are examined, with the analysis following as far as possible a common scheme for all countries, investigating the following main issues:

- Which gas market prices are regulated (wellhead, wholesale and/or retail, by consuming sector);
- The regulated price levels at wellhead, wholesale/or retail, consuming sector, distinguished by countries in relation to whether they are net importers, or exporters, connected by pipelines, or by the LNG chain;
- The nature of the gas regulator (Ministry, Local Governments, Government Agency, Independent Energy Regulator, Competition Regulator, Courts, or others);
- The basis for the regulation, if any (Cost of production, transportation, storage etc.; local or international market price or a combination; price of competing fuels; social affordability, including for electricity that is generated from natural gas; and others). In each stage, the main criteria that are used in other relevant countries for gas regulation are identified, including known methods for capital valuation, costing models, rates of return and their component, use of benchmarking, inclusion of exploration and selling costs, social or environmental fees, reference to competing fuels, etc.;
- The main criteria for price adjustment and indexation are also explored (regulation duration, indicators, frequency, trigger rule, relevant authority or legal basis, role of incentive or performance –based regulation, milestones for reducing regulations);
- The main non-price provisions of regulation (e.g. quality of service rules, production performances like available capacity, ramp-up, ramp-down, swing factors, take or pay commitments) that may be subject to regulation; are outlined as far as available.

The study is carried out by desk/web research, starting from existing surveys of international pricing practices, and resorts as necessary to direct written enquiries and interviews with country experts, regulators, and other stakeholders.

Given the limited time and cost budget, the Survey has considered selected countries:

- U.S.A;
- Brazil;
- Argentina;
- Europe (Overview and selected Member States: Italy, France, Netherlands);
- Algeria;
- Nigeria;
- Egypt;
- Russian Federation
- China;
- India;
- New Zealand

Chapter 3 provides a comparative summary of the main results of the Survey: the most interesting experiences are elaborated and discussed in relation with the Israeli situation and compared to current regulation, showing which cases are relevant, which experiences should be avoided, and why.

Chapter 4 is devoted to the analysis of the main options that can be inspired by the international experience. It starts from a preliminary description of regulatory criteria that are recommended by the theoretical literature is outlined. The framework of the Israeli gas market is then summarised, providing an analysis of the position of the Consortium that currently dominates gas supply, with a view to connection of Israel to the world gas market.

Finally, the main available options and suggestions for regulation criteria will be provided accordingly. These include:

- Basic price level
- Indexation clauses
- Control duration and re-opening clauses
- Supply performance regulation and other non-price clauses
- Other gas contractual terms that should be taken into consideration if defined as parameters that should be regulated

Where appropriate, the quantitative impact of the options on producers, consumers and government revenues are simulated. Finally, a suggestion is outlined for an appropriate regulation of Israel’s natural gas supply.

2. SURVEY OF DOMESTIC GAS PRICE REGULATORY PRACTICES IN SELECTED WORLD COUNTRIES

2.1 Foreword

In his Introduction to the 500-page book on gas prices in international trade, which he edited as the results of years of work by some of the best world experts, Professor Jonathan Stern noticed that a similar work on domestic gas pricing would require an even larger effort, so that the task had been sidelined for a while[1]. It is taken up in this Report even though the task would be far more demanding than the available resources allow, and results will only be rather preliminary.

This Survey of end user gas price regulation covers 13 countries from all Continents, representing about 52% of gas production in 2014, and a slightly lower share of gas consumption. The sample has been designed not only to ensure geographical coverage and adequate share of the world gas industry, but also with a view to include countries that have different positions towards international trade: net exporters as well as importers. Moreover, these countries are of different size and rely in various shares on natural gas as a source of wealth and energy. The main gas production, consumption and trade data of the sample countries are provided in Table 2.1, with a comparison to Israel.

Beyond the sample, the International Gas Union prepares every year an international survey of wholesale gas pricing practices, which does not however include many details. It shows that in 2013 most natural gas is priced after wholesale gas markets (43%) or indexed to oil and oil derivatives (19%). Another substantial share (12%) is priced in line with the cost of service or knowingly below it (8%), whereas in the remaining 18% governments price gas pursuant to political and social goals or after a direct commercial agreement with sellers. The tendency of the last decade clearly shows that price regulation are moving from political and social pricing criteria, usually requiring heavy or subsidization, towards more cost-reflective ones. An even stronger tendency is the move from cost-based ones towards market based criteria. Finally, among market-based criteria, there is a trend from oil-based towards gas market based pricing.

[1] J. Stern (2012). In fact, that book is an excellent starting point even for research on domestic pricing, at least for a few countries.

Table 2.1 - Main gas data of the sample countries, 2013 (Bcm)

Country	Production	Consumption	Net Exports	Net exports / consumption (%)
US	687,6	737,2	-49,6	-6,7%
Brazil	21,3	37,6	-16,3	-43,3%
Argentina	35,5	48,0	-12,5	-26,0%
Netherlands	68,7	37,1	31,6	85,3%
France	0,5	42,8	-42,3	-98,8%
Italy	7,1	64,2	-57,1	-89,0%
Algeria	78,6	32,3	46,3	143,4%
Egypt	56,1	51,4	4,6	9,0%
Nigeria	36,1	13,4	22,7	169,3%
Russian Federation	604,8	413,5	191,3	46,3%
China	117,1	161,6	-44,6	-27,6%
India	33,7	51,4	-17,8	-34,5%
New Zealand	4,4	4,4	0,0	0,0%
Israel	5,8	6,9	-1,0	-15,0%

Sources: BP Statistical review of World Energy. For Israel: Noble, CIA.

This Chapter reports results of our Survey, which has been conducted in 10/13 cases with the help of country experts, who are familiar with their language, regulation, and institutions. Egypt, New Zealand and Nigeria have been prepared by the main author, with the help of local contacts. Experts have followed a common list of questions, which is included in Annex 1. Some preliminary information about the country's gas industry is provided, in order to understand the reasons of the institutional and regulatory solutions and which lessons could be drawn from them.

2.2 The United States[2]

2.2.1 Introduction

The gas industry in the United States is more than a century old—and for about half of that time the federal government was involved in some form of gas price regulation as part of its efforts to organize and regulate the gas pipeline and distribution industry.

Today, the natural gas industry in the United States has reached a kind of regulatory equilibrium. Free of major controversy or initiatives for change, modern gas industry exhibits the following attributes:

- a freely competitive gas production sector with spot and futures markets throughout the continental United States (extending into Canada) unlike any other regional gas markets in

This section has been drafted by NERA

2

the world;

- cost-based regulation of gas transmission services provided under federally-licensed pipeline capacity and capacity contracts between pipeline companies (who own no gas themselves) and shippers;
- unregulated sales contract capacity rights to the existing licensed pipeline capacity, creating a competitive market in pipeline "space";
- largely passive regulatory certification/licensing of a vigorous and genuinely competitive market in pipeline capacity expansions; and
- a state-regulated distribution and retail supply sector that collectively is the largest collection of gas buyers in the country, and that passes those gas commodity and pipeline transport costs to their connected users at actual invoiced cost without margin, as they pass through their other purchases (such as labour and materials), at actual cost.

The most striking element of gas pipeline regulation, compared to Europe for example, is the lack of non-contractual "common carriage" or "third-party access" obligations on US gas pipelines. Gas pipeline regulation formed around pipeline contracts, instead.

The transition to open pipeline access and deregulated wholesale gas prices was not smooth or deliberate in terms of gas market regulatory policy. But the political and institutional story is critical to understanding the development of the world's only unregulated gas pipeline capacity market and its accompanying highly competitive gas market.

Creating contract-based gas transport companies was an important step towards the current regulatory framework. However, the construction of a genuine market in capacity rights was defining. In the end, a "Coasian" market in the legal rights to capacity on the US pipeline system developed, worked, and survived the various energy "crises" of the 21st century, including hurricane Katrina and the Californian Electricity Crisis.[3]

Gas pipelines now exist in a market with unusual regulatory equilibrium, which has overcome the certification/monopoly problem. The market determines who will use the nation's gas transport capacity. Further, it has allowed FERC action over regulated prices to recede to the point where it is little more than background noise. The development of modern gas pipeline regulation in the US ultimately demonstrates how hard it is to create regulations that satisfy the competing objectives of the critical interest groups.

[3] For a discussion of the US "Coasian" gas pipeline capacity, in reference to Ronald Coase who defined such markets, see J. Makholm, (2012).

The regulation of gas prices in the United States consists of the following reasonably well-defined periods:[4]

- No federal gas or gas pipeline regulation before 1938: Increasing concentration of the gas industry into multi-state holding companies formed to evade the state regulation of local gas companies as those companies switched form locally-produced coal gas to natural gas. The period ended with Congress passing - as part of a common legislative initiative - two important laws: (a) the Public Utility Holding Company Act (PUHCA) in 1935 unbundling (i.e., forcibly separating) state-regulated local gas companies from federally-regulated interstate pipelines, and (b) the Natural Gas Act (NGA) of 1938 regulating the interstate gas industry using the accounting and administrative tools developed by state regulators in the prior decades.
- Increasing gas commodity price regulation from 1938-1954: Uncertainty over whether the NGA permitted the Federal Power Commission (FPC) to regulate the price of gas in addition to pipelines ended when the Supreme Court in its Phillips Decision directs the FPC to engage in such regulation, which the regulator did with the cost-based accounting and administrative tools that it applied to pipelines.
- Regulation and constant industry and political disputes from 1955-1978: Cost-based regulation of individual, and then field gas prices, partly leading to a shortage of interstate gas shipments as within-state gas shipments were not subject to federal regulatory caps. All through this time there were unsuccessful legislative efforts in Congress to deregulate gas prices. 1978 marked the passage by Congress of the compromise Natural Gas Policy Act (NGPA) of 1978 that loosened the regulation of gas prices in response to perceived shortages of interstate gas shipments.

§ Phased deregulation of gas prices from 1978-1989: wellhead prices gradually loosened and then eliminated completely by Congress with the Natural Gas Wellhead Decontrol Act of 1989.

§ Phased unbundling and creation of “Coasian” pipeline transport market from 1985-2000: overlapping with loosening wellhead gas prices regulations, the Federal Energy Regulatory Commission (FERC — successor to the FPC) in various orders and actions unbundled the gas market from the pipeline transport market and created a competitive market in capacity rights, permitting shippers to access competitive gas prices with transparent, flexible and tradable cost-based-regulated pipeline capacity rights.

§ Vigorous and unregulated gas commodity market after 2000: The competitive gas market exhibits some pricing fluctuations, and shippers took some time to learn how to adapt to

[4] For a more complete summary of these well-document events, see: http://naturalgas.org/regulation/history/

flexible open access, but since 2008 the gas market has been vigorously competitive, with prices that have permanently split form oil equivalent prices (which are maintained in the rest of the world). Competition encouraged the application of new technology to the production of unconventional supplies at increasingly low costs.

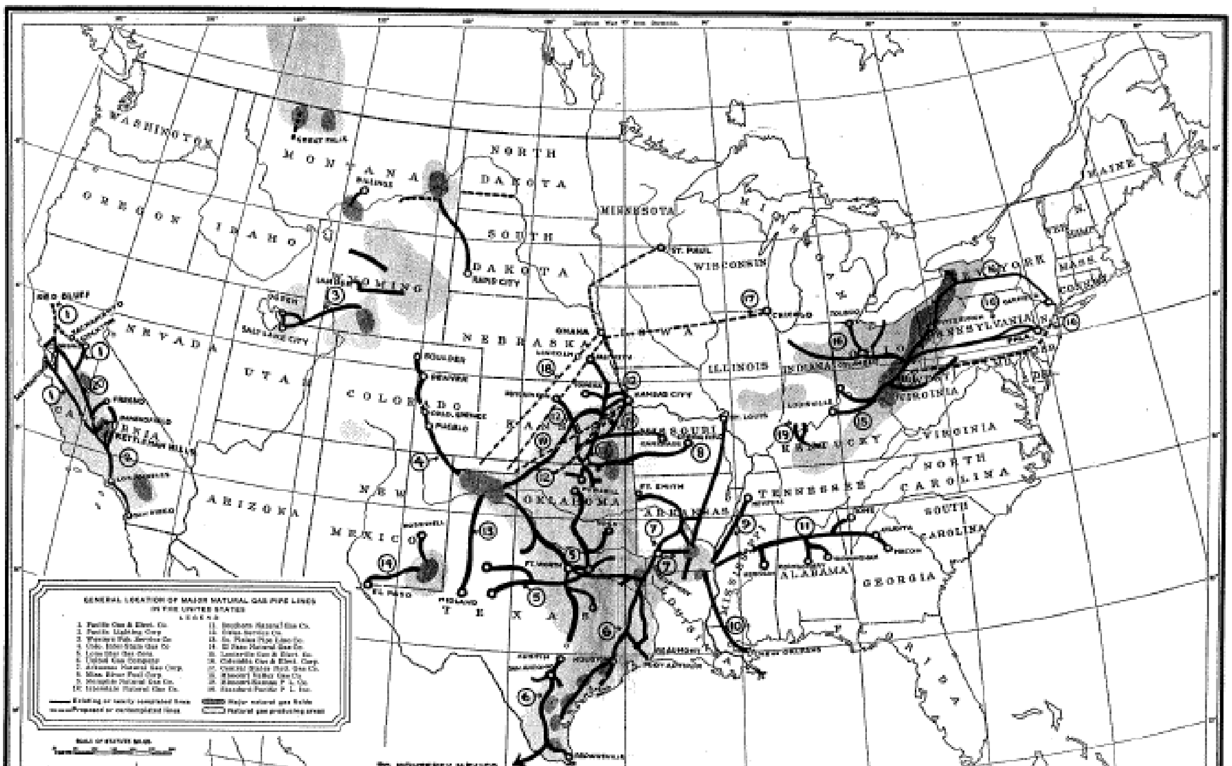
2.2.2. The infant unregulated industry

Prior to 1906, the US natural gas industry, and its supporting pipeline infrastructure was small and limited to the regions adjacent to the gas fields due to limitations of the materials pipelines were constructed from. The physical limitations of the infant gas industry meant it grew up, along with the oil industry as unregulated.

New technology, particularly the introduction of welding, combined with strong economic conditions meant gas pipeline construction grew rapidly in the 1920s. Gas was now able to be shipped between municipalities, leading to the rise of state based regulators to oversee regulation.

It was during this time that the long distance transport of gas from the Hugoton-Panhandle basin in Kansas/Oklahoma/Texas Panhandle to markets in the Midwest was first accomplished. Figure 2.2.1 shows the major gas producing basins and gas pipelines in 1930.

Figure 2.2.1. Major Vertically Integrated Gas Pipelines in the US, 1930



Source: Youngberg, *Natural Gas, America's Fastest Growing Industry*, p. 58.

2.2.3 Federal Jurisdiction

During the gas pipeline boom of the 1920s and early 1930s, before the Depression halted all gas pipeline construction until the mid-1940s, state regulators tried repeatedly to exercise a measure of control over the gas prices charged by their local distribution companies. Local distribution companies had increasingly become integrated, either by contract or consolidation, into national gas pipeline businesses. The charges for wholesale gas delivered to local distributors increasingly became a function of the gas and pipeline fees charged by companies outside state jurisdiction.

Starting in 1910, the Supreme Court used a series of interstate commerce cases to clarify and re-affirm the necessary role of Congress in regulating gas pipelines. For example, in 1924, the Supreme Court struck down an order issued by the Kansas Corporation Commission that fixed city gate rates charged by the Cities Service system. The Court stated:

> The transportation, sale and delivery constitute an unbroken chain, fundamentally interstate from beginning to end, and of such continuity as to amount to an established course of business. The paramount interest is not local but national—admitting of and requiring uniformity of regulation. Such uniformity, *even though it be the uniformity of governmental non-action*, may be highly necessary to preserve quality of opportunity and treatment among the various communities and states concerned.[5] (emphasis added)

Despite having jurisdiction over gas pipelines, small profit margins in the industry during the 1930s meant Congress delayed regulating the industry until there was more pressing concern about rates abuses by holding companies. Congress then passed two pieces of legislation. The first to restructure the holding companies; the Public Utility Holding Company Act, and the second to regulate interstate gas pipelines; the Natural Gas Act.

2.2.4 Abuses of Integrated Holding Companies

The holding company structure adopted by electric and gas utilities in the US during the 1920s and 1930s enabled a number of abuses. The holding companies' primary abuse of power involved using regulated franchises to cross subsidise non-regulated franchises, exposing regulated franchises to extraordinary risk of financial collapse with even the slightest non-performance. This allowed holding companies to earn excess returns on non-regulated franchises.

This kind of exploitation can occur in any regulated company, though modern accounting regulations and meticulous scrutiny of affiliate transactions by experienced regulatory jurisdictions ensures that many abuses do not take place. Until the 1930s, however, US regulatory methods were not equipped to handle such problems.

[5] *Barrett v. Kansas National Gas Co.*, 265 US 298, P.U.R. 1924 E78. Troxel presents a very good discussion of all of these cases in the second of three survey articles on the gas pipeline industry he wrote in 1936 and 1937*:* Troxel, C.E., "II. Regulation of Interstate Movements of Natural Gas," *The Journal of Land & Public Utility Economics,* Vol. 3, Issue 1 (1937), pp. 21-22.

In February 1928, the Senate asked the Federal Trade Commission (FTC) to conduct an investigation of the public utility holding companies. The report showed the degree of market concentration, highlighting that over half the gas produced and more than three-fourths of the interstate pipeline mileage in the US was controlled by 11 holding companies. The four largest holding companies controlled 58 percent of the pipeline mileage. The holding companies had also branched out into manufactured gas, electricity, oil production, and coal.6

The FTC report highlighted many gas market abuses perpetrated by the holding companies, including monopolistic control of gas producing areas, unreasonable differences in wholesale gas prices, pyramiding investment schemes in gas enterprises, excessive profits on transactions between affiliates, inflation of assets and stock watering, and misrepresentation of financial conditions.7

2.2.5 Restructuring of the Holding Companies and Interstate Gas Pipeline Regulation

Congress dealt with the abusive market behavior of the holding companies by passing the Public Utility Act in 1935. Title I of the larger act (known as the Public Utility Holding Company Act or PUHCA) gave the Securities and Exchange Commission (SEC) jurisdiction over public utility securities. As part of their new jurisdiction, the SEC was given the power to simplify the holding company structures of gas and electric utilities.

The SEC's goal was to establish integrated distribution systems that were confined to a single regional area, and to ensure that no holding company was so large as to impair local management, effective operation, or effective regulation.8 In passing the Holding Company Act, Congress effectively ended the vertical integration of gas pipelines and gas distributors. The relationship between companies holding extensive relationship-specific investments became clearly defined and almost purely contractual.

The Public Utility Holding Company Act was a very strong piece of legislation, as it prescribed an unprecedented structural reorganization of the US utilities. It was the last time that Congress was willing to bypass widespread industry opposition to take such strong action regarding the corporate structure of interstate pipelines.

The PUHCA did not provide for the regulation of the interstate gas pipeline industry (although it was part of a broader legislative initiative that included that subject). To govern the interstate pipeline market, Congress had to deal with powerful political and economic constituencies, including state regulators who objected to ceding any jurisdiction over local gas companies; gas producers who wished to avoid commodity price regulation; and the gas pipeline companies

[6] Sanders, *The Regulation of Natural Gas*, p. 28.
[7] Castaneda, *Invisible Fuel*, pp. 33-34.
[8] Phillips, *The Regulation of Public Utilities*, p. 634.

themselves, who feared the potentially destructive consequences of common carriage and the potentially cut throat competition of a highly capital intensive business.

Congress avoided direct confrontations with each of these three groups as it crafted the far-reaching legislation known as the Natural Gas Act, which became law in 1938. That the Natural Gas Act is still in force today is a testament to its underlying durability and effectiveness.

Importantly, the Natural Gas Act 1938 gave the Federal Power Commission (FPC), now the Federal Energy Regulatory Commission, the power to regulate the sale and transportation of natural gas. There are several sections of the Act that distinguish it from any other federal regulation of inland transportation, namely the Act:

- satisfies the States by stating that Federal regulation will only occur if in the public interest and that Federal regulation “shall not apply … to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas”;[9]
- rejects common carriage to satisfy existing gas pipeline users by stating that the gas pipeline companies commitment to existing customers has to come first;
- limits entry to satisfy incumbent pipelines by requiring the FPC to judge the economic need of any interstate gas pipeline;
- invokes a “just and reasonable” rate (tariff) standard, giving the FPC full power to investigate and adjudicate the rates of interstate gas pipeline companies; and
- allows the FPC to control accounts for ratemaking purposes preventing companies abusive accounting practices.

The Natural Gas Act also contained provisions concerning:

- the abandonment of lines (Section 7(b));
- regulation of depreciation practices (Section 9(a)); rules pertaining to administrative procedures (Section 15(a));
- procedures for re-hearing and appeal of Commission orders (Section 19(a)); and
- issues pertaining to the FPC’s enforcement powers (Section 20(a)).

In all, the Act provided an effective framework for regulating price and entry for gas pipelines as interstate gas pipelines. It resolved the issues raised by the state commissions, the gas pipeline company interests, and pipelines customers and, importantly, it relied on the quasi-judicial powers of the FPC, to deal with issues arising from the collision of interests between pipelines, their customers, and the public interest.

[9] Hooley, *Financing the Natural Gas Industry*, p. 37.

2.2.6 The Administrative Burden of the Natural Gas Act

Congress intended the Natural Gas Act (NGA) to fill a vacuum in the federal regulation of the fast-growing gas pipeline industry.10 The NGA provided for utility-style rate regulation, which, by the late 1930s, had developed into a form very similar to what it is today.

When Congress passed the Natural Gas Act, it did not anticipate that the Courts would determine that the regulatory body, the FPC (now the FERC) had to regulate both wholesale gas prices and transportation costs. Combined with the new regulatory accounting procedures, the resulting administrative burden led to gas price freezes and an apparent shortage in gas supplies sold to pipelines for delivery through interstate commerce.

New Regulatory Accounting Procedures

The Natural Gas Act tasked the FPC with regulating gas and pipeline charges, certifying new entrant pipelines, and defining its accounting methods for its various duties. None of these assignments had firmly established regulatory precedents that the FPC could reference, so the FPC had to set its own standards, with mixed results. While the FPC succeeded in creating accounting practices on its own, it required the Supreme Court to sanction its procedures for basic ratemaking, including the setting of the value of the "rate base," due to opposition from the gas pipeline industry.

Throughout the US, regulators and legislators alike came to accept the impossibility of effectively controlling utility rates without a separate, detailed set of accounting guidelines specifically targeted at the commissions' rate regulatory duties. Regulatory accounting methods had been developing in the US for at least 20 years prior to the passage of the Natural Gas Act. In 1923, the Supreme Court had ruled that the US Constitution required regulators to set regulated charges in a manner that would not deprive investors of the value of property devoted to serve the public[11]. However, by 1938 there was still no definitive standard for determining the value of the rate base, or utility property, then defined as part of a highly complex valuation equation[12].

The test case for the FPC's new powers to define the rate base came in 1942, with the *Hope Natural Gas* decision. There, in the first fully-litigated case filed immediately after the passage of the Natural Gas Act (NGA), the city governments of Cleveland, Toledo, and Akron, Ohio challenged the rates of the Hope Natural Gas Company, a Standard Oil subsidiary that sold West Virginia gas to distributors in Ohio. Using its new accounting methods, the FPC decided the case in

[10] It is important to remember, however, that the growth of gas pipelines ceased during the Depression, commencing again near the end of WWII.

[11] See: *Bluefield Waterworks & Improvement Co. v. Public Service Commission of the State of West Virginia et al*., 262 US 679, 693 (1923).

[12] The value of utility property was considered to be a function of the earnings that investor-owners could make from the property, which itself depended on the rates that were charged, which depended on the valuation of property in a cost-of-service formula, and so on in a logically circular loop.

favor of the city governments to value the asset based at actual recorded nominal book cost. Hope appealed the FPC decision to the appellate court, where Hope prevailed on the question of the valuation of its rate base (i.e., a "fair value" valuation substantially higher than actual recorded nominal book cost). The FPC then appealed further to the Supreme Court, which confirmed the FPC's 1942 ruling and defined the "opportunity cost" standard for providing a return to the investor owners of regulated businesses based on the nominal book cost of the capital devoted to providing regulated services.

The NGA was a highly advanced and concise (13 pages) legislative advance. Testifying to its brilliance is the fact that it could deal effectively with both the infant US gas industry of the 1930s (as reflected in Figure 2.2.1) and the competitive, technologically advanced gas industry of 2014. It is indeed a masterpiece of regulatory legislation deserving of more widespread emulation as other countries and regions attempt to pursue their own efficient gas markets.

Despite its brilliance, however, the Supreme Court had to specify how to value the capital devoted to the public service — rejecting intangible costs or circular notions of "fair value" for the purposes of computing regulated prices. These hard-won advances worked in setting pipeline prices — based as they would be on steel, construction costs, labor costs and objective measures of interest costs and paid-in equity costs.

But such tangible, cost-based measures for regulating pipeline prices did not work for regulating the price of gas as a depleting commodity resource—where the intangible costs and expectations drive market values for petroleum-based fuels; then as now. The FPCs' tools for regulating prices, based on the 1938 Uniform System of Accounts and the 1944 Hope decision were thus a failure in dealing with the federal regulation of gas commodity prices when the Supreme Court ordered the agency to do so in 1954.

2.2.7 Wholesale Gas Price Regulation

The issue of field gas price regulations proved to be a particular problem. The FPC had no desire to regulate the field price of natural gas. However, the Supreme Court interpreted the Natural Gas Act to extend FPC jurisdiction over gas sales to companies affiliated with regulated interstate pipelines.

In the Phillips Petroleum Co. v. Wisconsin (1954), the Court declined to make a distinction for affiliated interest transactions in interpreting the FPC's jurisdiction to regulate gas prices in either the Natural Gas Act or the Congressional debate leading up to it, and the Court would not read such a distinction into the NGA, a move that left the job explicitly to Congress.

Congress did not wish to direct private markets, preferring to leave that job to regulators and their industry experts. In addition, the Natural Gas Act was crafted during an era when it was assumed that a close affiliation existed between gas pipelines and production. In repeatedly turning aside calls for common carrier regulation of gas pipelines, Congress acknowledged that the pipelines owned the gas they shipped. The case was remanded to the FPC for the regulation of all gas prices sold to interstate pipelines, thereby sparking 40 years of controversy.

The stance that pipelines owned the gas they transported created problems for determining an appropriate rate of return in accordance with regulatory accounting standards. The main issue was the cost of production. The economists of the 1950s ran into insurmountable problems associated with two cost questions. The first was apportioning joint and common costs to regulated gas prices.[13] The second was the question of depreciation, or depletion as it is known in natural resource matters. The FPC could deal with neither source of cost as a practical matter.

It is important to understand the impossible administrative and legal burden that the FPC faced when the Supreme Court told it to regulate the price of a depletable fossil fuel. Regulating any private industrial activity in the United States is very difficult, for the US Constitution has definitive protections (in its 5th and 14th amendments) to the "taking" of private property without due process of law. Given this high barrier, no important piece of US regulatory legislation takes hold until it survives constitutional challenge in the courts (perhaps up to the Supreme Court) by those affected. And since the tools of regulating (accounting and administrative) can affect private property also, those tools also need to survive challenge in the courts (hence the Hope decision coming out of a challenge to the legality of the accounting tools for applying the NGA).

Thus, when the FPC was directed by the Supreme Court to regulate the price of commodity gas, it was going to use the tools it had based on the Uniform System of Accounts and the importance of nominal book costs in establishing equity values for the owners of gas wells, including book depreciation to record the expense of capital spread over the life of that capital. But commodity markets for fossil fuels, like prices in other commodity markets, are often only distantly related to tangible costs of any sort—either operating costs or some notion of the cost of capital. Commodity prices are driven by intangible expectations of both producers and consumers on a large scale.

Trying to tie regulated gas commodity prices to some tangible measure of recorded book costs, book depreciation and operating expenses was bound to be a failure. But one remedy to that predictable sort of failure—simple wellhead deregulation by legislation—was viewed as totally unacceptable by the distributors and representatives of consuming states in a world where gas pipelines simply re-sold gas at cost to captive consumers. So the application of unsuitable regulatory tools to forming wellhead gas prices continued.

[13] For an enduring description of the economics of joint and common costs, see*:* Kahn, *The Economics of Regulation, Volume 1*, pp. 77-86. Professor Kahn devotes two of only four graphs appearing in the text of the entire volume to this particular issue (other graph appear in footnotes, but the cognoscenti would not count those).

The sheer volume of rate cases brought on by the Phillips decision drew attention to the unmanageable administrative load carried by the FPC. By 1960, the FPC had received more than 2,900 applications for cost-based price reviews but had completed only ten. Each application required the FPC to find the original cost of producing gas for the particular producer and the particular field in question. The FPC itself estimated that it would not complete its caseload until the year 2043.[14]

In an effort to economize on administrative resources, in 1960 the FPC decided to set regional average gas prices on the basis of regional average production costs, a move that basically froze gas prices at a 1958-1959 level. The freeze was designed to be temporary, so that the FPC could begin “area rate” proceedings in order to set permanent prices. The area-rate proceedings lasted 10 years, however, so the prices of existing gas supplies did not change significantly until the 1970s. By that time, the FPC’s effort to regulate returns on investments in the gas production sector resulted in an apparent shortage in gas supplies sold to pipelines for delivery through interstate commerce.

All the while, producers could either sell gas to intra-state markets and avoid federal regulation altogether or could hold gas in the ground on the expectation that the “area rates” would ultimately be thrown out and the value of gas in interstate shipments would rise to a broader market level. Therefore, based on expectations of the futility of regulating wellhead prices based on the FPC’s practices for assessing costs, the perceived interstate shortage of gas was self-supporting. All the oil companies had to do was to wait, and the longer they waited the worse the situation became.

The Phillips decision came under withering criticism later when it was clear that wellhead price control was causing significant problems in the marketplace. Most of this criticism faulted the Supreme Court for failing to recognize that the market power problems in the interstate gas pipeline business lay in the pipeline component of the service, where significantly concentrated markets existed at the origin and destination of those pipelines, not with the sale of gas. In essence, the Supreme Court was being censured for not taking a more economic view of the Natural Gas Act.

In reality, the complaints over regulating the price of gas were mostly misplaced. Gas price regulation would end when pipeline companies left the gas business entirely. Yet that was an unthinkable requirement in the 1950s. It would take a complex series of events, and another 50 years, to make that change in the market possible. In the meantime, the social costs of trying to regulate an essentially impossible to regulate sector were what they were.

[14] MacAvoy and Pindyck, *Price Controls and the Natural Gas Shortage*, p. 12.

2.2.8 The Techniques of Gas Price Regulation

For those considering regulating gas prices elsewhere, it is probably helpful to look specifically at how the FPC tried to accomplish that task—apart from the wider issue of whether there was any realistic prospect for such regulation to be effective in a volatile fossil fuel market.

- **Costs**: The FPC was tied to assessing tangible and recorded costs of producing the fuel. Its Uniform System of Accounts had no realistic way of dealing with "depletion allowances" that might have some usefulness for corporate accounting or tax purposes.

- **Depreciation**: Depreciation is always apt to be a confusing issue in international discussions of accounting. For the accountant's view of depreciation is to the past (to spread one large book entry into a number of smaller book entries over some projected life of capital facilities) — or as one economist wrote, "a special method of writing history". The economists' view of depreciation is generally to the future, taking into account replacement and opportunity cost. Depletion accounting, for natural resource extraction, is a forward-looking economic concept; but the FPC, in history and today (through its successor, the Federal Energy Regulatory Commission) uses a strict accounting interpretation of depreciation.

- **Rates of return**: The modern methods for computing the market's view of a risk-adjusted rate of return (e.g., CAPM or DCF) had not been developed in the 1950s. Analysts at that time used comparable-profitability benchmarks of various sorts based on existing accounting methods applied to what they considered reasonable groups of peers. There is little in the details of "rate of return studies" in the 1950s that would look familiar, or be considered credible, from the perspective of modern financial analysis and it would not be very helpful to dig deeply into the methods employed at the time, even if the basic pursuit, under Hope standard was the opportunity cost of capital.

- **Trading margins**: There was no conception that either gas producing companies or the pipelines that bought gas at regulated prices from producers (and re-sold mostly to gas distributors) were entitled to a "trading margin." If there were any costs to "trading" (e.g., personnel, equipment and other costs), then those costs would be recorded like any other cost under the Uniform System of Accounts.

- **Incentive regulation for performance**: Modern conceptions of incentive regulation did not exist in the 1950s in the United States. Price regulation was tied strictly to measure of recorded costs, using accounting conventions to do so.

- **Pass-through of costs**: Both federally-regulated pipelines and state-regulated distributors passed-through the cost of gas without mark-up. Pipeline profitability, just like distributor profitability, was tied to the return gained on the capital devoted to the business, not margins on operating costs.

2.2.9 Redefining the FPC's Regulatory Functions

The slow administration of field price regulation was widely believed to have contributed to the gas shortages that developed in the early 1970s, as energy prices increased following the 1973 Oil Embargo. In 1978, Congress responded with a gradual and complicated partial deregulation of gas prices via legislation.[15] However, the shortage situation had already been alleviated by dampening demand or increasing supply. It was clear, though, that the FPC was incapable of effectively regulating the returns to gas producers.

Circumstances were different when it came to gas pipeline capacity. There, the FPC had full control of the quantity in the market and the cost of that capacity to the pipeline company owners, which made it possible to regulate rents. The FPC would demonstrate in the 1990s that it had the power to regulate the economic returns flowing to pipeline owners, thereby facilitating a competitive market for pipeline capacity. In that market, the traditional holders of capacity rights kept the rents controlled in a way that has not distorted the market in either the use or expansion of the nation's pipelines.

Embedded in the NGA, a type of standardized utility regulation, were three market distortions that loomed large for the interstate pipeline companies:

- the licensing/certification process for local gas or electricity distribution companies meant competitors would not enter the market;
- gas pipeline companies averaged the price of wholesale gas, removing the incentive to contracting for supplies at prices above what the market would generally bear; and
- pipeline companies could pass through the cost of gas, meaning gas pipeline companies were rewarded through the movement of gas, not through the acquisition and resale of the gas itself. [16]

From the 1950s through the 1970s, these mutually-reinforcing incentives, discussed respectively throughout this Section, damaged competition in the gas fields and led pipelines companies into such an overextended position in the 1980s that the FERC was able to restructure the gas pipeline market without a fight from the pipeline companies.

---

[15] The legislation was the Natural Gas Policies Act of 1978 (15 USC. 3301 *et seq.*).

[16] It is well known that under the more less standard regulatory model, utilities generate profits to their owners through the returns on invested capital, not on sales margins or the mark-up of operating expenses (like labor, fuel, etc). Perhaps the first comprehensive economic investigation into how such a regulatory model affected owners' incentives was by Professors Harvey Averch and Leland Johnson in a famous 1962 paper (known internationally as Averch-Johnson). (See Averch, H., and Johnson, L.L., "Behavior of the Firm Under Regulatory Constraint," *US Economic Review*, Vol. LII, No. 5. (December 1962), pp. 1052-1069.) It is clear under the Averch-Johnson that for company subject to traditional regulation, profit-making incentives do not apply to operating costs. To the extent that those costs are subject to some control, it is either by regulatory fiat (i.e., prudence examinations) or ultimately the market itself (despite the presumption that a market exists for the regulated product).

Uncompetitive Certification and Licensing

Under Section 7 of the Natural Gas Act, four standards had developed for controlling competition through certification of competing lines. The new entrant must show: (1) material benefit to the public; (2) the inadequacy of existing facilities; (3) that it will not duplicate existing facilities; and (4) that it has the financial capacity to render the service.[17]

The FPC developed its own criteria in a landmark case involving the Kansas Pipe Line and Gas Company, in which the FPC specified that it would certify a new entrant to a market containing an existing pipeline company if the entrant had secured adequate gas supply, had reasonable costs of construction, displayed adequate physical facilities and financial resources, proposed to charge cost-based rates, and could demonstrate market demand for the new capacity.[18]

In order to receive certification, rival pipeline companies had to go before the FERC with plans demonstrating both their financial ability to build a line and their acquisition of the gas to fill it. The issue of gas sourcing gave prospective pipeline developers an unusual incentive to secure large blocks of supply for a product that they merely proposed to transport through their pipeline for resale to local utility monopolies, which put upward pressure on gas prices.

Problems with Averaging Gas Prices

In 1942, Congress amended the Natural Gas Act to require certificates for all new construction, extension, or acquisition of gas pipelines.[19] Rising gas prices led the FPC set split regulations for “old” and “new” gas prices in 1965 to elicit new gas production for a rapidly-expanding market while continuing to regulate economic rents associated with gas flowing under old contracts. But by creating “old” and “new” gas prices, and allowing the pipeline companies to mix various gas streams to re-sell at an average cost to gas distributors the FERC created incentives encouraged another set of problems.

The regulatory formulae in the Uniform System of Accounts for gas pipelines specified that gas purchased for resale carry a single weighted average cost of gas (WACOG) for ratemaking purposes.[20] The WACOG was the price that pipeline customers paid their suppliers for gas, and it was problematic. Using the WACOG, gas pipelines could purchase certain “new gas” supplies at prices that themselves would have been above what buyers were willing to pay.

Incentive Problems with Cost Pass Through Arrangements

The next incentive issue for gas pipelines buying gas had to do with the nature and design of regulated pipeline rates themselves. Pipeline rates were designed in a way that gave the

[17] Clemens, *Economics and Public Utilities*, pp. 92-93.
[18] 2 FPC 29 (1939).
[19] Troxel, *Economics of Public Utilities*, p. 96.
[20] See US Code of Federal Regulation, Title 18, Part 201: Uniform System Of Accounts Prescribed For Natural Gas Companies Subject To The Provisions Of The Natural Gas Act.

companies an incentive to push gas through the pipeline. The practice originated in the two-part tariffs with “demand” and “commodity” components; the former is a fixed charge independent of the volume delivered, and the latter varies by the amount of gas sold.

Pipeline companies could under recover on fixed charges but stand to make extra profits if the quantities delivered were higher than those used to set the volumetric rates.[21] Between the 1950s and the 1980s, when gas prices were regulated, commodity loading was imposed on gas pipeline prices, skewing pipeline incentives toward shipping gas and away from the potential problem that buying too much expensive “new” gas might cause.

2.2.10 Deregulating Gas Prices

By the early 1970s, the problems in wholesale gas price regulation had reduced interstate shipments and contributed to the perception of a gas shortage in the north. As a result, many large gas users and industrial customers were unable to receive reliable gas supplies.

The 1978 Natural Gas Policy Act (NGPA) was Congress’s attempt to separate gas and transportation prices in order to help alleviate the interstate gas supply shortages.22 Congress perceived that the shortage had developed in response to the rigidly controlled wellhead gas prices and declining reserves of the early 1970s, and increased oil prices following the 1973 Arab Oil Embargo. The process Congress used for deregulation was both complicated and gradual.23

One of the NGPA’s major features was a legislative version of the “two-tier” pricing system already imposed by the FERC. These two-tiered regulated prices exacerbated an existing problem. Because the pipelines combined their “old”, regulated and “new”, decontrolled gas into a single average price, the effective price of new gas could rise above levels that would clear the market.

However, by the time Congress passed the NGPA in 1978, several factors in the gas market had brought the shortage to an end by reducing gas demand or increasing gas supply, including the increased price of “new” gas authorized by the FERC; the purchase of large volumes of unregulated imported gas; the increased supply of gas from the intrastate market; and increased Canadian supplies and offshore production. As a result, the NGPA, which was intended to spur

[21] This is a common issue for regulated utilities when fixed costs are collected according to volumetric a tariff (which is generally the case for most local distribution utilities where billing is unavoidably tied to volumetric meters). Ratemaking requires some “test year” volumes. When the volumes delivered during the period of time that those rates are in effect is greater than the test year, utilities profit. This gives utilities a powerful and unavoidable incentive to minimize those test year volumes, just as utility customers have an incentive to maximize them. The fight over the denominator of volumetric regulated rate calculations (where costs are the numerator) is one of the main administrative headaches of regulators around the world.

[22] An extensive analysis of the origin and politics of the NGPA appears in Sanders, *The Regulation of Natural Gas*, Chapter 7 (pp. 165-192).

[23] See Pierce, *Reconstituting the Natural Gas Industry*, p. 11.

production, actually contributed to overproduction and surplus. A number of market factors already at work also contributed to the overproduction that began to occur after the NGPA's passage.[24]

The gas surplus was further fuelled by the popular notion that gas prices would increase steadily throughout the 1980s. As a result, interstate gas pipelines engaged in an energetic round of purchasing "new" gas in the late 1970s and early 1980s. Gas and oil prices did not increase in the 1980s as many had expected, and by the middle of the 1980s gas demand had actually declined as oil prices dropped from their post-Arab Oil Embargo levels. As a consequence, the interstate gas pipelines that had been vigorously purchasing new, expensive gas supplies found themselves in financial straits as demand for natural gas fell and the weighted average cost of gas supplied by interstate pipelines rose.

In response to the rise in interstate pipelines' prices, many interstate pipeline customers (particularly industrial customers) tried to avoid buying expensive pipeline gas. Instead, these customers pursued certificates for "transportation" of cheaper gas through the pipelines than the pipelines themselves were able to offer. This caused the pipelines to act less frequently as merchants and more frequently as transporters of third-party supplies, which amplified the pipelines' difficulties by shrinking their captive gas markets even further.

The gas pipeline companies responded to their shrinking captive market by levying a charge for gas not taken by their customers, creating a parallel "take-or-pay" type of liability on the customer's part that would help the pipelines offset the risk of their gas purchase contracts. These "minimum bill" provisions in the pipelines' gas sales contracts required customers to pay for a percentage of the gas they could demand, even if they did not actually take the gas.

The FERC's abolished minimum bill provision exposing the interstate pipeline companies to the consequences of their own high-cost and high volume commitment gas purchasing practices. By 1986, the total take-or-pay liability for gas that pipeline companies could no longer bill to their connected customers was approximately \$11.7 billion.[25] The resulting threat to the pipelines' financial integrity gave the FERC the opening it needed to compel the pipeline companies into offering contract carriage service more widely.

This is actually the start of the modern part of the U.S. gas industry history, which is characterised by competition in gas supply and (albeit under tighter control) in gas pipeline capacity as well. As such, this part of the history is beyond the scope of the present Report. The interested reader may see Makholm (2006)).

[24] These factors included: (1) the recession of the period in the US, which dampened demand; (2) the sharp decline in world oil prices, which also dampened demand for gas because its substitute in many applications—oil—became less expensive; (3) increased conservation efforts by gas consumers due to higher energy prices in general, which also reduced gas demand; and (4) unusually mild weather, which reduced the demand for space heating supplies.
[25] See: "Pipeline Take or Pay Costs Continue to Mount," *Oil & Gas Journal*, August 10, 1987, p. 20.

2.2.11 Concluding remarks

Overall, the era of gas price regulation in the United States can be described as a slow-motion failure representing the unfortunate application to fossil fuel markets of a style of regulation that was, and still is, very well suited to pipeline markets. Indeed, the style of regulation that Congress crafted for the pipeline sector in the 1930s has proven to be a masterpiece: capable of dealing both with the young interstate gas industry of that time and the high-technology industry of today.

The failure of regulating US gas prices reflects the futility of using accounting methods to assess tangible costs (that inherently focus on the past) in an extractive resource market where values and prices are driven by intangible expectations of the future. The predictable results of applying misapplied regulatory methods to the gas sector were fuel shortages, various other social costs, heavy litigation and almost constant legislative action (successful or not). Those problems ended when methods were devised to incentivize the voluntary exit from gas market by pipeline companies ("voluntary" because the US Constitution prohibits peremptory regulatory action that affects property) and the making of a competitive pipeline transport sector that could deal with volatile gas markets.

Thus, the history of how US federal regulators dealt with a court order to regulate gas prices is a record of what did not work—and could not work given the regulatory and governance institutions that those regulators had at their disposal. There is never any reasonable prospect that federal pipeline regulators could successfully regulate the commodity price of gas in the public's interest. Given the legislation that they worked under, as interpreted by the Supreme Court, the only choice was to try to moot the question of gas price regulation by pursuing open access in interstate gas transport — and the ultimate deregulating of the commodity.

2.3 The Russian Federation[26].

2.3.1 Overview: the organizational structure of gas industry

The Russian gas industry includes production, processing, gas transport by main pipelines and distribution (sale) of natural gas.

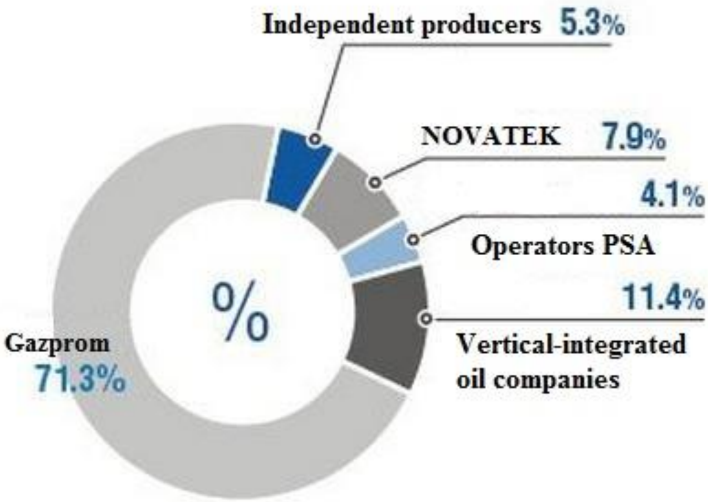
As of January 1, 2014, the organizational structure of the gas industry includes the following main business entities:

- 258 extractive enterprise engaged in the production of natural and associated gas, including 97 of them within the structure of vertically integrated oil companies;
- JSC Gazprom (16 companies);

[26] This Section has been drafted by Marina Afanasyeva, of the Institute of Energy Strategy.

- JSC NOVATEK (2 companies);
- 140 independent mining companies;
- 3 companies acting as Production Sharing Agreement (PSA) operators (see Figure 1).[27]

Figure 2.3.1 - The structure of gas production by companies, 2013



Source: Ministry of Energy of the Russian Federation, January 01 2014

Russia's largest gas company JSC Gazprom provides 71.3% of the total gas production in Russia in 2013, 6.9% less than in 2009. JSC Gazprom controls the Unified Gas Supply System (natural gas pipelines and underground gas storage facilities).

In 2013 the overall proportion of independent gas producers in Russia was equal to about 28.9%. In accordance with the strategic guidelines of the country, this figure will increase in the short to medium term.

Most of the independent gas producers (IGP) - 140 companies – are engaged in the development of relatively small local fields within the “Unified Gas Supply System” (UGSS). The largest IGP is JSC NOVATEK (56 Bcm). The company's share in total Russian gas production in 2013 was 7.9%. The contender for the leadership among independent gas producers is JSC NK Rosneft, which plans to achieve annual production of 98 Bcm in the near future.

Vertically integrated oil companies produce mainly associated petroleum and gas (APG).

The share of vertically integrated oil companies in gas production in Russia fell to 8.9% in 2010, but increased to 9.4% in 2011, 10.3% in 2012, and 11.4% in 2013. Key gas producers among the vertically integrated oil companies are JSC LUKOIL, JSC NK Rosneft, JSC Gazprom Neft , JSC

[27] According to the Ministry of Energy of the Russian Federation on 01.01.2014

TNK-BP (until 2013), which aggregate more than 96% of gas production of vertically integrated oil companies according to Central Control Administration of the Fuel and Energy Complex data.

The regional gas companies’ share in gas production ensuring of Russian Federation is less than 1%. Among the companies in this group are included JSC Norilskgazprom, JSC Yakutsk Fuel and Energy Company and Rosneft Sakhalinmorneftegaz LLC. These companies are not included in the UGSS regions and carry out gas-supply in these areas. Most of the regional companies are independent of JSC Gazprom, but belong to regional governments. The exception is Rosneft Sakhalinmorneftegaz LLC (a member of the JSC NK Rosneft[28]).

Dynamics of the companies-operators PSA in the Russian gas production industry structure is low, despite the increase in production volume in absolute terms, mainly due to the growth of gross gas production in Russia. Difference between the index in 2013 (4.1%) with the index of 2010 (3.6%) is only about 0.5% (in 2011, the share of the companies-operators PSA was 3.5%, in 2012 - 4%).

Processing of natural and associated gas is carried out at gas processing plants of JSC Gazprom, JSC SIBUR and of other various vertically integrated oil companies.

As noted above, the main transportation of natural gas is carried out by JSC Gazprom - the holder and the owner of the UGSS. In the eastern parts of the country this function is carried out by regional gas and gas pipeline companies mainly.

JSC Mezhregiongas (a subsidiary of JSC Gazprom), JSC Rosgazifikatsiya, and independent regional companies are engaged in the distribution and sale of natural gas in Russia.

JSC Gazprom currently has the exclusive right to export natural gas from Russia through pipelines. It’s branch organization - Gazprom export LLC carries out natural gas export. The Russian Government is currently considering the possibility of allowing other companies to export gas from fields in Eastern Siberia and the Far East.

In May 2014 in the State Duma of the Russian Federation was introduced a bill to expand the number of liquefied natural gas exporters. Previously, the only existing export LNG plant monopoly was owned by the state company JSC Gazprom.

Today, the right to export liquefied natural gas is awarded to JSC NK Rosneft , JSC Yamal LNG, JSC Gazprom and Gazprom export LLC.

Currently LNG production in the country is carried out only within the framework of the project "Sakhalin-2", which is operated by Sakhalin Energy Investment Company Ltd. (51% owned by JSC Gazprom). Gas companies are also developing other LNG-projects: LNG facilities of the Shtokman field (the major participant is JSC Gazprom), as well as of “Yamal LNG”, realized by JSC NOVATEK jointly with the French company Total SA.

---

[28] Data on gas of Rosneft Sakhalinmorneftegaz LLC are recorded in JSC NK Rosneft

2.3.2 The domestic and foreign markets' gas prices

Today the gas market model in Russia consists of the regulated and free (unregulated) sectors. The regulated sector has a dominant position in the domestic gas market.

According to the Federal State Statistics Service, the average producer price of Russian gas (taking into account the transfer prices within Gazprom) increased by 9.5%, to 0.65 $ / MMBtu in 2011. The comparable figure in 2012 increased over the year by 78% and amounted to 1.13 $ / MMBtu, and in 2013 increased by only 6% to 1.15 $ / MMBtu. The average actual cost of gas for industry increased by 17.3% (adjusted for annual inflation of 6.1%), amounting to 3.38 $ / MMBtu in 2011, and in 2012 increased by 14% compared to 2011, adjusted for inflation of 6.58%. The price increase for gas purchased by industrial enterprises in 2011 compared to 2010 was 13.5%, while in 2012 compared with 2011 - 12.9%.

In 2011-2015, in accordance with the 2009 official Document "The main directions of the state tariff and pricing policy in the infrastructure sector" out a change of tariff legislation in the infrastructure sectors of the economy has been expected in the following areas:

- transition to the establishment of long-term rates;
- synchronization of investment programs of natural monopolies;
- regulation of reliability and quality of services provided;
- the natural monopolies information disclosure;
- improving energy efficiency in electricity, gas, heat and water consumption;
- improving the efficiency and transparency of the regulatory authorities' activities.

In the gas sector the new tariff adjustment mechanism is characterized by:

- transition to gas prices, determined on the basis of equal yield of gas supplies for internal and external consumers (netback prices);
- the elimination of cross-subsidies in the wholesale and retail gas markets.

This transition to gas prices, determined on the basis of equal yield, must be gradual to prevent price shocks for domestic consumers.

New conditions for the natural monopolies services' market are aimed at encouraging energy efficiency and creating conditions to attract to this area large-scale private investment. At the same time, they create a significant risk of inflation in the period of 2011-2015 (period of the transition to electricity and wholesale natural gas prices liberalization). The growth of tariffs could lead to a significant reduction in the competitiveness of domestic producers and undermine the industrial

development financial investment base. The equal-profitability domestic wholesale gas prices depend on the export prices of natural gas. However, the export prices are substantially higher than natural gas spot prices in Europe. Because of this, a situation may arise in which the domestic wholesale prices in Russia will be equal to or even higher than wholesale gas prices in Europe.
The Gazprom Group (hereinafter referred to Gazprom) and regional monopolies' gas are sold to Russian consumers at regulated prices.

Figure 2.3.2 shows the dynamics of changes in wholesale gas prices in Russia (domestic market, the European market) and wholesale spot prices on gas in the United States.

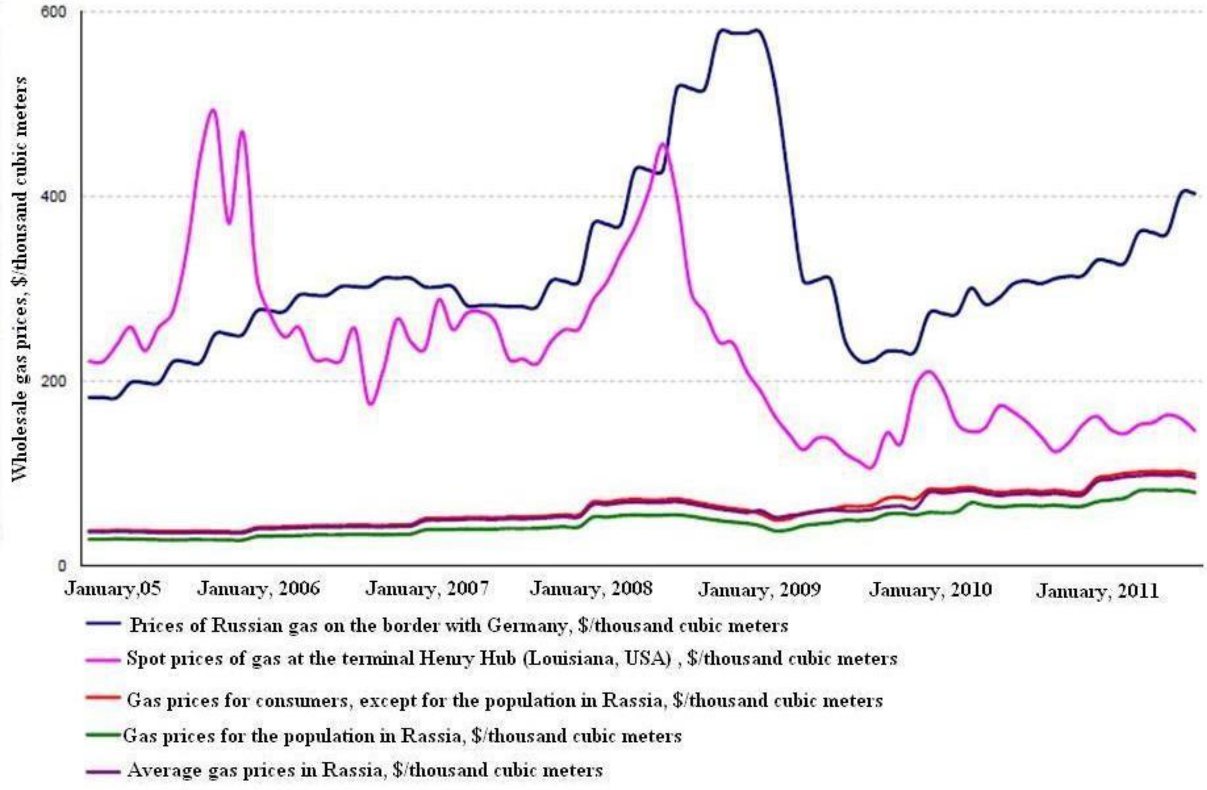
Dynamics of changes in wholesale gas prices for Russian consumers (households and industry) since 2000 is shown in Figure 2.3.3.

In accordance with the decisions of the Government of the Russian Federation requiring regulated wholesale gas prices to gradually raise to economically feasible levels, regulated wholesale gas prices in Russia were increased in 2009 by 15.7% compared to 2008, in 2010 the wholesale gas prices growth has averaged 26.3% over the 2009, average regulated wholesale gas price in 2011 was equal to 2.6 $/MMBtu (excluding value added tax (VAT)), in 2012 - 2.7 $/MMBtu, and in 2013 – 2.98 $/MMBtu.

Change of the settings for the wholesale gas prices are determined by the Government of the Russian Federation. Specific regulated wholesale gas prices, differentiated by price zones (which are based on the distance of consumers from gas production regions and consumer categories) are approved by the Federal Tariff Service (FTS of Russia). The Administration of the Russian Federation subjects (regions) determines the retail gas prices for the population.

As a part of the policy to move towards equal profitability for internal and external consumers (net back prices) December 31, 2010 the Government of the Russian Federation adopted the Decision No. 1205 on Perfecting State Regulation of Prices of Gas.

Figure 2.3.2 - Dynamics of changes in wholesale gas prices in Russia (domestic market and European market) and wholesale spot prices on gas in the United States



Source: International Monetary Fund (IMF), Federal Tariff Service of the Russian Federation (FTS)

From 2011 to 2014 the wholesale gas price supplied by JSC Gazprom to the domestic market (except new contracts and excessive gas supplies) carried out by a price formula, which provides a gradual achievement of gas supplies equal yield for the foreign and domestic markets. In this case, the decreasing coefficient for the domestic market will be reduced with 0.7 in 2011 to 1.0 in 2015. The Federal Tariff Service of Russia establishes the differentiation coefficient of the natural gas price by region depending on the consumption mode. In 2013-2014 the Federal Tariff Service of Russia approves the minimum and maximum price levels that may deviate from the values obtained from the formula by no more than 3%. Since 2015, we expect the start of a transition from state regulation of wholesale gas prices to the state regulation of tariffs for the gas pipelines transportation only (market liberalization).

Figure 2.3.3 - Average wholesale prices for Russian consumers in 2000-2014

Source: Institute of Energy Strategy according to the Federal Tariff Service of the Russian Federation available data, 2014

Independent producers and vertically integrated oil companies represent the unregulated sector of the Russian gas market. These companies sell the produced gas at free contract prices. At various times and in different regions, these prices may be either higher or lower than the regulated prices of JSC Gazprom. However, the prices of JSC Gazprom represent the traditional starting point for establishing prices for producers and consumers.

As a rule, the values of contractual gas prices are a trade secret. Therefore, evaluation of this market segment is possible only on the basis of experience of stock exchange trading, which took place in Russia in 2006-2008, based on the electronic trading platform (ETP) of JSC Mezhregiongas. In the experiment at free market prices on the ETP in 2007 and in 2008, 6.9 Bcm and 6 Bcm were sold respectively by Gazprom and by independent sellers. The main volume of gas (over 55% in 2007 and 86% in 2008) was purchased by the organizations of electric-power industry. On January 1, 2009 the exchange trading was halted, mainly because of its lack of demand for manufacturers and consumers on the background of a domestic demand slump. In June 2010, JSC Mezhregiongas conducted comprehensive tests to simulate the trading in futures contracts with terms of the gas supply from 1 to 18 months. 32 organizations took part in these tests. On March 11, 2011 the Russian President Dmitry Medvedev ordered to renew the stock exchange trading implement project since 2011. JSC Gazprom and its specialized subsidiaries together with the federal executive authorities are working on the implementation of Russian gas trading based on exchange technologies.

The average prices of gas sold on electronic trading platform were higher than the regulated prices set by the Federal Tariff Service of Russia, in 2007 by 36%, and in 2008 by 38.2%. The maximum difference between the consumer prices on the ETP and the average wholesale price for industry set by the Federal Tariff Service of Russia was in 2007 44%, in 2008 71.3%, the minimum difference were 23.7% and 23.5%, respectively.

Dynamics of natural gas export prices for JSC Gazprom’s contracts in 2013, as in previous years, was mostly formed in accordance to the movement of world prices for fuel oil. Overall, in the period from 2010 to 2014 may be noted the growth of prices for these products.

The system of market pricing implies a reference period (usually 9 months) in indexing the gas price formula. This procedure makes it possible to smooth out the dynamics of the export prices of Russian gas in comparison with the prices of liquid fuels. Therefore, the dynamics of the export prices of the natural gas lags behind the changes in fuel prices.

JSC Gazprom realizes gas exports mainly under long-term contracts (up to 25 years), which are usually based on intergovernmental agreements. Gazprom export contracts prices are pegged to oil prices, which explains the high correlation of price growth.

The maximum value of the gas price under the Gazprom contracts was reached in the 4th quarter of 2011 (11.8 $/MMBtu). In 2011 the weighted average price of gas was 10.9 $/MMBtu against 8.7 $/MMBtu of 2010 (an increase of 25.6%). In 2012, the average gas price for European countries amounted to 10.96 $/MMBtu, and the average gas price for the CIS countries and Baltic countries was 8.7 $/MMBtu.

In the 2014 budget JSC Gazprom has laid the average price of gas exports to Europe at 10.6 $/MMBtu, which is 4% lower than in 2013 (11.01 $/MMBtu).

Analysis of the current state of the Russian gas industry shows that the industry has exhausted the infrastructure potential inherited from 1970-1980 years, and needs a modernization. For gas production growth in the medium and long term, it is necessary to pay attention to the development of new fields, advanced production technologies, the transition to the new gas-producing regions (Yamal, Arctic and Far Eastern shelf, Eastern Siberia and Yakutia). This makes the gas industry one of the most investment-intensive sectors of the Russian economy. The total volume of capital investments in the sector up to 2030 could reach $ 0.58 trillion (in 2008 prices), of which up to 47% relates to transport capacity and underground gas storage (UGS) and just over 30% relates to production. The rest of the investment is allocated between the exploration and processing of natural gas.

JSC Gazprom continues to dominate in all segments of the gas industry based on the industry of formed by the USSR. At the same time the share of this company in natural gas production is gradually reduced, and increases in distribution and marketing of gas in the domestic market (2010-2012 tendency). The special role of JSC Gazprom provides extraordinary stability of the gas industry in Russia, including periods of economic crises (1998, 2008-2009.). However, this situation limits the possibilities for the independent gas producers' development.

Nevertheless, all of the past 13 years have seen a rapid growth in the independent sector of the gas industry in Russia, especially in the field of gas production. The internal structure of this growth allows only very cautiously talking about the real growth of competition: half of the independent sector is composed of the five largest vertically integrated oil companies with oligopolistic position in the domestic oil market. A large part of their production accounts for associated gas, which in general case precludes their direct competition with JSC Gazprom. The second half of the independent segment is represented by a number of small and medium gas companies, the key of which (primarily JSC Novatek) is in one degree or another affiliated with JSC Gazprom.

In such structure, almost all the investment burden placed on JSC Gazprom, and responsibility for the investments' planning and monitoring - on the state. There is a significantly different situation in the Russia's gas industry from the situation in the Russia's oil industry and in the post-reform Russia's power sector.

2.3.3 Questions and answers

Which market prices are regulated (wellhead, wholesale and/or retail)?

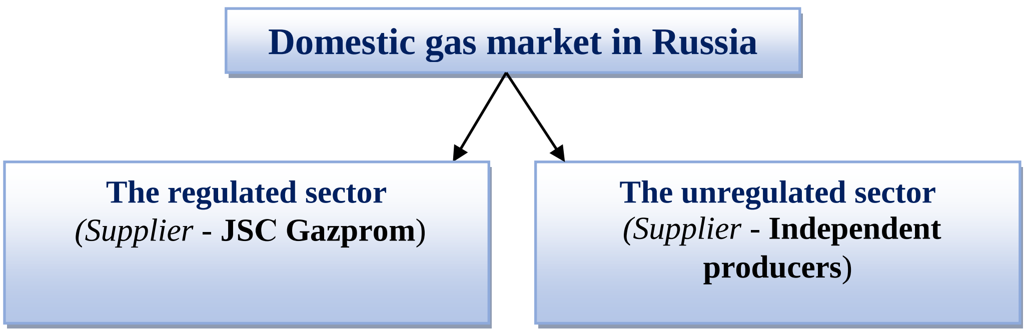
Among all fuel types, only the natural gas price, which is produced by Gazprom Group (hereinafter referred to Gazprom) and supplied to Russian consumers, is subject to state price regulation. The Russian gas market functioning model includes regulated and unregulated sectors. The current gas market model has a number of fundamental problems that hinder the further development of market competition: the high share of regulated sector, the economically unfeasible wholesale price level, and cross-subsidies in the regions.

The cross-subsidization between different Russian regions gas prices creates additional obstacles for development of competition. The current tariff policy suggests that Gazprom will compensate losses which arise from the gas supply to distant regions from the higher income from the gas sale to consumers located close to gas fields. However, because independent companies can offer more flexible gas supply terms, they almost completely supply some regions of Russia. This leads to a gas market imbalance and nullifies the competition.

Market competition is possible only in the case of the creation of equal opportunities for all market participants, with simultaneous start of organized gas trading in Russia and the introduction of a commercial gas balancing system.

The Russian market sector follows the principle of state priority over the unregulated sector. This blocks the action of supply and demand factors in the market pricing. In the total gas volume supplied to the domestic market through the Unified Gas Supply System (UGSS), the share of Gazprom in 2013 was 71.3% (the share of independent gas producers – 28.9%). While the Gazprom wholesale price, is set by the state, other market participants are selling gas at free prices.

Figure 2.3.4 – Gas market structure in the Russian Federation



Source: Institute of Energy Strategy

Under Russian Federation Government Decision of the Government of the Russian Federation No. 1021 of December 29, 2000 on the State Regulation of Prices for Gas, Tariffs for the Service of Transporting It and Payment for the Technological Connection of Gas-Using Equipment to Gas-Distribution Networks on the Territory of the Russian Federation, government regulates in the Russian Federation:

a) the gas retail price (for population);

b) the gas wholesale price;

c) the supply and marketing services payment amount, for services which provided to end users by gas suppliers (in the regulation of wholesale gas prices);

d) gas pipeline transportation tariffs (for pipelines belonging to independent gas transportation organizations-owners)

e) gas pipeline transportation tariffs for independent organizations;

f) tariffs for distribution networks gas transportation.

Thus, the formation of wholesale gas supply tariffs and gas retail price for end users (public) is under state regulation. Wholesale gas prices change parameters are determined by the Government of the Russian Federation.

Specific regulated wholesale gas prices are differentiated by region price zones. Price zones are determined taking into account the gas regions, consumers remoteness and consumer categories (see Annex 4). They are approved by the Federal Tariff Service (FTS) of Russia. Retail gas prices for the population are determined by administrations of the Russian Federation regions. The gas price for the end user is determined by agreement between the parties, taking into account the established limits, tariffs for the distribution networks transportation and a supply/sales services payment. The gas price for the end user is generally determined taking into account regulated wholesale gas prices, which are set by the FTS of Russia.

The unregulated sector major suppliers are independent gas and oil companies. Government regulation is not involved in the independent producers' gas supplied price determination. This means that 28.7 % of total gas volume can be sold at unregulated prices.

In this case, gas prices are set by the interplay of supply and demand. Gas prices are negotiated.

Unregulated natural gas market sector usually is formed due to gas consumers' direct purchases from independent producers (in the case of free gas transportation capacity availability). In this case, the market price for consumers is based on the independent producer contract price and regulated gas transportation services tariffs.

Which consuming sector do have regulated prices (power generation, industry, residential & commercial, feedstock, others)?

The Russian price formation system has some substantial changes in its history. Until January 1, 1992 there was a centralized, planned pricing system in the country. The State Prices Committee (a USSR Ministers' Council body) formed wholesale and retail prices lists for almost all kinds of products, which were produced in the country. And only 5% of the prices were formed by local authorities (some categories of food, light industry goods). Prices were unchanged for long periods of time, but did not fulfill the enterprises production and economic activity regulator role.

In 1991, the economic crisis, which led to a threefold gap between the money volume and commodity demand, and, together with it, to the food shortages, forced the state to go to price liberalization direction. On December 3 1991, the President of Russia signed The Decree of the President of the RSFSR No. 297 of December 3, 1991 on the Measures to Liberalize Prices, according to which from January 2, 1992 the country passed "mainly on the use of free (market) prices and tariffs formed under the supply and demand influence for the production technical purposes products, consumer goods, works and services". The decree provided for a three groups of activities:

1) price liberalization, that affected 90% of retail and 80% of wholesale prices, which were released from state regulation;

2) state regulated prices and tariffs, established for a number of socially significant consumer goods and services (bread, milk, public transport);

3) regulated prices established for the monopolies products.

These measures allowed to solve country trade deficit problems, but had some irreversible consequences. In the period of 1992-1998 consumer prices in Russia increased more than 4000 times. In this case, the nominal population income increased by only a thousand times. The result was a catastrophic drop in living standards. The state can't cope with this problem up to this date. In addition, "free" pricing led to a trading and intermediary sector profits sharp rise and profit reduction in the production sectors, especially in agriculture[29].

Since the adoption of the presidential decree on the Measures to Liberalize Prices pricing principles in Russia were not changed. The prices' majority are formed freely under the supply and demand factors influence. According this policy, up to this date, the state only aims at reduction of the role and control functions in this area (for wide products' list). A range of goods and services, which were a subjects for state prices regulation, consistently narrowed.

Today, according Decision of the Government of the Russian Federation No. 239 of March 7, 1995 on Measures to Streamline the State Regulation of Prices (Tariffs) , which has been amended 19

[29] Аналитический вестник Совета Федерации ФС РФ, №6.-2010.

times the last 15 years (last ed. 2014/06/1)), the Government performs state price and tariffs regulation for the several types of goods (services). For the energy industry, regulation applies only to:

- Natural (passing, liquefied, dry) gas;
- Nuclear fuel cycle Products;
- Electric[30] and thermal energy to supply wholesale market;
- Transportation through pipelines of oil and oil products;

The executive authorities of the Russian Federation regulate the prices for energy resources (solid fuel, domestic heating oil and kerosene) for sale to citizens, manage organizations, housing organizations, etc., as well as for other goods and services of public interest.

The main relevant law for the implementation of these principles are:

- Federal Law No. 147-FZ of August 17, 1995 on Natural Monopolies
- Federal Law No. 210-FZ of December 30, 2004 on the Principles for the Regulation of Tariffs of Municipal Complex Organisations
- Federal Law No. 41-FZ of April 14, 1995 on the State Regulation of the Tariffs on Electric and Thermal Power in the Russian Federation (with Amendments and Additions)
- Federal Law No. 35-FZ of March 26, 2003 on the Electric Power Industry
- Federal Law No. 69-FZ of March 31, 1999 on Gas Supply in the Russian Federation

Who is the regulator (Ministry, Local Governments, Government Agency, Independent Energy Regulator, Competition Regulator, Courts, or others)?

The parameters of wholesale gas prices are determined by the Russian Federation Government.

Specific regulated wholesale gas prices are differentiated by price zones (see Annex 5). They are approved by the FTS of Russia. Retail gas prices for the population determined by administrations of Russian Federation subjects.

The natural gas prices regulatory process in Russia includes the following key agents:

<u>Government of the Russian Federation</u>

- Defining the parameters of the regulated wholesale prices changes

[30] Decision of the Government of the Russian Federation No. 1178 of December 29, 2011 on Pricing in the Area of Regulated Prices (Tariffs) in the Electricity Industry (together with the "Principles of pricing in regulated prices (tariffs) in the power sector," "Rules of State Regulation (revision application) of prices (tariffs) in the power sector")

The Government is responsible for the overall pricing policy and for the key methodologies development in this area.

JSC Gazprom

- makes proposals to the government about the expected wholesale prices on gas, optimal for the monopoly (taking into account the cost evaluation system, the company's strategy, restrictions on natural gas for participants in the process of pricing in Russia)

Gazprom is a basis for modern gas market industry of the Russian Federation. The company is involved in the regulated gas prices formation.

Ministry of Finance of the Russian Federation[31]

The Ministry of Finance of the Russian Federation carries out legal regulation in the following areas directly or indirectly related to the natural gas pricing:

1. finance;
2. budgetary, tax, insurance, currency and banking activity;
3. processes of organization, preparation and execution of the federal budget;
4. inter-budget relations;
5. customs duties and the definition of the customs valuation of goods;
6. customs and tariff regulation;

This federal agency determines the tax rates, the value of the excise duty on oil products, export duties, and others.

Ministry of Economic Development of the Russian Federation[32]

The Ministry carries out functions of the public policy and legal regulation development in the following areas directly or indirectly related to the natural gas pricing:

7. macroeconomics,
8. financial markets and international financial center,
9. strategic planning, federal programs, including the Federal Targeted Investment Program,
10. support and development of small and medium-sized businesses,
11. trade,

[31] Federal Ministry of the Russian Federation, providing the implementation of a unified fiscal policy, as well as carrying out general guidance in the field of Finance of the Russian Federation.
[32] Federal Ministry of the Russian Federation, providing the formulation and implementation of economic policy of the Government of Russia on a number of areas.

12. investment policy,
13. special economic zones,
14. state guarantees,
15. regulatory impact assessment,
16. regulation of public procurement,
17. energy efficiency,
18. sectors of natural monopolies restructuring.

The level of wholesale prices of gas produced by JSC Gazprom and its affiliates, is determined in accordance with The Forecast of Socio-Economic Development of the Russian Federation on a three-year term. The Forecast is developed by the Ministry of Economic Development of the Russian Federation.

The Ministry of Economic Development identifies key macroeconomic indicators and indicators of the pricing policy development in the natural gas sector .

Federal Tariff Service of the Russian Federation

The FTS of Russia in accordance with the Constitution of the Russian Federation, federal constitutional laws, federal laws, decrees of the President of the Russian Federation and the Government of the Russian Federation, independently adopts:

19. normative legal acts in the established sphere of activity;
20. guidelines, including, methods for calculation of regulated prices for gas transportation tariffs, the amount of payment for supply and distribution services, the size of the special allowances to the tariffs for gas transportation.

The FTS of Russia is responsible for the establishment of specific regulated wholesale gas prices in price zones, taking into account the positions of other key agents.

What is the basis for the regulation?

The factors of social accessibility and producers' investment needs (especially for gas and electricity) are underlying in the regulatory framework for gas market. The ratio of these two basic factors of regulation varies from year to year.

With this, the regulation in the Russian Federation is not something integral and unified - each of the key pricing system agents (see above) have their goals taking into account at different stages of pricing.

All of the question items are used at different stages depending on the regulation aims. It should be noted that there is not an integrated regulation system of the energy markets in Russia.

Unfortunately, there is no coherent long-term strategy, in addition to the general policy of liberalization (in the framework of which there are many derogations and interpretation variants).

Main criteria used for regulation

The key of the listed factors in the gas pricing regulation for the Russian Federation (with reference to the upstream part of the value chain) are:

- operational expenditure;
- depletion fees, royalties, or user costs.

Gazprom, as a key business figure of the Russian Federation gas market, participates in tariffs' setting for wholesale prices.

On the basis of internal assessments (in the production processes cost area, calculation costs etc.) the company makes proposals to the Government of the Russian Federation regarding the optimal level of wholesale gas prices. Determination criteria are confidential information of the company, and factors like exploration and depletion costs are the key of the listed.

There is however no information about rates of return that can be applied to this industry, unlike in other sectors (like electricity transmission, heating, water supply and water drainage) , where they are published, and set by the Federal Service on Tariffs at levels typically ranging between 8 and 12%. Lately, the upper level of this range typically applies to such services.

The Government of the Russian Federation, taking into account these factors, as well as the criteria established by the Ministry of Finance and Ministry of Economic Development of the Russian Federation, issues further guidance.

Main criteria used for price adjustment and indexation

The *inflation index* has a key influence on the regulation of gas prices in Russia.

According to the scheme outlined above, the balance between containment of inflation (from the state and the population's sides) and the need to investment projects' support in gas industry (from companies' side, accounting overall long-term strategic reference points of the country) is the key aim today in tariffs' formation policy for the Russian Federation.

According to the available data, FTS of Russia approves wholesale prices for the population and industry with the following periodicals since 2010 (see Tables in Annex 5):

- for the industry: from January 1 until 2011, 1 time every six months (1 January and 1 July) since 2011;
- for the population: January 1 and April 1 until 2011, and update on a yearly basis (from 1 July) since 2011;

The price indicators of competing fuels are used for the updates, according to the formula of gas pricing (see Annex 4). This considers arithmetic averages of highest and lowest prices per month of heating oil with a sulfur content of 1% and gasoil with a sulfur content of 0,1%.

Latest available price level for the main large consumers

The information is placed in Annex 5, Table A.5.2.

Structure of the regulated price for the main consuming sector

In accordance with The Order of the Federal Tariff Service of the Russian Federation N 165-e/2 Jule 14, 2011 / 2 (ed. from 6 March 2014) on Approval of the Regulation on the definition of the pricing formula of gas, the gas price formula is based on the principle of gradual achievement of equal yield of gas supplies to the domestic and foreign markets in transitional period and takes into account the cost of alternative fuels.

Prices calculated in accordance with this Regulation are applied in the implementation of the gas price at the main gas pipeline transport system's exit, either directly to final consumers gas suppliers or to other entities for resale to final consumers using gas as fuel and / or raw material.

In the case of absence of the main gas pipelines in the gas supply scheme, the price is calculated at the entrance to the gas distribution network for gas suppliers, which supply gas directly to end-users.

Differentiation of gas prices is carried out by price zones in relation to the administrative borders of the Russian Federation (for more detailed - see Annex 5 2).
In the determination of the price zones are also included by FTS of Russia:

- The flows routing of gas intended for customers located in the territory of the Russian Federation;
- The cost and extent of the alternative fuels using;
- The presence of isolated gas supply system sections on the territory of the Russian Federation subject.

The gas price formation formula includes the following elements:

- the arithmetic average price for heating oil (masut) with a sulfur content of 1%;
- lowest and highest values of average monthly prices for heating oil (masut);
- the arithmetic average price for gasoil with a sulfur content of 0,1%;
- lowest and highest values of average monthly prices for gasoil;
- the official ruble's exchange rate to the dollar;
- the rate of export customs duty on gas;
- the specific cost value associated with the supply of gas to distant foreign countries

- expenses of transportation, storage and distribution of gas to distant foreign countries, outside the Russian Federation;
- the volume of gas sales to distant foreign countries;
- the decreasing coefficient providing a growth of gas prices rate in the settlement calendar year;
- differentiation coefficient reflecting the price variance for the 1-th zone price relative underlying zone price;
- the difference between the transporting gas average cost from gas fields to the border of the Russian Federation and the transporting gas average cost from gas fields to consumers of Russian Federation;
- the average distance of gas transportation, which produced JSC "Gazprom" and its affiliates, respectively, for export and the domestic market by main pipelines through the territory of the Russian Federation;
- rates (unit rates) of tariff of gas transportation services by the main pipeline

For full information about gas pricing formula – see Annex 4, for more detailed information about calculation - see *The Order of the Federal Tariff Service of the Russian Federation N 165-e/2 Jule 14, 2011 / 2 (ed. from 6 March 2014) on Approval of the Regulation on the definition of the pricing formula of gas*[33].

Relevant authority for price update

Competent authority to update the wholesale prices for regulated natural gas sector in Russia is the Federal Tariff Service (FTS of Russia). FTS of Russia is a federal executive authority for the natural monopolies regulation, which realizes the prices (tariffs) state regulation in the electricity, oil and gas industry, railway and other transport terminals services, ports, airports, telecommunication and postal public services and some another different kinds of goods (works, services), which are used for state regulation in accordance with the Russian Federation legislation.

For gas which is produced by JSC Gazprom and its affiliates, the level of gas wholesale prices' rise is determined by parameters of the Russian Federation socio-economic development on a three-year term. Russia Economic Development Forecast is developed by the Ministry of Economic Development of the Russian Federation and approved by the Russian Federation Government.

On the basis of the Russian Federation Constitution, federal constitutional laws, federal laws, Russian Federation President decrees and the Russian Federation Government decrees, the FTS of Russia develops its own legal acts, methodology guidance, including calculation of gas

[33] information available on request.

transportation tariffs regulated prices, the supply and distribution services payment amounts, the special allowances gas transportation tariffs in the established field of activity [34].

Legal basis of the regulation?

According to the Constitution of the Russian Federation, the sphere of its competence include issues of federal power systems, the legal foundations of the single markets, pricing policy principles, security of the Russian Federation. *Federal Law No. 69-FZ of March 31, 1999 on Gas Supply in the Russian Federation* is a fundamental legislative decree, which governs all relations in the gas sector. This law establishes the basic principles of state regulation and relations in the gas industry. In particular, the law states that the term "gas-supply" implies the form of energy supply, which means activities to ensure consumers with gas, including on the formation of the fund proven gas fields, production, transportation, storage and supply of gas. According to Article 3 of this law, it is based on the Constitution of the Russian Federation, the Civil Code of the Russian Federation, the Federal Law on amendments and additions to the Law of the Russian Federation "On Subsoil", the Federal Law on Natural Monopolies, the Federal Law on the Continental Shelf of the Russian Federation, as well as laws and other normative legal acts of the Russian Federation.

In Article 6 of the law provides a definition of "Unified System of Gas Supply (UGSS)". It is an industrial asset complex, which consists of technologically, organizationally and economically interconnected and centrally managed industrial and other facilities for the production, transportation, storage and supply of gas, and is owned by the organization, which formed in the civil legislation of the organizational and legal form and order.

This organization receives UGSS objects in the property in the process of privatization or acquires them on other grounds under the laws of the Russian Federation. Thus, the law stipulates that the UGSS is owned JSC Gazprom and is related to its core activities.

The access of independent organizations to gas transportation networks and gas distribution networks is according to Article 8 of this law within the powers of the federal authorities.

Article 26 of the Act prohibits Gazprom to commit acts that violate the antitrust laws and to create obstacles for independent gas producers access to the market for gas. Organizations, which are the owners of gas supply systems are required to ensure non-discriminatory access to available capacity of their gas transmission and distribution networks for any organizations operating in Russia in the manner prescribed by the Government of the Russian Federation. These organizations must ensure the quality of the gas, which must comply with national standards and confirmed by certificates of conformity to the requirements of the standard. Thus, the Act stipulates that the owners of gas supply systems (Gazprom and other organizations) will have the right to deny access to their gas transmission and distribution networks based on the formal absence of spare capacity, which is a clear barrier to the creation of a competitive gas market in Russia.

---

[34] Отчет Федеральной службы по тарифам о результатах деятельности в 2011 году и задачах на среднесрочную перспективу//ИА "ГАРАНТ" URL: http://www.garant.ru/products/ipo/prime/doc/70059900/#ixzz37jHkGipF

The *Federal Law No. 147-FZ of August 17, 1995 on Natural Monopolies* is an important regulatory element of gas market to maintain the principles of market economy. It defines the legal framework of federal policy with respect to natural monopolies in various fields, including in the sector of transport of gas through pipelines, and is aimed at balancing the interests of consumers and subjects of natural monopolies, ensuring the availability of the goods sold by them to consumers.

Today, the Russian government implements the state regulation of prices and tariffs on certain types of goods (services) according to the *Decision of the Government of the Russian Federation No. 239 of March 7, 1995 on Measures to Streamline the State Regulation of Prices (Tariffs)*, which was changed 19 times over the past 15 years. This list of products includes natural gas (accompanying gas, liquefied gas, and dry gas), electricity and heat supplied to the wholesale market, and others.

The Decision of the Government of the Russian Federation No. 1021 of December 29, 2000 on the State Regulation of Prices for Gas, Tariffs for the Service of Transporting It and Payment for the Technological Connection of Gas-Using Equipment to Gas-Distribution Networks on the Territory of the Russian Federation establishes a list of items that are subject to state regulation:

a) the retail prices of gas sold to the public;

b) the wholesale prices of gas;

c) the payment amount for supply and marketing services, which provided to end users by gas suppliers (in the regulation of wholesale gas prices);

d) tariffs for gas transportation through pipelines of independent gas transmission organizations;

e) tariffs for transporting by main gas pipelines for independent organizations;

f) tariffs for the transportation of gas by distribution networks.

Thus, government regulation covers the formation of tariffs for wholesale gas supply and retail sale of gas to end users.

The Decision of the Government of the Russian Federation No. 335 on the Procedure for the Establishment of Special Increments to the Tariffs on the Transportation of Gas by Gas Distributing Organisations for the Financing of Programs for the Installation of Gas Service was taken May 3, 2001 in order to develop the Russian regions gasification.

Since 2006, the Russian Government has taken steps to develop the Russian gas market in accordance with market principles.

May 28, 2007 the Government of the Russian Federation adopted the Decision of the Government of the Russian Federation No. 333 on the Improvement of the State Control of Gas Prices. This legislative act provides for a number of measures to liberalize pricing in the gas industry.

In particular, the JSC Gazprom had acquired the right to sell the gas to certain category of consumers at bargain prices. In this case, there was the mark-up limit which the FTS of Russia regulates. In 2011 this limit mark-up was 10% of the regulated price value.

In the initial phase the basics of wholesale stock exchange trading should be organized. It is necessary for the formation of market mechanisms of the participants of the Russian gas market and for determine the market value of natural gas, which should be formed on the basis of supply and demand. For this September 2, 2006 the Government of the Russian Federation adopted the Decision of the Government of the Russian Federation No. 534 on experimental gas sales on the electronic basis.

December 31, 2010 the Decision of the Government of the Russian Federation No. 1205 on Perfecting State Regulation of Prices of Gas was adopted. This document establishes a transition period from 2011 to 2014, during which the regulation of wholesale gas prices for all consumers (except for the population) will be based on the pricing formula. Gas price formula calls for the gradual achievement of equal yield of gas supplies to the foreign and domestic markets, as well as it takes into account the cost of alternative fuels.

Thus, the basis of legal regulation of the gas market include:

- Federal Law No. 147-FZ of August 17, 1995 on Natural Monopolies;
- Federal Law No. 69-FZ of March 31, 1999 on Gas Supply in the Russian Federation;
- Decision of the Government of the Russian Federation No. 239 of March 7, 1995 on Measures to Streamline the State Regulation of Prices (Tariffs);
- Decision of the Government of the Russian Federation No. 1021 of December 29, 2000 on the State Regulation of Prices for Gas, Tariffs for the Service of Transporting It and Payment for the Technological Connection of Gas-Using Equipment to Gas-Distribution Networks on the Territory of the Russian Federation;
- Decision of the Government of the Russian Federation No. 335 of May, 2001 on the Procedure for the Establishment of Special Increments to the Tariffs on the Transportation of Gas by Gas Distributing Organizations for the Financing of Programs for the Installation of Gas Service;
- Decision of the Government of the Russian Federation No. 534 of September 2, 2006 on experimental gas sales on the electronic basis;
- Decision of the Government of the Russian Federation No. 1205 of December 31, 2010 on Perfecting State Regulation of Prices of Gas.

Main non-price provisions of regulation tied to the price control

Methods of price regulation in the Russian Federation are determined in accordance with Decision of the Government of the Russian Federation No. 239 of March 7, 1995 on Measures to Streamline the State Regulation of Prices (Tariffs).

State indirect (non-price) method affecting price formation implies the indirect government authorities' intervention in the pricing process.

As a part of the non-price method can be distinguished some main forms of indirect state influence on the pricing process, which are based on the economic policy various parts (elements) use (monetary, budget, taxation, tariff, amortization, accounting, investment, foreign trade, currency, etc..).

In addition to the using of different elements of the state economic policy, the indirect method also includes standardization, quotas, licensing, and others systems.

Non-price state regulation method of pricing is a priority in a market economy. Non-price regulation methods for natural monopolies may be realized by the definition of consumers which are subject to compulsory service and / or the establishment of a level of supply minimum for consumers. In the case of impossibility of full goods requirements satisfaction (for commodity which are produced or sold by a natural monopoly). It is necessary also taking into account the need for protection the rights, nature and cultural values, legitimate interests of citizens, ensuring state security.

Non-price regulation methods are also a subject for legal regulation. Meanwhile, the analysis shows that non-price regulation methods are applied in practice rarely. For example, according to the Decision of the Government of the Russian Federation No. 364 of May 29, 2002 on Ensuring a Stable Gas and Energy Supply to Organizations Providing for the State Security, Financed at the Expense of Funds from the Federal Budget, there are some non-price regulation methods which are provided for specified in this Decree organizations.

For the gas industry with the policy tariff setting for Gazprom, there is not any necessary non-price measures to regulate the wholesale market. Gazprom tariffs is also a major landmark in tariff for independent producers, even if they are selling gas directly to end-users. So, in general case, methods of non-price regulation for Russia Federation gas market are not used now.

2.4 China

2.4.1 Scope of market price regulation

Domestic gas prices in China are regulated at each point along the value chain. From wellhead to city gate terminals, gas prices (wellhead prices, processing fees and transportation tariffs) are regulated by central government and administered by National Development and Reform Commission (NDRC). Local distribution charges (including connection fees) and end-user prices are regulated by provincial and local governments.

All consuming sectors have regulated prices. End-user prices beyond the city gate are regulated by provincial and local governments.

2.4.2 Who is the regulator?

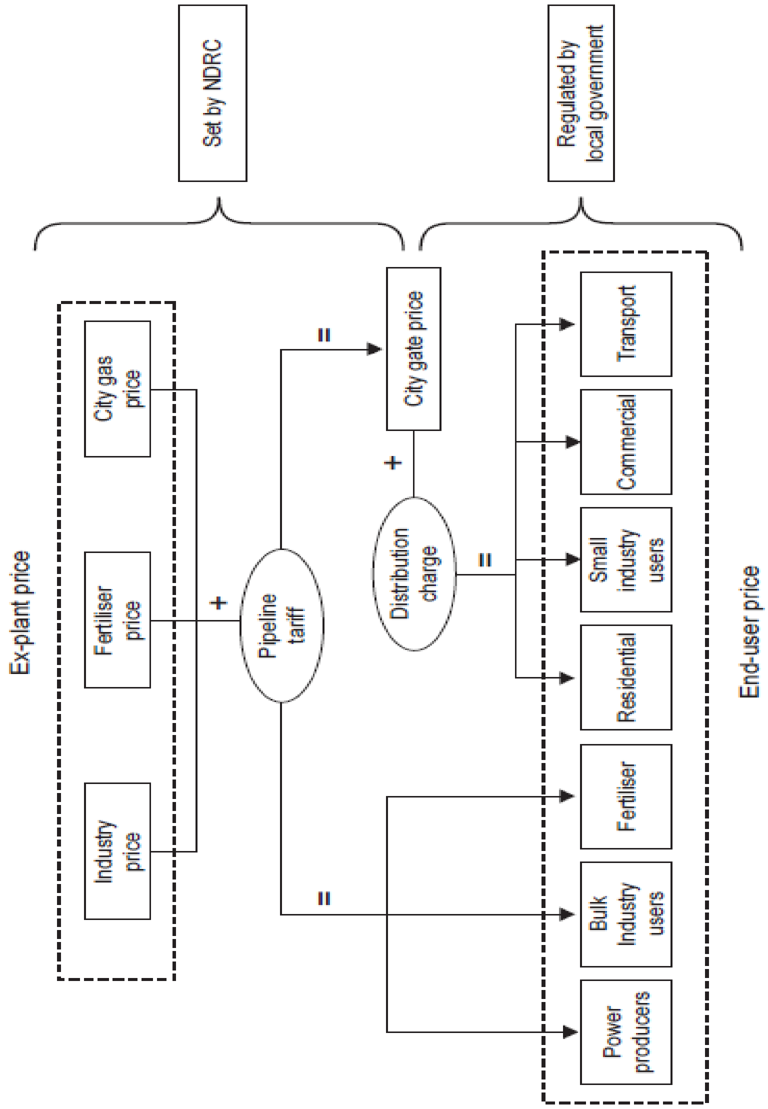
Pricing bureau of National Development and Planning Commission (NDRC) is the regulator and National Energy Administration (whose head is the deputy chairman of NDRC) advises the process. All major pricing decisions need to be approved by the State Council and notices are issued to national oil companies, central and local pricing bureau within government bodies.

2.4.3 Basis for the regulation.

Before 2013, Chinese gas pricing was based on cost plus model based on wellhead pricing regulation. The new net-back pricing system trialled in 2011 and implemented nationwide in July 2013 is in stark contrast to the cost-plus system as it moves the pricing point downstream from the wellhead to city gate.

Social affordability had traditionally been the deciding factor under the cost plus pricing model. However, the current netback pricing model (implemented since 2013 nationwide) means that the price of competing fuels and the cost of service - especially transportation - will be the basis for regulation and the government's price regulation shifts from well head to city gate.

Figure 2.4.1 – China's gas regulatory framework



End user pricing has traditionally been based on the cost of supply (the city-gate price set by the NDRC) plus a local distribution fee (including a cost-plus margin). They also take into account the following factors: the type of end-user, the user's ability to pay, the competitiveness of gas against other fuels, gas demand structure and efficiency, and a cost estimate for converting coal gas distribution networks to natural gas. In theory, when the NDRC adjusts ex-plant prices, provincial and local pricing bureaus pass costs downstream by raising retail prices. If the wellhead price of a source crosses a threshold set by the province, the project developer submits a proposal for a price change to the local pricing bureau for review, adjustment and approval. In practice, making price adjustments downstream following increases in upstream tariffs is a slow process: for example, it normally takes longer to review a price change for the residential sector than for other end-user groups since a public hearing is usually required. This has squeezed the distribution margin of city gas distributors, which tend to be private companies. End-user prices vary significantly from location to location and from sector to sector (according to local development priorities). The wealthier coastal regions, which are located a long way from key inland sources of gas, pay higher prices.

2.4.4 Main criteria used for regulation

Ex-plant prices, which include wellhead prices and processing fees, have been traditionally set by the NDRC in consultation with national oil companies for each well and each region in the case of onshore conventional gas. They are based on the type of end-user – for example, industrial, residential and the fertilizer and power sectors, which are supplied via different pipelines.

Gas industry's role in national macroeconomic development and consumer affordability has been the key drivers of ex-plant price regulation; However, production cost, which depends on the source of local gas, has over the years been advocated by national oil companies to negotiate with the government for wellhead price rise.

Wellhead prices are calculated from a base price (which takes into account project cost, taxes and loan repayments) as well as processing fees and an appropriate margin for producers (usually 12%). Processing fees are determined by the quality of the gas and subject to negotiations between the NDRC and producers. The ex-factory price serves as 'price guidance' against which producers and buyers can negotiate a final price within a +/-10% band. It applies only to conventional gas since the price of unconventional gas price is based on market rates.

2.4.5 Main criteria for capital valuation and others:

$$\sum_{t=1}^{n} (CI - CO)_t (1 + IRR)^{-t} > 0$$

CI— Cash Flow Input
CO—Cash Flow output
IRR- Internal rate of return
n-enterprise life cyle period

The above formula has traditionally been used by NDRC and Ministry of Construction for project evaluation to assess the NPV and IRR of the project in order to derive the wellhead price. Cash-flow input refers to the sum of income from sales, remaining value of fixed capital and free cash flow. Cash-flow output refers to sum of fixed capital investment, operational expenditure and tax payment.

Implementation of netback pricing in 2013 has meant that wellhead price would be a netback from city gate price (i.e. deducting from city gate price a corresponding transportation fee) which is indexed to import prices of alternatives (LPG and fuel oil). However, in reality it is still very opaque (partly because production and transportation of gas are bundled together by national oil companies) and only implemented for incremental gas volume (10% of total gas demand). Nevertheless, this means that reference to competing fuels and international gas price will be more relevant in adjusting the wellhead price than the other variables.

2.4.6 Main criteria used for price adjustment and indexation

a) Adjustment frequency and trigger rule. Current city gate price adjustment is ad hoc and there is no specific conditions and schedule publicly known to trigger the adjustment. However, the government aims to merge price of existing gas volume (2012 gas sales volume) with that of incremental gas (those gas sales volume exceeding 2012 level) by the end of 2015. The last price adjustment nationwide (July 2013) has substantially raised the city gate price.

b) Price indicators of competing fuels and/or market or other gas prices. A general formula was announced and is believed to be used to derive the current announced provincial city gate price ceiling.

$$P_{gas} = K \times (\alpha \times P_{\text{fuel oil}} \times \frac{H_{gas}}{H_{\text{fuel oil}}} + \beta \times P_{LPG} \times \frac{H_{gas}}{H_{LPG}}) \times (1 + R)$$

P_{gas}— Natural gas city-gate price (inclusive of taxes) in Rmb/cm

K— Discount rate (0.9)

α, β— Weighted percentage of fuel oil and LPG (60% and 40%, respectively)

$P_{fuel\ oil}$, P_{LPG}— Import price during the period in Rmb/kg

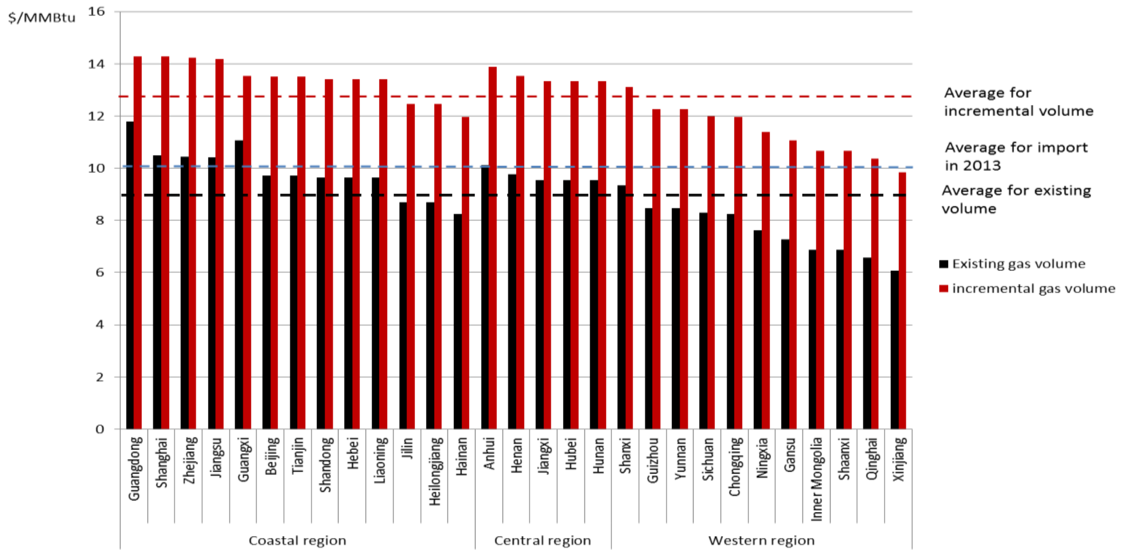
$H_{fuel\ oil}$, H_{LPG}、H_{gas}— Heat content of fuel oil, LPG and natural gas (10,000 Mcal/kg, 12,000 Mcal/kg, and 8,000 Mcal/kg, respectively)

R— Natural gas VAT rate (13%)

c) No inflation index or other macroeconomic indicator is applied.

d) <u>Ceilings and floors</u>. NDRC announced the city gate price ceilings for 29 provinces/municipalities in July 2013. Buyers (typically provincial grid company, owned by provincial government) and sellers and pipeline gas can negotiate below the guided price. It has not been revised since. Currently, the price ceiling for incremental gas is on average 40% higher than that of existing gas though there is great variation across and within regions.

Figure 2.4.2: Provincial city-gate prices across the main regions, July 2013



Source: NDRC (2013)

N.B: The original announced price ceilings were denoted in RMB per cubic metre. Annual exchange rate for 2013 from the People's Bank of China and unit conversion factor for energy content (1 MMBtu=27 cubic metre) is used for conversion of the prices into US dollar per MMBtu. It should be noted that there is considerable variation in the value of energy content across gas fields in China and imports.

e) There is no role for incentive or performance –based regulation at present.

2.4.7 Latest available price level for the main large consumers.

In 2013, average gas price for power generation is around $10.6/MMBtu while that for industry is around $14.6/mmbtu and transport is $17/MMBtu. Residential sector enjoys the lowest price of $10.4/MMBtu.

2.4.8 Structure of the regulated price for the main consuming sectors

The end use price has been traditionally set by local government, which cross subsidises residential and fertiliser gas use. For residential customers, there is a flat connection fee (fixed charge) based on the types of gas appliance in the property, such as stoves, water heaters and boilers. Currently economically more advanced province such as Guangdong is practising capacity related charges for residential gas users. It normally takes longer to review a price change for the residential sector than for other end-user groups since a public hearing is usually required. The NDRC announced on March 22, 2014 that residential tiered gas pricing will be implemented nationwide by the end of 2015 (a price ratio of 1:1.2:1.5 for the three tiers). Each city will calculate the average residential gas consumption volume and set three benchmarks. For the majority of residential users (0-80% households' average volume), the gas price will be determined based on the supply cost (basic tariff). For users with higher consumption volume, the extra volume will be charged at a higher price – 1.2x of basic tariff for the 80-95% volume tier and 1.5x for the 95%-100% tier.

Figure 2.4.3 - End-user price by sector and new city-gate price ceilings, 2013

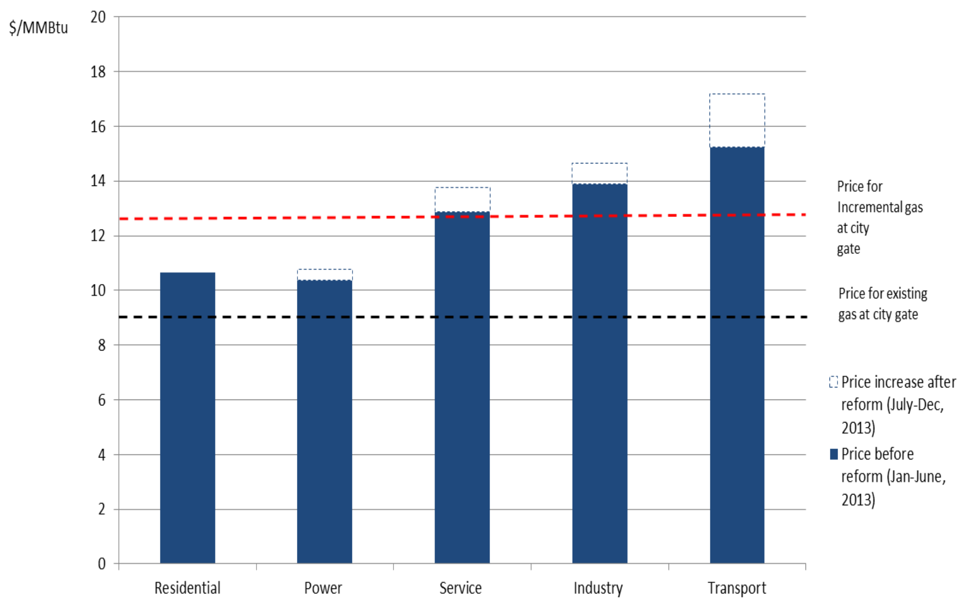


Table 2.4.1

Tiered Pricing Mechanism for Residential Gas Prices

	Volume Threshold	Price
Step 1	Monthly average usage of 80% of households in the covered region	Determined based on supply cost
Step 2	Monthly average usage of 95% of households in the covered region	~1.2x of Step 1 price
Step 3	Volume exceeding the Step 2 threshold	~1.5x of Step 1 price

Before Publication of the NDRC Guideline, Several Cities in Jiangsu Province Had Already Applied Tiered Pricing for Residential Natural Gas in 2013

City	Monthly Volume	Price (Rmb/cbm)			
		Before	After	% Chng	Abs. Chng
Xuzhou	< 75 cbm	2.20	2.45	11%	0.25
	75-125 cbm	2.20	2.70	23%	0.50
	> 125 cbm	2.20	2.94	34%	0.74
Wuxi	< 50 cbm	2.20	2.50	14%	0.30
	> 50 cbm	2.20	3.00	36%	0.80
Nantong	< 50 cbm	2.20	2.53	15%	0.33
	> 50 cbm	2.20	3.04	38%	0.84
Nanjing	Scenario 1: <=Three residents per household				
	< 15 cbm	2.20	2.20	0%	-
	15-50 cbm	2.20	2.60	18%	0.40
	>50 cbm	2.20	3.00	36%	0.80
	Scenario 2: >=Four residents per household				
	< 5 cbm*	2.20	2.20	0%	-
	5-17 cbm*	2.20	2.60	18%	0.40
	>17 cbm*	2.20	3.00	36%	0.80
Lianyun-gang	<40cbm	2.4	2.4	0%	-
	40-90 cbm	2.4	2.64	10%	0.24
	>90 cbm	2.4	2.88	20%	0.48
Yang-zhou	For household with four residents or less				
	<50 bcm	2.42	2.42	0%	-
	>50 bcm	2.42	2.9	20%	0.48
	For household with more than 4 residents, add 12.5bcm per month for each additional person.				

2.4.8 Relevant authority for price update and legal basis for the regulation

The Pricing Bureau of National Development and Planning Commission (NDRC) is the regulator responsible for price update. They are the same authority issuing the pricing methodology.

The legal basis of price regulation is the Price Law published on 1 January 1998, based on the principle of service cost, social affordability, market condition to set the government guided price, acknowledging the differences between procurement and sales price, wholesale and retail, regional and seasonal price difference.

2.4.9 Main non-price provisions of regulation that are tied to the price control

Under the new net back pricing regime starting July 2013, each province will have two city-gate price ceilings: one that applies to new (incremental) gas for non-residential users and the other to existing gas. For existing gas for non-residential use, the increase will be no more than Rmb 0.4/cbm ($1.6/MMBtu) and for gas used to produce fertilizers it will not exceed Rmb 0.25/cbm ($1/MMBtu). For incremental gas, the price will be set at 85% of the import cost of alternative fuels (60% for fuel oil and 40% for LPG). The goal is to increase gradually the price of existing gas so that it eventually equals that of incremental gas. The NDRC has stressed that these prices will converge by the end of 2015. Currently, the price ceiling for incremental gas is on average 40% higher than that of existing gas though there is great variation across and within regions.

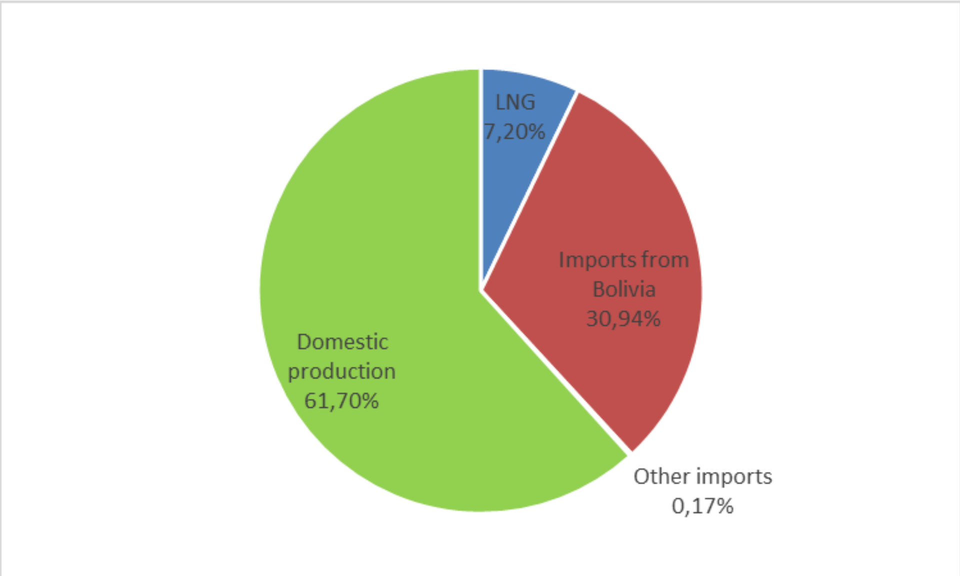
There is no clear mention in NDRC notice about any non-price provisions, although the price reform was for non-residential gas use. Subsequent introduction of tiered residential gas pricing and plan to have nationwide implementation by the end of 2015 shed some light on the central government’s determination on reforming residential gas pricing and local government’s price review timeline. In March 2014, NDRC also required National Oil Companies to allow other gas producers to use their grid networks (third party access) to supply gas whenever NOCs have spare capacity. In reality, this is very difficult to be implemented without a more fundamental reform in midstream.

2.5 Brazil[35]

2.5.1 Brief description of the industry

Brazil has a relatively small gas market, compared to the size and population of the country. Most gas is produced domestically, but the country is a net importer (Figure 2.5.1). Current proved reserves are not large (about 450 Bcm, or 21 years' consumption), but new offshore resources offer brighter perspectives in the long run.

Figure 2.5.1 – Brazil's gas supplies, 2013.



Even if legally any player could sell gas at the city gates, there is a monopoly de facto in Brasil, as Petrobras is in practice the only seller of natural gas to distributors. The prices at which Petrobras sells gas at the city gate have two components: capacity (fixed component) and flow of gas (variable component). Note that the capacity charge is not the transmission tariffs (regulated) but include it.

The gas price at the city gate in Brazil is formed using a hybrid mechanism, where part of the price is a regulated tariff and the other part a negotiated price. Legally, any player can contract gas (sell/buy) based on a bilateral agreement using any price formula. The distributors on the other hand are regulated players – regulated by state regulators. They can pass-through the city gate price to final consumers. Thus, contracted prices need to be transparent but they are not regulated.

[35] This Section has been drafted by Michelle Hallack.

Besides the distribution, the transport segment is also a regulated – by the Federal Regulator (ANP).

2.5.2 Scope of price regulation

Transmission tariffs and distributors' prices are regulated. The wellhead and wholesale price are based on bilateral negotiation. The difference between wellhead and wholesale prices should be equivalent to the transport tariff. However, the absence of available capacity in the transport network forces in practice all producers to sell their wellhead gas to Petrobras. The same applies to imports through pipes and LNG.

Petrobras is the main producer (81,9% in May 2014, when the historical peak was registered) and it is the only buyer in the wellhead and only seller of the gas in the wholesale. However, even in the presence of this *de facto* monopoly, regulation thinks of both markets as subject to competition - entry threats, in theory, avoids the need for price control. This context drove discussions on whether further intervention are necessary. In fact, there is a bill proposing regulation on the wholesale price; however, after one year of discussion no agreement has been reached.

There is also a special program for electricity, based on establishing a single price for electricity production, regardless of its origin or any other characteristic. The power plants that began their commercial operation before June 2003 have a special price. The thermal power special program (*Programa Prioritario de Termoeletrico*) should be extended until the end of the power contracts (electricity in Brazil is sold through Power Purchase Agreements).

All sectors but power generation have the same regulation in retail. However, by law, large consumers are able to buy gas from a non-regulated distributor (in principle, from anyone). In some states (as Sao Paulo and Rio de Janeiro), this federal rule was recently transposed and it is possible to develop a non-regulated retail market. The definition of large consumer, nonetheless, varies from one state to another, and it is currently subject to intense debate. In São Paulo consumptions above 100,000 cubic meters / year are allowed to choose their distributor, whereas in Rio the minimum consumption is 300,000 cubic meters. However, so far there is no such non-regulated final consumer. As for power plants, as mentioned above, they are included in the thermal power special program.

2.5.3 Who is the regulator?

There are two regulatory levels:

a) Federal level (Agencia Nacional do Petroleo e do Gas e dos Biocombustiveis). ANP is in charge of the regulation of the industry before the city gate (midstream and upstream);

b) State level, in charge of the regulation of distribution and commercialization. The two states with higher gas demand and most organized regulatory bodies are Sao Paulo's and Rio de Janeiro's, which are ARSESP and AGENERSA. Both are not specialized regulators including different utilities.

2.5.4 Basis for the regulation.

Transmission tariffs and end-users prices are regulated, but the wholesale/wellhead gas prices are not regulated and the price set by Petrobras is not completely transparent. The logic for transmission and distribution tariffs is close to a cost of service one. The costs of the regulated services (distribution and transmission) are added to the gas price, so the gas network components of the price are set of service criterion. However, the gas price at the city gate is set through bilateral negotiation between Petrobras and the corresponding distribution company, and the methodology used by Petrobras to define the price is not clear. Moreover, the line that separates Petrobras as a private company and Petrobras as a policy instrument is thin. It is frequently argued that Petrobras price is set to be close to the Bolivian imported gas price, which in turn is set with respect to an oil index. In that view, the basis for the "regulation" would be the price of competing fuels.

As for the gas devoted to electricity production, Petrobras supplies the gas but its price has regulated dynamics. In particular, this gas price is adjusted so that it mimics to some extent the dynamics of electricity tariffs. In that view, the basis for the regulation of gas dedicated to power production is to facilitate the investment and operation of those power plants.

2.5.5 Main criteria used for regulation

Upstream prices are not regulated, point a-j are part of internal calculations of Petrobras. The regulation only affects the upstream in terms of costs through the criteria established to value offers in the gas auctions (e.g. offers with high level of local contents are favored in the auction process). Nonetheless, as according to Petrobras, there is no free transmission capacity, all producers sell to Petrobras, which in turn sells at the city gate.

As mentioned above, it is thought that Petrobras sets the price to be close to the Bolivian gas (typically affected by policy factors). The Bolivian gas price, in spirit, was calculated using netback, so in that view it would be set with reference to competing fuels. However, it is important to highlight that the netback used in the Bolivian contract did not specify reopeners, so the market value implied by the contract is probably obsolete. Moreover, the evolution of the demand in Brazil changed from the time of the Bolivia contracting, so that the gap between the imported gas and what should be the netback price increased. Summing that to the fact that national gas price is not exactly the Bolivian gas price, it is not clear how the gas price is formed.

2.5.6 Main criteria used for price adjustment and indexation

The price contracted by distributors at the city-gate has a fixed and a variable component. The fixed component is adjusted annually using the IGP-M, which is a general price index calculated by the Fundação Getúlio Vargas. The variable component is adjusted quarterly taking into account exchange rates and oil prices. Oil prices are represented by a reference basket made up of a

HSFO (weighted 50% of the basket) and two LSFO (weighted 25% of the basket each). Oil derivative prices are considered in Northern, Southern Europe and the US Gulf Coast.
As for the distribution prices, being under the state regulator, it depends both on the particular state rules and on each of the concession contracts. In Rio de Janeiro and Sao Paulo, the methodology is RPI-X with regulatory periods of five years.

2.5.7 Latest available price level for the main large consumers

We reproduce data from de Ministry of Mines and Energy (MME). Prices in May 2014.

Table 2.5.1 Petrobras prices for state distributors (without taxes)

Region	Type of contract	Commodity price ($/MMBtu)	Transport price ($/MMBtu)	Total price ($/MMBtu)
South East	Import	8,1321	1,8020	9,9341
South	Import	8,1213	1,7983	9,9196
Mid West	Import	9,3189	1,8385	11,1574

Region	Type of contract	Non-discounted price ($/MMBtu)*	Discounted price ($/MMBtu)
North East	Firm Contract	12,8669	8,2863
South East	Firm Contract	12,8671	8,2864

*Petrobras argues that, on its own initiative, in May 2014 it applied a temporary discount for all distributors but GASMIG (the Minas Gerais distributor) of 35,6%.

Table 2.5.2 Petrobras prices for Industry's prices ($/MMBtu, with taxes)

Region	2x10e-6 bcm/day	2x10e-5 bcm/day	5x10e-5 bcm/day
North East	16,4501	15,8312	15,4194
South East	19,115	15,7631	15,1658
South	19,8159	17,9648	17,5779
Mid West	17,7658	15,1424	15,0477

Table 2.5.3 Petrobras prices for power generators for thermal plants within the thermal special program of 2002 (2014; $/MMBtu, without taxes)

Jan	Feb	Mar	Apr	May
4,46	4,50	4,56	4,66	4,67

2.5.8 Price structure

Prices at the city gate have commodity and capacity charges. Capacity charges do not correspond to transport costs but include them. They do not have fixed charges.
Distribution companies typically offer a wide range of tariffs, virtually always offering quantity discounts. They also tend to offer different tariffs discriminated by end-use of the gas. For instance, COMGAS in São Paulo offers tariffs for residential, commercial, industrial, gas vehicles, LNG, cogeneration, and cooling customers. All these segments have different quantity discounts.

2.5.9 Price update

The Federal Regulator ANP is the relevant authority for issuing the pricing methodology, as well as for updating them. The distribution and final price update is in the hands of state regulators. In both cases, the same entity issues the pricing methodology and updates prices.

2.5.10 Legal basis for the regulation

The main relevant primary law includes:

- Hydrocarbon Law (called mainly as ‘Oil Law’) - Law nº 9.478 from 1997. It broke the monopoly status of the industry and opened up the sector to competition. This is the bases for the price liberalization of the wellhead gas price.
- Gas Law n° 11.909, March 4, 2009. It focused on regulate gas infrastructures, especially gas transport pipelines. The pillars of gas transmission tariffs can be found in this law.

In addition, some of the relevant pieces of regulation are:

- Regulation Decree n° 7.382, December 2, 2010.
- Resolution CNPE (Conselho Nacional de Política Energética, “National Council for Energy Policy”- Advisory to the President in charge of the formulation of energy policy)
- Resolution nº 8, December 8, 2009 (Establish guidelines for exports of non-used LNG).
- Decrees (Portarias) of MME (Ministry of Mines and Energy)
- Decrees n° 67, March 1, 2010 (Procedures to obtain authorization to export non-used LNG to the short-term market).
- Decrees n° 472, August 5, 2011 (Guidelines for the open season process).
- Decrees nº 94, March 5, 2012 (Procedures for third party participation on the construction of the pipeline system).
- Decrees nº 232, April 13, 2012 (Procedures to obtain authorization to import LNG).
- Decrees nº 130, April, 2013 (Rules and procedures for EPE to ask and receive data from industry players in order to develop Studies for the Expansion of the Pipeline Transmission System).
- Decrees nº 14, January 9, 2014 (Authorization for Petróleo Brasileiro S.A. - PETROBRAS, to export non-used LNG to the spot market)
- Decrees n°128, March 26, 2014 (Aprove the Ten Years Plan for the Expansion of the Pipeline Transmission System – PEMAT 2022)

Moreover, the following Regulations and Resolutions of ANP relevant:

- Decree ANP n° 6, February 3, 2011 (Approval of the Network Code, Regulamento Técnico ANP n° 2/2011 - Regulamento Técnico de Dutos de Terrestres para Movimentação de Petróleo, Derivados e Gás Natural - RTDT).
- Decree ANP nº 51, September 29, 2011 (Regulation of registry as auto-producer and auto-importer).

- Decree ANP nº 52, September 29, 2011 (Regulation of the authorization of the activity of gas commercialization, the registry of gas seller described in the decree nº 7.382/2010, and the registry of sale and purchase contracts).
- Decree ANP nº 42, December 10, 2012 (Guidelines for third party access to gas infrastructures).
- Decree ANP nº 51, December 23, 2013 (Regulation on the authorization to become a shipper)
- Decree ANP nº 15, March 14, 2014 (Regulation on the criteria to calculate transmission tariffs, regarding firm, interruptible and exempted services; and the procedure to approve e tariffs proposals from transmission owners subject to authorization regimes)

2.5.11 Main non-price provisions of regulation

Regulations tied to price control are as limited as the price control itself. Contract clauses (take-or-pay, reopeners, etc) are not set by regulation but they are the result of bilateral negotiations. There is no regulation on production performance either (at least directly, i.e. not related to the oil E&P activities).

As for quality of service rules, applied at the distribution level, they again depend on the state regulator and the particular concession contract. For instance, in São Paulo the concession contract specifies in Annex 2 of the concession contract ("Projeto de qualidade"), the quality rules that the distribution company is committed to honor.

In addition, somehow breaking the rule that distribution is regulated by state regulators, there is a regulation from ANP (Regulamento Técnico ANP n°02/2008, annex to Resolução ANP n° 16, June 17, 2008) where the chemical characteristics of the gas commercialized in Brazil are established.

2.6 Argentina[36]

2.6.1 Introduction

Compared to Brazil, Argentina has currently smaller reserves but higher production, with an R/P ratio just below 9 years. In spite of that, it has a higher self-sufficiency, but it is also a net importer.

Yet, the country has an over 60-year long gas industry history, during which it has moved from net importer to exporter, and back to importer. Plans to export into Brazil and the construction of a connecting pipeline have not been successful for long, with production suffering from and early decline and a shortage emerging. This history is closely related to that of pricing.

[36] This Section has been drafted by Miguel Vazquez

Figure 2.5.1 – Argentina's gas supplies, 2013.

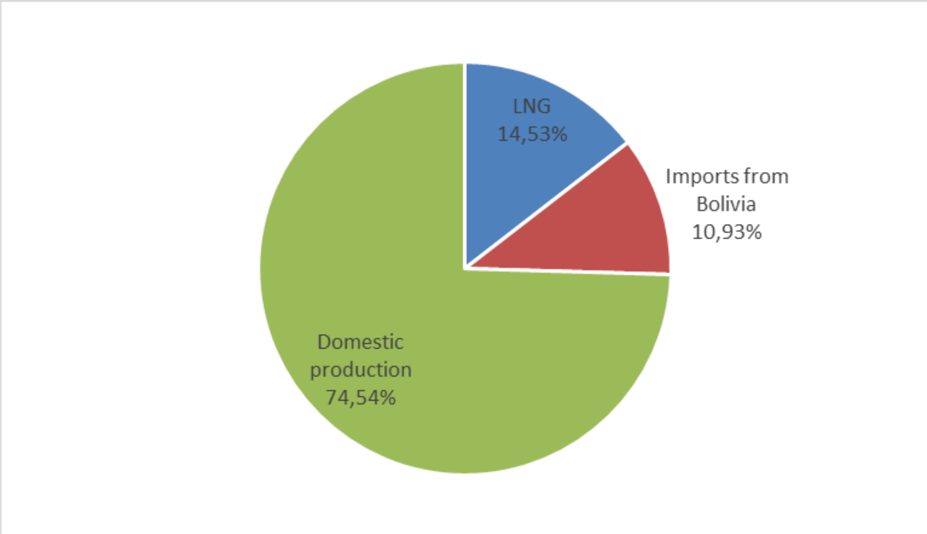
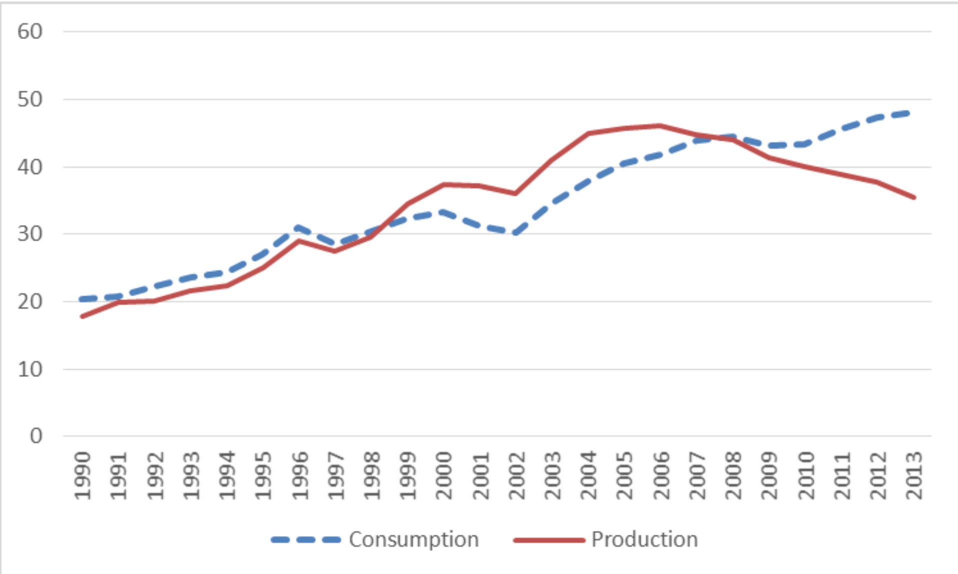


Figure 2.5.2 – Argentina's gas production and consumption, 1990-2013 (Bcm).



We can group Argentinean gas price regulation under three periods:

1) 1992 - 2000: liberalization (privatization and development of regulatory framework);

2) 2001 – 2003: economic crisis (end of the convertibility peso/dollar);

3) 2004 – 2014: Successive crises of the gas industry (price controls and underinvestment).

The legal framework ruling the natural gas industry is from 1967 and 1992 (respectivaly Law 17319 "Ley de Hidrocarburos Liquidos y Gaseosos" and Law 24076 "Regula el transporte y distribuición de gas natural"). It has not changed after the crises, but the regulatory framework has been altered by several decrees and resolutions.

The initial framework (1992 – 2000) was based on the regulation of transmission and distribution infrastructure by the regulatory agency (Ente Nacional Regulador del Gas – ENARGAS), which applied a price-cap regulatory regime. The wellhead gas price was liberalized and the wholesale gas market was based on bilateral negotiations. The retail regulation was based on adding up transmission tariffs, gas prices and the distribution regulated margin. The costs regarding transport tariffs and wellhead gas prices were passed-through to the end-user tariffs[37].

The economic crises seriously impacted the gas industry in Argentina, initially by decreasing the demand and then by increasing it steeply. With the aim of avoiding the acceleration of inflation during the financial crisis, the government froze some prices in its peso value. Concretely, in the gas natural industry, all gas prices and contracts were frozen between 2001 and 2003, except for some export contracts. That resulted in a strong gasification of the economy, as a consequence of a strong increase of the other fuel prices –oil derivates, etc. The increasing demand and the low incentives for investment (because of the low gas prices) led Argentina to an imminent gas crisis, which is the industry scenario since then.

Since 2004, an enormous set of rules (in different formats: decrees, resolutions, dispositions notes...) have been put in place. In summary, the main features of the new framework are: wellhead regulation by the Energy Secretary (Executive power); transport and distribution tariffs are still frozen at pre-crises levels (they should be updated by ENARGAS).

2.6.2 Scope of the regulation

Under the current natural gas regulatory regime, all prices are regulated in some degree. All sectors have regulated prices.

Wellhead price regulation can be grouped under the headers of "old" and "new" gas fields. Gas prices for old gas fields are set by an agreement between producers and the government. Moreover, it is established through decrees and resolutions. Prices are thus based on case-by-case bargaining so there is no clear methodology.

"New" gas fields are governed by the "gas plus pricing". Under this methodology, the project approval is subject to an analysis of risks and necessary investment. If the project is considered a risky one, the Energy Secretary can propose a defined price for a gas volume. This technical evaluation is subject to the Ministry approval.

[37] Besides the complete pass-through of gas prices, the distributors could choose another system. It was proposed in the Decree N 2731 (1993). Its main idea was to share between consumers and distributors the potential gains that the latter could have in case the gas bought by distributors was paid below the reference price. The regulator (ENARGAS) established a mechanism to calculate a reference price based on the set of wellhead contracts, and in this regime if the distributor bought the gas at a lower-than-reference price, part of the difference (50%/50%) became distributor profit. However, if distributors buy gas higher than reference the loss should be partially born by the distributors and part of the price was passed through to the tariffs (50%/50%).

The transmission tariffs regulation is responsibility of ENARGAS. In any case, the last update was in 2002 and it is currently applied. The price was established with a distance-based methodology, and it depended on the region where the gas was injected and the region where the gas was withdrawn. The distribution margin that until 2002 was reviewed by the regulator ENARGAS, was also frozen after the crisis. However, the final tariffs were changed by the Executive Power. The consumers were strongly differentiated in different groups and the tariffs were reviewed to include the wellhead prices agreed. Note that both distribution and transmission tariffs were frozen at 2002 levels in pesos (the local currency), not in dollar as previously agreed.

2.6.3 Who is the regulator?

There is a formal regulatory agency (ENARGAS), which is supposed to be responsible of regulating transport and distribution tariffs. However, as prices have been not update after 2002, its function is mainly bureaucratic and acts as an advisory to the Energy Secretariat. The Energy Secretariat is directly subordinated to the Ministry (*Ministerio de Planificación Federal de Inversión Publica y Servicios*). Under the new regulatory framework it is the main “regulatory” agency, as it is responsible to propose prices and writes technical proposals, which must be endorsed by the Ministry.

2.6.4 Basis for the regulation.

The basis for the current regulation is mostly political bargaining, which the government justifies as social affordability. There is no clear and transparent explanation for the tariff updates. The tariffs nonetheless keep being an addition of the transmission, distribution, wellhead prices plus taxes and charges.

The justification of the wellhead prices under the “gas plus” program are justified by the costs and risks of the project. Even if the calculations are not transparent, we can think of the regulation as a cost of service one[38]. In resolution 24 (2008), it is established that the commercialization price should recover the associated costs and a reasonable return on investment. Moreover, when the transport tariffs and distribution margin were established, the basic idea behind them was a cost of service regime.

The “gas plus” regime is a mechanism to allow higher gas prices for producers. On the consumer side, industry and power plants may be interested in this kind of contract, for instance, if they cannot sign contracts under the price agreement – they need of gas that has not been contracted before. Along the same lines, consumers might prefer these contracts to avoid interruption. In

[38] As an example of the gas plus program, we might point out the contracts agreed with Apache for the exploration of the field Anticlinical Campamento. The Ministry authorized the sale of 1,5 millions of cubic meters to gas up to 5 US$/MMBtu, from July 2010. This contract was sold to Grupo Pampa Energia (which is a power plant).

principle, this new contracts should be more protected against shortfalls of gas. In practice, however, even consumers buying “gas plus” contracts have been interrupted[39].

2.6.5 Main criteria used for regulation

There is no clear and transparent parameter regarding the definition of the wellhead prices in Argentina. However, the government assumes that the wellhead tariffs are enough to cover costs including rates of return, depreciation, operational expenditure, depletion fees, royalties, and user costs. Regarding the “Gas Plus” pricing, the basic idea is to include the costs and risks associated to exploration of new areas. In practice, the “Gas Plus” program has not been able to create new exploration areas, but it has increased exploration[40].

Transmission tariffs were regulated under a price cap methodology. Tariffs were established based on the costs (capital costs and maintenance) of an ideal pipeline. That implies a kind of benchmarking. The distribution margin was based on the logic of allowed revenue, and allocation of the services was based on tenders to potential suppliers.

2.6.6 Main criteria for price adjustment and indexation

The current regulation has not clear adjustment periods or indexation. Nonetheless, the possibility of being part of the “gas plus” program is reserved to players that have previously honoured volume and frequency contract provisions. We can see it as a criterion that allows a producer to ask for a higher revenue in a certain volume of gas just in case it has been able to deliver what was previously agreed – possibly a case of reputation-based regulation.

Regarding transmission and distribution, the rules before 2002 and still in place in absence of update is a RPI-X+K. The adjustment periods are five years. The factor X is the efficiency factor that allows to transfer part of the efficiency gains to the final consumer. The factor K should reflect the new investment expected in the period. There was also an inflation update by semester, which was based on the PPI (Producer Price Index) from United States.

2.6.7 Latest available price level for large consumers

There is a big range of consumers in Argentina, prices change by region, and the pricing methodology is not always clear. We calculate prices based on official data, resolutions from the energy secretary and Enargas.

---

[39] One of the main complaints of the industrial consumers is the interruption, and the short notice of such interruption.

[40] According to specialists, until 2011 around 50 projects, and 85% of well perforation were successful. This success rate might suggest shows that the amount of areas considered for gas plus projects (that is, risky (or unexplored) areas) is likely too high.

Table 2.6.1 - Argentina's Prices for large consumers in April 2014

(To be included)

The table below contains regulated wellhead gas prices for large consumers.

Table 2.6.2 - Wellhead prices

Wellhead price - US$/MMBTU		
Field	April 2014	**Since August 2014**
Nothwest	0,42	0,82
Neuquina	0,43	0,87
Chubut	0,40	0,76
Santa Cruz	0,38	0,72
Tierra del Fuego	0,38	0,71

This price does not include prices of the Gas Plus program, as it is different from case to case (it is based on bilateral negotiations). However, industrial consumers using this gas noted that prices around 5 or 6 US$/MMBtu are not rare in this kind of contract.

In addition, the next table contains the average price for each field in 2013. It includes every kind of contract (based of the government data for the payment of royalties).

	CHUBUT	JUJUY	LA PAMPA	MENDOZA	NEUQUEN	RIO NEG	SALTA	STA. CRUZ	T. DEL FUEGO	EST. NAC.
US$/ MMBTU	1,69	0,74	1,58	1,65	1,18	1,98	1,32	1,19	1,41	1,59

2.6.8 Structure of the regulated price for the main consuming sectors

The final price for big consumers has three elements:

i) a fix charge that depends on the consumer classification (depending on volume and kind of service, e.g. industry, power plant...);
ii) a capacity charge;
iii) a commodity charge, which is also related to the range of consumption).

2.6.9 Relevant authority for price update

Currently the main authority responsible for update and issuing the pricing methodology is the Ministry. The regulator ENARGAS still have formal power for both issuing and update pricing methodology but has not been actually used since 2002.

2.6.10 Legal basis for the regulation

There are too many documents in the current frame of this regulation. We list below the key documents for understanding the current tariff regulation system.

Laws

- Hydrocarbon Law - Law nº 17.319 from 1966. It established principles for the oil and gas industry. The principle regarding the supply security is used by the government to justify the wellhead prices intervention and direct contact with producers in the last decade.
- Gas Law n° 24076, from 1992. It focused on regulate gas infrastructures as distribution and transport. It creates the regulator (Enargas) which is responsible for the tariffs regulation.

Besides these two fundamental laws, there are also three recent laws: Law 26095, Law 26197 and Law 26741. The first ("Créanse cargos especificos para el desarrollo de obras de infrastructura energética para la expansión del sistema de generación, transporte y/o distribuición de los servicios de gas y eletricidad") from 2006 focused in the creation of a specific charge to finance investment in energy infrastructure called "Fideicomisos". This charged are included in the tariffs. The second, from 2007, pass the administration of the oil and gas field from the federal government to the provinces. The third and most recent law (26197) declares as public interest the energy self-sufficiency and expropriate 51% of YPF S.A. shares, held by Repsol. In addition it follows some of the relevant pieces of regulation, note, however it is not an exhaustive list.

Decrees

- Decree 1738/1992 allow the privatization of the State company 'Gas del Estado' and approve the some regulatory measures from transport and distribution (following the law 24.076).
- Decree 180/2004 establishes an especial regimen for natural gas basic infrastructure investment. And it created and regulated the electronic market for gas.
- Decree 181/2004 gives the powers to the Energy Secretariat to sign agreements with producers of natural gas aiming to establish wellhead prices.
- Decree 929/2013 determines a new investment regimen. It aims to incentivize the alliance between national and international investors. It allows under some conditions the exportation of part of the hydrocarbon. In this scenario it may appear two different wellhead price national and for exportation.

Resolutions

- Resolution MPFIPS (Ministerio de Planificación Federal, Inversión Pública y Servicios) 208/2004 homologates the agreement for the framework for normalization of wellhead gas prices.
- Resolution ENARGAS (Ente Nacional Regulador del Gas) 3689/2007 establishes the specific charges according to the Resolution MPFIPS 2008/2006. The specific charge aims to pay investment in new transmission infrastructure.
- Resolution SE (Secretaria de la Energia) 752/2005 defines an agreement of the wellhead gas prices normalization for big consumers.

- Resolution SE 599/2007 homologates the agreement with producer of natural gas establishing wellhead prices and volumes to face national demand.
- Resolution SE 24/2008 creates the gas plus program. It allows different wellhead pricing mechanisms for the fields that needed higher investment provisions.
- Resolution SE 1031 /2008 modification in the gas plus program.
- Resolution SE 1070/2010 complementary agreement for the resolution SE 599/2007. It redefines the consumers' classification and defines the criterions for the allocation of the found of the 'Fiduciario' Program.
- Resolution SE 695/2010 modifications of some eligibility criterion for the gas plus program. There are government explanatory notes related to this resolution, Nota SE 4663/2010, Nota SE 4389/2011, Nota SE 0202/2011.
- Resolution SE 172/2011 determines the extension of the agreement established in the resolution SE 599/2007. It means temporal extension to the wellhead prices defined in the agreement with producers for 2007-2011. It means that wellhead gas prices were not changed since the agreement until 2014.
- Resolution SE 1445/2012 Resolution SE 226/2014 determines the new wellhead gas prices for the services of compressed natural gas.
- Resolution SE 226/2014 determines the new wellhead gas prices for the different fields and use. It defines also incentives for the decrease of gas consume as it give discount in the tariffs for consumers decreasing their consume if compared with the last years.
- Resolution ENARGAS 2851/2014 approves the new tariffs for final consumers. It changes the final price according to the wellhead price defined by the resolution SE 226/2014.

2.6.11 Main non-price provisions of regulation tied to the price control

It is possible to think of two non-price provisions in the Argentinean regulation. First, the obligations to face priority demand, which is the condition for a producer to be able to sell gas under gas plus conditions, which means higher prices. Second, the investment charges paid by consumers in the last revision, April 2014, which gives incentives to players to decrease their consumption level. There is a discounted tariff for consumers whose consumption decrease by more than 20%, and also for consumers decreasing consumption between 5% and 20%. The decrease of gas consumption is measured with respect to the last year. The relation between full tariffs and tariffs with discount is given below:

	Residential	Large consumers
% discounted tariff (tariff for consumers decreasing it consumption in 5 - 20%)/ full tariff	25%	52%
% discounted tariff (tariff for consumers decreasing it consumption in 20%)/ full tariff	71%	76%

As observed in the table above, if residential consumers decrease 20% with respect to its last year bill, she would pay 25% of the full price. In the case of large consumer, this discount is lower and the consumer would pay 52% of the full tariff. If the consumer decrease is between 20% and 5% of its previous consumption, the residential and large consumer will pay respectively 71% and 76% of the full tariff.

2.7 Europe[41]

2.7.1 Introduction

This Section and the following two discuss whether, by whom and how prices along the gas value chain are regulated in Europe. We refer to the price of the commodity only, network tariffs are not within the scope of this report. First we provide a general overview of Europe and then we present three case studies: Italy, France and the Netherlands.

2.7.2 Overview of gas pricing regulation in Europe

Gas prices along the value chain are mostly liberalised in Europe. This is the result of the EU Energy Package liberalization measures[42]. Such measures should also apply to the member countries of the Energy Community[43], although with an extended time schedule for implementation. At the wholesale level, the EU liberalization process brought about the principle of market liberalization and introduction of competition on a free single market by eliminating entry barriers for newcomers, allowing third party access to infrastructure and requiring the unbundling of the network from energy suppliers. At the retail level, the principle of free supplier choice for end consumers was introduced: the Second Energy Package in 2003 had already set the deadlines for

[41] Sections 2.7, 2.8 and 2.9 have been drafted by Beatrice Petrovich.

[42] The European legislation on the creation and development of the electricity and gas single market is grouped into three different Packages. The First Energy Package was issued in 1996-8 and comprises: Directives 96/92/EC for electricity and 98/30/EC for gas). The Second Energy Package was issued in 2003 and includes: Directives 2003/54/EC for electricity and 2003/55/EC for gas, Regulations 1228/2003/EC for electricity and 1775/2005 for gas. The Third Energy Package was issued in 2009 and includes: Directives 2009/72/EC for electricity and 2009/73/EC for gas, Regulations 713/2009, 714/2009, 715/2009 for the creation of Agency of the Cooperation of Energy Regulators (ACER) electricity and for gas, respectively. EU Member States were obliged to transpose the 3rd Package into national law by March 2011.

[43] Contracting Parties of the Energy Community are: Bosnia and Herzegovina, Serbia, Montenegro, Kosovo, FYR of Macedonia, Albania, Ukraine and Moldova. In the area of gas, the Contracting Parties of the Energy Community implement the Third Energy Package legislation since 2011. With the exception of Article 9 (Unbundling of transmission systems and transmission system operators) and 11 (Certification in relation to third countries) of Directive 2009/73/EC, the general implementation deadline is 1 Jan 2015. For Contracting Parties of the Energy Community, the deadline for the market opening for households is 1 Jan 2015. Whilst the general implementation deadline of market opening for non-households was set for 1 Jan 2008, it is 1 Jan 2013 for Moldova and 1 Jan 2012 for Ukraine.

the full opening of gas retail markets, namely July 2004 for non-household customers and July 2007 for households[44].

The EU explicitly chose to regulate network access rather than pricing. The rationale behind the full market opening - and avoidance of price regulation- is that it generates benefits in terms of efficiency gains, price reductions, higher standards of service and increased competitiveness.

Nonetheless, the European legislation also ensures protection of small consumers in a fully open market by setting service obligations on suppliers and allowing some form of price regulation.

More specifically, a set of commercial obligations are imposed upon suppliers: obligations to connect users, to ensure continuity of service and stability of pressure in the grid, to adopt transparency in prices, fairness in commercial clauses as well as regular frequency of invoicing, to respect the maximum length of time to switch supplier, to provide reduced prices to low-income customers and not to disconnect vulnerable customers[45] in critical times.

Additionally, the legislation allows that some retail prices may be regulated for consumer protection aims, on a temporary basis[46]. In fact, Member States may impose public service obligations which may relate also to the pricing of supplies, on the ground of the general economic interest, provided that such obligations are clearly defined, transparent, non-discriminatory, verifiable and able to guarantee equality of access for all EU gas companies to national consumers.

According to CEER[47], as of January 2012 in roughly half of the EU Member States, regulated end-user prices exist, namely Belgium, Bulgaria, Cyprus, Denmark, France, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Northern Ireland, Poland, Portugal, Romania, Slovakia and Spain. Protected customers who entitled to regulated end-user prices are mostly households, closely followed by the small businesses, whereas medium and large businesses as well as gas intensive gas consumers are less frequently protected. In particular, Bulgaria, Denmark, France and Poland extend regulated prices to all end-users, though. Retail regulated gas prices, according to CEER, will continue to stay regulated in most cases in the near future. In fact, as of January 2012, only six countries (Denmark, Ireland, Poland, Portugal, Romania, and Slovakia) have plans to phase out regulated gas prices, and concrete action was taken only in the case of Portugal and Ireland.

While regulated retail prices are quite common in Europe, there are few exceptions to the price liberalization at wholesale level. The price for domestic gas production in Poland, Bulgaria and Hungary as of 2013 was regulated on an irregular basis, mostly in response to political/social needs. In the last two cases, there have been complaints that prices may have been set below the cost of service. Also Romania still has regulated pricing for domestic production. Some form of

[44] Household customer means a customer purchasing natural gas for his own household consumption; non-household customer means a customer purchasing natural gas which is not for his own household use.
[45] Member States have different understandings of what a concept of vulnerable customers entails.
[46] Ruling of the European Court of Justice, Grand Chamber, 20 April 2010, case C-265/08.
[47] CEER (2012).

regulated pricing also remains in Croatia, the latest country that has entered the European Union, and in all Energy Community signatory parties.

2.7.3 Trends in the pricing of internationally traded gas in Europe

Although the pricing of internationally traded gas (as opposed to domestic gas) is not the main focus of this Report, it is worth discussing here the main trends in the pricing of gas which crosses borders in the liberalized European market, as they are key to understand the evolving features of price regulation in Europe.

Wholesale price formation mechanisms changed rapidly in Europe in the last 10 years, reflecting the change in procurement strategies.

In the non-liberalized era, European wholesalers (being usually the national monopolists) procured virtually all gas volumes through long term gas purchase agreements signed directly with the main producers/exporters. Such contracts typically contain a take-or-pay clause applying to a high share of the total contractual quantity (90-80%) and offer flexibility as they allow for changes to the daily supplied quantities (nominations). The pricing details of these contracts were strictly confidential, however they generally foresaw an import price updated on a monthly or quarterly basis as the result of a formula composed of a base price (also known as P0) and an escalation clause. The latter was linked to the price of competing fuels, typically crude oil, gas oil and/or fuel oil (in some cases coal price). More specifically, the price escalation clause was defined as the weighted average over twelve/nine/six month moving averages of the monthly quotations of selected oil crudes and products, with the weights reflecting the importance of such products in the fuel mix of the destination countries. The adoption of a moving average aimed to smooth and delay the impact of monthly highs and lows.

This price formation mechanism is known as oil indexation (or oil price escalation). Its rationale was that natural gas initially was not widely adopted as a fuel, and had to compete (on a net useful energy basis) with other fuels, mostly oil derivatives, to be chosen by customers. Gas producers aiming to conquer shares in the energy mix therefore created a formula to ensure a reselling price for the “new-comer” that should remain competitive over time against other already established energy sources. This model was first adopted for international sales of Dutch gas and later adopted by all exporters into Europe.

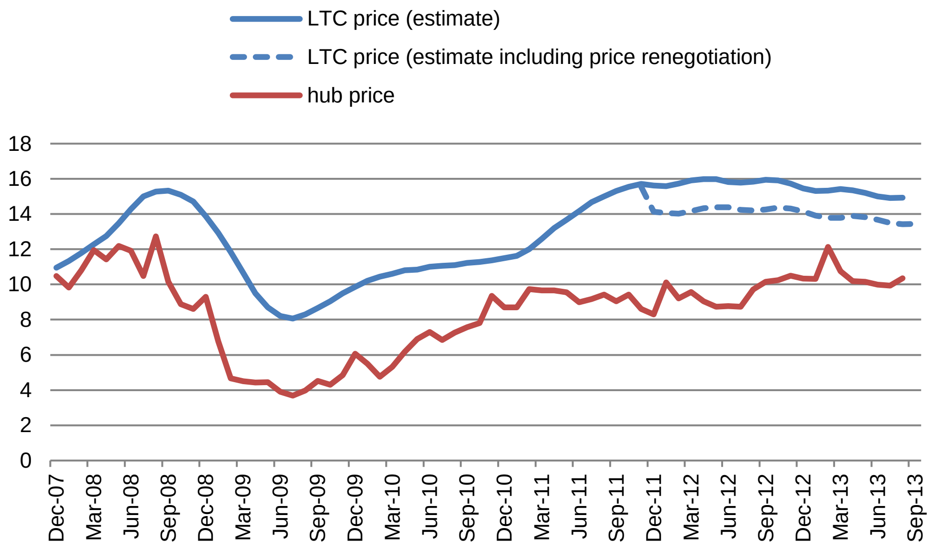
The liberalization process, as well as changing market conditions, led to a shift away from this traditional paradigm based on oil indexation.

As a consequence of pro-competitive measures for gas at EU level and the gas glut triggered by the demand slow-down, oversized take-or-pay obligations and the surge of LNG supply to Europe in the 2008 to 2011 period, liquid wholesale market places emerged, starting from Great Britain in the ‘90s and then developing over Continental Europe as well, although with marked geographical differences. In such markets (also known as “gas hubs”) the commodity is traded between multiple participants over a variety of different standardised products differing only on the delivery period (day ahead gas, month ahead gas, summer gas) and the price for gas is determined by the interplay between supply and demand (so called "gas-on-gas competition" pricing).

As gas could be bought at the hub without direct relationship with producers, along with long term contracted gas, wholesalers began to procure gas also on the wholesale markets, introducing the so called "spot gas procurement" in their portfolios.

Around 2008-9 hub prices (often simply referred as "spot gas prices") became considerably lower than those of oil-indexed long term contract prices (Figure 2.7.1).

Figure 2.7.1 - Hub price and long term contract price in Europe ($/MMbtu)



Note: hub price = TTF day ahead monthly average; LTC price (estimate) = estimate for European long term contract price, Italian Gas Release 2007 formula; LTC price (estimate including price renegotiation) = estimate for European long term contract price, Italian Gas Release 2007 formula with a 10% rebate.

Source: Platts

The unprecedented downwards pressure on spot prices for gas was driven by the collapse of demand due to the crisis, the greater availability of LNG, the new self-sufficiency of the USA due to shale gas, as well as liberalization measures, notably the opening -up of transport networks and fostering transport capacity accessibility on many borders.

This situation lasted until today, with only very short periods of convergence between oil indexed and hub based prices. It prompted a number of buyers committed to the traditional long term purchase agreements to ask for a price cut in their contracts[48]. Buyers asked for greater alignment of long term contracts to hub prices, which came to be regarded as a reliable reference for the "fair" value for gas, also for resale prices on their national markets, albeit not by traditional suppliers. Price disputes boomed and most supply contracts to Europe were eventually

[48] Traditional long-term contracts (sale and purchase agreements) explicitly assumed the purpose of making gas prices competitive on destination markets and they therefore contained clauses which allowed for renegotiation if they became uncompetitive as a result of unexpected market changes.

renegotiated, in some cases after the intervention of an external arbitration. As a result, rebates in the base price were granted and escalation clauses amended, to the point that long term purchase agreements started to use hub price indices to determine the contract price, rather than competing fuels indices.

Currently, in Europe, requests to introduce an explicit link with the prices that are formed on European gas hubs are on the increase; Europe's gas suppliers are putting up varying levels of resistance to change the traditional structure of pricing formulas, however Russian and Algerian suppliers are reluctant to give up with oil-indexation. As opposed, new contracts for gas supplies in Europe, both via LNG and pipeline, show a decided preference for indexation to hub prices.

Despite opposition from major gas exporters, the result of the renegotiations is a growing degree of hub indexation at the expense of pricing formulas linked to oil for the wholesale supply of gas to Europe. Precise statistics however are not available as there is little transparency over pricing decisions. The situation nevertheless remains unequal in different areas of Europe. The degree of spot indexation in North West Europe is 80% (in the United Kingdom in particular it seems that the last oil-linked contract was signed in 1995), which falls to 50% in Central Europe and just 15% in Mediterranean Europe, while it is practically non-existent in South East Europe[49].

Although hub indexation does not necessarily imply short-term supplies, procurement strategies are moving towards shorter-term supply contracts (from one to three years), which however may feature less flexibility compared to the old style take-or-pay oil-linked contracts.

The change in gas procurement strategies poses important challenges for price regulation. In fact, European Regulators aim to allow the coverage of costs incurred by a supplier when setting the end user regulated prices. Therefore, correctly estimating the supply procurement costs often plays a key role in the determination of regulated prices. Traditionally the cost of gas included in regulated prices has taken oil-linked long term contracts as a benchmark and hence has foreseen indexation to oil product prices, rather than gas prices formed on the marketplaces. The transition to the new supply strategies and the growing degree of hub indexation at the expense of oil-linked formulas in long term contracts spurred a process of re-designing the structure of regulated prices, which, in some cases, brought about an actual price reform, as it was the case in Italy. Albeit the relatively fast pace of change in European portfolio strategies, the transition toward the new paradigms of gas pricing had to be gradual. Step-by-step change was adopted also to take into account differences among different suppliers when more than one company supply the users eligible for the regulated prices; compensation measures has been adopted for suppliers, as it was the case in Italy. Additionally, Regulators faced some difficulties in finding a reliable "spot" benchmark in those countries where the national gas hubs are not considered enough mature and

[49] Source: IGU (2014). The regions referred to defined by the IGU are as follows: North West Europe (NWE) is composed of Belgium, Denmark, France, Germany, Ireland, Netherlands, United Kingdom; Central Europe of Austria, Czech Republic, Hungary, Poland, Slovakia, Switzerland; Mediterranean Europe is composed of Greece, Italy, Portugal and Spain; South East Europe is composed of Bosnia, Bulgaria, Croatia, Macedonia, Romania, Serbia and Slovenia.

reliable yet, often they resorted to indexing against a market different from the national one. The Dutch TTF, which is by far the most liquid marketplace for gas in Europe, was taken as a reference in Italy and France for instance. Another concern generated by the transition to market pricing is price volatility, as gas prices are more volatile than the indexes traditionally adopted in the oil price escalation.

In fact, the scope of end user price regulation may be even larger than reported in the latest official enquiries. In a few countries where local governments actually controls locally dominant suppliers (like Germany's *Stadtwerke* or municipal companies) it is likely that some price control is informally exercised, at least as moral suasion to avoid sharp increases.

Moreover, dissatisfaction with liberalized retail markets appears on the rise, even in the most open and early liberalised markets, like the UK. In this country, an official inquiry has lately been launched about the market power of the largest suppliers, known as the "Big Six", which control over 90% of the market. Whereas this is not likely to reintroduce formal controls, this evolution may at least discourage further removal of controls where they are still in force.

In any case, these controls are mostly applicable to small customers. Larger ones, notably power generators, are fully involved in the free market, and are widely seen as beneficiaries of the liberalisation, as it prevents cross subsidisation of smaller ones.

2.8 Italy

2.8.1 Scope of price regulation

In Italy, import prices, wellhead prices as well as wholesale prices are fully liberalized, being the outcome of bilateral negotiations between the parties or the result of the interplay between demand and supply on the wholesale market.

Price regulation concerns only retail prices, although to a limited extent. In fact, gas retail prices were fully liberalized since the 1st of July 2003, following the implementation of the First EU Energy Package[50] and anticipating the mandatory deadline set by EU law. However, exceptions to this general rule are allowed on the ground of consumer protection. In fact, regulated retail prices are currently in place only for protected gas end-users (also known as "safeguarded gas end-users"), who have the right to opt-out of the liberalized market and opt instead for regulated prices (also known as "reference price conditions") set by the independent Energy Regulator. As of July 2014, only households and residential buildings consuming less than 200 thousand cubic meter per year (mcm/y) are eligible for the regulated retail gas prices. In 2013 a law made the conditions for being protected consumer stricter; before 2013 non household users consuming less than 50 mcm/y and public service users were also eligible for the regulated retail prices.

[50] Legislative Decree n. 64, 23 May 2000.

As of 2013, about 74% of the Italian gas customers were under regulated prices, while in terms of volumes, gas sold at regulated prices represent 23% of the total[51].

Reference price conditions for protected consumers are expected to set a maximum fair price level. Unlike in the Italian power sector and in other countries, there is no single buyer to supply protected consumers: as far as protected consumers are concerned, all the gas retail suppliers are bound to include the regulated reference prices in their commercial offers along with their free market sale offers.

2.8.2 The legal basis for the regulation

The legal basis for the regulation of the retail gas prices for protected consumers is a 2007 law[52], entitling the Italian Energy Regulator with the power to define 'reference prices' for the sale of gas to "protected" customers, based on the actual costs of the service. The Italian legislator, when implementing the Third Energy Package[53] in 2011, confirmed this provision and specified that the Regulator should do this on a transitory basis.

In the past Italian suppliers appealed against the power of the Regulator to set reference prices arguing that it was a breach of Community law requiring the full opening of gas retail market by 1 January 2007 for household consumers. The European Court of Justice[54] rejected the argument and ruled that national price regulation through the definition of 'reference prices' was not a breach of EU law provided that such intervention pursues a general economic interest, features proportionality, holds for a period that is limited in time and it is characterized by transparency and non-discrimination. According to the Italian Courts, the regulated prices set by the Italian Regulation meet these criteria. Currently, regulated prices for protected consumers still exist, although there is a tendency towards narrowing the perimeter of users allowed to stick to the regulated price. A debate on whether to maintain this form of price regulation is currently going on, but the Regulator has no explicit plans to phase out regulated prices.

2.8.3 Who is the regulator and what is the relevant authority for price update

Regulated prices for small residential gas users are set by an Independent Energy Regulator, who sets determination criteria (pricing methodology) by issuing resolutions and also is responsible for price update. A consultation process is adopted to foster the transparency and inclusions of all stakeholders' interests. When the need for a relevant change in the design of protected gas prices arises, the Regulator usually issues a first publicly available consultation paper illustrating broadly its intentions and, usually, one or more proposals. Stakeholders are called for participation in the consultation process and may reply to the consultation paper issued by the Regulator within a

---

[51] AEEGSI (2014), P.156.
[52] Decree-Law n.73 , 18 June 2007 converted into a Law, after amendment, by Law n. 125, 3 August 2007.
[53] Legislative Decree n.93, 1 June 2011.
[54] Ruling of the European Court of Justice, Grand Chamber, 20 April 2010, case C-265/08.

predefined timeframe, then the Regulator issues a second consultation paper taking into account received feedback. Final criteria often results from compromises.

Unlike network tariffs, which are issued for fixed regulatory periods, there is no schedule set in advance for the review of the protected price design.

The key principles inspiring the decisions on price regulation are:

- Stability of decision principle, which translates into changes put forward gradually
- Cost reflectiveness
- Incentives towards efficiency, which translates into the identification of costs incurred by an efficient market player, rather than the actual costs incurred by the supplier
- Economic sustainability both on the side of consumers and retail companies

Companies have the right to challenge AEEG resolutions in front of the administrative court (*Tribunale Amministrativo Regionale*, TAR). The administrative court sentences can be grounded both on the basis of merit (e.g. resolutions were unreasonably detrimental) and procedural arguments (e.g. lack of a proper motivation or missing consultation process). In fact, the issue of regulated end user gas prices has been a major source of litigation: a number of cases have been raised in the past, and many sentences have voided previous regulatory decisions. The TAR repeatedly confirmed that the price regulation is lawful but, even in presence of incentive mechanisms, should ensure the recovery of the actual costs. This is a crucial issue as the regulator often privileged incentive mechanisms over cost reflectiveness in the past, which has triggered the most important lawsuits (see Section 0 below).

2.8.4 The basis for the regulation and the structure of the regulated price

When setting regulated prices for the protected segment, the aim is allow the coverage of costs incurred by an efficient supplier, including both infrastructural costs and commodity procurement costs (cost of service regulation).

Accordingly, the structure of protected regulated prices foresees different components, encompassing all activities of the gas value chain: commodity wholesale procurement, transportation, storage[55], distribution and retail marketing[56]. Tariffs for transport and distribution are differentiated geographically and retail prices also for different user clusters.

The components reflecting the costs of retail marketing and distribution networks are fixed (expressed in € per year per user), while all others are variable (i.e. depend on consumed volumes).

[55] Storage component was eliminated since October 2013. According to the Regulator, the reason behind this decision is that, following the adoption of a 100% “spot” benchmark for the wholesale gas procurement component (See next Subsection), the remuneration of storage activity is already included in the winter-summer premium that is implicit in spot gas prices.

[56] On top of this, protected prices may include additional components aimed at financing some system costs, such as volume risk mitigation measures for regulated businesses.

Infrastructural cost components depend on network tariffs and the Regulator makes some assumptions in order to convert the fixed network charges into variable components[57]. The retail marketing component includes: costs related to customer service, information management costs including invoicing costs, costs for acquiring new customers such as promotion and advertisement (only starting from October 2013), costs of unpaid bills[58]; the corresponding values are assessed by the Regulator also on the basis of yearly data collection concerning a sample of suppliers. Determination criteria concerning the wholesale procurement component are presented in the bext Subsection 3.5.

All the components of the regulated end user price are cashed in by the supplier, except for the distribution component, which is collected by the supplier and then passed on to the distribution system operator.

2.8.5 Main criteria used for price adjustment and indexation

Here we focus on the wholesale gas procurement component of the regulated price, which is a single national one and is composed by:

- a pure "raw material" or gas cost component, being the value of the gas molecule located at point where the title is transferred from the wholesaler to the retailer, either the border flange or the virtual trading point[59];
- a component for other procurement costs such as operating costs, including the fair margin allowed to the wholesaler, and costs related to hedging and portfolio management[60].

The latter is assessed by the Regulator. No detailed criteria have ever been published for the determination of the fair margin and operating costs allowed to the wholesaler, anyway their joint level has been unchanged since 2009 and equals about 0.67 $/MMBtu[61], which over the 2009-2013 period corresponded to about 5%-8% of the whole wholesale procurement component of the regulated price. Costs relating to hedging and portfolio management were introduced in October 2013 and remunerate costs for the activities carried out by the supplier (directly or indirectly) to hedge the risk to procure on the wholesale market additional gas volumes compared to the planned ones, which may result for instance from exceptionally low winter temperatures. These

[57] More specifically the Regulator assumes a load factor of 25% for the exit transport capacity and a load factor of 90%. These values are set according to the Regulator's expert judgement and are subject to the consultation process.

[58] In order to assess bad debt costs, the Regulator refers to the "unpaid ratio", being the share of the bills due and unpaid two years after the invoicing date. Bad debt costs are hence assessed as the unpaid ratio times total revenues. "efficient unpaid ratio" equal to 1.94% of the whole revenues in 2013, which is less than the average sample level; the less performing suppliers were in fact ignored.

[59] First known under the acronym of QE and currently C_{MEM}. QE was the estimate of the price of gas at the Italian border flange, while C_{MEM}, currently in place, is an estimate of the price of gas already injected into the Italian high pressure grid (including entry costs to Italy, which is part of the transmission tariff).

[60] First known under the acronym of QCI and currently CCR. QCI was the estimate of the international transport costs plus fair wholesaler margin and operating costs, while CCR, currently in place, is an estimate of the non-commodity costs related to the procurement of gas on the wholesale markets.

[61] 0.47 €/GJ. An exchange rate $/€ equal to 1.37 $/€ is assumed.

values are assessed applying standard national criteria based on the Regulator's expert judgement and historical data.
The value of the gas cost component is updated on a quarterly basis. The cost of gas in the protected prices is based on a formula, which is designed to correctly reflect the efficient (rather than the actual) average import price62 to Italy. It is very important that the formula avoids the risk of being based on benchmarks which may be easily manipulated in their favour by suppliers to the Italian protected consumers, like those of national markets that may not be aligned with international ones. Explicit inflation indexes have never been adopted, as international prices are not related to domestic inflation.
The Italian regulatory approach consistently pursued the objective of incentivising efficient gas procurements by suppliers, notably by avoiding the pass-through of actual costs, and preferring the use of an objective cost-of-gas formula. The incentive consists in the fact that suppliers may keep any gain resulting from lower procurement cost with respect to the formula. However, they know that such gains could eventually be partly or totally transferred to end users. The reliability of the gas cost benchmark, in fact, is checked over time through constant monitoring by the Regulator.Inquiries are used to fine-tune the formula and to prove its robustness.
Such formula has evolved over time to reflect changes in supply conditions. Initially it was updated using an indexation basket including only oil derivatives, representing the prevailing fuels competing with gas in Italy. More specifically, the formula was such that the value of gas evolved consistently with the changes in an index defined as the weighted average over nine month moving averages of the monthly quotations of selected oil crudes and products, with the weights reflecting the importance of such products in the Italian fuel mix. The adoption of a moving average aimed to smooth and delay the impact of monthly highs and lows. The weights were:

- 49% light fuel oil (Gasoil);
- 13% Brent, which replaced in 2004 a basket of eight crude oils;
- 38% low sulphur fuel oil (LSO).

Following the shift away from oil-linked long term contracts and the spread of hub-indexation and procurement on the European "spot" markets (see Section 0 above), starting from 2012 the Regulator, prompted by a Decree Law[63], gradually phased out the link to oil product prices, which ended on the 30th of September 2013. As of July 2014, the gas cost in the protected gas prices is based exclusively on prices for the gas delivered at the Dutch wholesale market TTF, to which costs of transport to the Italian hub (PSV), as determined by the Regulator, are added. The TTF is chosen as it is by far the most liquid hub in Continental Europe. More specifically, the reference for the TTF price is the monthly average of daily OTC price assessments for the Q+1 product for

[62] The reference is to import prices as Italy is highly dependent on import, with a very small share of domestic production, which is nonetheless priced very similarly to imported gas.
[63] Decree Law n. 1, 24 January 2012.

delivery in relevant quarter at the TTF hub, referring to the second to last month before the relevant quarter, as published by a leading Price Reporting Agency[64].

The long term objective is to take the prices quoted by the Italian physical future exchange (MT-GAS) as a benchmark. MT-GAS was launched in the second half of 2013 but it was not used by any trader yet as of July 2014. The Regulator proposed and consulted on some criteria and thresholds to decide when (and whether) the Italian exchange becomes liquid enough to be considered a reliable (manipulation-free) price benchmark for the protected prices.

Instruments, such as price ceilings, are envisaged to protected consumers from hub price spikes but are neither fully determined nor in place yet.

2.8.6 The latest available price level for the main large consumers

In Italy, there is a lack of publicly available detailed information on gas pricing and price level for the main large consumers, who are free to choose their supplier on the liberalized wholesale market. This is due to the sensitiveness of information perceived by these consumers.

However, aggregate data are published on an annual basis by the Italian Energy Regulator. Latest available price levels are presented in Table 2.8.1.

Table 2.8.1 - Retail gas prices by demand sectors and annual consumption (thousand cubic meter) in 2013 in Italy

	Annual consumption (mcm)		
$/MMBtu	200 -2 000	2 000 - 20 000	>20 000
Households	15.02	13.93	-
residential buildings	16.92	12.80	-
Public service users	15.79	12.91	-
Tertiary	14.51	13.06	-
Industry	12.84	12.15	12.15
Gas to power	14.44	12.66	11.82

Source: AEEGSI (2014)

2.8.7 Main non-price provisions of regulation tied to the price control

The Italian Regulator regulates the quality of service for both protected and non-protected customers. For protected customers, these are mostly related to issues of safety, like gas odourisation, emergency intervention and pipeline leakage prevention; and to indices of customer service and satisfaction.

[64] Platts until September 2014. Then starting from October 2014 the benchmark will be computed based on ICIS Heren price assessments. Price assessments may slightly differ across provides. In fact, as OTC trades are concerned, there is no obligation for transparency in the disclosure of the prices of trades. In this context, one price discovery service that is used very much is that provided by specialist agencies (“price reporting agencies”), which furnish surveys of prevailing prices on markets, based on interviews with a panel of traders. These are increasingly accompanied by the calculation of the average weighted price of a certain number of transactions.

2.9 France

2.9.1 Scope of price regulation

In France, import prices, wellhead prices as well as wholesale prices are fully liberalized, being the outcome of bilateral negotiations between the parties or the result of the interplay between demand and supply on the wholesale market. Price regulation concerns only retail prices.

As of 1 January 2014 users consuming up to 100,000 MMbtu/year (no matter whether they are households or small businesses) are always eligible for regulated prices (*tarif réglementé*, TRV), while those consuming more than 100,000 MMbtu/year are not allowed to opt out the free market when they sign a new supply contract[65].

Until mid-2014, France was one of the very few countries (along with Poland, Romania, Bulgaria, and Latvia[66]) where regulated prices persist for large industrial consumers. However, in March 2014 the Government passed a plan for the progressive phasing out of price regulation[67] for non-household gas consumers. By the 19th of June 2014 all the consumers connected to the high pressure grid should buy gas at market prices. Non-household end users consuming more than 67,500 MMbtu/year (200 MWh/year) and non-household end users consuming more than 100,000 MMbtu/year (30 MWh/year) should choose a free market supplier by January 2015 and January 2016, respectively.

Any household who chooses a free market offer retains the right to return to regulated prices at any time. Only customers featuring a consumption level of 100,000 MMbtu/year are legally prevented from switching back to regulated prices.

In additional to this, there is a solidarity tariff applicable in situations of fuel poverty.

Regulated gas prices dominate the households and small businesses market in France. As of 31th December 2013, 75% of French consumers opted for the regulated prices, accounting for the 34% of total gas consumption in France[68]. More specifically, in 2013 77% of residential and 50% of non-residential customers were in the regulated regime (Table 2.9.1).

65 However users consuming more than 2.8 mcm/year can maintain the regulated prices if they opted for them in the pre-liberalization period.

66 CEER (2013), P.163.

67 LOI n° 2014-344 du 17 mars 2014 relative à la consommation, article 25, http://www.legifrance.gouv.fr/affichTexteArticle.do?idArticle=JORFARTI000028738295&cidTexte=JORFTEXT000028738036&dateTexte=29990101&categorieLien=id

68 http://www.cre.fr/marches/marche-de-detail/marche-du-gaz

Table 2.9.1. French Retail gas market structure as of 31/12/2013 (%)

	Residential		Non-residential	
	N.users	Annual Consumption	N.users	Annual Consumption
Regulated prices	77%	77%	50%	19%
Free market prices	23%	23%	50%	81%

Source: CRE (2014)

Only the incumbent suppliers (*fournisseurs historiques*), namely GdfSuez, Total Energie Gaz (Tegaz) and the local distribution companies (*entreprises locales de distribution*), such as Gaz de Bordeaux and Gaz Electricité de Grenoble, supply consumers who choose the regulated option. All other suppliers are referred to as alternative suppliers (*fournisseurs alternatifs*) and supply only free market consumers.

GdfSuez accounts for the majority of total selling to end users opting for regulated gas prices. In fact, the only important areas where the incumbent differs from GDF-Suez are the districts of Bordeaux, Strasbourg and Grenoble, which were originally supplied by local companies.

There is a public service contract between the Gdf and the French State.

2.9.2 The legal basis for the regulation

The decree n° 2009-1603 dated 18th December 2009[69] requires that the Ministry of the Economy and the Ministry of Energy decide on regulated tariffs, by accepting or rejecting a CRE proposal.

In May 2012 the European Commission once again called[70] on France to bring its legislation on regulated gas prices for non-household end-users in line with European Union law. The main argument against French price regulation is that regulated prices eventually set by the Government are artificially too low and discourage GDF Suez's competitors from entering the retail market.

2.9.3 Who is the regulator and what is the relevant authority for price update

Basically, regulated price is ultimately set by the French Ministries for Economy and Energy, after a proposal by the independent Energy Regulator CRE. In 2012 France, Spain and Hungary were the only EU gas markets where the government still has the final say on regulated prices[71], while the Regulator provides a consultative opinion only.

However, in practise the setting of regulated gas retail prices is a complex procedure. First, a cost formula is set for each supplier by the relevant Ministers after consulting with the CRE. This

69 http://www.legifrance.gouv.fr/affichTexte.do;jsessionid=76F8783A060DDB15F1C5CB2D116DD69F.tpdjo17v_3?cidTexte=JORFTEXT000021504554&dateTexte=20130806.

70 Infringement proceeding was opened in 2006.

71 CRE(2013), P.169.

formula specifies the gas procurement and non-gas procurement (i.e. infrastructural) costs for each supplier (GDF Suez is by large the most important one).
Then, a decree by the Energy and Finance Ministers, after a proposal by the CRE, sets the rate of change for regulated prices. It is therefore the Ministry who eventually sets the regulated price, also discretionally deviating from the objective application of the formula. For instance, in December 2011 under the existing formula the regulated prices should had gone up by 10%, but the Prime Minister opposed a 10% rise and preferred a 5% maximum. In the past, the Government had ruled for price freezes, for instance in autumn 2011, when the government of the day blocked a 6% increase cleared by the Regulator, and in 2012 when a government decree[72] capped GDF Suez's October 2012 price hike at 2%.
More than once in the recent past suppliers appealed against Government decrees setting the rate of increase in regulated prices and the State Council (Conseil d'Ètat), France's top administrative appeals court, overturned the government decisions on gas regulated prices. This happened in 2011, twice in 2012 and three times in the beginning of 2013. The State Council cancelled the Ministerial decrees setting the increase in regulated prices on the grounds that they did not fully cover GDF Suez's average costs[73].
Pursuant to the law[74], the Regulator shall carry out any consultation with energy market players that it deems useful before formulating its opinion or proposals, including those regarding regulated natural gas retail prices.

2.9.4 The basis for the regulation and the structure of the regulated price

The French regulated price allows the full coverage of costs (cost of service regulation), including both infrastructural costs and commodity procurement costs, incurred by the energy companies supplying users opting for regulated prices.
Infrastructural costs include the cost for the use of the grid (transport and distribution) and the cost of access to storage. The former is set by the Government after the proposal of the Regulator and is differentiated among different consumer classes, while the latter is set by the storage companies.
The procurement cost (*tariff de fourniture*) is added to the infrastructural cost component to make the regulated price that is set by the Ministry.

2.9.5 Main criteria used for price adjustment and indexation

Here we focus on the gas procurement component of the regulated price.
Gas procurement cost component is reviewed at least annually if necessary, in the past it has been updated on a quarterly basis and, since January 2013, on a monthly basis. Any change in this

[72] Decree 26th of September 2012.
[73] Conseil d'Etat 10 July 2012 decision.
[74] Article L.445-2 of the French Energy Code.

component of regulated price should be consistent with changes in the supplier's procurement costs. In fact, it should allow the full coverage of procurement costs. Suppliers may propose changes in the regulated price to the CRE, together with a justification of the proposal. The CRE either approves or rejects the proposal on the basis of whether the requested change mirrors an actual change in their procurement cost.

Supplier's procurement costs are assumed to be correctly represented by the procurement cost formula that is approved by the Energy and Finance Ministers after consulting with the CRE. More specifically, the procurement cost formula should provide an accurate estimation for GDF Suez's and other incumbent suppliers' gas procurement costs, otherwise, as repeatedly noted by CRE, this may jeopardise the offers from alternative suppliers as well as a fair comparison by end customers; moreover, the benefits from any improvement in procurement strategies should be transferred to end customers. The CRE regularly audits the adequacy of the formula with regard to GDF Suez's actual supply portfolio costs. In March 2009, the formula was published in order to increase the transparency. It is interesting to notice that this was actually seen as an important decision, and not a straightforward one: this shows how sensitive are any issues related to price gas formation.

Until 2010, the procurement cost formula was fully indexed to oil products, reflecting the structure of Gdf Suez's portfolio, featuring virtually only long term oil-linked contracts (see Section XX). The recent change in procurement strategies (see Section XX) triggered a progressive revision of the formula structure, supported also by the ruling issued by France's top administrative appeals court[75].

In 2011, the French Ministry of the Economy requested the Regulator to provide its expert judgments on actual GDF Suez's procurement costs so that a new formula could be envisaged. The CRE carried out an audit of GDF France portfolio to define the incumbent's costs[76]. Accordingly, the procurement cost formula was adjusted with the step-wise inclusion of a spot-related component, namely the monthly average of the forward products delivered at the Dutch TTF[77].

In 2011, wholesale hub prices accounted for 9.5%; this share was increased to 26% in January 2012, and to 36% in January 2013. In mid-2013 the share indexed on the wholesale natural gas market in the GDF Suez procurement cost formula was set at 46% and on the 1st of July 2014 the weight of this component rose to 60%

[75] On 29th of November 2012 the State Council (Conseil d'Etat) required the Government to come to a new decision on the criteria setting regulated sales gas prices.

[76] CRE press release, *CRE has released its report on GDF SUEZ's supply costs which it submitted to the Government on the 28 September 2011*, dated 24 October 2011, available at: http://www.cre.fr/en/documents/press/press-releases/cre-has-released-its-report-on-gdf-suez-s-supply-costs-which-it-submitted-to-the-government-on-the-28-september-2011.

[77] http://www.cre.fr/marches/marche-de-detail/marche-du-gaz

The latest decision was taken following the publication of the CRE's audit of GDF Suez' long-term contract portfolio in June 2014[78]. CRE concluded that gas hub pricing accounts for 60% of the costs, up from 45.8% in 2013, due to renegotiations of GDF Suez' long-term contracts, which now include more, and sometimes full, indexation to hubs. The CRE has also showed that the "gas-year-ahead" and indexing to prices recorded at PEG Nord (the most liquid French wholesale market) gained an increasing weight in the indexing of Gdf Suez's contracts. Accordingly, CRE recommended taking into account these facts in the formula. However, while the price of the gas-year-ahead product with delivery at TTF was added into the formula approved by the Government in July 2014, the PEG Nord prices were not included.

As of July 2014, the formula that sets the rate of change in the Gdf Suez's procurement costs, is the following[79]:

Δm = ΔFOD€/t*0.00546 + ΔFOL€/t*0.00431+ΔBRENT€/bl*0.05597+ ΔTTFQ€/MWh*0.11292 + ΔTTFM€/MWh*0.45572 + ΔTTFA€/MWh*0.02936 + ΔUSDEUR*1.16332

Where:

- FOD€/t : light fuel oil with 0.1 sulphur content quotation recorded over the eight month period ending one month before the date of the update, in €/tons
- FOL€/t : low sulphur heavy fuel oil quotation recorded over the eight month period ending one month before the date of the update, in €/tons
- BRENT€/bl : Brent crude quotation recorded over the eight month period ending one month before the date of the update, in €/barrel
- TTFQ€/MWh : quotation of the quarterly product delivered on the Dutch TTF in the quarter of the update, recorded in the one-month period ending one month before the quarter of the update, in €/MWh
- TTFM€/MWh: quotation of the monthly product delivered on the Dutch TTF in the month of the update, recorded in the one-month period ending one month before the month of the update, in €/MWh
- TTFA€/MWh: quotation of the annual product delivered on the Dutch TTF in the year of the update, recorded in the one-month period ending one month before the month of the update, in €/MWh
- USDEUR : exchange rate €/$ recorded on the eight-month period ending one month before the date of the update.

---

[78] CRE Press Release *La CRE publie son rapport d'audit sur les coûts d'approvisionnement et hors approvisionnement de GDF SUEZ*, dated 4 June 2014, available at: http://www.cre.fr/documents/presse/communiques-de-presse/la-cre-publie-son-rapport-d-audit-sur-les-couts-d-approvisionnement-et-hors-approvisionnement-de-gdf-suez.

[79] Arrêté du 30 juin 2014 relatif aux tarifs réglementés de vente du gaz naturel fourni à partir des réseaux publics de distribution de GDF Suez, http://www.legifrance.gouv.fr/affichTexte.do;jsessionid=DCF5BE7A22B36886B0A6189F49B5452C.tpdjo17v_3?cidTexte=JORFTEXT000029167907&dateTexte=20140701

2.9.6 Latest available price level for the main large consumers

Aggregate price data for industrial users are published by Eurostat. The French Energy Regulator refers to these data source. The latest available price levels for large industrial users in the 2nd half of 2013 in France are estimated by Eurostat, the EU's official statistical body, at 12.97 $/MMbtu for customers of up to 950,000 MMBtu/year and 12.69 $/MMbtu for larger users.

2.9.7 Main non-price provisions of regulation tied to the price control

The French Regulator monitors the quality of service for both protected and non-protected customers. There is no evidence of non-price provisions of regulation that are tied to the price control.

2.10 The Netherlands[80]

2.10.1 Introduction

From the early 1960s onwards, the Netherlands benefited from the exploitation of its large natural gas reserves. At the end of 1963, the first delivery of gas took place and by 1968 all municipalities and most households were connected to the national grid. Yet, Dutch gas was not only of influence in the national energy sector. The manner in which Dutch gas was exported to and marketed in neighbouring countries has been of decisive importance for the development of the mainland European gas market from the mid-1960s onwards. First of all, it permitted the construction of a trans-European gas transportation network that connected most of the main centres of consumption and thus laid the foundation for an integrated gas market. Secondly, it ensured the creation and expansion of a European gas sector which otherwise might have been thwarted by the over-supply of oil products in Europe at the time. Thirdly, it established the principles and patterns of an 'orderly' and controlled European gas trade. Despite adjustments arising from the emergence of new suppliers, the institutional framework and the principles that governed gas production, marketing and pricing and the distribution of the profits have prevailed until the turn of the century.

Since the late 1980s, the European Commission has pursued policies which seek to liberalise the energy sector. This process slowly gained momentum and in December 1997 the Council of EU Energy Ministers signed a Gas Directive to secure a gradual liberalisation process in European gas markets. Prior to this, in December 1995, the Dutch Minister of Economic Affairs had published his Third *White Paper on Energy Policy (EZ 1995)* including new liberal guidelines for electricity and gas policy. This not only anticipated a liberalized European energy market but was also a response

[80] This Section has been drafted by Aad Correljé of Technical University Delft.

to changing circumstances in the supply of energy, especially gas and electricity. These proposals implied a radical alteration to traditional Dutch gas policy.

This section examines the regulation of prices in the Dutch gas sector in the period preceding the liberalization post-1998. Subsection 2.10.2 describes the development of the Dutch institutional framework and natural gas policy since the early 1960s and subsection 2.10.3 provides an account of the main changes proposed in the White Paper on Energy Policy, the later elaboration thereof in a policy paper, *Gasstromen* and the proposals for a new *Gas Law* and a *Mining Law*.

2.10.2 Development of the economic and institutional framework

In essence, the economic and institutional framework of the Dutch natural gas sector has experienced a high degree of continuity over the post-1962 period. Nevertheless, the changing perceptions of the situation in the energy market, by 1974 and again by 1983, have induced a number of important adjustments. These are reflected in pricing decisions, in the origins of the gas purchased by Gasunie and in shifts in the volumes of gas sold to the several types of customers (Correljé et al 2003).

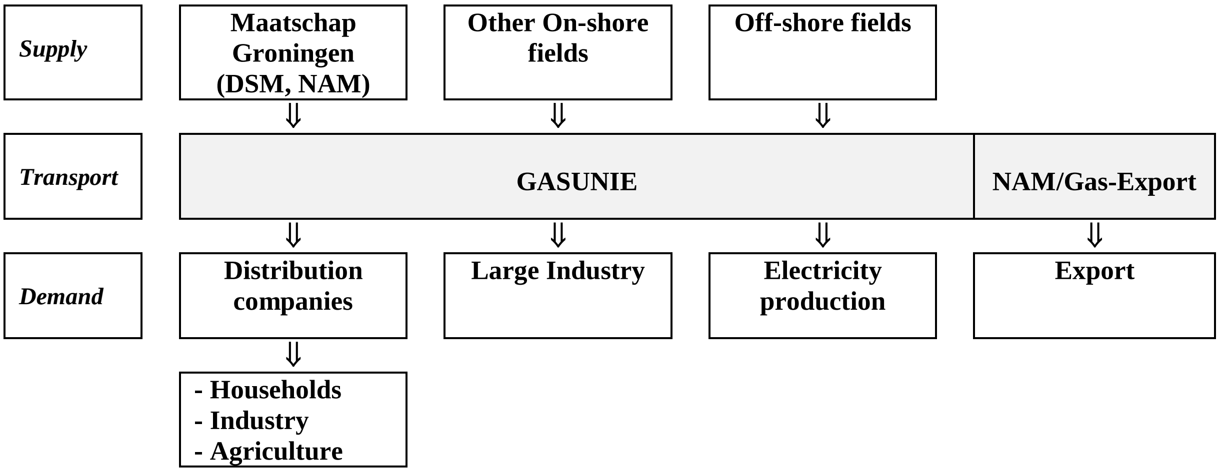
Three years after the discovery of the large Groningen gas field in 1959, the Minister of Economic Affairs, De Pous, established the main principles of Dutch gas policy in the *Nota inzake het aardgas* (Kamerstukken II, 1961-1962, nr. 6767). Firstly, in order to generate a maximum of revenues to the state and the concession- holders, Minister De Pous – on the advice of Exxon - introduced the "market-value" principle. The gas price to the various types of consumers was linked to the price of the most convenient substitute fuels, i.e. gas oil for small-scale users and fuel oil for large-scale users. Consumers would thus never have to pay more for gas than for alternative fuels. Yet the market value principle also ensured that they would not pay less and thus enabled the concession holders, Shell, Exxon and the Dutch state, to secure high revenues, compared to a situation in which the consumer price was related to the low production costs of gas from the Groningen field. An essential precondition for maintaining the 'market value' principle was that no alternative supplies of low-priced gas could reach the market - a condition which was fulfilled until recently in the Netherlands and until the early 1970s in Europe.

Secondly, the *Nota De Pous* stated that the exploitation of the Dutch gas resources should proceed in harmony with the sale of the gas, in order to avoid disruptions of the energy market. Thus, control over the supply of gas was seen as a government task. Yet, it was also stated that the exploitation and marketing of the gas reserves should be undertaken by the private concession owners, Shell and Exxon, in order to benefit from their knowledge, experience and financial resources.

In 1963, the Dutch government and both companies agreed upon a structure that effectively united these principles (see Figure 2.10.1).

- The holder of the Groningen concession, the *Nederlandse Aardolie Maatschappij* BV (NAM), a 50/50 joint venture of Shell and Exxon, undertook the production activities.
- Gasunie was established as a joint venture owned by the *Dutch State Mines* (DSM) (40%)[81], the Dutch State directly (10%) and Exxon (25%) and Shell (25%). Gasunie was given the responsibility to co-ordinate the commercialisation of Dutch natural gas resources on behalf of the State and the concession-holder NAM in the Netherlands. NAM/Gas-export - operating on account of Gasunie - was established to co-ordinate the sale of Dutch gas to foreign markets.

Figure 2.10.1 Structure of gas sector 1963 – 1974



- The state, via the *Staatsmijnen* (later Dutch State Mines or DSM), participated in the costs of the exploitation of gas from Groningen field and in the flow of revenues through a financing partnership, known as the *Maatschap* (40% DSM, 60% NAM)[82].

Thus, though direct state ownership/control of Groningen gas was avoided, the state's direction of the financial flows emerging from gas production and the management of the state's interest by DSM established a kind of arm's length relationship with the gas industry. State revenues were collected in several ways: first, through the dividends paid to the state by Gasunie and DSM; second, through corporate taxes (48%) on the profits of the Maatschap, Gasunie and DSM; and third, by a 10% royalty on the profits of the Maatschap (Wieleman 1982a, 12).

---

81 In 1972, in response to the increasing number of participations, a separate entity was established: *DSM Aardgas BV*. In 1989, *Energie Beheer Nederland BV* (EBN) replaced DSM Aardgas when DSM was partly privatized. EBN has remained a part of DSM, surrounded by a so-called Chinese Wall. The state pays DSM a management fee.

82 See Correljé et al (2003). Peebles (1980), Stern (1984), Kort (1991) and Ausems (1996) for a detailed account of the development of the institutional structure and the government's policy.

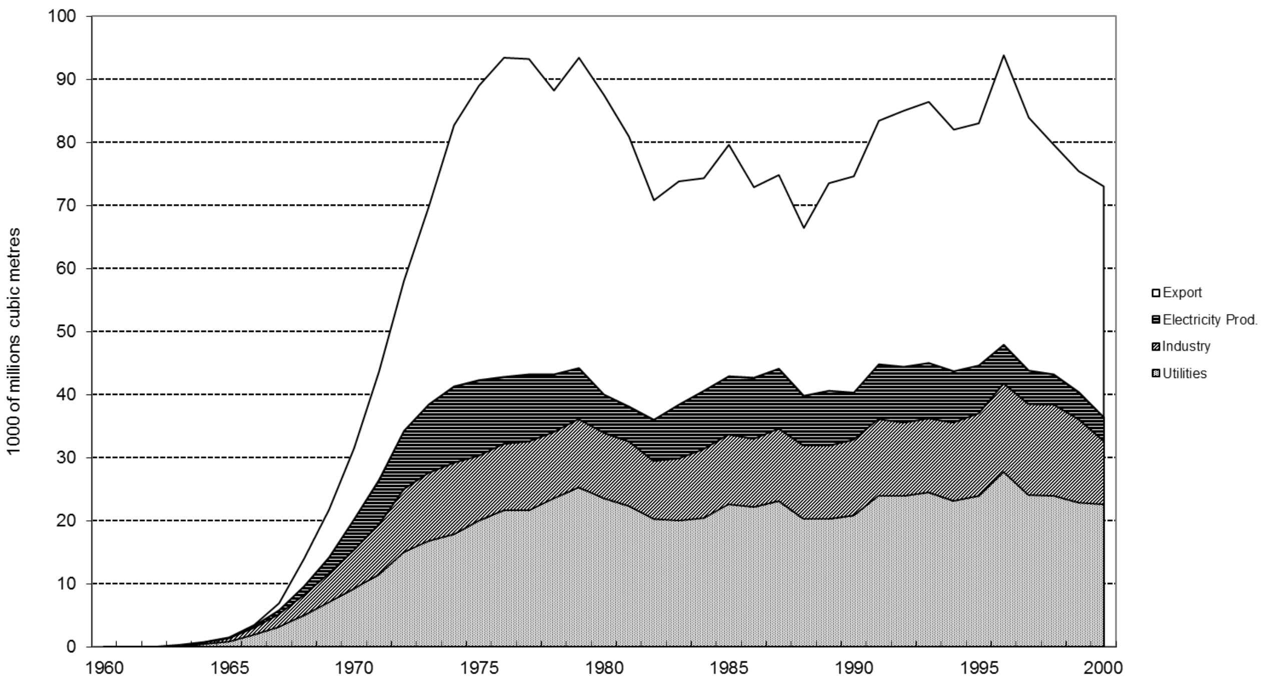
3 The older concessions, of which – most importantly – Groningen remained outside this new concession regime.

The role of the Ministry of Economic Affairs was confined to the responsibility for formally approving decisions proposed by DSM and Gasunie, in respect of prices, production and trade volumes and the construction of transport and storage facilities.
After its establishment in 1963, Gasunie handled virtually all natural gas produced in the Netherlands (apart from exports until the mid-1970s) plus most of the volumes that have been imported since the 1980's. Over the 1962-1974 period, gas policy was driven essentially by, on the one hand, the fact that the declared gas reserves in Groningen increased year by year and, on the other, by the perception that these reserves as declared should be produced and sold before the expected widespread use of nuclear energy would make the gas redundant. This objective was reflected in the pricing policy, in the rapid expansion of the national distribution grid and in the search for new markets in the Netherlands. Markets abroad were selected by NAM.
Yet, after 1974, government policy reduced the amounts of gas available for export because of fears of scarcity. In the inland market, Gasunie, after initial restrictions, sold the gas to all potential consumers (including electricity producers and large scale industrial users). In export markets, however, the level of border prices, through the influence of Shell and Exxon, restricted the sales of gas to so-called high-value markets, in which natural gas would not have to compete with cheap fuel oil or coal. As a consequence, inland sales increased rapidly and exports peaked in 1976, when commitments under contacts negotiated in the 1960s/early 1970s reached maximum volumes agreed (Gasunie 1988; Ausems 1996, p. 17). This is illustrated in Figure 2.10.2. In this period most gas originated from the Groningen field.
The successful exploitation of this field had induced further exploration activities elsewhere in the country and offshore. This inspired the development of a new oil and gas regime under which new concession owners were required to seek state participation through a joint venture with DSM, while Gasunie was given the right of first refusal regarding the purchase of the gas they produced, as was determined in new legislation governing exploration and production activities on the Dutch continental shelf and the mainland (Mijnwet Continentaal Plat, 23 september 1965, Staatsblad 428; KB 27 januari 1967, Staatsblad 24; Wet Opsporing Delfstoffen, 3 mei 1967, Staatsblad 258)[83]. Towards the end of the 1960s, small volumes of gas were being purchased from new on-shore locations (Figure 2.10.3).
The 1973/1974 oil crisis gave rise to the first revision of the Dutch gas policy, as documented in the first *White Paper on Energy* by Minister Lubbers. In the atmosphere of perceived energy scarcity at the time, the government primarily sought to achieve security of supply - defined as Gasunie's guaranteed capability to satisfy the foreseen demand of its customers for the following 25 years on the basis of the Dutch reserve position. In order to achieve this objective, on the one hand, consumption of gas was discouraged. Gas sales to the electricity production sector and large scale consumers were reduced and additional export contracts were prohibited. The increase in gas

[83] The older concessions, under which - most importantly - Groningen remained outside this new concession regime.

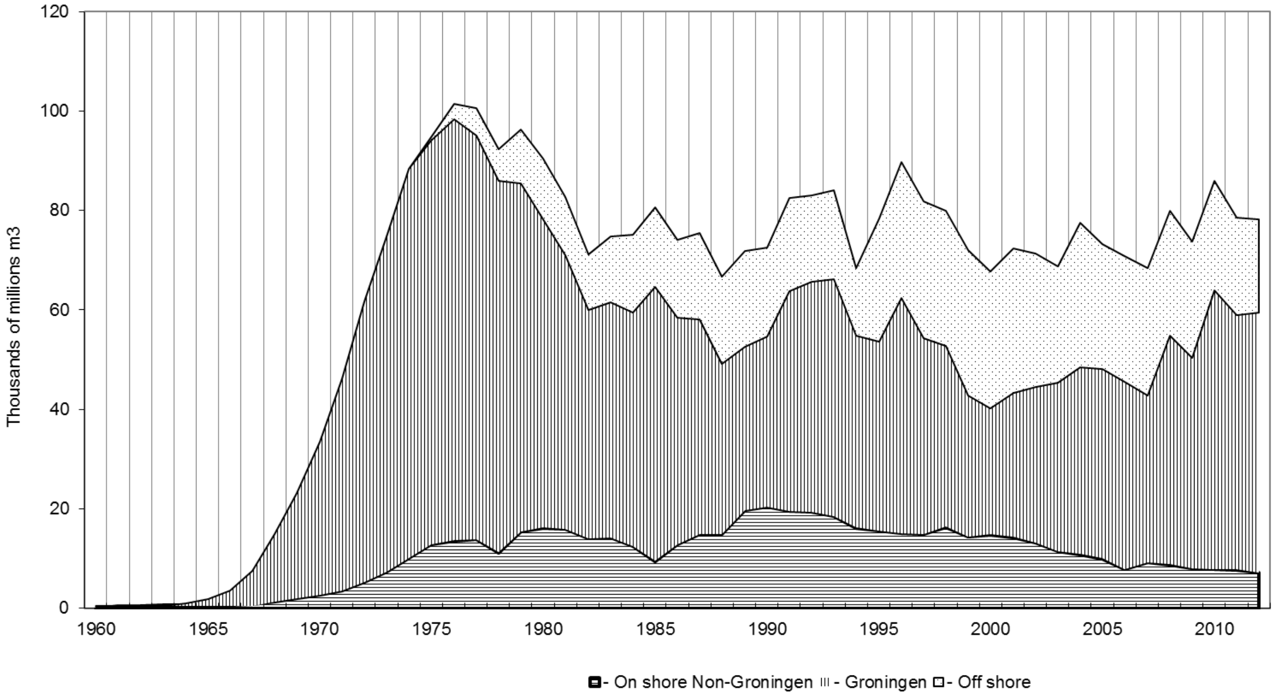
prices - linked with the price of oil - in combination with the economic recession at the time, brought about a decline in household and industrial consumption (Figure 2.10.2).

Figure 2.10.2 Natural Gas Sales by Gasunie/Gasterra



On the other hand, the sources of gas supply changed. The depletion rate of the large low-cost Groningen field was brought down while, at the same time, the search for and the development of new on- and off-shore deposits was encouraged by assurance given to the operators of these fields that Gasunie - having the right of first refusal - would purchase the gas they offered based on optimal depletion rates against acceptable prices. As a result, from the mid-1970s onwards, increasing volumes of gas were supplied from off-shore fields in the Dutch part of the North Sea. Altogether around 600 billion cubic metres (Bcm) (on-shore) and 500 Bcm (off-shore) of gas were discovered and taken into production (Oil and gas in the Netherlands 1996, p. 25). In fact, the large low-cost Groningen field became the marginal source. As a swing producer it supplied the volumes of gas that filled the gap between the increasing production of the small fields and Gasunie's falling total requirements. From around 85 Bcm in 1976, production from Groningen fell to 45 Bcm in the early 1980s and to only 30 Bcm in the early 1990s (Figure 2.10.3).

Figure 2.10.3 - Natural Gas Supply



The details of the agreement between the state and Gasunie and NAM have never been revealed. It can be assumed that it involved a trade-off between, on the one hand, the reduction of highly remunerative production at the extremely low cost Groningen field and, on the other, the fact that unit price paid by Gasunie for gas from the Groningen field was high enough to sustain both NAM's and the government's revenues. The link between oil and gas prices had already induced an enormous expansion of the revenues to Gasunie and the NAM (Tweede Kamer, zitting 1974-1975, 13109, nr.1), as a result of which the tax rate on gas from the Groningen field had been increased.

Following the 1979/80 oil shock and the *Second White Paper on Energy*, by Minister Van Aardenne, this policy was continued even more vigorously. Moreover, the Dutch state succeeded in negotiating higher export prices from most of the importing countries - albeit at the expense of sales which were stretched out over an extended period. Additional windfall profits were however now left untouched, in return for which Exxon and Shell agreed to the government's demands that they must reinvest the large profits originating from the second oil shock in expanding their activities in the Netherlands so as to benefit the Dutch economy.

Consequently, from 1974 onwards, Dutch natural gas functioned under two separate regimes: the regime for the large Groningen field, operated by NAM/de Maatschap, and the regime for the small on- and off-shore fields, operated by a variety of consortia (but dominated by NAM to which most concessions had been allocated). This is illustrated in Figure 2.10.4. Within the context of very high oil and hence gas prices from 1974 to 1985, the Dutch state collected large revenues from the exploitation of gas reserves. In the early 1980s, the aggregate state revenues from gas amounted to around 15 - 16% of total state income (exclusive of social security contributions). Currently, this share is around 4%[84].

Figure 2.10.4 Structure of gas sector 1975 - 1997

Supply	**Maatschap Groningen (DSM, NAM)**	**On-shore fields**	**Off-shore fields**	**Import**
	⇓	⇓	⇓	⇓
Transport	**GASUNIE**			
	⇓	⇓	⇓	⇓
Demand	**Distribution companies**	**Large Industry**	**Electricity production**	**Export**
	⇓			
	- Households - Industry - Agriculture			

From 1983 onwards, the objectives of energy policy were gradually adjusted to the then emerging perception of abundance in energy supply and to the falling sales of gas at both home and abroad. In particular, the decline in sales diminished the output of the Groningen field and therewith threatened the state revenues - badly needed to reduce the state deficit at the time. Thus, in 1983, Minister Van Aardenne lifted some of the restrictions on the use of gas in industry and electricity production and allowed the renewal of export contracts.

Towards the end of the 1980s, with low oil prices and an increasing supply of natural gas from Norway and the Soviet Union to Europe, Minister De Korte acknowledged the need to re-establish the status of Gasunie as a gas exporter. Nevertheless, the yardstick by which the government decided whether or not to authorize additional export contracts was kept in place. Gasunie had to guarantee that it would be able to continue to supply its inland customers for at least 25 years, on the basis of the Dutch reserve position and the estimated evolution of demand (Nota De Korte, 1989). In spite of this restraint, regular additions to proven reserves at this period subsequently allowed for new export contracts, particularly after 1989 (Figure 2.10.2).

2.10.3 Pricing of natural gas

As stated above, Gasunie's pricing policy was based on the principles set forth in the 1962 *Memorandum concerning Natural Gas*. In practice, this means that the market value was taken as the basis for determining the price of gas. The value of gas is based on the costs that consumers

---

[84] Calculations based on data from: *Oil and gas in the Netherlands*, 1985, 1996; *Jaarverslag De Nederlandse Bank*, 1991, 1994.

would incur if they were to use a substitute fuel. The gas price is in most cases linked to the price of oil products. For most industrial users, this means heavy fuel oil; for domestic consumers, heating gas oil. In both cases, the fuels used as the reference are the cheapest alternatives to gas. Although the importance of gas oil and fuel oil declined in the Netherlands over the years, these fuels nevertheless continued to provide benchmarks.

For example, on 1st July 1999 the (delivered) commodity price of gas to consumers supplied by Gasunie was calculated as follows:

Table 2.10.1 - Gasunie's price formula, third quarter 1999

For each m3 between:	Zone	Dutch cents/m3
0 and 800	a1	"domestic price" = 38.607
800 and 5,000	a2	"domestic price" = 54.587
5,000 and 170,000	a3	"domestic price" = 49.047
170,000 and 1 million	b1	P* x 38.2 + 7.35 = 25.218
1 million and 3 million	b2	P* x 38.2 + 7.35 = 24.508
3 million (m.) and 10 m.	c	P* x 38.2 + 3.60 = 20.758
10 m. and 50 m.	d	P* x 38.2 + 1.80 = 18.198
above 50 m. (plus transport)		P* x 37.2 -).80 = 13.075
(One m3 = 9.769 kWh = 27.8 MMbtu and 1 € = 2.204 NLG = 220.4 Dutch cents		

2.10.4 Prices to domestic and small commercial consumers

The threshold for to Domestic and Small Commercial Consumers is 170,000 m3 of 8,400 kcal (1.66 GWh) per year. The prices at which the distribution companies purchase from Gasunie are ultimately related to a formula (supervised by the Ministry of Economic Affairs).

This formula starts with the mean of the high and low FOB Rotterdam Platt's barge prices of gasoil in the half-year up to two months before 1 January and 1 July (e.g. the gas price for January to June is related to gasoil prices from May to October) converted to Dutch guilders (later Euros, 1 EUR = 2.204 NLG) using average monthly exchange rates against the U.S. dollar.

To the resulting guilder price were added excise duties of NLG 10.26/hectolitre (EUR 46.56/ m3), compulsory stock cost of NLG 1.10 per hectolitre of (EUR 5.90/ m3) and a distribution margin of NLG 100/ton (EUR 45.38/ton), giving a value known as G.

If G was less than NLG 550 (EUR 250)/ton, then 0.8 of G plus 0.2 of 550 (EUR 250) is taken to calculate a new G; between NLG 550 (EUR 250) and 750 (EUR 240) per ton, the actual G is used but if G is above NLG 750 (EUR 340)/ton, then 0.8 of G plus 0.2 of 750 (EUR 340) is applied.

G is then multiplied by 37.2 to give a price in Dutch (or Euro) cents per cubic metre (ct/m3) and a "market value" supplement of 1.70 (EUR 0.77) ct/m3. A price change during the year (i.e. at 1st July under the formula) was limited to a maximum of 3 1.36 c (EUR ct)/m3 after which it was "capped" at that level for the next period. So, the gas price followed oil prices with a delay.

This cap means that increases which would have been more than 1.36 cEUR/m3 can be carried forward, as was the case in January 2002, when the gasoil prices were lower than in the previous six months.

The price paid by the distribution companies is calculated by subtracting a margin from the Gasunie formula level described above. This margin is negotiated with the distribution companies, but we estimate that it is around 2.54 cEUR/m3, plus the standing charge. Within the total tariff, the purchase price of gas has to be passed through with no mark-up but non-gas costs (transport and distribution) are subject to maximum price control by the Ministry of Economic Affairs (later DTe). The following examples for the second half of 2002 show typical regional differences between the companies in Table 2.10.2.

Table 2.10.2 - Representative prices charged by Netherlands' LDCs, second half 2002

Company		**Standing Charges**	**Proportional Charges**
		EUR/year	cEUR/m^3
Essent	Noord	45.88	24.81
REMU,	Utrecht	35.01	25.41
NUON	Zuid Holland	114.52	24.75
ENECO	Midden Holland	60.10	24.52
Eneco	GMK	41.65	24.45
Eindhoven		40.23	23.85
Source: EnergieNed			
Prices include excise duty (Brandstoffenbelasting) of 1.06 cEUR/m^3 but not the eco-tax (REB). NUON's standing charges for the second half of 2002 were originally 67.66 EUR/year, but these were recently almost doubled (the amount shown above is after deduction of a special rebate of EUR 10.96/month for the months of September to December 2002.			

Both the standing charges and the proportional charges contain the transport and distribution elements, which are subject to the maximum price control by DTe. These elements can vary widely: for example in 2001 NUON's standing charge was 86% transport and 14% distribution while that of Essent Nord was 98% transport. REMU's proportional charges were 14% transport and 86% distribution, while those of ENECO Rotterdam were 93% distribution.

The averages of all 29 tariffs in the second half of 2002 were EUR 51.64/year for the total standing charge and 24.35 cEUR/m3 for the total proportional charge, including excise duty.

Gasunie's formula price on the same basis was 24.65 cEUR/m3 for the same period.

P* is the Platt's mean quotation for 1% sulphur heavy fuel oil in barges fob Rotterdam, averaged over the previous six months, plus NLG 48.00/metric ton and divided by 500. The U.S. dollar value is converted to Dutch guilders using average monthly exchange rates and the charge of NFL 48.00 allows for excise duty of NLG 34.24 and average transporatation costs within Holland of NLG 14.00 (rounded down to NLG 48.00). No account is taken of the "voluntary" charge of NLG 10.00/ton for compulsory stocks, which we understand is paid by most large fuel oil users. The value of P for the third quarter of 1999 was 195.79.

The prices in Table 2.10.2 above include taxes. Consumers supplied by Gasunie do not pay any MAP regional levies. In the three northern provinces of Groningen, Friesland and Drenthe, plus a small part of Overijssel, there is a discount of 0.85 ct/m3.

Following an agreement signed in 1994, all new gas customers are supplied by the distribution companies if their annual use is less than 10 million m3 (97.69 million kWh) per year and by Gasunie above this threshold. Existing customers (e.g. those of Gasunie below 10 million m3/year) remain subject to the pre-1994 conditions. We estimate that about 100 of the total of 250 consumers in Zone c (between 3 and 10 million m3/year) are still being supplied by Gasunie.

2.10.5 Prices to Small Industrial Consumers

The Gasunie formula for consumption between 170,000 and one million m3is

P = P* x 38.2 + 3.34 (cEUR/m3)

Where:

P* is the Platt's mean quotation for 1% sulphur heavy fuel oil in barges fob Rotterdam (P), averaged over the previous three months, plus EUR 22.00/metric ton and divided by 500(*). The U.S. dollar value is converted to Euros using average monthly exchange rates and the charge of EUR 22.00 allows for excise duty of EUR 15.54 and average transportation costs within Holland of EUR 6.35 (rounded to EUR 22.00). The value of P* for the fourth quarter of 2002 was 0.3446, compared with 0.2778 in the first quarter.

38.2 is a conversion factor from tons to m3

3.34 is a "market value" supplement for small industrial users

Thus the Gasunie formula price excluding tax is 16.50 cEUR/ m3 in the fourth quarter of 2002. The distribution companies' average price in this sector of the market is normally below the formula calculation (e.g. in 2001, by 1.03 cEUR/ m3)

2.10.6 Prices to Larger Industrial Consumers

Transport tariffs now apply above firm annual volumes of one million m3 of 8,400 kcal (there are no interruptible supplies to industry).

With the partial deregulation of the Dutch market in January 1999, tariffs for transportation and associated services (until end-2002 the so-called CSS system) have been published since then by Gasunie (since January 2002 by the Transportservices division, later GTS). The gas price in both the CSS and the new entry/exit system is made up of three main components: commodity, transmission and other services.

The commodity price is either calculated each quarter from the formula

P* x 37.4 - 0.363 (cEUR/ m3)

where

- P* is as defined above in Section 2.10.5
- 37.4 is a conversion factor from tons to m3
- 0.363 is a fixed discount, or at a fixed price, generally for a year (see example below), or at a price related to spot market levels of coal (mostly for power stations)

Our research has revealed the following types of pricing in the market in the period around 2000:

1. Gasunie's direct sales: no negotiation, either on the fuel-oil related price per quarter, or on the other alternatives.
2. Essent, Nuon and Eneco purchasing from Gasunie: final price can be up to 0.5 cEUR/m3 lower (usually achieved through careful attention to offtake patterns etc)
3. Essent and RWE Gas imports (from the UK and elsewhere): between 0.5 and 1.0 cEUR/m3 below the Gasunie commodity price, depending on the indexation formulae in purchasing contracts; we are of the opinion that such imports are almost certainly linked to Continental pricing and Euro rather than p/therm and the NBP
4. Other importers from Germany, Norway, etc (e.g. Duke), at discounts of up to 1.5 cEUR/m3, although we understand that some potential customers have doubts about security of supply and/or difficulties in obtaining adequate or correctly-located transportation capacity, especially because the DTe is unable to intervene to any extent

We have been able to examine a fixed-price contract for the year 2002 (dated 30 January) between Gasunie and an industrial consumer of 3.5 million m3 per year. This specifies a fixed commodity price of 11.13854 cEUR/m3, compared with the formula price of 10.02670 in the first quarter of 2002, i.e. a "premium" of 1.11184 cEUR/m3.

When the fixed price is compared with the average of the four quarterly formula prices in 2002 (11.18368 cEUR/m3), the consumer in this case had a price advantage of 0.04514 cEUR/m3, or 0.4%. It is thus very important for suppliers to estimate correctly how the formula price will move over the year, especially if they do not hedge their offers.

2.10.7 Prices to Power Stations and for Co-generation

Prices to power stations supplied by Gasunie were on the same basis as those to large industry until the end of 1998, except that the indexation (known as Pc) is based on a six-month period starting seven months previously, i.e. for July to September the P value is calculated from fuel oil prices from November to May (instead of January to June as for industrial prices).

There are also upper (+$4/ton) and lower (-$1/ton) limits to the value of Pc, which is first calculated from the mean of the high and low Platts quotations for heavy fuel oil, cargoes fob N.W. Europe (1% sulphur). If the mean of the high and low quotations for the same grade of fuel oil, barges fob Rotterdam, falls within the range as calculated above, then the barges value is taken as Pc; if it is higher or lower, then the upper or lower limits from the cargoes calculation is taken.

This calculation resulted in a Pc value of 185.80 for the third quarter of 1999, compared with a P of 195.79 for normal industrial consumers, giving a typical price of 16.42 ct/m3 including tax.

The special terms which existed for power stations until the end of 2000 have been abolished and from then onwards prices became subject to the Entry/Exit system rather than the old zonal structure with a special P value. However, from the beginning of 2001 gas to power stations has been exempt from the Brandstoffenbelasting (the REB did not apply because it is levied on electricity). Gas used in co-generation has been exempt from the Brandstoffenbelasting and the REB, provided that an efficiency of at least 65% (as defined by complicated rules) is achieved.

2.10.8 Other special prices

Prices of gas used mainly as feedstock by the chemical industry are normally about 1.00-1.05 cEUR/m3 below those to large industry, because of

- a rebate equivalent to the fuel oil excise duty on 70% of the volume (deemed to be the non-energy part)
- no brandstoffenbelasting on the non-energy part
- load factors higher than a typical large industrial user

Greenhouse growers using more than 30,000 m3 per year received special terms laid down in a tripartite contract between EnergieNed, Gasunie and the Produktschap Tuinbow (Greenhouse Growers' Association). Their prices were about 30% less than to commercial consumers of comparable volume.

There are special rules for greenhouse growers, who have regulated prices in two tranches: up to 170,000 m3/year and from 170,000 to 835,000 m3 (not 1 million m3). For the first quarter of 2002, for example, the prices have been set (excluding tax) at 15.53 cEUR/ m3 in the first tranche and at 15.04 cEUR/m3 in the second. These are the maximum controlled prices for the country as a whole; by distribution company they can vary by less than 1%.

These prices compare with an estimated 22.90 cEUR/m3 to domestic and commercial consumers in the first tranche and 12.91 cEUR/m3 in the second.

Greenhouse growers pay the full Brandstoffenbelasting but much less REB than other consumers, namely 0.165 cEUR/m3 for the first 5,000 m3, 0.077 cEUR/m3 from 5,000 to 170,000 m3 and 0.014 from 170,000 to 1 million m3. They also pay only 6% recoverable VAT instead of 19%.

Above 835,000 m3, greenhouse growers are subject to the Entry/Exit system, but with the above concessions on REB.

2.10.9 The liberalisation after 1995

By the end of 1995, the Minister of Economic Affairs, Wijers, proposed a number of changes designed to liberalise the organisation of the Dutch energy sector in his White Paper. This was followed in December 1997 by the specific paper on gas *Gasstromen* (EZ 1997) These changes originated in the wish to adapt the sector to future EU regulations and from the pressures from large energy intensive industry for lower energy prices (EZ 1995; SIGE 1995). In the electricity sector, however, liberalisation was also seen as an instrument to force efficiency upon the sector. This allowed the government to present the restructuring of the sector as an objective of 'national interest' (Correljé 1997). In the natural gas sector, the situation is much more complicated. As shown above, Dutch gas policy has always been associated with objectives such as the generation of state revenues, security of supply and at a later stage also protection of the environment. Hence, until mid-1996, the Netherlands was among the fiercest opponents of the several initiatives of the EU Commission for a liberalisation of the gas market.

The first actual alteration to the Dutch gas regime took place in 1994, when Gasunie's right of first refusal to Dutch gas producers was terminated, by accepting the EU Hydrocarbons Directive (RL 94/22/EG. PB, 1994, L164).

In 1999, a new Gas Law started the leberalisation of the industry, in line with the 1998 EU Directive:

- Customers obtained free choice regarding their gas supplier(s), with large consumers, accounting for around 46% of Gasunie's home market sales, explicitly allowed to seek alternative suppliers immediately[85]. In 2002, medium sized users, representing 16% of the market, followed. Small users were explicitly made dependent on the regional distribution companies[86], but they were allowed to shop around freely by 2007.

- New suppliers and traders were given the right of negotiated access to the transport and distribution networks.
- Gasunie and the distribution companies were required to establish Chinese walls between their trading and transport activities and to publish separate indicative prices for the services provided. Later on Gasunie was separated in Gasterra, as the commercial gas wholesale company, and Gasunie Transport Services (GTS), the regulated TSO.
- The Minister of Economic Affairs established a controlling agency DTe - within the Competition Authority (NMA) - to correct collusive behaviour and to guarantee the interests of the small consumers in particular.

The basic structure of the industry, with a key role for Gasterra and De Maatschap/NAM - including a cross shareholding - was maintained. This is because, as was argued, it provides advantages of scale and organisation and allows for the continued co-ordination of gas sales and purchases from Groningen and the small fields[87].

Thus on the demand side, notwithstanding the fact that initially only large consumers are allowed to negotiate with other suppliers, eventually all Gasunie's current customers will be free to 'shop around' for lower cost gas supply - either on an individual basis or as part of a gas buyers' consortium[88]. On the supply side, both internal as well as foreign suppliers had already been given the right to sell gas to others than Gasunie. Thus, with the new Gas Law, the combined monopoly-monopsony position of Gasunie has been legally terminated.

The more recent part of the Dutch experience falls in line with general European liberalisation, with regulated access to both transmission and distribution tariffs and legal unbundling of transport companies from suppliers[89]. Unlike several other EU Member States, the Netherlands have not maintained any gas price regulation.

Thanks to its natural resources, his long history in the gas industry, as well as the quick adaptation to a new regulatory framework, the Netherlands have managed to maintain a leading position in Europe, in spite of market integration forbidding any discrimination within the EU, based on

---

85 Dutch definitions are as follows: *large users* have an annual consumption of above 10 mln. m^3 annually; *medium-size* users, between 10 mln. and 0.17 mln. m^3; *small* users, less than 0.17 mln. m^3.

86 In the future, these distribution companies will be free to purchase their gas requirements from other (non-Gasunie) suppliers, provided that they present a robust *dekkingsplan* (plan of supply), showing their capability to supply their customers over a specified period (EZ 1995: 131, 132).

87 EZ *ibid.* (1998), pp. 18-22.

88 Until then, it was not determined by law that small - or any - consumers were tied to Gasunie. Yet, the fact that Gasunie was always able to underbid other potential suppliers *de facto* gave Gasunie the supply monopoly. It should be noted that, over the past ten years, the Dutch distribution sector went through a process of extensive vertical and horizontal concentration. Only a few large integrated companies now supply the country (Correljé, 1997).

89 The interested reader may consult Correljé (2005).

national borders. Indeed, the Dutch gas hub (known as Title Transfer Facility or TTF) has become the leader in continental Europe, is often seen as a pricing benchmark and has challenged the primacy of the British hub.

2.10.10 Summary of questions and answers[90]

1. Dutch price regulation covered wellhead, wholesale and retail prices.
2. Consumer price regulation distinguished power generation, medium and large industry, three segments of residential & commercial users, feedstock, and the greenhouse sector.
3. Prices were determined on the basis of established formulas, adapted at fixed half year intervals by Gasunie in coordination with the SEP (cooperating power producers) and the regional distribution companies, eventually approved by the Ministry of Economic Affairs. Overall competition control over the sector was carried out by the Competition Authorities.
4. Dutch price regulation covered wellhead, wholesale and retail prices, according to the market value principle for distinguished segments of national consumers, combined with cost plus remuneration for the distribution companies and the Gasunie transmission function, resulting in a netback price to the producers. A similar mechanism applied to export contracts, in which the extra costs of transmission beyond the Dutch border were deducted from the revenues.
5. The upstream part of the value chain received netback values.
    a. criteria for capital valuation; n.a.
    b. rates of return and their main component; not explicitly but part of the cost plus allowance for the transmission function in Gasunie and the distribution companies.
    c. depreciation rates; idem
    d. operational expenditure; idem
    e. use of benchmarking techniques; n.a.
    f. exploration costs and their evaluation criteria; n.a.
    g. depletion fees, royalties, or user costs; 10% royalty to the Dutch state, in addiction to profit sharing regimes: A (40%) for small fields, and B from 70 up 90% for gas supplied from Groningen, depending on the price level.
    h. social or environmental fees and subsidies; guaranteed off take of gas from the small fields, above supplies from Groningen.
    i. reference to competing fuels; Net back, based on cost plus and market value pricing.
    j. reference to international gas prices; n.a.
6. What are (were) main criteria used for price adjustment and indexation? Please outline in particular, as appropriate:

a. Adjustment frequency (if any) and trigger rule: Half yearly adjustments, with a capped pass through factor.

[90] Answers are referred to the Netherlands before full liberalization.

b. price indicators of competing fuels and/or market or other gas prices; For most industrial users, this means heavy fuel oil; for domestic consumers, heating gas oil.

c. inflation index or other macroeconomic indicator; n.a.

d. ceilings and floors; Only in the speed of adjustment of gas prices to changes in oil product prices.

e. role of incentive or performance –based regulation. n.a.

7. Please indicate the latest available price level for the main large consumers (power generation, industry, feedstock, local distributors), and specify the date of the quote; see above

8. How is (was) the structure of the regulated price for the main consuming sector? Are there…

a. Commodity charges only? Lump sum charge to consumers, including all costs.

b. Capacity related charges? Tariff structures established on the basis of consumer segment and maximum contracted annual off take.

c. Standing (fixed) charges? As an element in the pricing formula

d. Decreasing or increasing blocks? n.a.

9. What is the relevant authority for price update: Gasunie and Ministry of Economic Affairs. Pricing methodology is negotiated between Dutch government and Exxon and Shell, pre-1962.

10. What is (was) the legal basis for the regulation? Until 1998 the legal basis was the Policy paper covering natural gas, the Nota inzake het aardgas (Kamerstukken II, 1961-1962, nr. 6767). This was not a law. Moreover, relations with the oil companies were arranged under private law in contracts with DSM/EBN, representing the State.

11. What are (were) the main non-price provisions of regulation that are tied to the price control? Outline in particular, as appropriate:

a. quality of service rules; n.a.

b. production performances like available capacity, ramp-up, ramp-down, swing factors; Such aspects were incorporated in the pricing formula

c. take or pay clauses that may be subject to the regulation and related flexibility arrangements (e.g. make-up gas); Such aspects were incorporated in the pricing formula

d. price review clauses; Each half year.

e. destination clauses (by sector or country); Applied in (export) contracts to both sectors and countries.

2.11 Egypt

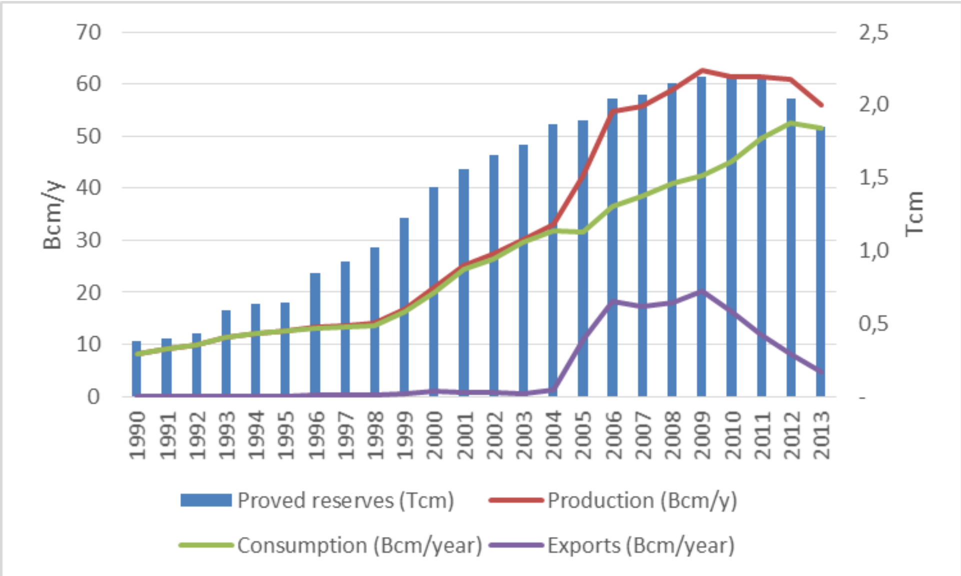
2.11.1 Introduction: the Egyptian gas industry

The Arab Republic of Egypt owns the 16th largest proved commercial reserves in the world (2040 Bcm) and is the 15th current gas producer (60.9 Bcm in 2012). The origins of its gas industry date back to the 1960s, but production has taken off mostly in the 1980s and 1990s.

Egypt has a complex and rather mature gas industry. It is dominated by National Companies, notably by The Egyptian Petroleum Holding Co. (EGPC) and by its subsidiary EGAS (Egyptian Gas Holding Co.), whereas the much smaller GANOPE is in charge of exploration and production in the South of the country (Upper Egypt). In particular, EGAS acts as a single buyer of natural gas from production, which is operated by the company itself and by a number of joint ventures involving oil& gas majors (notably ENI, BG, BP, Shell, Gas Natural) and several independents like Apache, Dana Gas and others.

Gas is treated in about 20 plants, of which three operate under a common carrier regime and are open to all producers on a negotiated basis. Treatment plants also separate condensates, the production of which amounted to 39.8 million barrels in fiscal year 2011-12[91]. Treatment plants are operated by EGAS and its subsidiary GASCO, as well as by JVs and private companies.

Figure 2.11.1 – Gas production, consumption, exports (left scale) and proved reserves (right scale) in Egypt



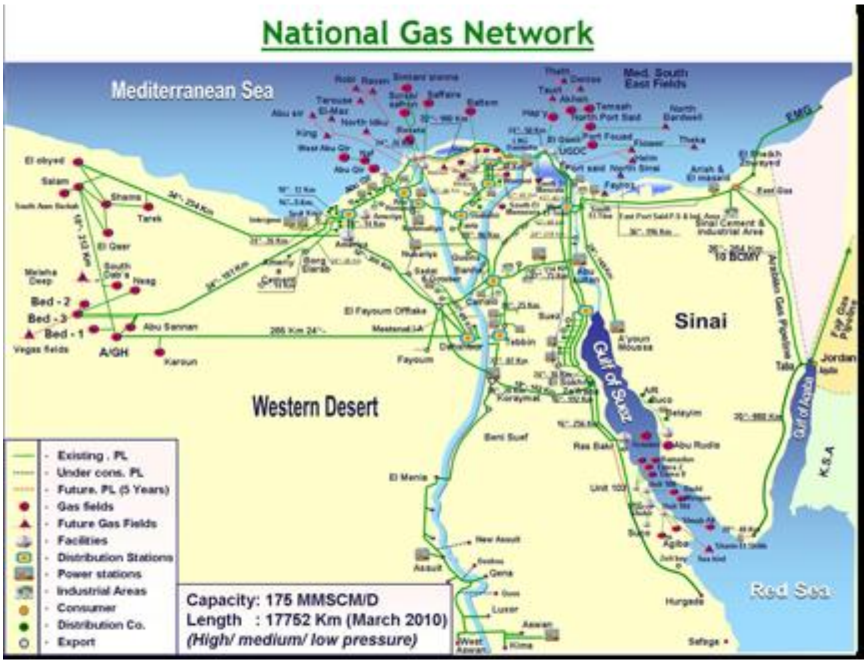
Source: BP, Statistical Review of World Energy, 2014.

EGAS sells gas to end users. However, it is not a fully integrated company: transmission is operated by GASCO, and local distribution is operated by 16 local distribution companies. EGAS pays fees to both GASCO and distributors for their services, but retains the gas retailer position.

The gas network has been extended to almost all governorates, with a total length of nearly 18000 Km, of which about 3500 of high pressure transmission.

[91] All data in this section are from EGAS, Annual Report 2011-12, unless specified otherwise. The value of condensates at international market prices would be around one sixth that of the natural gas output, however values at domestic prices would be substantially lower (see below).

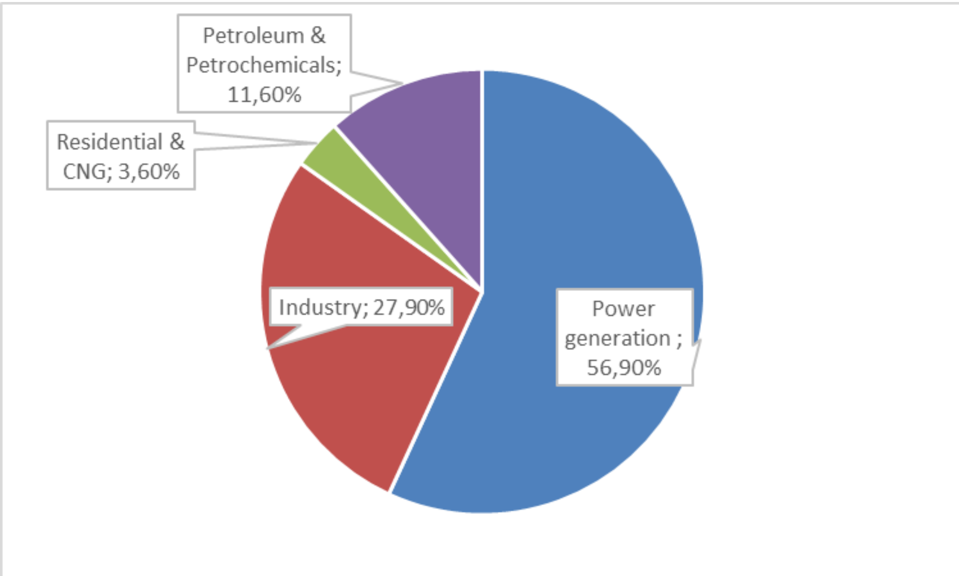
Figure 2.11.2 – Egypt's gas production, treatment sites and transport network



Source: EGAS

Most natural gas has always been consumed locally. The market mostly consists of power generation, however industry plays an important role. Local distribution and the transport sector are still minimal, even though the gas network has now over 5 million connected households and other small customers.

Figure 2.11.3 – Gas consumption by sector, 2011-12



Source: EGAS

Exports have started in 2003 by the Arab Gas Pipeline to Jordan, followed in 2005 by LNG from the Damietta liquefaction terminal in the Nile Delta Region. Later, a second terminal has been opened in Idku LNG terminal near Alexandria, and pipeline exports have been extended to Israel, Syria and Lebanon. However, since 2009 a stagnation of production and reserve finds, together with a continuous fast growth of domestic consumption have led to the mothballing of Damietta and later of Idku LNG plants, and to a reduction of pipeline exports, which are now reduced to a minimum[92].

Lately, despite the suspension of exports, the country is effectively short of gas, and has contracted a floating LNG gasification and storage unit, which is expected to start importing LNG in September.

2.11.2 The market and pricing

EGAS has actually the pivotal role in the system: it sells gas to the domestic market, which is supplied through Production Sharing Agreements with International Oil Companies. Such agreements are negotiated in bidding rounds, and involve a common structure:

- A share of production, known as *cost gas*, covers the operator's costs;
- The remaining (*profit gas*) is shared between all joint venture participants, among them in Egypt there is always EGAS or another National Company, usually with a 50% share[93];

Any gas that EGAS needs (for domestic consumption) in excess of its share of profit gas is purchased at an agree price. This price was originally linked to crude oil, with a floor and a ceiling, through a mechanism, widely used in international trade, known as S-curve. However, since the ceiling of 2.65 $/MMbtu was related to a Brent crude of $22/bbl and above, in fact this is the price at which EGAS purchases most gas. The S-curve has a floor at 1.50 $/MMbtu for Brent below $10/bbl, with linear interpolation within these thresholds[94].

Such price is regarded as adequate for old fields, but not for new ones, which are mostly in the Mediterranean deepwater offshore.

It is clear that the gas price formula has been set at a time when oil and gas market prices were much lower: Brent crude prices in the 10-22 $/bbl range date back to the 1990s. However, this fixed price could adequately serve the upstream Egyptian market even later, because flexibility and competition were provided by other conditions of the Concession Agreements. In particular, EGAS/EGPC and the Contractors (IOC's) could bargain on items like:

- The share of cost and profit gas (with the former typically around 35%);
- The shares of the JV, and hence of profit gas (usually, but not always, at 50%);
- The duration of the concession and the possibility of extension;

[92] Frequent attacks by armed groups on the AGP in North Sinai have also hampered the reliability of this pipeline, jeopardising exports to Jordan. The contract for exports to Israel has been scrapped in 2012.
[93] In a few cases, PSAs are between IOCs and EGPC or GANOPE rather than EGAS, but this does not affect the organisation of the industry and its gas flows.
[94] The Euro-Arab Mashreq Gas Market Project, Egypt Diagnostic Report, December 2006, MEDA/2004/016-703.

- The minimum required seismic exploration and drilling efforts;
- Rates of return, usually comprised between 12 and 16%;
- The “bonuses”, or lump sums paid by the Contractors upon obtaining the Concession.

In fact, several clauses are defined in a separate PSA, that is negotiated and signed once a commercial discovery occurs, yet its terms are related to those of the original Concession Agreement. In particular, the development and production duration and its possible extensions are defined considering the characteristics of the field.

Besides these negotiated clauses, others have remained fixed: among them, not only the gas prices, but also (most importantly) the fiscal terms, and the take or pay conditions, which are typically set at 75% for the NOCs’ purchases.

This model and its related conditions have allowed a superb development of the Egyptian gas exploration and production for several years; so that they have been taken as a model by other countries (see the Section about Nigeria). In particular, experts regard Egypt’s fiscal terms and take or pay conditions as slightly more producer-friendly than the average international standards.

Formally, the Egyptian oil and gas policy envisages that resources should be split as “one third for domestic use, one third for export, and one third for future generation”. Yet it is not clear what this means in practice, If resources kept for the future are related to new additions, the policy is clearly neglected since 2009 at least, as reserves have been actually stagnating or shrinking. Furthermore, exports have never reached more than half the level of domestic consumption.

However, the rapidly increasing domestic consumption has limited the availability of gas for export, jeopardizing the economics of the IOC’s projects in the country. Moreover, the cost of most new offshore development clearly exceeds the maximum allowed price level of 2.65 $/MMbtu. Whereas EGAS and the Egyptian Ministry of Petroleum have lately accepted higher prices for selected projects (reported up to $4), the loss of profitability and increasing delays in the payments owed by EGAS to IOC’s has led to a stagnation of investments, which in turn has led to stalling reserves. In the last two years proved reserves have actually been eroded, and the natural decline of older fields has led to a reduction of production, now entirely dedicated to local consumption. Although the political upheaval of 2011-13 has also been blamed for the crisis of the Egyptian gas industry, it is worth noticing that the decline of investments, reserves and production actually started before such events.

EGAS’ single buyer role leads to complete independence between the price at which gas is purchased (upstream) and the prices at which it is sold to domestic customers.

As a World Bank – ESMAP Report[95] explained a few years ago:

"Egypt has no specific gas law. The policy and regulatory roles are not clearly defined and separated, and third party access to transmission networks and independent regulation of gas prices are not currently in place. Egypt does have a functionally separate transmission system operator (GASCO). The Ministry of Petroleum is aware of the shortcomings of the gas market and is in the process of making changes, including plans to establish an independent gas regulator". The institutional situation has not basically changed since them, although steps are being taken to set up a separate gas regulator.

A number of policy decisions have led to the prominent rise in domestic gas consumption in Egypt. In the early 1990s, attractive fiscal and gas pricing terms were introduced on the supply side, creating the incentives necessary for upstream producers to develop existing reserves and explore new gas reserves. However, domestic gas tariffs have remained heavily subsidized, funded through the State's share of the natural gas rents. World Bank estimates indicate that natural gas subsidies range between 32 and 85 % depending on the customer class, with the greatest subsidies (85 percent) provided to the residential sector. It is understood that the Government intends to phase out subsidies over time, while establishing other social protection measures that target the truly needy. Such actions will dampen the rate of growth in domestic gas demand".

As part of this approach, retail prices have been largely maintained below supply costs, with a view to:

- promote gas usage in residential sector

- attract energy intensive industries like cement and steel;

- ensure competitiveness of local fertilizer production; and in particular:

- generate cheap electricity, with an average price (also through further subsidies) of 3.5 US cents/kWh.

In fact, this situation had already lasted for several years. A previous and accurate Report, sponsored by the European Union[96], had concluded that:

"The retail pricing of domestic gas sales (and electricity and petroleum products) is below economic levels. EGAS buys gas for $2.65/MMbtu and sells for $1.25/MMbtu in the domestic market (FY2005/06 rates). The $1.40 difference is covered by the State's share of natural gas resource rent. As in any energy market, persistent sub-economic pricing leads to increased and affordable energy access; but it also leads to wasteful consumption, misallocation of resources, underinvestment and the need for subsidies. As one would expect, the suppression of energy

[95] World Bank Energy Sector Management Assistance Program, *Potential of Energy Integration in Mashreq and Neighboring Countries*, Report No. 54455-MNA, June 2010.
[96] See fn. 94

prices for the domestic market has led to consumption in excess of the economic norm. In the current cost environment, increased retail prices are almost certainly required to minimize the extent of subsidy required". For example, the role of the combined cycle technology in the Egyptian power generation is still very limited, with most plants featuring a rather low efficiency. The role of renewables is also a minor one despite the remarkable solar and wind resources that are available.

Eight years after the EU Report and four years after that issued by the World Bank, the situation has hardly changed. In fact, only very limited increases have been reported, particularly for energy intensive industries (like cement or steel), which cover about 10% of total consumption. As the domestic consumption now requires (and is about to fall short of) all production, the export gas rent has all but vanished and the burden of subsidies that are necessary to keep prices below costs are clearly unsustainable. It has been estimated that such burden amounts to 14 $ billion, which is more than the Egyptian state spends on defense, education, or healthcare. Of these, subsidies for natural gas only could be estimated at between 3 and 4 Bn. $.

Very recently (July 2014) a Government decision has imposed a substantial correction of these practices, with significant price hikes for most consumption categories, including power generation. In this way, prices would be on average close to cost reflective levels.

Table 2.11.1 Consumer prices in Egypt ($/MMbtu)

	Before May 2008	After May 2008	2013	Since July 2014
Energy intensive industries	1.91	3.01	4.00	7.00 – 8.00
Other industries	1.32	1.32	1.25	4.50 – 5.00
Residential	0.80*	0.80*	0.80*	1.55 - 5.81
CNG	2.38	2.38	1.75	4.26
Power generation	1.32	1.32	1.25	3.00

It is too early to say whether these sudden hikes will be successful. In several countries, too fast removal of subsidies without proper preparation of public opinion and compensation for the most vulnerable customers[97] has led to social unrest and the repeals of the increases.

[97] A general discussion of problems related to reduction or removal of energy subsidies is beyond the scope of this Report. See International Monetary Fund, Energy Subsidy Reform: Lessons and Implications, January 2013.

2.12 Nigeria

2.12.1 Facts and Plans

Nigeria, an historical OPEC Member State, has the 9th largest proved commercial reserves in the world (5200 Bcm) and is the 20th current gas producer (43.2 Bcm in 2012). The rapid growth in gas production in the last 20 years has been mostly driven by exports, particularly LNG (27.2 Bcm), with minor quantities delivered to neighboring countries through the West African Gas Pipeline.

Gas production is dominated by international oil&gas companies, including several majors and a few independents. The Nigerian gas is on average rather rich in gas liquids, and often associated with oil. Production has been often driven by the need to commercialize these liquid products, therefore associated gas production that cannot be reinjected is flared. The share of flared gas has however declined in Nigeria, from 46% in 2003 to less than 23% in 2012.

The Nigerian Gas Company (NGC), a subsidiary of the Nigerian National Petroleum Company, plays a major role: it is a producer as it enters into joint ventures with several international companies, and is the owner and operator of the national transmission grid. Two other companies (Shell Nigeria and Gaslink) operate local distribution and supply.

Natural gas is a major source of tax revenue for the Federal Government of Nigeria (FGN). The total government take is estimated at 93% for onshore and 91% for offshore fields, one of the highest values in the world.

Domestic gas consumption is mostly for power generation (about 80%), but important shares are also utilized as feedstock for the production of fertilizers and methanol, and for consumption by other industries. The residential and commercial sector represent only a tiny share. Overall, natural gas covers 27% of national primary energy requirements.

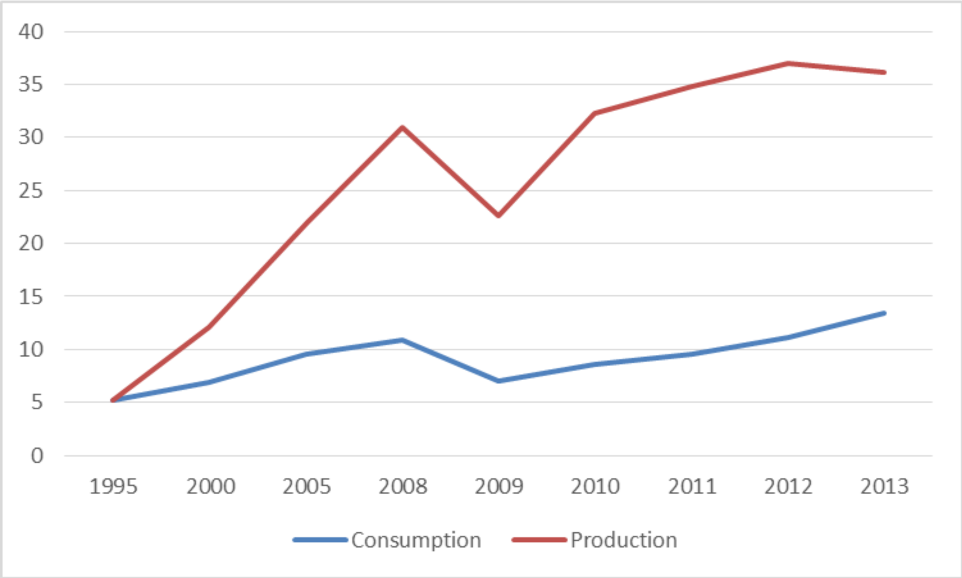
Whereas exports have taken off, with an average growth rate of 14% since 2000, domestic gas trade and consumption have lagged behind, and this is widely seen as a source of the persistent electricity generation deficit of the country[98]. The problem has been also exacerbated by unavailability of power plants, due to lack of maintenance, and by sabotage of pipelines and unrest in the main producing region (Niger Delta). Yet, inadequate gas transportation and processing infrastructure, and an history of commercial poor performance of the domestic gas sector – with low price, unpaid bills, weak and unenforceable supply agreements (GSPAs) – have been also blamed for slow growth[99]'.

---

[98] Nigerian Electricity Regulatory Commission (NERC), Multi-Year Tariff Order for the Determination of the Cost of Electricity Generation for the Period 1 June 2012 to 31 May 2017, 1st June 2012, www.nercng.org

[99] D. Ige (2010), "Strategic Aggregator" Roles and Functions in the Nigerian Domestic Gas Market, www.gacn-nigeria.com ; T.O. Okenabirhie (2009), "The Domestic Gas Supply Obligation: Is this the Final Solution to Power Failure in Nigeria? How Can the Government Make the Obligation Work?", University of Dundee, Centre for Energy, Petroleum and Mineral Law and Policy.

Figure 2.12.1 – Gas production and domestic consumption in Nigeria (Bcm/year)



Source: ENI, World Oil&Gas Review 2013.

To avert this situation, the FGN has adopted since 2008 a new gas policy, which has been translated into a Gas Master Plan and embodied into the National Domestic Gas Supply and Pricing Regulation 2008 (NDGSPR), aimed at boosting the national use of gas resources. The pillars of this policy are:

- a legal obligation to reserve 40% of the production for domestic use (Domestic Gas Supply Obligation or *Domgas*);
- a price reform, aimed at ensuring commercial viability of domestic gas market, and eventually bringing prices in line (on average) with those of gas aimed at LNG export.

Both pillars aim at avoiding that companies privilege the export market, curbing supplies to the domestic one. A peculiar way of implementing this goal is the establishment of an *aggregator*, or single buyer, known as Gas Aggregation Company of Nigeria. Legally, it is a joint venture owned by the country's gas producers, but in fact it acts as a public body under FGN control. This is a most interesting feature of the Nigerian case.

The Aggregator has several roles, that are expected to evolve over time. In the short term, it deals with demand management, including the rationing of inadequate resources. Its most interesting role is however indicated as Aggregate Price, Securitization and Escrow Management.

In fact, the Aggregator buys gas from producers, taking it from their quotas pertaining to the Domgas and from other sources, like excess gas or currently flared gas. A public purchase procedure is envisaged.

For these purchases, the Aggregator negotiates pricing and commercial conditions pursuant to the Pricing Regulation principles outlined by the NDGSPR. This is not however a detailed price control order, nor does it define prices. It is rather a general policy requiring that projects maintain an internal rate of return of 15%. Since gas production sites are very different for their costs, location (and hence transportation costs), and particularly for their contents in liquids, actual prices and their escalation clauses can be rather different, but they are normally related to the prices of natural gas liquids. For example, for some Niger Delta fields that are very rich in gas liquids, the production cost of residual (dry) natural gas can be as low as 0.1 $/MMbtu. For this reason, this approach is also known in Nigeria as "liquids based pricing".

The Aggregator is not a regulator, although its institutional goals include the optimal protection of both producers and consumers, and it is the only body that is actually involved in the negotiation of prices with producers. However, the official natural gas regulator is the Department of Petroleum Resources (DPR), under the Ministry of Energy.

A consequence of this approach is the lack of information about contractual details. In fact, in order to maximize its bargaining power, the Aggregator would not reveal the details of prices and indexation clauses that are negotiated in each case.

The purchased gas is then sold to the domestic market, which is segmented into three sectors for the sake of price regulation. Hence, gas prices are fully regulated in Nigeria, but regulatory criteria differ by consuming sector:

1. For power generation, the largest consuming sector, the price is assumed to be based on the cost of supply (*regulated pricing regime*). Since about 80% of domestic consumption is for power generation, it is understandable that a cost based pricing of such gas should not be far from the average production cost. This approach seems to have been roughly followed for some time, with costs evaluated by the "liquids" method, i.e. with costs netted of the liquids' sale revenues.
   However, a progressive upward price review is now envisaged, bringing prices towards the export parity target. Therefore, regulated prices are not apparently fully based on cost, but seem to be the outcome of a political decision aimed at incentivising gas domestic use. The original plans are illustrated by the following Chart 2. The target price for this sector is $2/MMbtu for 2014.

More recently, these plans have been included in the electricity regulator's Multy Year Tariff Order (MYTO 2012-17), which reads:

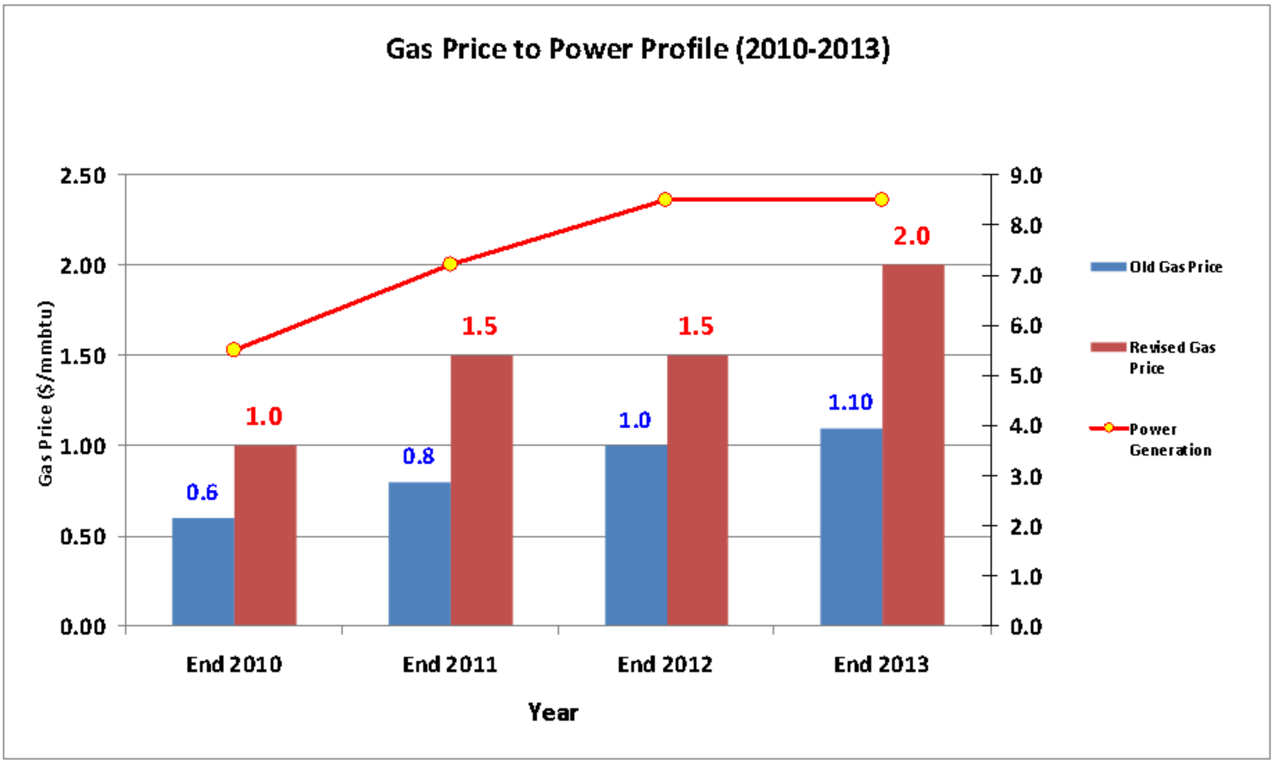
"Gas prices have been regulated since the adoption of the MYTO in 2008 and the regulated prices as applied in the 2012- 2016 tariff are as follows:

Table 2.12.1 – Planned Gas Price for Power Generation (incl. transmission cost; $/MMbtu)

	2012	2013	2014	2015	2016
Price	1.80	1.80	2.30	2.37	2.44

Gas prices are pass-through costs for the electricity producers. Where there is a material change in the price, the NERC will effect a commensurate change to the wholesale contract price".[100]

Figure 2.12.2 – Actual gas price and power generation (RHS, TWh)



Source: National Electricity Regulatory Commission of Nigeria

In the other main consuming sectors, other approaches are adopted:

2. In the "gas based" industries that use gas mainly as feedstock (methanol and fertilizer production), prices are indexed to those of the end products, which are largely traded in international markets. This is defined by the NDGSPR as *pseudo-regulated pricing regime*.
3. In the other industrial sectors, where gas is used to produce heat or to (locally) generate electricity, prices are defined in relation to those of competing fuels, typically on a useful energy equivalent basis[101]. The target price for this sector is $3/MMbtu in 2014.

[100] See fn. 98. A "material change" is defined as a change in any cost item of more than ± 5%.
[101] This is a traditional practice of the gas industry in less developed markets and has been long used in Europe as well before gas market liberalization. It is also known as the approach where prices to each sector (or in some cases even to

In both cases, the Aggregator is in charge of negotiating exact prices but, as in the case of the gas purchase price, details are not known for confidentiality reasons.

2.12.2 Comments

It has been noted that the Domgas obligation has in fact been hardly implemented by the IOCs that it targeted. Whereas several of them have pledged to devote more gas to domestic use, including by building new gas fired power stations, these plans have not been implemented, and the growth of gas exports has clearly exceeded that of domestic consumption, even after the NDGSPR has been enforced in 2008. Delays in the implementation of the pricing part of the Policy and political problems including terrorist attacks in the Delta have been blamed for this outcome, but the majors allege that burdensome details of the Policy have jeopardized its implementation, and that its direct application under the current resource availability would lead to breach of their take or pay commitments towards foreign customers.

Despite some delay, the gas-to-power price seems to have been broadly aligned with the plans, and to have made a substantial contribution towards alignment with export parity. Faced with substantial inability to force IOCs to abide by the domestic gas obligation, the FGN seems to be playing the card of incentives, raising the domestic prices towards export parity. It is interesting that this has happened in spite of the availability of a National Gas Company that was involved in many production JVs.

Unfortunately, the policy of pricing production on a case by case basis prevents the definition of clear criteria. The official rate of return is known and rather high at 15%, which is understandable given the general risk level of this country.

2.13 Algeria

2.13.1 Scope of regulation

Domestic gas prices in Algeria are regulated in both upstream and downstream markets. Sonatrach, the national oil company, purchases gas from international oil companies (IOCs) at the wellhead at netback export prices and sells it on domestically on the wholesale market to power generators and heavy industries at regulated prices. The retail market is controlled by Sonelgaz, Algeria's state-owned utility, which purchases gas from Sonatrach and sells it onto domestic and commercial users at regulated prices.

---

each individual consumer) are adjusted to the "bearing capacity" of the sector (consumer). This approach is also close to what is known as "Ramsey pricing" in theoretical economics, where prices are related to inverse demand elasticities. Yet the idea of bearing capacity includes not only the capacity of the demand side to react to higher prices, e.g. by improving efficiency or switching to other energy sources, but also the politicial capability of consuming sectors to accept higher prices.

Regulation covers all downstream consuming sectors. There has been a debate in recent years in Algeria about the level of the price of gas sold to heavy industrial users owned partially or wholly by foreign investors and whose output is marketed in export markets, but that debate never extended on to the subject of full liberalisation of domestic gas prices. With the increasing scarcity of gas and the impact of growing domestic demand on the level of Algerian gas exports, the government seems to have decided to raise the price of gas sold to such users, though the price remains fundamentally regulated.

2.13.2 Who is the regulator?

Different regulators are involved in the regulation of gas prices in different market segments in Algeria. Prior to 2006, the ministry of energy was the only regulator in the upstream and wholesale segments of Algeria's domestic gas market. However, with the introduction of new Hydrocarbon Law 05-07 in 2006, regulatory powers were given to two new nominally independent agencies, namely ALNAFT (*Agence nationale pour la Valorisation des Ressources en Hydrocarbures*) for the upstream and ARH (*Autorité de Régulation des Hydrocarbures*) for the wholesale market. Given that wellhead prices are based on netback export prices realised by Sonatrach, ALNAFT's role is essentially to provide IOCs with monthly notices of the reference export price. ARH for its part is charged with adjusting domestic wholesale gas prices annually based on the formula below.

Prices in the retail consumer market are set by downstream gas and electricity regulator CREG (*Commission de Regulations de l'Electricite et du Gaz*), which was set up by the 2002 Electricity and Gas Law. This law was designed to liberalise the electricity market and gas distribution, but it has so far only succeeded to introduce a limited degree of liberalisation in the generation segment of the power market. Distribution and pricing of gas and power remain heavily controlled and regulated by the State.

2.13.3 Basis for the regulation

In the upstream segment, gas prices are based on netback export prices. With IOCs de facto not allowed by Sonatrach to market their gas production entitlement on export markets, the national oil company buys such gas quantities at a negotiated price based on netback export prices. More recently, Hydrocarbon Law 13-01, which was introduced in February 2013 as an amendment to Hydrocarbon Law 05-07, established a domestic market supply obligation for IOCs. Such quantities are sold to Sonatrach at the wellhead based on the volume-weighted average of the prices realised by IOCs in their sales contracts with Sonatrach for the volumes that do not fall under the domestic market obligation. This is meant as an incentive to IOCs given that domestic gas prices in Algeria remain well below international prices.

In the wholesale market, which is controlled by Sonatrach, prices are fixed by ARH on the basis of Article 10 of Hydrocarbon Law 13-01, which stipulates that wholesale gas prices should only cover the cost of production; the cost of the infrastructure used specifically for the domestic market; the operating costs of the export infrastructure used in part to transport gas dedicated to the domestic market; and some reasonable profit margin for each of these activities. The above costs should also cover the return on existing investment, as well as new investments needed to maintain supply activities. Executive Decree No. 07-391, dated 12 December 2007, which aimed to define the modalities and procedures of wholesale gas price regulation, states that the supply price is based on the "cost of economic returns" plus a "premium to cover the additional cost of mobilizing new resources to meet long-term demand". These cost concepts may not be consistent with the precepts of mainstream economics. To the extent that it encourages economic efficiency and promotes sustainable investment, the long-run marginal cost of supply (LRMC) would have been a better reference for regulating prices. Furthermore, as already noted, the latest revision of the 2005 hydrocarbon law has introduced the concept of export-based opportunity cost of gas for remunerating Sonatrach's foreign partners relinquishing their share of gas to the domestic market. To let domestic prices evolve towards that level in time, a "depletion premium" would have to be added to the LRMC in order to factor in the opportunity cost of consuming an exhaustible resource now rather than in the future.

In the retail market, prices are de facto based on social affordability given that the residential and commercial segment accounts for an insignificant share of domestic consumption.

2.13.4 Main criteria used for regulation

As outlined above, wholesale gas price regulation is based on the cost of production, the cost of the infrastructure used specifically for the domestic market, the operating costs of the export infrastructure used in part to transport gas dedicated to the domestic market, and some reasonable profit margin for each of these activities. The above costs should also cover the return on existing investment, as well as new investments needed to maintain supply activities. However, wellhead prices, which are negotiated between Sonatrach and its foreign partners with reference to Sonatrach's gas export prices, are based on Sonatrach's unstated objective of limiting IOCs' profits (rates of return) in the relevant ventures in which the Algerian national oil company is a mandatory partner (with minimum equity of 51% since the introduction of Hydrocarbon Law 05-07 in 2006). So depending on the size of the reserves under development, Sonatrach will decide what rate of return IOCs will reasonably require for their investment and concede a gas price accordingly.

2.13.5 Main criteria used for price adjustment and indexation

The formula used to define domestic gas price adjustments by ARH is outlined in Executive Decree No. 10-21, dated 12 January 2010 and is as follows:

$P_{i+n} = P_i \times (D_{i+n} / D_i) \times (1+r)^n$

Where:

P_n: is the adjusted pre-tax gas price (in Algerian Dinars AD per 1000 M3) for year n

P_i: is the pre-tax gas price for the base year

D_n: is the parity of USD relative to AD as quoted by the Bank of Algeria on the first Business Day of year n

D_i: is the parity of USD relative to AD as quoted by the Bank of Algeria on the first Business Day of the base year

R: is a constant rate of inflation, currently fixed at 5%.

The base price is adjusted every five years by the ARH, except in the event of an important variation in one of the parameters of the above formula. At the beginning of each of the intervening 5 years, the ARH issues a notice to gas producers (essentially Sonatrach), providing an update based on the AD/USD exchange rate and the 5 percent fixed inflation rate. As the Algerian economy is structurally dependent on large imports, the ‘pass-through’ of exchange rates and import prices to domestic inflation is fairly strong. Most frequently, a decrease in the exchange rate (depreciation) and a rise in foreign prices lead to an increase in domestic prices in nominal terms.

2.13.6 Latest available price levels for the main large consumers

ARH’s notifications pursuant to the relevant Executive Decrees referred to above have been sporadic rather than annual as required by law. Of the three price notifications made so far, the first, which came in decree 2005, set a dual supply price, one at DZD780/Mcm ($0.28/MMBtu) for the power generators and public distribution, the other at DZD1,560/Mcm ($0.56/MMBtu) for the industrial sector. The second notification, which was made by ARH in 2008, set the supply price at DZD828/Mcm ($0.33/MMBtu) and the wholesale price at DZD1,203/Mcm ($0.48/MMBtu). The third in 2011 set the supply price at DZD1,024/Mcm ($0.37/MMBtu) and the wholesale price at DZD1,404/Mcm ($0.51/MMBtu). Whatever the pace and modalities of successive adjustments, primary gas prices in Algeria have remained very low by any standard. They are lower than costs and are also the lowest across the MENA region.

2.13.7 Structure of the regulated price for the main consuming sector

According to the Electricity and Gas Law of 2002 (Law No. 02-01) and Executive Decrees 08-114 dated 9 April 2008 and 10-95 dated 17 March 2010, the regulated gas price comprises commodity charges, capacity-related charges and standing charges. Standing charges vary between 25 and 100 AD depending on the level of consumption. In addition to these charges, TV and council taxes are also collected through gas & electricity bills.

2.13.8 Relevant authority for price update

As mentioned above, the wholesale gas price regulator is ARH, whereas retail prices are set by CREG. Price updates are meant to be issued by both regulators on a regular basis (yearly), but, for unknown reasons, in reality the frequency of their issuance tends to vary.

2.13.9 Legal basis for the regulation

The legal basis for wholesale gas regulation consists of the relevant hydrocarbon laws and associated regulation (Executive Decrees)[102] and the 2002 Electricity and Gas Law and associated regulation (Executive Decrees).[103]

2.13.10 Main non-price provisions of regulation tied to the price control

According to Chapter X of the Electricity and Gas Distribution Law of 2002, "Activities contributing to … gas supply shall be paid on the basis of legal provisions based on objective, transparent and non-discriminatory criteria. These criteria shall favour the improvement of management efficiency, technical and economic profitability of activities as well as the improvement of the quality of the supply." Gas transportation and distribution tariffs, which feed into retail prices, include also incentives for the reduction of costs and the improvement of the quality of the supply. There are no known destination clauses in domestic gas supply contracts in Algeria. Even in Sonatrach's gas export contracts, pressure from EU competition authorities led in 2007 to the removal of destination clause restrictions for European costumers.

2.14 India[104]

2.14.1 Scope of the regulation

All gas market prices in India are regulated, i.e. at wellhead, wholesale and retail. It is pertinent to note that the proposed formula by Rangarajan Committee (see below) has not been implemented as the rationale behind it is not very well accepted by the stakeholders. The gas pricing mechanism in India that is currently implemented follows typically two regimes namely:

- Administered Pricing Mechanism (APM)
- Non-APM or Free market gas

The price of APM gas is set by the Government principally on a cost-plus basis. As regards non-APM/free-market gas, this could also be broadly divided into two categories, namely, (i) imported Liquefied Natural Gas (LNG), and (ii) domestically produced gas from New Exploration Licensing Policy (NELP) and pre-NELP fields.

---

[102] A registry of Hydrocarbon Laws and Executive Decrees can be found here: http://www.mem-algeria.org/francais/index.php?page=hydrocarbures-2.

[103] A registry of Electricity and gas laws and Executive Decrees can be found here: http://www.mem-algeria.org/francais/index.php?page=electricite-et-distribution-de-gaz.

[104] This Section was drafted by Ravi Shekar of SNP-Infrasol.

All the consuming sectors in India have regulated gas prices, which are being supplied through APM mechanism. This was done in view of the natural gas scarcity in the country. The priority for the commercial utilization of domestic gas was decided by the Government of India, to make its most optimal use. The priority for utilization of gas produced from fields under APM, i.e. gas produced by NOCs - ONGC and Oil India, for the fields awarded on nomination basis prior to the PSC regime and for the natural gas produced by NELP[105] contractors including RIL's KG D6 field was decided by GoI. The guidelines for the gas sold from NELP fields were issued by the Empowered Group of Ministers[106] (EGoM) in May 2008. APM gas is mainly allocated to existing power and fertilizer plants. The order of priority has been laid down to give first priority to the existing plants to ensure utilization of capacities already created and to obtain faster monetization of natural gas.

The second preference is given to substitute liquid fuels in energy-intensive industries and the third preference to plants in easing bottlenecks and expansion. The order of priority for existing units is as follows:

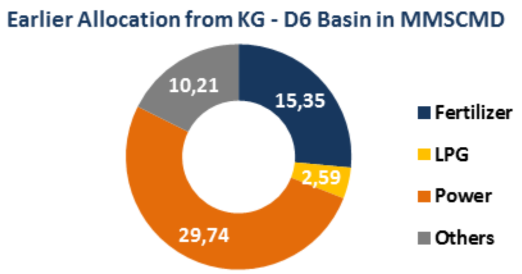
1) Fertilizer Plants
2) LPG & Petrochemical Plants
3) Power Plants
4) CGD (PNG + CNG) Networks
5) Refineries

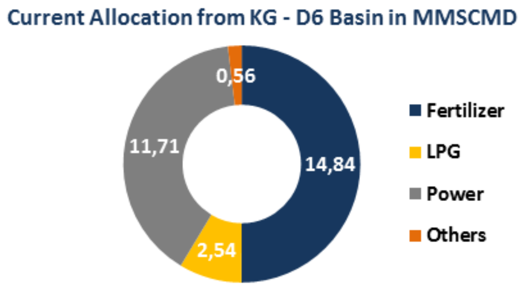
and for greenfield units:

1) Fertilizer Plants
2) Petrochemical Plants
3) CGD (PNG + CNG) Networks
4) Refineries
5) Power Plants

[105] New Exploration and Licensing Policy
[106] Constituted by Government of India in 2008, which currently stands dismantled as per notification by the new Government in 2014

Figure 2.14.1: Allocation of Gas from Krishna Godavari (KG)-D6 Basin in MMSCMD to Different Consuming Sectors





2.14.2 Who is the regulator?

The Ministry of Petroleum and Natural Gas (MoPNG) is the apex regulatory body representing Government of India that regulates and oversees exploration, exploitation and utilization of petroleum resources, including natural gas. Also, there are other two regulatory bodies under MoPNG namely:

- Directorate General of Hydrocarbons (DGH) – Regulates Upstream Hydrocarbon Sector
- Petroleum and Natural Gas Regulatory Board (PNGRB) – Regulates Downstream Hydrocarbon Sector

2.14.3 Basis for the regulation

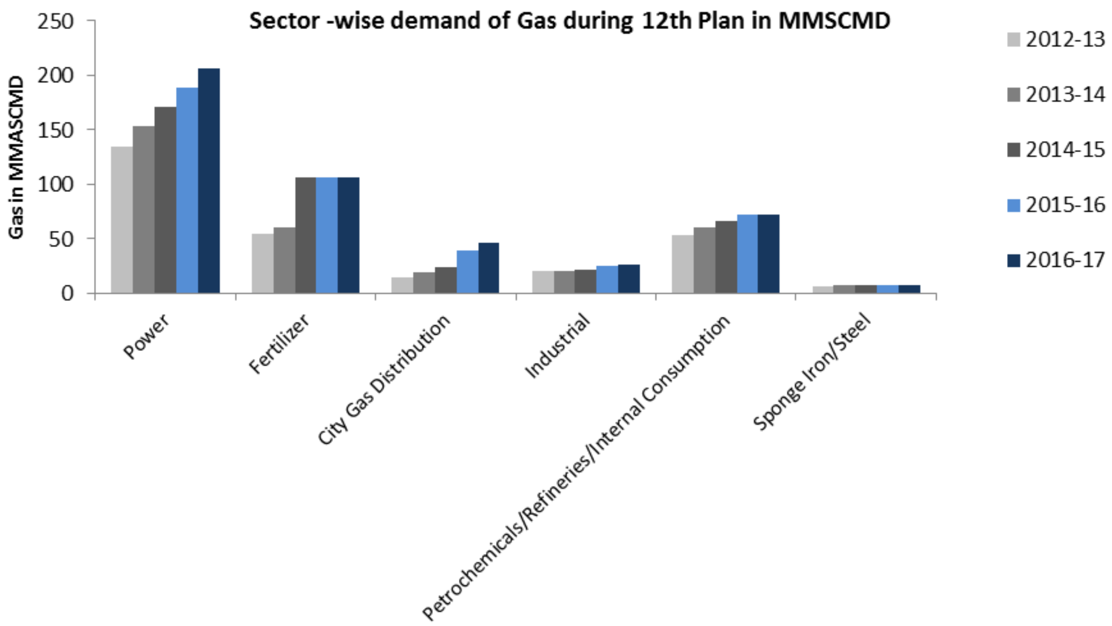
There are broadly two pricing regimes for gas in the country currently – one for the gas priced under the Administered Pricing Mechanism (APM), and the other for the non-APM or free-market gas. The price of APM gas is set by the Government principally on a cost-plus basis. As regards non-APM/free-market gas, this could also be broadly divided into two categories, namely, (i) imported Liquefied Natural Gas (LNG), and (ii) domestically produced gas from New Exploration Licensing Policy (NELP) and pre-NELP fields.

Further, there are two important concepts of gas pricing regulation in India:

- Cost Recovery: The contractor bids the Cost Recovery Factor – i.e. the percentage of revenues, which he is entitled to take in a year to recover his exploration, development and production costs. This percentage can be up to 100 percent. The higher the cost recovery factor that the contractor bids, the earlier the costs can be recovered; however, in such a situation, his fiscal package will be relatively unattractive as part of the bid evaluation.
- Local Market Price: The sale price must at all times be on the basis of similar arms - length sales in the market.
- Social Affordability: The fertiliser and power plants are heavily subsidised by the Government, otherwise there would be direct pass through to the end consumers.

Moreover, gas pricing mechanism in India is presently driven by sectoral prioritization, administered gas allocation and pricing, apart from huge supply-side constraints. While short-term demand changes in international demand due to weather-related causes are quite frequent, the Indian gas market has not seen such volatility in demand in the short-term. This is mainly due to the fact that gas consumption is concentrated in the fertilizer, power and LPG sectors. Other factors resulting in short-term volatility, like business cycles and supply interruptions are also not relevant here. However, all these factors impact international gas price in the spot market and may impact on the profitability of the Indian gas industry substantially.

Figure 2.14.2: Sector - wise demand of Gas during 12th Five Year Plan (From 2012-17) in India in MMSCMD



The latest natural gas pricing guidelines which were supposedly applicable from April 01, 2014 after the Rangarajan Committee recommendations, were deferred by firstly the Election commission of India in the event of General elections in the country and secondly by the new Government. The aim is to find a judicious way of pricing of gas against the universal opposition of for pricing is depicted as below:

The Government has issued the Notification regarding Domestic Natural Gas Pricing Guidelines, 2014 on 10 January.2014. These Guidelines are hosted on the website of the Ministry and published in the official Gazette of India. Salient features of the Domestic Natural Gas Pricing Guidelines, 2014 are:

- These Guidelines shall be applicable to all natural gas produced domestically, irrespective of the source, whether conventional, shale, CBM etc.

- These Guidelines shall not be applicable where prices have been fixed contractually for a certain period of time, till the end of such period, as well as where the production sharing contract provides a specific formula for natural gas price indexation / fixation. Further, the pricing of natural gas from small / isolated fields in the nomination blocks of NOCs will be governed by the extant policy in respect of these blocks issued on 8th July 2013.
- The prices determined under these guidelines shall be applicable to all consuming sectors uniformly. These guidelines shall also be applicable for natural gas produced by ONGC/OIL from their nominated fields.

The pricing of natural gas produced domestically shall be based on the following methodology:

1. The netback price of all Indian imports at the wellhead of the exporting countries will be estimated. Since there may be several sources of gas imports, the weighted average of such netback of import prices at the wellheads would represent the average global price for Indian LNG imports.
2. The weighted average of prices prevailing at trading points of transactions – i.e., the hubs or balancing points of the major global markets will be estimated. For this, (a) the hub price (at the Henry Hub) in the US (for North America), (b) the price at the National Balancing Point of the UK (for Europe), and (c) the netback wellhead price at the sources of supply for Japan shall be taken as the average price for producers at their supply points across continents.
3. The simple average of the prices arrived at through the aforementioned two methods shall be determined as the price for domestically produced natural gas in India.
4. Domestic Gas prices shall be notified in advance on a quarterly basis using the data for four quarters, with a lag of one quarter.
5. In respect of D1 and D3 gas discoveries of Block KG-DWN-98/3, these guidelines shall be applicable subject to submission of bank guarantees in the manner to be notified separately.

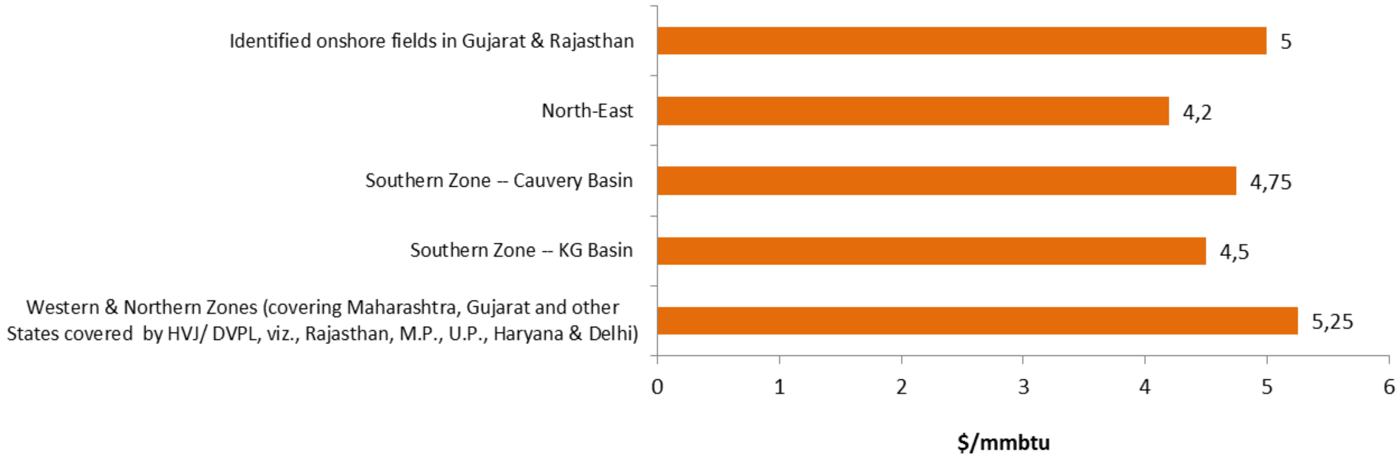
2.14.4 Latest available price level for the main large consumers

In India, as mentioned in previous section also, the gas pricing follows four major pricing regimes for domestic gas in the country – gas priced under Administrative Pricing Mechanism (APM), Pre-NELP, non-APM and NELP (New Exploration Licensing Policy). The price of APM & non-APM gas is fixed by the Government. As regards NELP & pre-NELP gas, its pricing is governed in terms of the Production Sharing Contract (PSC) signed between the Government & the Contractor. As far as imported gas is concerned, the price of LNG imported under term contracts is governed by the Sale & Purchase Agreement (SPA) between the LNG seller and the buyer; the spot cargoes are purchased on mutually agreeable commercial terms. All consuming sectors have to bear the prices under these mechanisms only as per the priority for allocations as set by Government of India.

In addition, the gas produced from existing fields of the nominated blocks of NOCs, viz., OIL & ONGC, is supplied predominantly to fertilizer plants, power plants, court-mandated customers, and customers having a requirement of less than 50,000 standard cubic metres per day at APM rates. The Government fixed APM gas price in the country, with effect from 1.6.2010, is $ 4.2/mmbtu (inclusive of royalty), except in the Northeast, where the APM price is $ 2.52/mmbtu, which is 60% of the APM price elsewhere, the balance 40% being paid to NOCs as subsidy from the Government Budget.

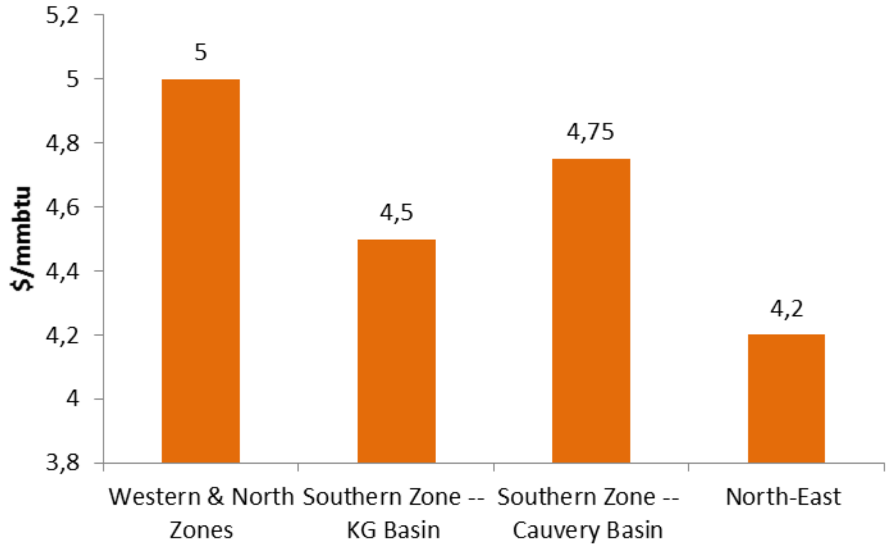
The prices are indicated in the set of following figures along with the dates from which they are applicable[107]:

Figure 2.14.3: Price applicable from 1.7.2010 to Customers Not Entitled for APM Gas ($/MMbtu)



[107] The prices from NELP blocks are under compilation and shall be included in the final Report.

Figure 2.14.4: Price applicable from 1.7.2010 to gas sold by NOCs for non-APM Gas ($/MMbtu)



2.14.5 Regulatory criteria and price structure

The criteria used for regulation for the upstream part of the Gas value chain in India can be classified under two headings:

- For Domestic Gas Production
- For Gas Imports

We cover the domestic and gas imports sections separately, indicating the main criteria used for regulation. Considering the domestic gas production section first, we detail out the major criteria that are utilised to regulate the upstream sector.

Unfortunately, methodologies are known, but there is little quantitative or detail information.

Capital Valuation is used in India for upstream regulations of domestic gas segment, but only to define depreciation rates. No rates of return are applicable in India, hence the cost of production only include depreciation and operational expenditures. Exploration Cost are applicable but it is unclear whether and how they are charged as part of the cost of production or not. Depletion fees & royalties are also part of recovered costs.

For PRE-NELP blocks & KG D-6 Basin, prices are tied to an internationally traded fuel oil basket and international crude oil prices respectively.

Reference to International Gas Prices is not currently applicable in India ,for domestically produced gas.

The cost of production of domestic gas as per different components are depicted in Table 2.14.1, which do not include from returns of capital employed i.e. (ROCE).

The typical price-reopening occurs every 5 years, with notifications to be done on quarterly basis. The trigger for reopening is mostly related to the marketing priorities determined by the Government

Price indicators of the competing fuels, nflation ndex or other macroeconomic mndicators are not usually applicable in India.

Ceiling and floors are also used in India but for Pre-NELP blocks and KG D6 Basin only. Details are not generally known For NELP blocks the prices are determined only on "Arms Length" (commercial) basis (see section 2.14.6 below for legal definitions) The extent of ceilings and floor applicable for Pre-NELP blocks is of 7 years.

As an exception, for KG D6 the pricing formula approved by E-GoM is as below

SP (US$/mmbtu) = $2.5 + (CP-25)^{0.15}$

where:

- SP is the sales price in $/MMbtu (on Net Heating Value /NHV basis) at the delivery point at Kakinada;CP is the average price of Brent crude oil in US$/barrel for the previous financial year, based on the annual average of the daily high and low quotations of the FOB price of dated Brent quotations as published by Platts Crude Oil Market wire.

CP is capped at US $60/bbl, with a floor of US$ 25/bbl. CP is fixed for each contract year and is based on the CP for the preceding financial year. The financial year, which commences each year on 1st April and ends on the following 31st March. The selling price comes to US$ 4.2/MMbtu for crude price greater than or equal to US$ 60/barrel. The price basis/formula is valid for five years from the date of commencement of supply, i.e., till March 2014.

Incentive or performance based regulation is not currently applied in India, as of now the cost plus structure exists, which does not encourage E&P activities in India under the PSC mechanism.

Pricing criteria and tariff structure are always related to the source of gas to the major consuming sectors, which can be classified into two categories, namely domestic and imported gas, which can be further split as following:

- **Domestic Source of Supply**: This can be further split into supply from NOCs under APM and Non-APM gas, Supply from pre-NELP blocks (PMT & Ravva) and all the NELP blocks.
- **Imported Source of Supply**: This is inclusive of the LNG which is being imported through either long-term contracts and spot contracts

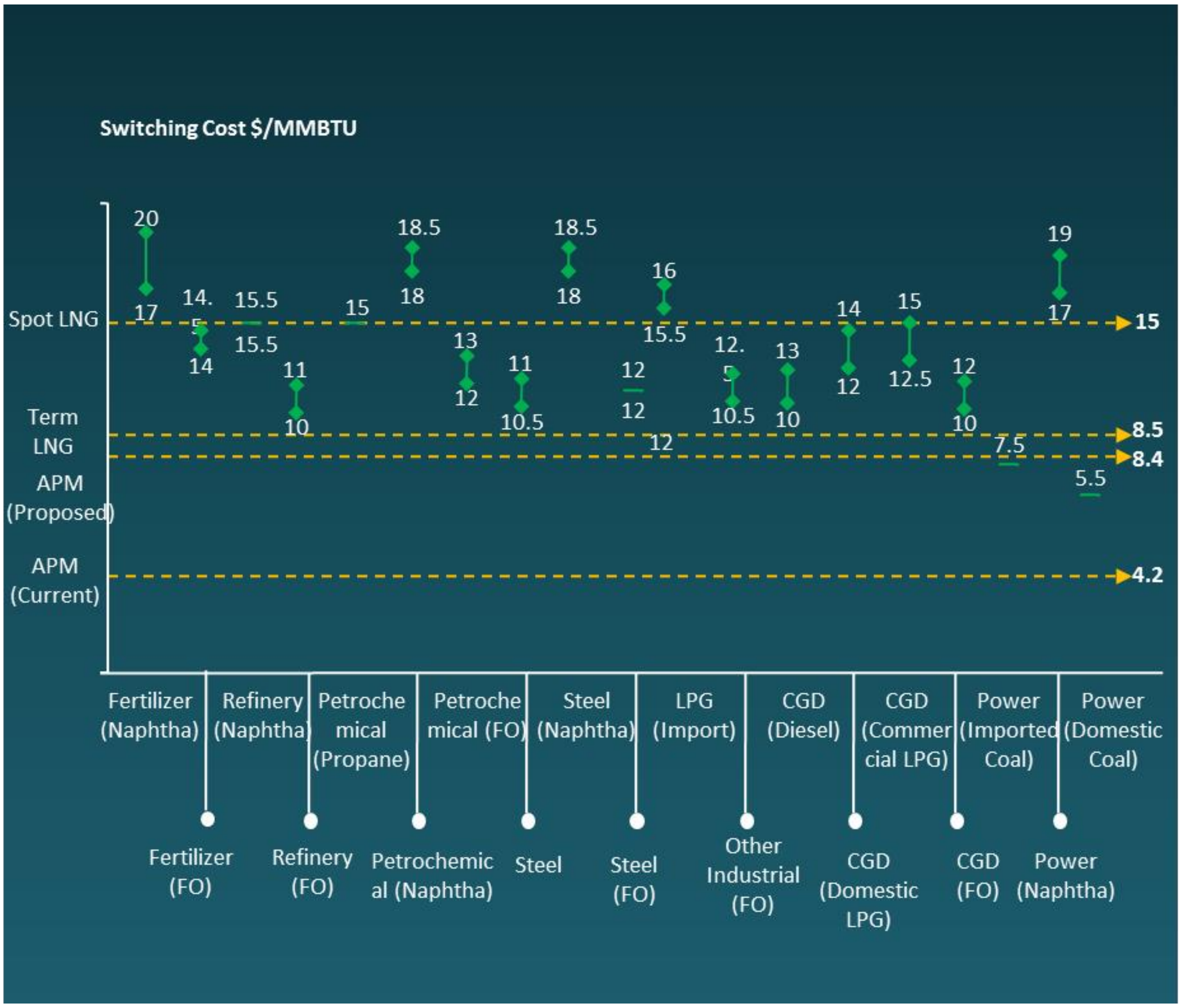
In case of domestic source Government pre-determines the prices as per the source and PSC mechanism. However, as far as the imported gas pricing is concerned the pricing is determined by the parties entering the contract wherein the Government acts as facilitator for infrastructure with taxes and royalties leading to the revenue for the Government. The pricing from different sources of gas for different consuming sectors are found in Table 2.14.1. Also, the switching cost of gas in different sectors is depicted in Figure 2.14.5.

Table 2.14.1. Cost of Production of Domestic Gas Break - Up as Per Components in India

Gas Source	Typical Consumers	Gas Price (in $/mmbtu)
National Oil Companies (NOCs) (APM)	Customer outside North East	4,2
NOCs (APM)	Customer in North East	2,52
Panna-Mukta-Tapti (PMT)	Weighted average price of PMT except RRVUNL & Torrent	5,65
PMT	RRVUNL	4,6
PMT	Torrent	4,75
Ravva	GAIL	3,5
Ravva Satellite	GAIL	4,3
Ravva Satellite	GPEC	4,75
Ravva Satellite	GSPC	5,5
Ravva Satellite	GTCL	6,22
Hazira (Niko)	GACL/GSEG/GSPC Gas	4,61
Olpad (NSA)(Niko)	GGCL	5,5
Dholka	Small Consumer	1,77
North Balol (HOEC)	GSPC	2,71
Palej (HOEC)	Small Consumer	3,5
KG -D6	All Consumers	4,2
Amguri Fields (Canero)	AGCL	2,15
Amguri Fields (Canero)	GAIL	1,29
Term R-LNG	For all	6,75
Spot R-LNG	For all	6.75-11.7

Source: GAIL & SNP Infra Research

Figure 2.14.5: Switching Cost for Gas in India as per Consuming Sectors (in $/MMbtu)



2.14.6 Relevant authority for price update and legal basis of regulation

[108]In India, constitutional provisions serve as the overarching structure under which activities of the oil and gas sector are conducted. They stipulate the role of federal, state and municipal governments, the role of a National Oil Company, private and foreign investments, and the type of host government contract that is possible in the country. The Indian constitution (Articles 294 – 297) mandates government ownership of hydrocarbon reserves. Thus, any contractual structure adopted by the Ministry of Petroleum and Natural Gas must ensure that the title of hydrocarbons is retained with the Sovereign.

Petroleum Law is the cornerstone of an effective petroleum legislative framework. It confirms state property rights to petroleum, creates a "Competent Authority" with jurisdiction over management of the state's interest (whether it be a Ministry, a regulatory body, a National Oil Company, or all of these). Petroleum Regulations implement the policy and objectives of the Petroleum Law by

[108] Excerpts are from BCG Report

contemplating host government contracts, establishing the mechanism for awarding the contracts, and creating environmental protection procedures.

Host government contracts are the result of the laws and regulations in place. In India, ORDA[109] act, 1948, and PNG[110] rules, 1959, govern the upstream activities–including granting of E&P licenses and mining leases–in respect of Petroleum and Natural Gas. In India, PNG rules allow creation of any contract whether it is concession, a production sharing contract, a joint venture or a service contract.

Thus, it is clear that MoPNG (Ministry of Petroleum & Natural Gas) is the relevant authority for price update and it is also the authority which issues the pricing methodology after consultation of the stakeholders like regulators (Directorate General of Hydrocarbons & Petroleum & Natural Gas Regulatory Board), E&P companies and marketing companies.

The legal basis which determines the ownership and pricing of gas in India comprises of following regulations:

- ✓ The Oilfields (Regulation and Development) Act, 1948
- ✓ Petroleum and Natural Gas Rules, 1959
- ✓ Natural gas pricing guidelines, 2013 (Yet to find application)
- ✓ Article 1.8 PSC Provisions:"Arms Length Sales" means sales made freely in the open market, in freely convertible currencies, between willing and unrelated sellers and buyers and in which such buyers and sellers have no contractual or other relationship, directly or indirectly, or any common or joint interest as is reasonably likely to influence selling prices and shall, inter alia, exclude sales (whether direct or indirect, through brokers or otherwise) involving Affiliates, sales between Companies which are Parties to this Contract, sales between governments and government-owned entities, counter trades, restricted or distress sales, sales involving barter arrangements and generally any transactions motivated in whole or in part by considerations other than normal commercial practices.
- ✓ Articles 21.6 PSC Provisions: (Valuation of Natural Gas) The Contractor shall endeavor to sell all Natural Gas produced and saved from the Contract Area at arm’s length prices to the benefits of Parties to the Contract.
- ✓ Articles 294-297 of the Indian Constitution
- ✓ E-GoM Gas Utilisation Policy

2.14.7 Non-price provisions

The main non-price provisions of regulations that are tied to price control in India are highlighted in Table 2.14.2. below. Unfortunately there are no further details.

[109] The Oilfields (Regulation and Development) Act, 1948s
[110] Petroleum and Natural Gas Rules, 1959

Table 2.14.2 Non-price Provisions of Regulations to Price Control of Gas in India (Refer Excel Sheet)

Main Non-Price Provisions Tied to Price Control	Criteria's Applicability	Remarks
Quality of Service Rules		Not applicable in India
Production Performance like available capacity, ramp-up, ramp down, swing factors		Only applicable partially for NELP blocks to impose penalties by Government if the production capacity is not as much required by consuming sectors as per priority
Take or pay clauses that may be subject to regulation and related to flexibility arrangements (e.g. make-up gas)		Only finds partial application and that too in terms to payment of penalties. Flexible arrangements do not exist in principle in India, however the Government can allow increased gas to the consuming sector's as per priority and demand if deemed fit by offsetting the consumption by other sectors.
Price Review Clauses		Yes, it is applicable and the review takes place over a frequency of 5 years
Destination Clauses (By Sector or Country)		Yes, only as per consuming sectors

2.15 New Zealand

2.15.1 The market and its regulation story

New Zealand is indeed an interesting case in gas pricing regulation[111]. It is a relatively small and isolated market, with consumption and production fluctuating between 4-6 Bcm in the last 20 years). Nowadays in spite of its small size, it is a very competitive market, with several suppliers at both wholesale and retail level.

The industry started in the late 1960s with the discovery of two fields, Kapuni and Maui. In particular, development of the large offshore Maui field brought consumption beyond the 4 Bcm/year threshold as early as 1986. In fact, the Maui field almost monopolised the market after 1985, with a market share over 90%. On the other hand, the market was not large enough to develop more fields. As a consequence,it’s the price was regulated by the Commerce Commission in 1996 and remained almost constant for 6 years, at a level of about US$3.2/MMbtu.

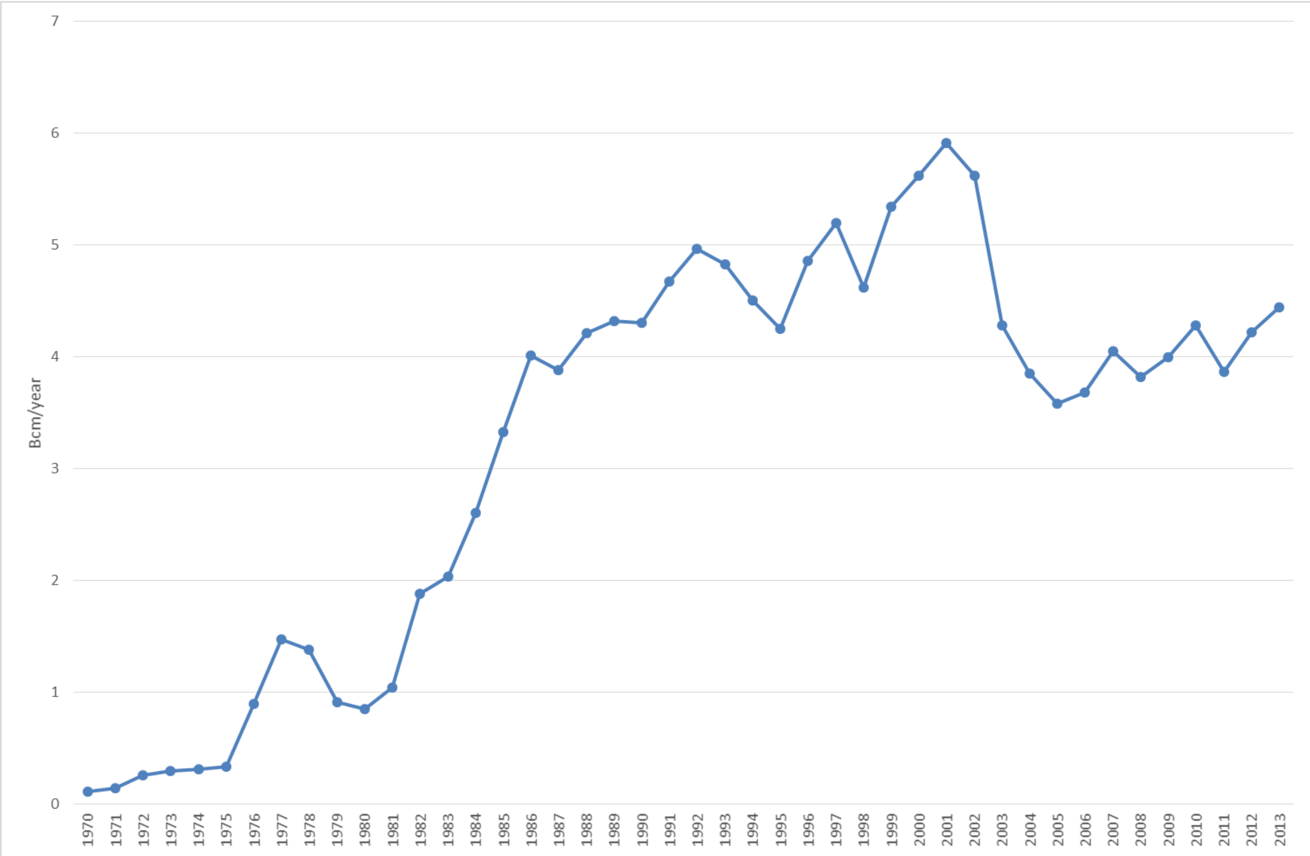
Little information could be detected online about details of such regulation. Apparently, the Commerce Commission did not calculate the costs but used a legacy contract that was deemed to precede the rise of Maui’s market power, and mandated its application to the wholesale market. The mechanism was a compulsory purchase of the gas by the Government, which in turn sold it to power generators and retailers.

The contract ensured a reduction (in real terms) of the price, as this was supposed to increase by the larger of 50% of the inflation rate, or the inflation rate itself minus 3% (see Figure 2.15.2). However this price was too low to clear the market.It triggered consumption growth but did not foster the discovery of new reserves, thus the reserve/consumption ratio fell from 14.6 years in 1997 to 7.4 in 2002, when the cap was gradually lifted. Demand kept increasing, peaking at 5.9

[111] For details please see “The New Zealand Gas Story. The State and Performance of the New Zealand Gas Industry, 2nd Edition – April 2014, http://gasindustry.co.nz/publications/new-zealand-gas-story-second-edition.

Bcm in 2001, but increasing prices and lack of reserves led to a slump. Production fell to a historical minimum of 3.6 Bcm in 2005, and only slowly recovered after that[112].

Figure 2.15.1. New Zealand's gas consumption



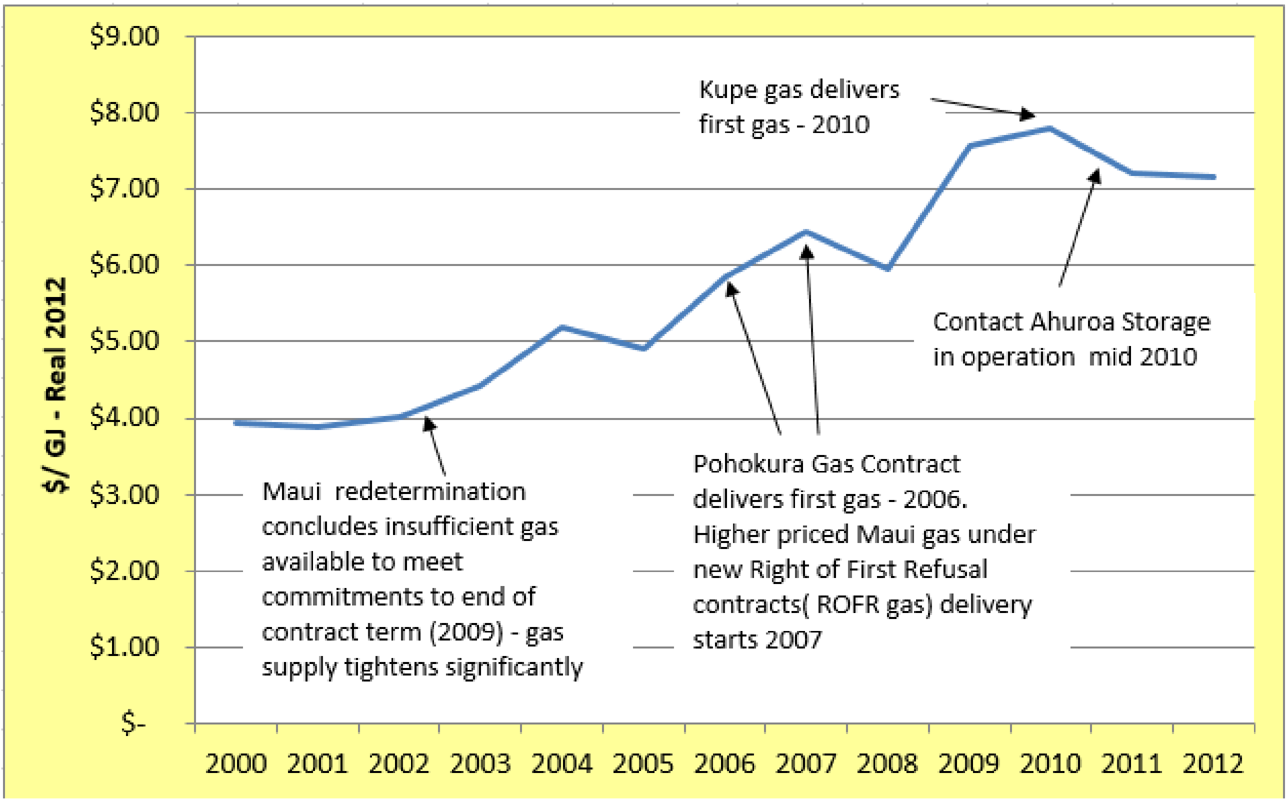
Source: BP Statistical Review of World Energy 2014

"The original Maui contract had minimum take or pay provisions, but it also allowed buyers to bank gas paid for but not taken – known as prepaid gas. Maui take or pay quantities also applied over a 12-month period, allowing buyers to balance their obligations across different seasonal demand periods. So long as the buyer had taken the minimum take or pay quantity at the end of the 12 month period, the average price would match the marginal price (i.e. fully variable). […] The Maui contract enabled buyers to uplift gas paid for, but not taken, at a later date for no cost apart from the Energy Resources Levy. As such, it gave buyers flexibility to vary their daily offtakes to match

[112] Ibidem, p. 105.

their demand within minimum and maximum quantities, while guaranteeing producers a stable income to underwrite their investment in the field"[113]

Figure 2.15.2. New Zealand's wholesale gas price development



Source: Gas Industry Company of New Zealand, The New Zealand Gas Story 2nd ed., 2014.

As Levin and Duncan[114] explain, "In 2003, the Maui supply contract was re-determined. A portion of the gas was removed from the supply agreement and allowed to be sold at market prices. […] the prevailing market prices for gas after 2003 were considerably higher than the price under the legacy contract. With the increase in wholesale prices following the Maui re-determination, producers undertook significantly more investment in exploration and development of reserves. Subsequently, proven reserves have increased significantly with large new discoveries" These have eventually ended Maui's market dominance, which had already lasted for nearly 15 years. At

[113] Ibidem, p. 131.
[114] Stanford L. Levin* and Alfred J. M. Duncan, "Policy Considerations for the New Zealand Natural Gas Industry", New Zealand Institute for the Study of Competition and Regulation, July 2011. www.iscr.org.nz

that point, the Commerce Commission managed to open the market and established a limited control on transmission pipeline tariffs and quality, which has lasted to date.

After the depletion of the Maui field competition has increased, but reliance on smaller fields has led to price increases, which have however eased after 2011. New Zealand's wholesale gas price in 2013 averages 6.15 US$/MMbtu.

2.15.2 The regulatory framework

New Zealand is also interesting for its peculiar regulatory model. It has no national company, and government interests in the industry were sold in the early 1990s. Also, there is no sector or energy regulator, but a model known as co-regulation. The actual Regulator is the Commerce Commission, which acts both as a Competition Authority and as a sectoral regulator wherever necessary, i.e. where competition is found as inadequate after a due process. In such cases, the Commission declares control and a regulated regime is established.

On the other hand, there is an industry body, the Gas Industry Company, which is in charge of proposing several industry standards and to provide technical expertise to the Regulator, wto which is tied by a MoU. The Gas industry Company also undertakes a detailed industry monitoring, following Guidelines from the Regulator.

3. SUMMARY OF THE MAIN RESULTS OF THE WORLD SURVEY

3.1 Regulatory models

As the IGU Survey has shown in general, there is a world tendency towards deregulation of gas prices, starting from the wholesale level and from larger customers. In our sample 9 out of 14 countries still have regulated wholesale prices, and only 7 regulate prices for the larger consumers, which are normally power generators. 8 keep regulated prices for industry, and 12 for residential and other small customers (mostly the commercial sector and public services). The sample is not representative, as it was explicitly selected to study regulation experiences.

Table 3.1 - Regulation and other pricing mechanisms by sector

Country	Wellhead / Wholesale	Residential & Commercial	Industry	Power generation
US	GOG	HUB/RCS	GOG	GOG
Brazil	RCS	RCS	RCS	RSP
Argentina	RBC	RSP	RSP	RSP
Netherlands	GOG	GOG	GOG	GOG
France	GOG	HUB/RCS	HUB/RCS	GOG
Italy	GOG	HUB/RCS	GOG	GOG
Algeria	RCS	RSP	RSP	RSP
Egypt	RCS	RSP	RSP	RSP
Nigeria	RCS	RSP	RSP	RSP
Russian Federation	GOG or RCS	RBC	RBC/GOG	GOG
China	RCS	RPS	NET	NET
India	RCS	RCS	RCS/GOG	RCS/GOG
New Zealand	GOG	GOG	GOG	GOG

For definitions: see annex 2.

The pattern is relatively simple. The most advanced economies (OECD Members) have all phased out wholesale gas price regulation, even though they generally maintain (and have indeed enhanced) the regulation of network services like transmission, distribution and (in some cases) also storage and LNG regasification. However, the regulation of networks, which are often monopolies in each market or jurisdictions (sometimes on a local basis), must not be confused with that of gas prices, and is outside the scope of this Report.

For retail, several OECD countries (US, France, Italy) still keep some type of price control, particularly for smaller customers. In other cases, there is no control even for retail prices, and prices are only subject to ex-post control from Competition regulators (Netherlands and several other EU countries, Australia, New Zealand). In a few cases, if there is a specialised regulator, it retains a market monitoring and advisory role towards the government or the Competition regulator.

In fact, the US have phased out wellhead and wholesale price wholesale regulation since the early 1980s. It was a complex and burdensome practice, which had been lasting for several decades and has been widely seen as partly liable for the shortage that affected America's gas industry in the 1970s. Yet the US, unlike Europe, has not mandated retail competition and the distribution and retail sectors of the industry are usually bundled and regulated by State Public Utility Commissions. The cost of gas is however normally taken from wholesale markets and passed through to end customers.

The European countries have liberalized their markets in different steps, but all of them had to comply with a European Union Directive requiring the liberalisation of the wholesale market by 2004 – even though some have kept some price controls for years, and implementation has often been slow. After 2007, all end users are eligible to choose their suppliers, the market is in principle fully open and wholesale as well end user price caps should be lifted as well. However, in fact national markets are not always fully competitive, as limited infrastructure or contractual arrangements still limit the interconnection of national markets, particularly in the Central-Eastern and South-Western part of the Continent. Therefore, several regulators have actually maintained price controls, particularly for smaller (residential and commercial) customers, and in few cases also for larger ones.

The main issues that are discussed are the conditions for removal of the caps, and the wholesale markets to be chosen as benchmarks or indicators for gas wholesale costs: in most cases, regulators do not interfere in the price at which wholesale suppliers procure their gas, which is mostly imported, an traded in increasingly competitive hubs.

The main interest of European cases lies in how, in a few cases, regulators have defined the way gas costs are recognized by reference (at least partly) to spot markets; and have also promoted escalation of prices to gas market rather than oil market indicators. It is also interesting to see how such definition of indicators occurs in practice, and how escalation works, for example in terms of frequency, the choice of indicators, the use of moving average rather than point values, and the responsibility and clauses for price adjustment. The issue has been a frequent source of litigation in Italy, as linkage to foreign hubs like the Dutch TTF could have led to losses by suppliers that were not able to procure gas at the hubs prices, due to their legacy contracts. Likewise, in France the government has often tried to lower prices (or to avoid price increases) by referring to a basket of supplies which could be cheaper than the actual one. In a couple of cases, the Ministry has been defeated in lawsuits, with the energy regulator (which is not formally in charge of end user prices) providing its expertise to the Court, and has been forced to adjust its regulation.

Unlike these cases, the Netherlands are an historical exporter, and actually the first important exporting country in the world, starting in the 1960s after the discovery of the huge Groningen field. The Dutch market is today fully integrated within Europe and actually the home of the most liquid trading hub after the British one. Yet, it is interesting to consider how prices were regulated for the domestic market before liberalization was implemented, starting in the late 1990s.

The fundamental approach of the Netherlands until full regulation was to price gas after the competing fuels, with some discount. The price indexation followed similar criteria, mostly following oil derivatives market price indicators, with some delay. This approach was applied to all sectors, with the appropriate benchmarks, and also to exports, after allowing for transportation costs.

The rationale for this approach was to use gas also as a source of state revenue, and as way of boosting security of energy supply and reducing environmental pollution. This choice was made possible by the existence of a state-owned monopolist, which purchased gas from the Groningen field (operated by a joint-venture of the state and two large IOCs), and later from a few smaller fields as well. Nevertheless, gas use was quickly expanded in the country, which came to use gas as a primary energy source more than any other European country.

In the large emerging markets of the BRICs, the tendency is also towards market based pricing although China (a net importer) is moving towards links to oil derivatives (in line with the Dutch approach), whereas Russia, the largest world exporter, has planned 8but not fully implemented) an export parity principle. Since Russian exports prics are in turn related mostly to oil derivatives' this may end up as a similar approach. However, the Russian intermnational pricing has been slowly forced to move towards hub based pricing, and the domestic pricing may also reflect this.

In fact, domestic gas pricing in the Russian Federation is mostly cost-based, yet a fair degree of liberalisation has lately occurred, and a vibrant market has developed for power generation and large industry customers, even though regulated prices still exist and are dominant for the smaller customers. An official policy has long existed (and has been to some extent been implemented) to increase prices towards the "netback" levels, where they would be aligned with those of exported gas, minus the transport cost. However, as international gas prices have increased, the government has been wary of reaching the netback levels. Lately, the progressive extension of liberalization seems to be the most likely tendency.

A somehow similar pattern occurs in China, which (unlike Russia) is a net importer. Domestic production has been mostly regulated on the basis of individual field costs. The industry has been offsetting high cost of imports with low costs of domestic production, but it is now suffering rising losses as the share of imported gas has increased. Therefore, a pilot mechanism has been introduced in two provinces)and is lately being extended to the whole country) , where prices are related to those of competing fuel.

India has also often cross-subsidised imports with the low costs of domestic fields, yet this has slowed down the development of marginal ones. Heavy litigation between the government and suppliers in Courts and arbitrations has characterised the regulatory framework. Lately, a policy of raising prices towards market levels has been announced, but implementation is lagging behind.

Brazil is an earlier development stage, and still a net importer. Prices are not regulated in the wholesale market, which is dominated by a state-owned company, therefore interfuel competition is the main factor affecting pricing practices. India is also moving in principle towards prices based on those of competing fuels, but they are still mostly regulated after costs, with a huge litigation burden.

All of these countries have started from more or less subsidised prices, or at least from cost based regulation that led to prices below market levels. Yet such pricing regulation practices are generally not transparent, and little information is available about their details.

Although it is now fully liberalised, an interesting case in historical perspective is New Zealand, a relatively small market (4-6 Bcm/year) that has long suffered from dependence from a large single gas field. In fact, the large offshore Maui field was able to almost monopolize the market after its development, and the market was not large enough to develop more; therefore, its price was regulated by the Commerce Commission in 1996 and remained almost constant for 6 years. This has slowed the discovery of more costly new reserves, and the reserve/consumption ratio fell from 14.6 years in 1997 to 7.4 in 2002, when the cap was gradually lifted as shortage was looming.. Demand peaked at 5.9 Bcm in 2001, but increasing prices and lack of reserves led to a slump of the market, which fell to a historical minimum of 3.6 Bcm in 2005, and only slowly recovered after that.

Whereas New Zealand may have largely overcome such difficulties, a similar (and more difficult) case is Argentina, where prices have long been kept below import and even domestic field costs for a long time after the 2001 sovereign default and the ensuing macroeconomic disaster. Even though the Argentinean market is larger and has not suffered from serious monopoly problems (but only from YPF dominant position) the very low price ceiling has cut all new exploration incentives and led to reserve decline and wasteful consumption, with the country having to fill the gap by costly LNG imports. The subsidy burden is among the main causes of the further deterioration of the State's public finances.

The sample includes three developing countries (Algeria, Egypt and Nigeria) that are historical gas exporters. All of their market models have "single buyers", which have the role of producing and/or negotiating and purchasing gas from foreign companies and joint-ventures. In fact, such buyer shares some regulatory role, even though a separate regulator exists in Algeria. Negotiations in such cases are based on price as well as on a number of other features, including take or pay factors, but also exploration efforts, bonuses, pricing of natural gas liquids, and taxation.

It is not surprising that large gas producing countries have chosen this regulatory model. It is related to the fact that gas production has different and specific features in each field, which are not easily standardized and understood. The establishment of a National Oil (and /or Gas) Company (NOC) allows governments to maximize their revenue, first by acquiring a deeper knowledge through its direct involvement in exploration and development of mineral resources and secondly by defining tailored purchase conditions for each field[115].

For many years, Egypt actually set the wholesale gas price at the then reasonable level of $2.65/MMbtu. However, such price has later been regarded by oil&gas producers as too low for the development of more costly deepwater fields, and production development has stalled after 2009. At the same time, gas has been sold at heavily subsidised prices to the internal market, notably to the power generation sector, which covers about 65% of the market. At the same time Egypt, like other countries that are mentioned in the next section, has been unable to raise domestic prices, with few exceptions. This has led to a huge imbalance, which has eventually forced Egypt to suspend all its exports, even in break of contractual obligations, in spite of its huge reserves. Only recently some new fields have been awarded higher prices, but the positive consequences are not expected to appear for several years. Only very recently, consumer prices have been raised for most sold gas, to curb the boomed State subsidy burden, widely regarded as unbearable. The outcome of this decision are not yet clear.

Nigeria has explicitly followed the Egyptian model, but has recently separated the single buyer role, which has been attached to a special body, jointly owned by oil&gas companies and regulated by the Ministry. Yet, unlike Egypt, Nigeria’s market has always been dominated by exports. Potential demand is large, as a large shgare of the population still lacks access to electricity, yet the slow development of pipelines and power plants has not allowed the exploitation of the huge gas resources of the country, which are still largely flared. The attempt to regulate prices below those of exports has triggered a vicious circle, with international oil&gas companies (IOCs) often failing to implement their pleas.

Thus, although Egypt and Nigeria have a similar institutional model and are both formally following a policy of resource partition between domestic consumption and exports, both of them have actually failed to implement it, but in opposite ways. In Egypt, domestic consumption has left less and less available gas for exports, and currently all production is absorbed by the domestic market. In Nigeria the downstream infrastructure development has lagged behind exports. In both cases, inadequate pricing policies may be partly responsible, with too low upstream and far too low domestic prices in Egypt (with few exceptions) triggering the growing imbalance, and too low

[115] The main risks of such models are the establishment of large and powerful bureaucracies that may propser on their exclusive knowledge of valuable insider information.

domestic prices in Nigeria hampering the development of infrastructure. Both countries are now actively trying to fix the problems.

In Algeria, a similar pattern also occurred, with slow updates of upstream prices, whereas those for the domestic market are kept well below costs. However the larger reserve base of the country and its smaller domestic absorption have managed to keep enough exports to subsidize domestic consumption. Yet, recent tenders for exploration acreage have not been very successful and the country is struggling to maintain its export levels.

3.2 Regulatory responsibilities

The next Table shows how regulatory responsibilities are assigned to institutions in each country. Institutional settings of countries are very different, as so are the power separation, and transparency standards, hence the independence of formally separate regulatory bodies may be very limited in several cases.

Table 3.2 - Regulators in charge of gas pricing mechanisms by sector

Country	Wholesale	Power generation	Retail (industry)	Retail (Residential & Comm.)
US	None	None	None	State PUCs
Brazil	None	Special program (Govt)	None	State regulatory Agencies
Argentina	Energy Secretariat (Ministry of Energy), Regulatory Agency			
Netherlands	None	None	None	None
France	None	Ministry of Energy		
Italy	None	None	None	Energy regulator
Algeria	Upstream regulator (ARH)	Energy regulator (CREG)		
Egypt	Ministry of Petroleum			
Nigeria	Ministry of Petroleum			
Russian Federation	Various	GOG	Federal Tariff Service	
China	Pricing bureau of National Development and Planning Commission			
India	Ministry of Petroleum & NG	Petroleum & Natural Gas Regulatory Board (PNGRB)		
New Zealand	None	None	None	None
Israel		PUA		

Even among Western style democracies, responsibilities are very different. Whereas energy regulators are normally in charge of setting network tariffs, in a few cases the responsibility with gas prices has remained with the government. The same happened in the past, when more OECD countries has gas price regulations:

In the U.S., before controls were abolished, they were issued by Public Utility Commissions in and with the Commerce Commission in New Zealand[116] but by the Ministry in the Netherlands and (even now) in France. In Russia and China, tariffs are formally issued by a Government Agency, but this is hardly independent from Government opinions.

The Ministry is also the regulator of the gas industry in large producing countries like Egypt and Nigeria, and is in fact the regulator in Argentina as well, leaving to the official regulatory body that was in charge in the 1990s a mostly advisory role.

3.3.Economic conditions of regulation

The previous sections have already outlined how the regulation of natural gas prices is far less widespread, transparent and standardized than that of electricity industry. This is not necessarily true of networks, but it is particularly true for gas prices, notably where natural gas is domestically produced rather than imported.

This situation is not necessarily the result of political choices, but is probably related to the “natural resource” character of gas, which, unlike industrial products like electricity[117], is produced in each field under almost unique circumstances, which cannot be properly benchmarked against those of other fields. Therefore, the regulator is not usually able to properly assess the costs, e.g. by comparing them with those of akin plants, as it happens in power generation.

This is true not only for costs, but even more for the quality of services parameters. For example, the duration (depletion time) and the performances of the field in terms of peak and flexibility (ramp up or ramp down rates) cannot be properly assessed by the regulator, and their negotiation is subject to a serious information asymmetry in favour of the company. The regulator’s ability to benchmark the production site performances and their costs are also hindered by the high confidentiality of the industry: most companies or even their clients or regulators would not disclose field or treatment plant performance data, as this may damage their international market competitiveness.

Difficulties that are even more serious emerge in the assessment of some specific cost items of gas productions. In particular:

[116] The Commerce Commission of New Zealand is mainly a Competition Regulator, but has also the power to regulate Utility tariffs where necessary.
[117] Hydro and other renewable sources of electricity are more akin to oil and gas fields on this respect.

1. Since any gas field is exhaustible, its use has a certain “user cost”, which can also be seen as the opportunity costs of producing the gas now rather than “leaving it in the ground”, or keeping it as an asset for the future. This is known as *Hotelling’s rent* in the economic literature and its analysis dominates the economics of exhaustible resources. There is a general agreement that the user cost of mineral resources is positive, but its level and trend is uncertain. From a practical perspective, neglecting it would be wrong, but its actual value can hardly be estimated, as it is related to the evolution of technology, demand, resources and regulation.
2. The twin problem of the above is the uncertainty about depletion – and hence depreciation rates of the fields. The next Chapter will practically show how widely prices can change if different depletion rates are used, yet this is far from certain for the regulator. This problem has been noticed in the American experience.
3. A substantial part of the oil and gas industry’s costs lies in the exploration stage, which is not always successful. It is not clear and not internationally agreed how to charge such costs on successful investments. The problem was already addressed in the 2012 report.
4. There is often some natural gas liquids production that is associated to that of gas, and is highly valuable. Its share is very variable and even uncertain across time, and its value is strictly related to the trend of oil prices. Any properly cost-based regulatory mechanisms should therefore be related to oil markets, at least through this way.

All of these difficulties help explaining why cost based regulation is not common in the more advanced regulatory systems, and why it is not transparent in others. The available information on regulatory practices hardly exceeds the rather general information of Table 3.1 above.

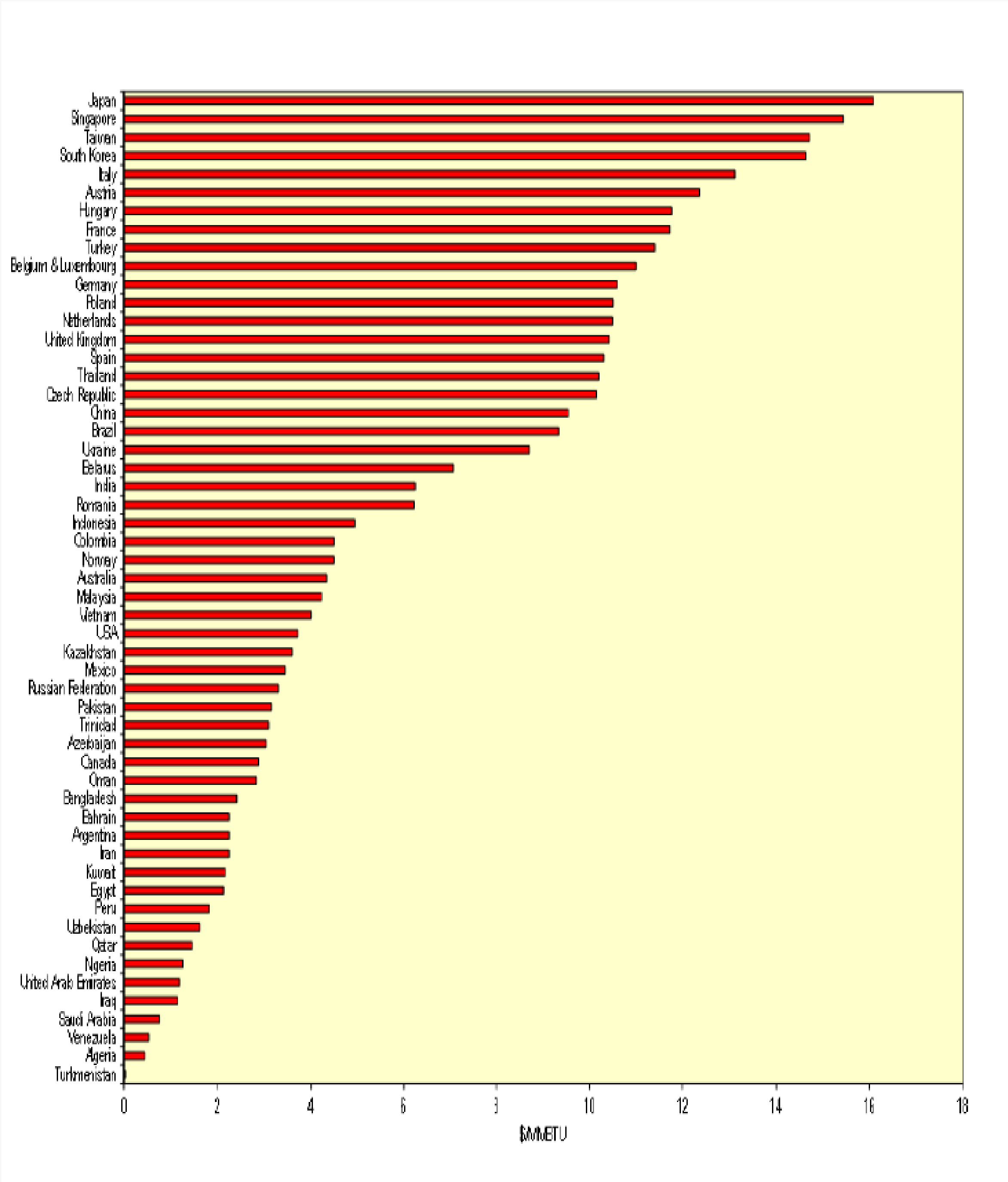
Some more information exists about rates of return that are allowed on upstream investments, which are typically in the 12-15% range. They are somehow related to the “country risk”, and this explains why these rates are above the average yields of the oil and gas industry, which are in the 9-10% range[118]. On the other hand, if depreciation is a problem for upstream resources, the valuation of capital is less so than for networks, or for aged power generation equipment. Most assets are relatively young and most investment costs are recent, therefore CAPEX valuation is less problematic if company accounts are available.

3.4 Price levels

The IGU Survey publishes a Chart of world wholesale gas prices, which is not as transparent as our Survey, but covers a much larger number of countries (see Figure 3.1). The information can be usefully compared with that of Table 3.3, which is taken from our Survey.

[118] Pindick, quoted by Smith (2012).

Figure 3.1 – World Gas Prices



Source: IGU Wholesale Gas Price Survey - 2014 Edition

Looking at both sources of information, it is clear that a basic difference exists between self-sufficient countries and net exporters on one side, and net importers on the other side[119]. There is indeed a gap in the Chart between the lowest level importing country (Romania), which lies around

[119] Since the U.S. and Canada are a fully integrated and liberalized market, they can be regarded as a single market, and are now (if taken together) a self-sufficient area, with minimal external trading flows. Likewise, the EU is now an almost integrated market, with limited internal price differences, and is a net importing area. Therefore, even the Netherlands have now the typical price levels of net importers.

6 $/MMbtu, and the highest level self-sufficient country (Indonesia), which is in the low 5$ range[120]. This gap is partly explained by transportation costs, which can be as low as a few tens US¢/MMbtu for pipeline connection between small neighboring countries, but may exceed $6 for LNG transportation at long distances.

Table 3.3 - Gas price levels, 2013 (Averages or ranges; excl. sales taxes)

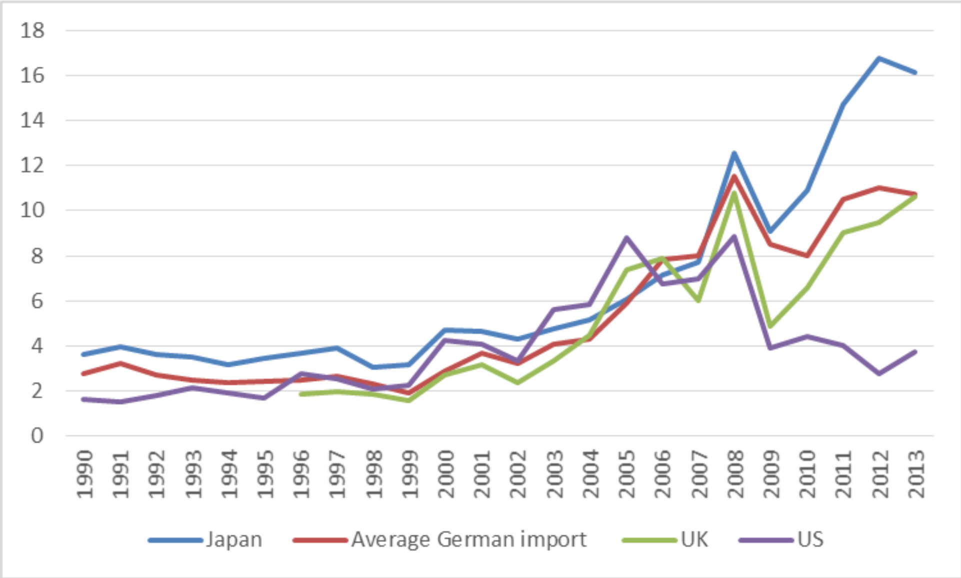
Country	Wholesale	Power generation	Industry	Residential & Commercial
US	3.71 – 7.04	4.49	4.66	8.13 – 10.33
Brazil	8.13 - 9.32	4.46 (Jan. '14)	15.05 -19.82	N.A.
Argentina	0.74 – 1.98			
Netherlands	10.54	11.08 – 11.56		None
France	10.75	11.65 – 12.97		
Italy	10.90	11.97 – 12.97		Energy
Algeria	0.37	0.51	0.51	N.A.
Egypt	2.65	1.25	1.25 – 4	0.8
Nigeria	0.8	1.8	2-3	N.A.
Russian Federation	1.93 – 3.63	2.98		
China	6 – 14	10.6	14.6	10.4
India	4.2 – 5.25			
New Zealand	6.15	6.15	6.85 – 7.9	24-40
Israel	5.4	5.04-5.89		

In fact, the 2013 situation is not regarded as an equilibrium one, as price have been driven apart by the shale gas revolution in North America, and by the fast Chinese demand growth coupled with the Fukushima events, which have exacerbated East Asian demand. LNG shipping capacity is not currently enough to bring price gaps down to the level of transportation costs, but gaps are expected to close in the future, and they have been historically lower (see Chart)[121]. Expansion of the LNG carrier fleet, entry into service of new liquefaction capacity in Australia and elsewhere, the start of US LNG exports, of Russian pipeline exports to China are all factors pointing to gap closing.

[120] In fact, Romania is largely self-sufficient and still rather isolated within Europe, with a heavily regulated market: this explains why it has kept a relatively low price level. Indonesia is on the edge of becoming a net importer.

[121] The short term tendency of 2014 is clearly towards closing the gaps, with Asian spot LNG prices as down as 11 $/MMbtu, and European price in the 6-7 $ range.

Figure 3.2 – Selected World Gas Prices: historical trend



Source: BP Statistical Survey of World Energy 2014

It is interesting to notice that at 5.4 $/MMbtu, Israel's wholesale prices are clearly above those of self-sufficient countries and net exporters, though still below those of net importing areas. This is a major lesson from this Survey.

3.5 Price escalation

Table 3.4 summarizes the results of our Survey regarding price escalation mechanisms, where available. As one can notice, inflation is not a common index and is only sometimes used as a secondary indicator. Normally gas prices are indexed to four classes of prices:

- Competing energy sources, notably oil derivatives, sometimes coal, with a view to ensure competitiveness of natural gas towards them;
- Gas market hub prices: these are used as a way to approximately reflect the procurement costs of natural gas by marketers, while at the same time providing an incentives on them to purchase gas as cheaply as possible. This is due to the fact that the index is (largely) independent of the actual procurement cost, therefore a smarter than average buyer could achieve some extra gains;
- Actual costs of gas supplies (pass-thru): this type of indicator is derived from the supplier's accounts, and is similar to the previous one. It is more precise (cost-reflective), but provides less incentives to reduce gas purchase costs for retailers or distributors;
- Prices of products made with gas: electricity is the most obvious example, but there also examples with methanol and fertilizers. It is a practical approach only if the products are

sold in liquid and competitive markets where their prices cannot be affected by the producers[122].

Table 3.4 – Indexation mechanisms

Country	Wholesale	Power generation	Industry	Residential & Commercial
US	Not applicable	Not applicable	Not applicable	Hub price – Gas cost
Brazil	Inflation, Oil product prices; RPI-X for distribution			
Argentina	Not clear			
Netherlands	Not applicable (Oil product prices until 2002)			
France	Not applicable	Oil products and gas hub prices		
Italy	Not applicable	Not applicable		Gas hub prices
Algeria	Fixed growth factor (5%) and US$ exchange rate			
Egypt	Not applicable			
Nigeria	Convergence towards export parity			
Russian Federation	Inflation, oil products prices			
China	Oil products prices			
India				
New Zealand	Not applicable (Inflation until 2002)			
Israel	5.4?	5.04-5.89	?	?

In Europe, the discussion of escalation mechanisms for regulated tariffs has recently centred on the evolution from oil price based towards gas hubs based mechanisms: this is related to the increasing liquidity of gas hubs and hence on their reliability as an unbiased indicator. In the US, pass-thru mechanisms are more common.

Besides regulated tariffs, it is also important to consider the escalation mechanisms of private, unregulated trade. Indeed, this has its own rationality, and it is useful to understand it, as it should be considered by a regulator to decide what should – or should not – be required from a private supplier.

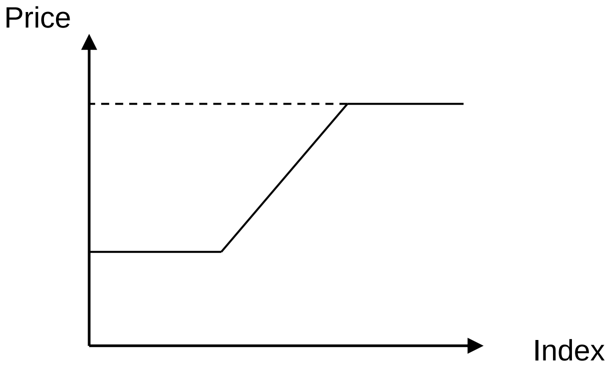
The traditional risk split of gas markets is to leave the price risk upon the producer (supplier) and the quantity risk upon the buyer. The escalation mechanism is tailored to confirm this risk allocation: in particular, if prices are related to those of competing fuels, the buyer will be

[122] Hence, this approach is not suitable for a regulated electricity market like Israel's.

reasonably sure that gas keeps a competitive price that is against those of competing fuels[123]. This helps the buyer to be protected against demand swings, and shifts more price risk towards the seller. However, the buyer is not protected against the risk of a demand slump, as he must pay for gas at least a certain minimum quantity (take or pay clause), even if the gas is not withdrawn. On the other hand, the producer carries the risk of seeing prices going down, and is therefore incentivized to hedge such risk by integrating downstream[124].

In practice, there are variations around this theme. The most common one is represented by S-curves: the indexation mechanism only holds within a certain range, with a floor protecting the producer against too low prices, and a ceiling protecting symmetrically the buyer.

Figure 3.3 – S–curve pricing with floor and ceiling



In international trade, the typical practice is to link gas prices to those of oil and/or their derivatives: this is the traditional approach, which the Dutch sellers pioneered in the 1960s and Russian and Algerian producers have staunchly defended until today. It is still the predominant approach where no liquid hubs are available and relevant, as is the case of the LNG-based Asian trade. Other major exporters have been more flexible, notably those from Norway and Qatar, and even Russians are now accepting increasing shares of hub price escalation.

Even more interesting is the fact that Asian purchasers have been lately accepting different mechanisms, including the indexation of gas to the main US (Henry) hub, particularly for new contracts for export of LNG from the US. For example, some Indian, Korean and Japanese companies have accepted, or are considering, price formulas where the price amounts to a percentage (between 85% and 115%) of the Henry Hub[125] price, plus a fixed premium. This approach amounts to a slightly different risk allocation between the parties: it reassures the

[123] This is perfectly rational even for the indexation of gas purchased by a power producer under monopoly, as it would guarantee that the price is aligned to that of a competing fuel. That is why in the original 2012 Report (sections 4.1-4.2), we have considered the indexation of the gas price to that of coal.

[124] For example, the seller would have an incentive to buy interests in gas retailers or in power generators, to the extent that end products prices are not entirely linked to wholesale ones.

[125] Henry Hub is the main US gas hub and its spot and forward prices are priced at the New York Mercantile Exchange (NYMEX) and extremely liquid.

producer that the price he receives will be aligned with the alternative market. Yet, it is also an implicit reassurance for the buyer, who will see his counterpart always eager to sell him the gas, without the risk of seeing him walk away from contractual supplies, or seeking price reviews, as it has recently happened in several cases. Moreover, the price is linked to a market that is seen as very competitive, and therefore protected from extreme and lasting swings.In any case, periodical (typically three-five years) price are always foreseen to deal with major changes of the market environment.

4. LESSONS FOR ISRAEL

4.1 Pricing theory and its applications

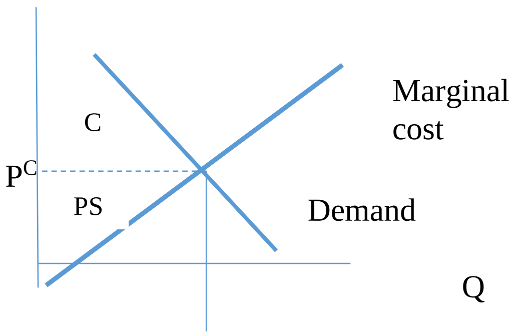
Economists have consistently suggested that prices should be aligned with the marginal cost of supplies, which is the cost of providing further (new) supplies; and with the opportunity cost of gas, that is:

- the value gas would have if sold to another market,
- the price of another fuel with comparable performances.

The former definition is particularly relevant for self sufficient and (net) exporting countries, the latter for net importers. In a competitive, unregulated market, as shown in the well known graph of Figure 4.1, the equilibrium price P^C would prevail, where the marginal cost is equal to the opportunity cost. Hence, in a perfect market the equilibrium price would equal both the marginal cost and the opportune ity cost, or the value that gas is given by consumers.

In this graph, economists notably point at two areas: the “consumer surplus” (CS), which is the area below the demand curve and above the market price equilibrium; and the “producer surplus” (PS), which is the area below the market price equilibrium and above the supply (marginal cost) curve.

Figure 4.1 - Outcome of a competitive market



However, in markets that are dominated by a reduced number of suppliers (and even more if by a single monopolist), it is likely that the price is set at a higher level P^M (Figure 4.2), as it can be shown that this level would maximise the profits of the monopolist, or cartel. Conversely, in a market that is regulated by a public authority on behalf of consumers, it is possible that the price is set below the equilibrium competitive price, for example at the average production cost, that just covers average production cost (P^R). In this case, the producer would just cover its total costs: in the natural gas case, this can happen if the producer internally cross-subsidises more costly fields by the cheaper ones[126]. In this way, the consumer surplus is maximized, but consumers' gain are ouweighd by the loss of producer surplus, hence total social welfare is not maximised (Figure 4.3).

Figure 4.2. Outcome of a monopolised market

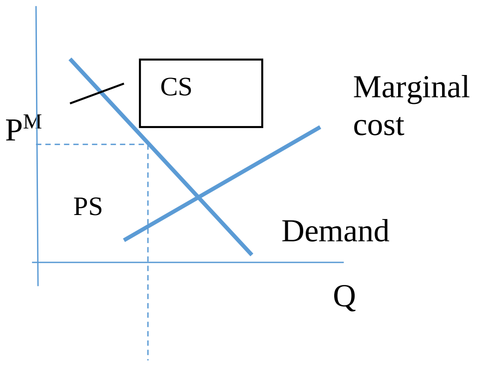
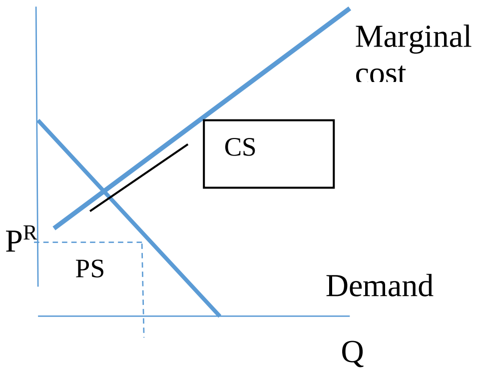


Figure 4.3. Outcome of a market regulated at the average production cost



Economists criticize both of these solutions. In case the monopoly cannot be broken and a regulated price is necessary, they recommend regulating near the marginal cost of supplies, which is in practice the cost of the marginal fields, usually those that enter the market at a later stage. In case such information cannot be adequately worked out, for reasons discussed in the next section, and if the country is tied to international markets, they recommend pricing at the opportunity cost, which is the price at which the gas would be valuable on international markets minus transportation cost[127]. This is known in the industry as the "netback" price of gas for the exporting country.

The reasons why both the monopoly price and the average cost price are criticised are twofold.

In the short term, both such solutions would not maximise the total (consumer and producer) surplus, which is a measure of total welfare. There would be a "welfare loss", also known in the literature as deadweight loss. Whereas this argument is true in principle, the deadweight loss may in practice not be very large.

[126] This has indeed happened in the U.S. under wholesale price regulation. See above, section 2.2.8.
[127] Transportation cost would include liquefaction and re-gasification if gas is transported as LNG.

This argument is often criticized on distributional grounds. Politicians (and regulators if that is their mandate) may have a preference for a redistribution of the surplus, for example from producers to consumers. In other words, they may prefer a smaller total surplus, but a larger one for consumers. In most countries, producers (even including workers) are seen as a limited group, whereas consumers are the large majority of the population.

As a rejoinder, economists suggest that such redistribution is more effectively achieved by other solutions, notably what is known in the literature as “tax and transfer system”. The strength of this argument has been long discussed in the economic literature, and cannot be solved theoretically, but it depends on how effective is the tax and transfer system. For example, use of electricity prices below costs has been advocated for very poor countries, as they are not likely to have an effective tax and transfer system, so that delivering electricity (or other basic products) below cost may be an effective way to redistribute income. Furthermore, access to electricity at very low prices is often the only way to provide several electricity-based basic services to the largest population. Pricing gas at the lowest feasible level when gas is an important fuel for power generation is just another way of achieving the same goal.

However, in countries with a higher per capita income, such approach easily carries the risk of providing subsidies even to a relatively affluent part of the population, which is highly inefficient. For these reasons, most international organizations like the International Monetary Fund, the World Bank and the International Energy Agency are consistently criticizing energy pricing below marginal cost as a way of redistributing income, unless this is limited to groups of vulnerable customers, or for basic consumption levels (blocks). This point is even stronger in case prices are effectively subsidized, and set even below the average cost[128].

In the special case of the upstream oil and gas industry, the tax system includes taxing supernormal profits out of the producers. This can be achieved in a relatively easy way, as oil and gas production can normally be tracked. After the recent reform, Israel is aligned with international practice of upstream taxation, where the marginal tax rate is close to 90%. Hence, almost all supernormal profit are taken from the producers if prices exceed costs, therefore the distributional argument for providing gas below its marginal (market based) price level seems at first to weak, except possibly for limited sectors of the population.

In the long term, the adverse consequences of wrong pricing are much more serious. In fact, energy demand is normally rather price- inelastic in the short term. In other words, demand does not react significantly to price changes. This is truer for electricity, and a little less true for gas and oil products. However, in the long term, when consumers and producers have had the time to adjust their facilities and appliances, things differ. For instance, a power generator is likely to push more on other energy sources if the gas price is too high, so that gas demand would in the long

[128] International Monetary Fund, *Energy Subsidy Reform: Lessons and Implications*, January 2013, www.imf.org

term be less than appropriate if its price was kept too high, and the energy mix of the generator (and of the country) would be inefficient and more costly.

Conversely, if the price is regulated at a level that is too low for new developments, like the "average cost", the market could be rationed on the supply side. Companies would probably refrain from developing more costly fields, or simply prefer to invest their development resources in other, more profitable basins. That would reduce investment in the country, jeopardising further production. There have been many such cases in the world. Two of them could be of particular interest for Israel, although for different reasons.

The first such case is New Zealand, a relatively small market (between 4 and 6 Bcm/year) that has long suffered from dependence from a large single gas field. In fact, the large offshore Maui field was able to almost monopolize the market after its development, and the market was not large enough to develop more; therefore its price was regulated by the Commerce Commission in 1996 and remained almost constant for 6 years. This blocked the discovery of new reserves, and the reserve/consumption ratio fell from 14.6 years in 1997 to 7.4 in 2002, when the cap was gradually lifted. Demand kept increasing, peaking at 5.9 Bcm in 2005, but increasing prices and lack of reserves led to a slump of the market, which fell to a historical minimum of 3.6 Bcm in 2005, and only slowly recovered after that.

A second interesting case is Egypt, where the wholesale gas price has long been fixed (for most gas production) at the level of $2.65/MMbtu. Such price was reasonable for some time is regarded by oil&gas producers as too low for the development of new deepwater fields, and production stalled after 2009. At the same time, gas has been sold at heavily subsidised prices to the internal market, notably to the power generation sector, which covers about 65% of the market. At the same time Egypt, like other countries that are mentioned in the next section, has been unable to raise domestic prices, with few exceptions. This has led to a huge imbalance, which has eventually forced Egypt to suspend all its exports, even in break of contractual obligations, in spite of its huge reserves. Only recently some new fields have been awarded higher prices, but the positive consequences will not appear for several years. Since consumer prices have not been raised for most sold gas, the subsidy burden on the State has boomed, and is regarded now as unbearable.

Generally speaking, regulated prices below marginal cost or market levels are most feared by producers, who are often more aware than governments that subsidies cannot be sustained forever, and that once prices have been capped at a certain level, the political difficulties of lifting them are often unsurmountable. Hence, the issue of removing (explicit or implicit) energy subsidies has become a major concern of many governments, as well as of world environmental policy for negative impact on emissions. A number of countries have been struggling to lift prices towards levels that are necessary to boost new exploration and production. A few examples have been found in our Survey (China, Egypt, India, Nigeria, Russia).

The above theoretical cases are based on the assumption that the market is transparent, so that a single price prevails[129]. On the other hand, the typical solution for buyers in case they feel to be under a market power by producers is by forcing *price discrimination*. If buyers can pay different prices, in relation to the marginal costs of supply, all producer suprsplus can in principle be transferred to consumers (and/or to the State). However, to achieve thgis it is necessary to have either a single buyer, which is the most typical solution (Algeria, Egypt, Nigeria, and others) or by regulating the prices at different, cost based levels (Argentina, China, India). Yet, this approach does not necessarily solve all problems, as producers must get a sufficient return to incentivize them to keep investing in the country. Whereas previous (sunk) investment may lead governments and regulators to expect them to keep producing in the country, competition between countries (and other jurisdictions) may yield different outcomes. The cases of Algeria, Argentina, New Zealand and (in other periods) even Russia and the United States show that the risk of loss of investments, and hence of production decline, should not be underestimated.

4.2 Suggestions for Israel: the framework and recent facts

This Report represents an update of the 2012 NEWES Report, which had examined the Tamar contracts for supply of natural gas to the Israeli electricity industry. This Report will not further discuss the general framework. Only the main events that have occurred after the 2012 Report was issued are briefly summarized here for the sake of completeness:

1. The Tamar Consortium has signed contracts with the IEC as well as with several IPPs for sale of a total of 230 Bcm of natural gas over 15 years (which can be extended by two if necessary), at base prices comprised between 5.04 and 5.89 $/MMBtu. This amount refers to the total contractual quantity, and may be reduced, with take or pay factors that vary among the purchasers.

2. Sales have exceeded expectations, and preliminary agreements have also been stipulated for sales to the Palestinian Authority and to a few Jordanian customers. It is understood that the existing contracts have saturated the expected processing capacity of 62,000 MMbtu/Hr. (41.6 Mcm/day). This is expected to be achieved by 2015, as current capacity is 44,000 MMbtu/Hr.

3. Prices for IEC are indexed to the US and Israeli inflation indices, plus 1% / year for the first 8 years and minus 1%/year for the following 8 years. Prices for IPPs include similar indexation clauses, but a transitional clause linking the base price to the average generation cost of the country may bring the base price down to 4.9-5 $/MMbtu. Floor prices are 4.7 $/MMbtu for most IPPs.

[129] This means that the same price obtains for similar services. The price could be actually differentiated by time of the year or day, quality of service, location, or size of the consumer.

4. The PUA has decided that almost all contractual conditions that are included in contracts will be transferred into electricity tariffs, but there remain some limited gaps, which are borne by IPPs.
5. Contracts include other conditions, notably take or pay clause of between 60% and 80%.
6. Another large reservoir, known as Leviathan, and two smaller ones, have proved reserves, j. The Leviathan concession belongs to a Consortium that largely overlaps with Tamar, with the same three main shareholders (two of which interrelated), representing respectively 66,25% of Tamar and 85% of Leviathan. Latest unofficial estimates mention higher numbers for Israeli reserves, with Leviathan only at 625 Bcm[130] and the total up to 1100 Bcm.
7. The Israeli Antitrust Authority has decided that the owners of Leviathan resources will be required to sell at least 15 Bcm at regulated conditions, such as to allow substantial competition, unless new significant finds occur. This decision will be revised in 2020.
8. The Israeli Government has approved the new upstream taxation regime, endorsing the set of proposals known as "The Shishinsky Report". This Report had been already used as the basis for production cost calculation in the 2012 Report.
9. The Israeli Government has approved a National resource depletion policy, requiring that 60% of the officially estimated national reserves (540 out of 900 Bcm) are kept for domestic consumption. That would leave for export at least 360 Bcm if the reserve estimation is correct.
10. Despite several exploration efforts, no further significant commercial reserves have been found in Israel's territory and exclusive maritime zone. This confers upon Noble and Delek Group a substantial monopoly power, if allowed to jointly market their gas, as they would control about 80% of proved reserves, or even more if the other partners also market their gas together. In principle, this would allow the Antitrust Regulator to fix their prices and other contract conditions.
11. No other major oil&gas company has entered the Israeli gas market. After some preliminary negotiations, Australian LNG specialist Woodside has withdrawn from taking a stake in Leviathan, with a view to building a liquefaction plant. This has been interpreted as the temporary end of the idea that Israeli gas may be exported through a land based or a floating gas liquefaction plant.
12. On the other hand, Tamar and Leviathan Consortia have signed non-binding Memorandums of Understandings with owners of two Egyptian liquefaction plants,

[130] Scheer, Steven; Goodman, David (13 July 2014). "Israel's Leviathan gas reserves estimate raised by 16 pct". Thomson Reuters.

envisaging the sale of gas for liquefaction to the currently idle plants of Idku and Damietta, which may allow them to abide by their supply contracts and the Egyptian Government to avoid painful arbitration proceedings.

13. Related to the above is the pledge to lay another pipeline connecting the Tamar reservoir and Israel, with capacity of 7-8 Bcm per year. The pipeline would connect near the border with with a link to Union Fenosa Gas' LNG terminal in Egypt, according to the above mentioned, non-binding agreement, which envisages sales of 4 Bcm per year. This means that the hourly capacity to Israel will increase from 42,000 MMbtu to around 67,000 and the total capacity will increase from 42,000 MMbtu per hour to 75,600, or about 18 Bcm/year at full load.

4.3 The options

Henceforth, we outline the main options that could be envisaged for the regulation of the Israeli gas market, after considering:

- The main lessons from the international experience;
- The main results of economic theory regarding price controls;
- The background of the Israeli gas market, as summarized above

These options are analyzed in turn, outlining their main pros and cons, notably as regards prices. Finally, a suggested option is illustrated and discussed. A separate section addresses other (non price) contractual conditions.

Since these policy options are largely related to those already discussed at length in the 2012 Report, the general discussion will not be repeated here. The interested reader is referred to the 2012 Report, notably section 1.1 and 2.2. This Report takes stock of new facts and perspectives, as outlined in the previous section, which may justify the choice of a different regulatory approach, and will provide synthetic assessments on the economic impact of the regulation, including their adequacy from a policy perspective. The main criteria that are considered for the assessment of the options are:

- Economy efficiency in the short and long term, including the impact on consumption and investment decisions by suppliers, consumers, power producers and other actual and potential stakeholders;
- Cost-reflectiveness of prices, i.e. their ability to cover current and future costs, and to convey to consumers information about the costs of gas and power supply;
- Stability and transparency of the pricing process and of other contractual conditions;
- The consistency with international market and regulatory pricing practices;

- Impact on the revenue of Tamar suppliers, the Israeli government and the customers.

On the other hand, any analysis of the legal feasibility of the options, considering the requirements of the existing contracts and the laws of the State of Israel, is beyond the scope of the Report.

Some of the options are also simulated, with assumptions about quantities and prices as outlined in Annex 3. This analysis of quantities does not aime to provide realistic, but only plausible scenarios, in order to compare the main options. In particular, the analysis of quantities of Annex 3 has been undertaken only to evaluate plausible levels of Tamar sales, which are now foreseen at substantially higher levels than in the 2012 Report. This affects the production cost estimation.

Option 1: Maintaining existing contracts and prices

As the 2012 Report has shown, current contracts with IEC as well as with IPPs would yield Tamar revenue clearly above costs. Under the common assumptions (see Annex 3) this would yield an average (2013-30) Tamar price of 7.34 $/MMBtu and an internal rate of return of 23.5%[131]. Since the rate of return is so high and the investments would be already largely depreciated after eight years of supplies, we assume that IEC would successfully renegotiate the price after eight years,. and that a further 10% reduction would be achieved three years later.

It is worth underlining that the downward price review is not likely to occur as a result of market conditions. As already noticed, the dominance of the similar Consortia that control both Tamar and Leviathan is not expected to lead to price reductions, as the Israeli domestic gas supply would remain extremely concentrated. However, in case the supplier opposed the price reduction IEC may call an arbitration, where it could easily demonstrate that, at such prices and the associated rate of returns, the price would be excessive even for an “anchor buyer” (a buyer whose outlays justify the investments).

In any case, even if the maximum contractual price reductions did not happen, the overall impact on Tamar’s business case would be limited, due to the late occurrence of the price reviews and due to the floor prices of the IPP contracts. Without the price review, the average 2013-30 Tamar price would be 7,90 $/MMbtu and the rate of return would be 23.8%. The IRR would be even higher if further sales are accounted for, like the proposed sales to UFG for liquefaction at the Damietta LNG plant, or if post- 2030 sales were taken into account.

This last case is entirely plausible, as the assumptions only include total sales between 2013 and 2029 of 198 Bcm. Hence, these assumptions lie on the prudent side. With more generous assumptions of sales in line with the ACQ foreseen by current contracts (230 BCM until 2029) the

[131] A similar conclusion has been reached by Professor James L. Smith of the Southern Methodist University, Dallas, Texas in his testimony in a lawsuit promoted by a customer against Noble Energy Ltd.

average price would be 7.11 $/MMbtu and the rate of return would be 24.6%. In such case, without the price review, these figures would be respectively 7.63 $/MMbtu and 24.9%[132].

Hence, this approach would yield prices that are above cost reflective levels. Such prices would not be efficient, except by chance. In fact, prices would not be related to market determination, or the interplay of demand and supply, but would be driven only by a long term contract, with prices updated only in line with Israeli and US inflation. These prices would also be clearly above the levels found in any net exporting country in the world, which are all below 5$/MMbtu (see Figure 3.1 above).

Moreover, all of the above simulations lead to rates of return for the Tamar reservoir that are between 23 and 25% (after tax), well beyond the typical levels of the world oil&gas industry, which are typically below 10% on average. Even in relatively risky emerging economies, such rates of return are usually in the 12-15% range.

The price review conditions also do not help, as they foresee a price review after eight years (in IEC's contract case) and none for the IPPs – however, four of the five IPPs would indirectly benefit, as the reduction of the average generation cost PT would lead to some decrease of their price.

The existing contracts fare better on the stability criterion, as the price would be very predictable in real terms.

On the other hand, the price of existing contracts is at odds with almost all international practices, both in free and in regulated markets. It is related neither to costs nor to prices of other markets or of other fuels, nor is it set on a competitive market[133].

The same could be said of inflation indexation, which is a common practice for network tariffs under European style incentive regulation (usually with productivity factors partly offsetting the increases) but is unusual for gas supplies, where linkages are normally referred to competitive markets (either gas or other fuels) or to those of end products.

Option 2. Setting prices in line with netbacks of end products

This option is used most frequently for consumption of natural gas as raw material (non energy use), i.e. for the production of fertilizers, methanol, etc. Since such products are traded on a global, competitive market, it is not too difficult to find a suitable price indicator to which the gas price could be linked. Hence with this approach the risk of price swings would be shared between the producer of the end product and the gas supplier.

---

[132] With a larger total sales volume, the average price would be slightly lower as the weight of the pricier sales to industry and other sectors would be lower. Nonetheless, returns would be higher.

[133] Using the classification of the IGU Survey (see section 2.1), it can be described as a case of bilateral monopoly pricing, but with a weak bargaining power ion the buyer's side, as they are not really a monopsonist, as required by the definition of bilateral monopoly. In fact there are other purchasers, namely IPPs, industry and potentially also foreign customers. The seller is aware that the alternative would be LNG or LFO, due to the constraints on expanding coal-fired generation.

This approach can in principle be used (and is indeed used sometimes in Europe) for sales to power generators as well, but only if the price of electricity is set on competitive markets, otherwise a logical circularity between gas and electricity price determination occurs. Since there is no such competitive power market in Israel, this approach is not currently applicable and will not be further discussed.

Option 3. Regulating prices in line with production costs

This approach has been discussed at length in the 2012 Report, subsection 1.1.2, to which the reader is referred for a more detailed discussion. The calculation has been updated (see table A.3 in Annex 3 for the new values). It is however noteworthy that such values are in fact substantially lower than the typical rates of return awarded to IOCs in developing markets, which are more in the 12-15% range. Although the determination of the cost of capital for Israel, couples with the main Tamar operator individual risk factor (beta) yields the results that are given below, it is legitimate to raise doubts that this approach fairly represents the perceived risk of an IOC working in Israel.

Accepting the approach and figures of the Annex 3 assumptions would yield a constant price between 2013 and 2030 of 1.73 $/MMbtu. This value is substantially lower than the value reported in the 2012 Report, due to the fact that Tamar sales are far higher and concentrated in a shorter period.

Allowing a higher return rate (12%) would raise the regulated prices to 2.60 $/MMbtu for a constant price between 2013 and 2030.

Whatever the rate of return, this would be an average price for the whiole period and for all gas consumers. This simulation is without prejudice to how the price could be adjusted over time or for different consumers (IEC, IPPs, industry, and others).

This approach would ensure both cost reflectivity and stability of the tariff. On the other hand, its efficiency record is mixed. As discussed in the theoretical section 4.1 above, setting the price at the average supply cost is not necessarily efficient. In a large, very competitive market (like the U.S.), it is likely that the average and marginal cost are close to each other, and that they are also close to the level that clears the market[134]. However, this is not necessarily the case in international markets, which are largely imperfect due to long time lags and the influence of several geopolitical and policy factors.

In fact, prices that just match costs may be regarded as inadequate by IOCs. This may be partly related to practical difficulties in setting the cost based regulated prices. In particular:

---

[134] In the U.S., this has become even truer after the shale gas revolution, because shale gas plays feature shorter lags between production decisions and their implementation: more wells are required, but they are relatively short-lived, compared to conventional gas. In markets based on conventional resources, long time lags entail far less inefficient markets, and development decisions are heavily affected by expectations about prices, taxes and other policy decisions.

- A share of unsuccessful exploration should be added, and this is rather uncertain;
- costs of actual development may be currently uncertain, as cost overruns are possible. Tariff systems should explicitly include the possibility for them yet regulators cannot blindly accept any future cost increases in advance. Hence a source of regulatory uncertainty;
- in the Israeli case, the cost of capital for the main Tamar developers (Noble Energy and the Delek Group) are relatively low according to publicly available estimates[135], and in line with our estimation. Yet it seems unlikely that the reported WACC is acceptable for IOCs: our survey has shown that Middle Eastern and African countries typically offer rates of return in the 12-15% range, and it is likely that Israel's could be much lower once general risk factors are considered.

The perception of low returns and prices may lead to companies neglecting or postponing development work, or using scarce resources like rigs and specialized personnel in more profitable spots. This is probably the reason why cost based pricing is declining in the world, and why the international experience we have surveyed shows mostly negative results in the mid-long term. In countries as diverse as Egypt, Argentina, the U.S., Algeria, India and New Zealand, cost based pricing has reduced resource development, leading to shortages, which have lately proved very expensive to address[136]. Several of these countries have later lifted price controls: this has indeed happened in almost all OECD economies, except in a few cases, mostly for residential and other small customers; others have lifted prices themselves, or have planned to move towards "export parity" (see Option 5 below). Yet this goal, announced in different ways in Russia, India, China, Egypt, has seen some steps in the desired direction but has not yet been fully achieved in these countries, due to the political difficulty of raising prices after they have been long kept at low levels.

In Nigeria, the regulated prices have slowed the development of infrastructure for domestic gas use (pipelines and power stations), while allowing (and actually pushing) the development of the more profitable export projects. In Russia, a similar problem appeared when financing difficulties slowed new field developments in the late 2000s, but the growth of oil and gas prices has later allowed to overcome the problem, as the main Russian state company (Gazprom) has managed to cross-subsidize domestic consumption by exports. For these reasons, such regulation should be considered with great care.

---

[135] A well known source are the Damodaran Tables (http://pages.stern.nyu.edu/~adamodar/), which estimate an equity cost of 6% for Noble and 9.7% for Delek. Professor Smith also suggests a 9.2% nominal cost of capital before tax, which is not far from our estimates.

[136] As a summary, the reader may refer to Sub-section 2.2.11, about the U.S., notably where it reads: "The failure of regulating US gas prices reflects the futility of using accounting methods to assess tangible costs (that inherently focus on the past) in an extractive resource market where values and prices are driven by intangible expectations of the future. The predictable results of applying misapplied regulatory methods to the gas sector were fuel shortages, various other social costs, heavy litigation and almost constant legislative action (successful or not)." More details are found particularly in subsections 2.2.6 – 2.2.8.

Option 4 – Regulating prices in line with prices of competing fuels

This option has been discussed and simulated at length in the 2012 Report (subsection 1.1.1.d), where coal was identified as a possible benchmark for the Israeli gas price. Therefore, it will not be discussed further.

Shortly, this is in general a reasonable approach where no comparative gas markets exist, so that the main benchmark is the price of alternative fuels. On the other hand, this approach makes sense if there is actual competition between the fuels, which is not the case in Israel, where coal is constrained to a low and decreasing role by a policy aimed at reducing its environmental impact and to keep coal-fired generation as strategic power reserve. Hence, it is hardly a suitable competitive reference.

Option 5 - Regulating prices in line with international markets (export parity)

This option is nowadays much more interesting than at the time of the 2012 Report, therefore it deserves a more in depth analysis.

In the last two years, Israel has defined its export policy, which amounts to keeping for domestic consumption about 60% of available reserves, or about 540 Bcm. Exports from the Israeli offshore are therefore becoming closer to reality. Israel's isolation from the world gas market is expected to be ended once export plans are finalized, much more than it happened with the limited imports of the last two years.

Thus, Israel is moving towards integration with world markets, and the relationship between domestic consumption and exports is already widely discussed. Therefore, it is reasonable to consider export parity as a pricing option. This is the policy that is already prevailing as a result of market forces in net exporting where the market is competitive and there is no price regulation, like Canada or Australia; and it is the type of regulation that is the objective of other exporting countries, like Russia and Nigeria.

Basically, export parity pricing amounts to setting the domestic pricing in such a way that producers earn the same price from national and export sales. Since export prices are defined mostly in competitive markets or (if these are missing) are related to the prices of competing fuels (see Chapters 2 and 3 for details), the (wellhead) price of domestic gas under export parity would be:

WELLHEAD DOMESTIC PRICE = INTERNATIONAL GAS PRICE – TRANSPORTATION COST.

In practice, the difficulty of defining what this amounts to is the actual definition of both the international gas prices and the transportation costs (including where necessary all costs of the LNG liquefaction and re-gasification chain). In fact, it is necessary to define the markets where Israeli gas can be sold, and the routes to transport it into such markets. It is appropriate to define these as precisely as possible, however, this is always an approximate definition, as markets by their own nature change faster than regulatory decisions, which cannot be modified too quickly. The experiences of such countries like Italy, France, China and India in defining baskets of gas and oil products as indices for their internal prices shows that changes normally occur not less than every 2-3 years, or even less frequently. The following pages illustrate which realistic reference markets and indicators can be considered for Israel.

Lately, the announcement of the export policy and other events have contributed to a refocusing of proposals for Israeli exports. In fact, the limited new reserves in the East Mediterranean (including in neighboring exploration areas, notably Cyprus) are now suggesting that reserves may not be enough to conceive a new liquefaction project. This more skeptical attitude also depends on the growing competition from other producing areas, which have been reevaluated (East Africa, Australia, Latin America), on the increasing probability of significant US and Canadian exports, and on the risk that Israeli demand growth may be underestimated, further reducing the amount of reserves left for exports. The withdrawal of Woodside from purchasing a share of Leviathan can be seen as further proof that more promising LNG development projects are to be found elsewhere.

Moreover, the siting of a liquefaction facility would not be easy in the rather densely populated Israeli shores, and the costs of such facilities have remarkably increased in the last few years. For example, the cost of a 5 Mtpa (8 Bcm/year) facility like Egyptian British Gas' Idku plant have been about $2 billion when it was built in the early 2000s, but the current costs of a similar plant are put to as much as $ 6 billion.

Finally, both Idku and the other Egyptian liquefaction terminal, Union Fenosa Gas' at Damietta, are currently almost idle due to lack of gas supplies, as all Egyptian production has been diverted towards domestic consumption, and the country is actually about to start its own LNG imports.

For these reasons, the more recent information about export perspectives point at "regional" rather than long distance sales. Platts' International Gas Report[137] lists among the regional possible sales:

- BG's and UFG's Egyptian terminals, with which non binding agreements have already been stipulated for supplies of (respectively) 7 and 4.5 Bcm7year;
- Jordan (up to 4 Bcm/year);
- the Palestinian Authority (1.5 - 3 Bcm), part of which should however be subtracted from Israeli sales, as IEC would reduce its electricity sales to the same region;
- Cyprus (0.8).

[137] Platts' International Gas Report, 14 July 2014. See also World Gas Intelligence, 18 June 2014.

Other, more ambitious options involve connection of the Israeli (and possibly Cyprus' and Lebanon's) offshore resources to the European Union gas grid, either by a direct connection to Greece, or via Turkey. The Greek solution would entail a very long and costly deepwater pipeline, but the second one would require a shorter route (about 600 km offshore pipeline, plus nearly as many on Turkish land to reach the TANAP pipeline to Europe). The offshore part would not be very different from the 500 Km needed to link up to the Egyptian terminals. In any case, given the economies of scale that would be necessary to justify such project (10-16 Bcm/y), it would be an alternative to the "Egyptian" route, as current Israeli and other East Mediterranean (mostly Cyprus') reserves are not regarded as enough to sustain both[138].

All of these projects involve significant geopolitical risks, including Israel's relationship with its neighbors; Egypt's internal situation; economic zone demarcation problems with Lebanon; and uncertainty about Cyprus' territorial waters, stemming from the controversial status of the island and its pending conflict with Turkey. Analysis of such risks is beyond the scope of the present Report. However, since non binding MoUs have already been signed for delivery to the Egyptian LNG terminals, we have simulated the *export parity price* that would obtain if this route was followed.

For this simulation, we assume that gas is sent to the Idku plant by a submarine pipeline. Reported costs of the facilities are $ 2 billion for the pipeline and about the same for the Idku plant, with operational costs and depreciation in line with international standards and rates of return on investment at 12%. The cost of exporting gas through the smaller Damietta plant would be very similar: it is slightly closer to Israel's borders but its unit capacity cost is probably higher.

Gas would be sold to world markets: probably this the is most difficult choice for the valuation of this approach, as there is currently no homogeneous LNG world price. The difficulty arises from the current unbalance of world LNG markets, where Asian and Latin American prices are much higher than European ones – albeit the gap is not expected to survive in the long term and has actually started to shrink in the first half of 2014. If that happens, the choice of destination markets would be less relevant.

For the simulation, we assume that gas from the Egyptian terminals is sold:

- one third to Asian markets, where a transparent Japan price indicator exists
- one third would go to North-West Europe, where it would be priced after British NBP and Dutch TTF hubs;

[138] "Israel's Export Quota Not Sacrosanct" World Gas Intelligence, 18 June 2014.

- the remaining third would go to Southern Europe and be priced after Italy's PSV, which is the most liquid and transparent market in the area. [139]

Hence, international gas prices are taken from these market, which have published prices. The above suggestions are preliminary and should be tested with a proper consultation of stakeholders, including the purchasing traders. An important principle that comes from the European pricing regulation experience is however to link prices to objective indicators, which cannot be easily affected by the concerned transactions[140].

Having chosen the benchmark markets and a route to reach them (the Egyptian LNG terminals) it is possible to calculate netbacks to Israeli gas fields as a simple subtraction, as in the above formula. The above assumptions would involve a fixed liquefaction and transportation cost to the suggested price locations of between 3.93 and 5.06 $/MMbtu, plus a variable (price-related) component of between 0.81 and 1.02 $/MMbtu. The latter value would be related to a base wellhead gas price of 4 $/MMBtu). The gas price related component consists of own gas consumption of liquefaction and re-gasification plants, of pipeline own consumption and losses, and of "boil-off" gas used as fuel in shipping. All other costs are fixed and do not depend on the gas price, they are taken from the experts' databases and experience, based on publicly available information. Further details on the assumptions are provided in Table 4.1.

Table 4.1 – Costs of Israeli gas exports via Idku or Damietta LNG terminals

Item	Unit	North West Europe	Italy	Japan
Offshore pipeline	km	500	500	500
Offshore pipeline	Capex MM$	2000	2000	2000
Pipeline fixed cost	$/MMmbtu	0,71	0,71	0,71
Pipeline own consumption	$/MMmbtu	0,13	0,13	0,13
Shippinng distance	Nautical miles	3015	1200	8100
Shipping fixed cost	$/MMmbtu	2,52	2,05	3,85
Regasification fixed cost	$/MMmbtu	0,6	0,6	0,6
Shipping &Regas own cons.	$/MMmbtu	0,86	0,81	1,02
Entry fee EU	$/MMmbtu	0,20	0,20	

Figure 4.4 shows the export parity prices (netbacks) that would be calculated from these assumptions with the Israeli (FOB) prices equal to the international gas prices of the last 6 years minus the liquefaction, transportation and regasification costs. For Europe, an entry fee is also added, which is necessary for transportation to the virtual hubs where prices are quoted.. To calculate the price for Israeli customers, costs of treatment and local transportation should be added.

[139] A rather similar approach is suggested in the new Indian regulatory formula, currently under implementation (see section 2.14). in that system prices are tied to European hubs, Japan's netbacks and US prices. However, the logic of having a mix of CIF and FOB prices (i.e. with and without transportation cost) is questionable.

[140] Linkage of prices to external benchmarks, like Platts' quotation of European and Asian prices, entails an incentive for purchasers to bargain harder with suppliers, as they can cash in the savings with respect to the indices, with benefits for the industry that can eventually be partly transferred to end customers. This incentive does not hold if buyers can see their actuals costs directly passed through to end customers.

In line with widespread regulated gas pricing practice, the link would be to a moving average rather than the monthly price, in order to smooth the harshest market price swings. Thus, the Chart shows the 3-month lagged average of the three netbacks, and their simple average.

This option fares well in terms of efficiency properties, as it would ensure that domestic and export sales yield similar returns to the producers. Hence, the companies would have no incentive to privilege either of them. On the other hand, it is less cost reflective than the cost based approach (Option 3) but probably more cost reflective than current contracts (Option1).

Since market prices fluctuate significantly, it is not possible to foresee which prices would be entailed by such option beyond the short term. If such approach were applied in July 2014, based on the latest available prices, the average price would be 2.98 $/MMbtu. Forecasts based on the averages of longer time series of gas prices would be as follows:

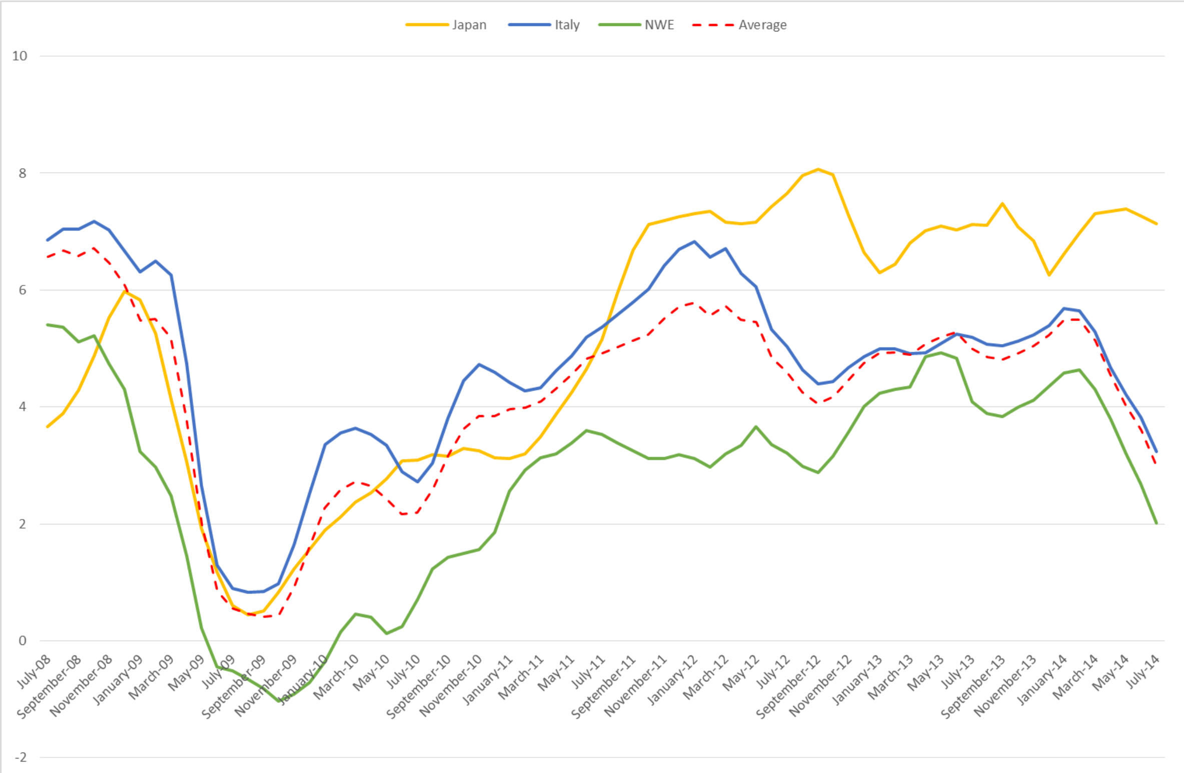
Average of	$/Mbtu
1999-2013	3.07
2004-2013	3.81
July 2008 – June 2014	4.24
July 2011 – June 2024	4.98

It may seem that prices have gone up steadily, but this is not necessarily the case. In fact, prices have fallen in the last summer, as well as in the 1990s and after the 2008 financial crisis; their lon term increase in real terms has been limited and lower than in the oil case.

The linkage to international price would also be in line with the most recent tendencies of gas pricing, both in free private transactions and in regulated markets. It would be in line with the latest practice of price regulation in Europe, with the declared policy objectives of India, Russia and China, and with the recent practice of many international contracts. As such, this approach should in principle be acceptable by IOCs as well – even though no company would accept at first sight a regulatory approach involving a fall of profits.

However, the results of this approach would be hardly acceptable in terms of price stability. Prices could even fall into negative territory, or rise to rather high levels, unless very long average are taken. In fact, using moving averages is partly a solution to the price swing problems, and the duration of lags should be also a matter of consultation, with international practices typically spanning between 3 and 9 months, and some contracts using futures rather than spot prices. Yet, too long lags would jeopardise the efficiency and offer a broader scope to arbitrage practices[141].

Figure 4.4 – Netback values of Israeli gas exported via Idku/Damietta LNG terminals



In regulatory practices of European countries, where prices are typically linked to international benchmarks, they are usually updated every three months: this is also the typical update frequency of the international supply contracts of the most important suppliers. Emerging economies have preferred more stability, with annual or even less frequent updates, but these have often triggered losses by domestic suppliers (notably in China). Whereas state-owned companies may withstand such margin swings, this would probably scare off international oil & gas companies.

4.4 The roles of new Israeli supplies and of other policy options.

One the major new facts of the last two years has certainly been the appraisal of the new deepwater discoveries, notably the huge Leviathan field, one of the largest reservoirs found in the last decade in the world. This appraisal, at over 600 Bcm, together with Tamar and smaller fields brings total reserves to over 900 and possibly up to about 1100 Bcm.

[141] For example, if the indexation led to countercyclical prices of Israel originating supplies, this could trigger an unusual sales pattern. This is not necessarily damaging, but it should be carefully considered by concerned companies as well as by regulators.

Whereas it is not yet clear nor has been decided how the new fields will be exploited, it seems most likely that they will be connected to the Israeli domestic grid. Hence, there will be no physical separation between the domestic market and export systems.

Given the huge size of the new finds, it is difficult to adopt recommendations that do not consider Leviathan and the other fields as well. However, there is no much information about Leviathan other than it is in ultra-deep water (even deeper than Tamar). Estimations of its cost of development are only found in the press at about $6 billion, or twice the initial cost of developing Tamar. Such information is too little for a sound estimation of production costs. However, at first sight and considering that the reservoir is also assumed to contain some 600 billion barrels of oil equivalent as condensates, it seems that its final costs should not be dramatically different from Tamar. It is worth recalling that the latest estimation of Tamar's investment costs (used in our update of the Tamar production cost estimation, as discussed under Option 3) is up to 4.8 $ billion. It is likely that for Leviathan costs to reach levels similar to Tamar's, their investment cost would have to increase to over 10 $ billion[142].

For comparison, the giant Shah Deniz field in Azerbaijan's Caspian offshore, with reserves estimated at 1000 - 1200 Bcm, will be developed at a cost approaching $25 billion, including a domestic pipeline to the Georgian, with a production of nearly 16 Bcm/year.

Compared to Shah Deniz, Leviathan would yield a less sour gas, but would require shorter pipelines for landing to Israel. Using this benchmark and assuming a cost inflation of investments up to 22000 $ billion for a capacity of 15 Bcm/year would yield (at 12% discount rate and with the same unit operational costs and taxation of Tamar) an average cost of 3.03 $/MMbtu.

Thus, the order of magnitude is unlikely to become very different from Tamar, but no conclusions can be assured without a proper and specific assessment, which can only be obtained from a specific, geological and engineering study. Acquisition of the company studies, including those prepared for the proposed Woodside investment, would be a preliminary and useful step.

The participants of the Tamar and Leviathan consortiums, particularly their operator (Noble), may hold the development of the new reservoir as a card in the negotiations with the government about price control. They can claim that that if there is price control of sales of gas from this reservoir to the Israeli market (not to export), its profitability is jeopardized so that they would look for better opportunities elsewhere.

It is worth noting that if the Turkish route was viable, it could haul East Mediterranean gas to Europe at costs that would be competitive with Caspian or Northern Iraqi gas. However, if such route was not practical, development of Leviathan would be probably lower and its exploitation

[142] Professor Smith also suggests that the cost of further, larger developments in the same area should not exceed that of Tamar.

deferred in time, unless some gas is old locally, i.e. in Israel and neighbouring countries. Forecasts are extremely difficult, as demand has been growing fast not only in Israel but in the whole region, with Egypt, Jordan, Lebanon, Iraq currently short of gas, but with huge geopolitical difficulties hampering long term investment. Limiting the analysis to Israel and the LNG sales foreseen by the recent non-binding MoUs, it is worth recalling that the Egyptian terminal capacity does not exceed 11.5 Bcm/year, and that if Egypt's production recovers its growth – as allowed by its huge reserves of over 2500 Bcm – this route can only have a limited significance.

As for the domestic market, with potential supply of up to 16 Bcm per year and 67,000 MMbtu per hour from Tamar only, Israel may expect a supply guaranteed until the depletion of this reservoir (in about 20-25 years). However, international observers (as quoted by WGI, Platts' International Gas Report and other similar sources)have become increasingly skeptical about forecasts in the Middle East and North Africa (MENA) region. Population and income growth have driven electricity demand beyond all expectations, and exploration failures – often fostered by regulatory inadequacies, as shown in the Egyptian and Algerian case studies of Chapter 2 – have led to gas shortages that are now found almost everywhere in the region. For example, Kuwait has become a net importer, Iraq and the Emirates have suffered from shortages and struggle to develop more of their reserves, Oman has reduced its exports, and even Saudi Arabia has not developed its potential but to a small extent[143]. It is understandable that such points – tight price caps coupled with unexpected booming demand, may be used by international companies as a point in their cases.

Moreover, the official export policy that has been described in section 4.2 above sub. (9) clearly sets the amount of natural gas that should be kept for domestic consumption and not exported to 540 Bcm. This is clearly much larger than any estimate of the Tamar reservoir, hence domestic consumption is legitimately assumed by stakeholders to significantly weigh on the Leviathan (and smaller fields) as well. Hence, the official policy of announcing a reserve split between domestically and export resources – although not uncommon, as Nigeria's and Egypt's example have shown – can be actually damaging in the short term, as it gives a point to IOCs about the risk of domestic price regulation.

Experiences described in Chapter 2 have shown that exports quotas are often not implemented, as market forces or regulatory constraints prevail, either by exceeding or falling short of the export quota. It is also very difficulty to qualify such strategy, i.e. by specifying over wihich periods it is is supposed to be verified. A different approach is currently being followed in the U.S., which are – just like Israel – on the eve of becoming an exporting country. In the U.S., authorizations to exports have been preceded by cost – benefit analyses, trying to compare the benefits from export

[143] On the other hand the main success story (Qatar), as noticed by a rare comment from Exxon –Mobil's CEO, has been triggered by a sound regulatory regime that has been based on the alignment of the interests of the host country and of its international partners.

revenue against the costs in terms of domestic price impact and its consequences for the country. This would be the basis for limited export licenses, which are not expected to be repealed except in extreme cases.

A full analysis of the Leviathan market potential lies beyond the scope of this Report. In any case, the integration and connection of all main reservoirs is advisable, also for security of supply reasons. It might be that at peak demand the interconnection may help avoid shortages, so that export and import markets would be further integrated. LNG exports out of interconnected reservoirs would certainly help towards avoiding peaking problems, as peak demand and higher prices in the LNG market are normally achieved in winter, whereas in temperate countries like Israel and other MENA countries demand peaks in the summer, due to air conditioning boosting electricity demand.

More generally, the threat of not developing a huge reservoir (like Leviathan) should be taken seriously. The cases of Argentina, Egypt, Algeria and Saudi Arabia (and in the past, also the U.S. and New Zealand), show how the availability of huge reserves does by no means ensure that they will be developed, as scarce resources can indeed be moved towards countries with a better regulatory framework.

The main focus of this Report is on price regulation, and aims to suggest a reasonable pricing policy that may strike the balance between producers and consumers, and be acceptable to both. However, before a proposal for such price regulatory policy is outlined in the next section, it is worth recalling that price regulation is neither the only nor necessarily the best policy. In fact, most producing countries, notably net exporters, have variously relied on two other classes of policies. These are not suggested, but only recalled, as at least a reasonable threat of such policies is advisable. In fact, exclusive reliance on price regulation has typically triggered shortages or loss of export potential even in the advanced countries where it has been used, like the U.S. until the early 1980s and New Zealand in the late 1990s. On the other hand two other major classes of policies are available:

1) **Antitrust action**. This originates back to the Sherman Act of the United States in the late 19th century, and has widely affected the oil & gas supply industry. Lately, antitrust action has been most effective in Europe to break gas monopolies, with the EU or National Competition Authorities requiring the divestment of essential infrastructure and gas contracts or volumes (*gas release*) in countries like the U.K., Italy, Germany, Austria, Spain, and Turkey. This has not entirely solved market power problems in the gas sector (in the Regulators' view, see section 2.7) but has certainly allowed the development of adequate competition for large industry customers like power generators;
2) **Nationalization**. However draconian this solution may be, it is worth noticing that most net exporters in the world do have their national (oil&) gas companies. This is the case of all

producers from emerging and formerly centrally planned economies, both in the sample of our Survey (Russia, India, China, Egypt, Nigeria, Algeria, and recently also Argentina) and outside it (other MENA countries, Indonesia, Malaysia, Venezuela, Bolivia, Iran, Azerbaijan, Turkmenistan, etc.) as well as of several countries of market oriented, Western tradition (Italy, the Netherlands, Brazil, and others).

3) **Single buyers**. This solution is short of the establishment of a national company, but would establish simply a body in charge in charge of purchasing gas and supplying it to the market at regulated prices. It could have the required expertise to assist government and regulators in the proper setting of regulated prices, after Guidelines issued by the latter. Examples of this model are available in Nigeria, New Zealand (in the past) and also in the electricity sector.

All countries in the world have adopted at least one of these policy instruments, with antitrust action prevailing in the "Western style" free market economies and nationalization prevailing in the others. In the Western, industrial countries price regulation is either absent or has been generally market oriented, with domestic prices in line with export netbacks. For example, on of Australia's most influential regulator, the New South Wales Independent Price Regulatory Tribunal, has recently acknowledged that:

"The ability to export LNG is driving a fundamental change in eastern Australia's wholesale gas market. With gas reserves being directed to these exports, eastern Australia is becoming part of a single global market for commodity gas, and wholesale gas prices are being influenced by international prices."

Exceptions are found in the past, like the U.S. and New Zealand cases, but cannot by any means be regarded as success stories.

These observations should not be interpreted as a suggestion to set up an Israeli national oil & gas company (NOC). Overall, the establishment of such bodies has pros as well as cons. On the positive side, national companies can gain a remarkable expertise, which allows them to better evaluate costs and performances of contractors and joint venture partners much more thoroughly than any regulator can do. In fact, negotiation between NOCs and IOCs span over a number of parameters, including exploration effort, production performance and flexibility, environmental impact control and monitoring, and others, which are beyond the capabilities of typical energy and competition regulators. NOCs can to some extent step in or reasonably threaten to get rid of producers that exploit their positions by extorting too high rents.

On the other hand, NOCs can turn into large and bureaucratic institutions that become extremely influential within countries, and are hardly controlled by democratic governments. In Europe and elsewhere, they have become – and often still are – a major obstacle towards market opening, sometimes substituting their market power to that of IOCs, and being less easily eradicated than the latter. Limited bodies, like single buyers, run lower risks of the kind, notably if their mandate is limited in time.

As a conclusion, it is unlikely that the problems of market power can be solved only by regulatory action acting through price and tax leverage only. It is likely that substantial antitrust action should be undertaken to break dominant positions, unless a national company is established, possibly through the nationalization of the main companies based within the country. However, further analysis of such policies is beyond the scope of the present report.

4.5 The suggested solution: S-curve pricing based on international markets

There are no perfect solutions. Any regulatory as well as private contractual solution is the result of balancing often conflicting objectives, and of bargaining power, including the possibility for companies to “walk out” of the country or to abstain from development investment. This has often occurred, as shown by the experience of a few countries analysed in this Survey;

In turn, sovereign countries may also partly or totally nationalize the gas industry, by establishing a National Company. This is indeed the typical approach whenever governments want to pursue goals that are significantly at odds with market opportunities, as shown by the cases of Russia, China, Nigeria, Egypt, Algeria, Brazil and (more recently) Argentina.

With these (rather extreme, but not negligible) cases in mind, and with a view to maximize the positive features of the above analysed options, we suggest a mixed solution. This solution would consist of:

- a price defined by netback with respect to a suitable basket of international prices, for an intermediate price range, as discussed above as Option 5;
- a floor price, to be defined in relation to a minimum cost necessary for the development and operation of the Tamar (and/or other fields), as discussed above as Option 3;
- a ceiling price, defined by the price level of current contracts, as suggested under Option 1.

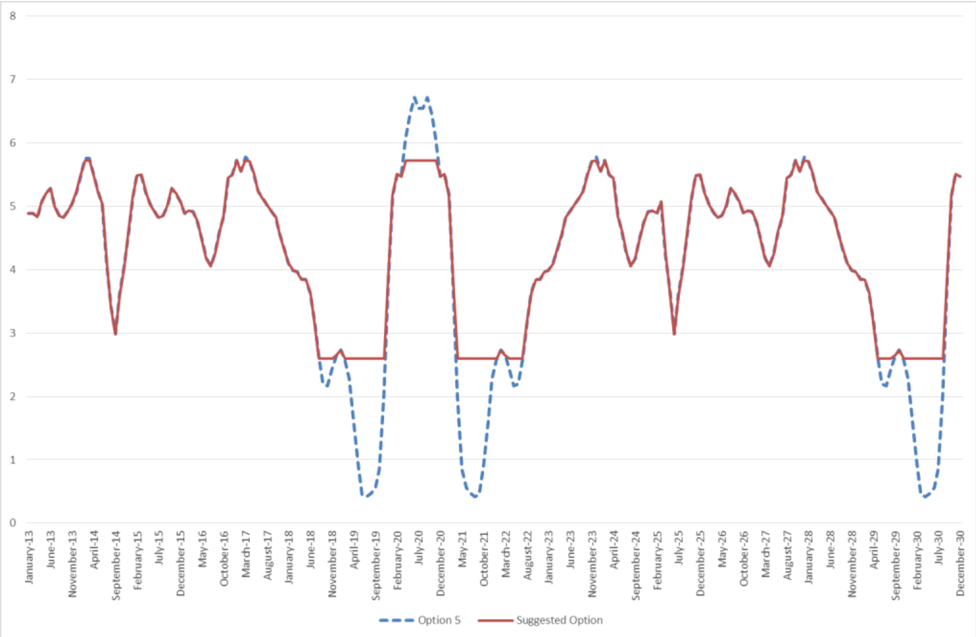
This pricing rule would therefore amount to what is known in international gas opricing practice as an S-curve. It is similar to, but slightly different from, Option 5 that has been discussed above. Figure 4.5 shows how it could differ from Option 5, due to its floor and ceiling, assuming that hub prices follow the same pattern of the last 6 years. This is of course just a simulation. Different assumptions would lead to different results, but caps and floors would remove the risk of extreme drifts.

This Report does not discuss the legal means that may be necessary to implement such suggested solution. The following discussion tries to show why this could be a reasonable compromise between producers and consumers, aimed at avoiding too harsh litigation.

The main benefits of this solution would be as follows:

1. The regulation would reckon that current contracts have been signed in an unsustainable monopoly situation, and are unjustifiably too onerous for the Israeli customers;
2. The proposed solution is in line with international pricing practices, as it is related to international markets, providing in general an incentive to treat domestic and international sales on an equal footing. This is consistent with the regulatory practices of the most advanced countries, including current exporters like Australia and Canada, and likely future exporters like the U.S.A. This approach is highly recommended by institutions like the International Energy Agency;

Figure 4.5 – Possible evolution of prices under the suggested option.



3. The export parity concept is also consistent with the pricing objectives of several other gas producing countries including net exporters (like Russia and Nigeria) and net importers (like China and India);
4. The linkage to domestic (where available) or international gas hubs is recommended by the regulatory practice of U.S. and European countries;
5. The price floor would ensure that costs are covered anyway, and the possibility of increasing the price above that level would lead to a fair profit sharing of the differences between costs of Israeli supplies and their international value (opportunity cost).

Furthermore, being a floor rather than a fixed regulated price, the uncertainty of the cost valuation process become less relevant;

6. The price would be aligned with international prices, and hence it would convey to Israeli customers the right information about the opportunity costs of using natural gas. As such, it would discourage wasteful consumption. Moreover, a substantial (dominant) part of any revenues increases (above the floor price) would be taxed away by the Israeli State, offering the opportunity of lowering other taxes or raising public expenditure;
7. In return for the floor guarantee, the Israeli consumers would be guaranteed a maximum ceiling. This could be most easily defined as the current contract price, but another basis may be also envisaged after appropriate consultation;
8. This compromise solution should be carefully considered by concerned parties, as it would offer a way to strike a reasonable balance between the needs of a fair pricing of natural gas for Israeli consumers and that of rewarding companies that have taken heavy risks by investing huge sums in the exploration and development of the resources.

The floor price would be the price that results from the cost calculation, which has been revised under Option 3 in section 4.3. Under the (conservative) assumption of a 12% rate of return and with the expected quantities, as calculated under Option 3, such floor price would be 2.60 $/MMBtu. This price is higher than the calculation with a typical European-style WACC calculation (1.79), as well as above the best estimate of Professor Smith (2.34 - 2.47)[144], hence it can be deemed as conservative. Being only a floor reduces the relevance of the uncertainty underpinning the estimate of this production cost.

Once data for the Leviathan (and others') development costs will be available, the floor price could be modified. It is however not advisable to introduce different floors, as this would lead to a totally regulated market where confusion may prevail. The cases of India, China and Russia (and the U.S, until the 1980s) show how unexplained price variations within the country lead to lack of transparency and defer the development of a real market. The Regulator may try and estimate the costs of new supplies by a specific study, so as to ensure that no big increases will be necessary if such supplies become pivotal in the satisfaction of domestic demand.

Regarding the ceiling price, this could be set in line with existing contracts, as discussed above under Option 1. There is no way to justify such values in relation with production costs, and the only reason to pick them up is related to their being accepted in the existing contracts. However,

[144] depending on tax assumptions. The lower value (2.34 $/MMBtu) would be more comparable with our tax assumptions, but Smith uses 2.47 as his best estimate. The difference between our and Professor Smith's estimates depends partly on the quantities (and related economies of scale), and partly on the rate of return. Smith takes an international average, which is an intermediate value between the European-style WACC estimation and the conservative 12% level that we propose, which is based on results of the international Survey of Chapter 2.

we suggest to remove the inflation (CPI) indexation, which is not justified for such costs and is rarely used in the international experience.

The ceiling price would amount to the average Tamar (or possibly Tamar and Leviathan) price from domestic sales. As such, it would include sales to IEC, IPPs and industry[145].

As noticed in the international survey of the Report, very few cases include inflation as a relevant index for price escalation. In Europe, inflation is used for the escalation of network tariffs, but not for gas (or electricity) supply prices. For network tariffs, the impact of inflation is offset by the productivity (X) factor and by the depreciation of the assets, which applies at least when tariffs are revised, every 3-5 years. This offsetting factors are not present in the Tamar-IEC contract, therefore its price always increases.

Moreover, gas production costs are not normally related to inflation, except operational costs, which are a minor part (less than 10%).

Thus, we suggest to replace the CPI – indexed price with a constant average. Using the 2013-2029 average, which is related to almost all gas sold by Tamar under the existing contracts (about 200 Bcm), we calculate an average of 5.64 $/MMBtu. This value takes into account the price reduction that are related to the IEC price reviews (after 8 and 11 years respectively), which could not denied, as we discussed in the section 4.3 under Option 1; as well as their indirect impact on the average generation costs, and hence on the pricing of IPP supplies.

All details should be a matter of consultation. This Report cannot go into all details, which depend on the legal framework. In particular, detailed proposals should be related to whether the price would be eventually regulated for all gas purchasers. If that is the case, the price should be the same for all, unless different contractual conditions justify it. For example, more flexibility or smaller amounts could justify a slightly higher price (see next section)[146].

In principle, any regulation of the Tamar selling price should apply to the average price. Therefore, if contracts are renegotiated after the regulation, contracts should take this into account. Otherwise, PUA may regulate only IEC's and monitor the average, and apply the ceiling only if the average exceeds the predetermined level[147].

More generally, all assumptions for the calculations (including the costs of the various supply chains) should be set after consultations, ,subject to quantitative analysis and used for a PUA

[145] This Project provides a simple tool for the calculation of the average Tamar price, based on reasonable but possibly not precise assumptions, which should be revised and fine-tuned by the Regulator, or re-built from scrap.
[146] The current contracts are not based on these cost-related criteria, but they are rather linked to Tamar's (hedging) logic of selling more gas at lower prices to IPPs, so that it keeps selling gas in case IEC manages to reduce its generation cost (e.g. by burning more coal, other gas, renewables etc.).
[147] The spreadsheet used for the calculations of this Report already calculates the average Tamar price, considering the link between IPPs' purchasing prices and the generation cost, which in turn depends on IEC's purchasing price. However, for practical usage it should be carefully revised and controlled by PUA, as details and operational models must be defined and mastered by regulatory permanent staff.

decision. The level of transparency depends on PUA's practice and the requirements of the Israeli legal system. Among OECD countries, there are rather different practices regarding confidentiality of calculation methodologies and data, and different public consultation standards.

A quantitative comparison of the suggested solution, as compared with Options 1 (current contract prices) and Option 3 (cost based prices) is reported in Table 4.2. These prices reflect the average of Tamar sales, including those to industry and other sectors, which are priced at a discount to the energy equivalent price of competing fuels.

Numbers of the Table are only indicative and originate from publicly available information, but should be checked with the relevant operators before a decision is taken. The cost assumptions should be revised from time to time (at least every 3 years). This process can be certainly implemented by PUA staff, but the time needed depends on the interaction with stakeholders[148]..

Regarding escalation: prices could theoretically be adjusted even every month. It is preferable to update every three months, as this period reflects the market trends properly, without generating too many swings for consumers. It should be based on 6-9 month moving averages. This adjustments frequency and link to the moving average are taken from international practice, notably in the European market, both of regulators like Italy's or France's. Unregulated suppliers like exporters from Russia, Algeria, Norway, the Netherlands and others follow similar patterns. [More information about the U.S. on this topic has been requested to U.S. partners].

Once assumptions have been defined and turned into formulas, the implementation is easy and only takes a few minutes for each update. International prices are necessary and can be obtained from specialised journals like Platts', World Gas Intelligence, ICIS-Heren. The cost is subscription – between 1500-10000 $ each year, depending on which ones are necessary..

It is of course impossible to forecast prices that will prevail in the main international hubs, yet they have been lower in the recent past. However, it is finally worth noticing that, if prices reverted to the mean level of the last 10-15 years, the average price under this suggested option would be just above the floor price.

This suggested option does not consider how the price should be tailored to individual customer. Pricing theory suggests that prices are typically related to swing factors, with lower prices for lower withdrawal flexibility. Moreover, for a similar swing factor, smaller consumers normally pay higher prices.

[148] The Italian practice was to publish available (non-confidential) information in consultation documents or (if deemed confidential) inform sensitive stakeholders and threaten their publication as "best estimates". In this way, stakeholders are pushed to publish their own data and calculation and to provide advice or more accurate data: this is usually preferable than being regulated on the basis of wrong estimates.

Table 4.2 – Results of the simulations for the main applicable pricing options (2013-2030).

	Average consumer price ($/MMbtu)	Tamar internal rate of return	Total tax revenue ($ billion)
Option 1a – Current prices	7.22	24.1%	47.89
Option 1b – Current prices with price reviews	5.64	19.6%	34.24
Option 3 – Cost reflective regulation	1.73	8.1%	9.89
Option 3 – Cost reflective regulation (12% return)	2.60	12.0%	15.93
Option 5 – Export parity*	4.24	17.9%	26.89
Suggested option – bounded export parity*	4.33	18.2%	27.96

(*) based on the hub prices that have prevailed between July 2008 – June 2014

4.6 On non price contractual conditions

It is reasonable for a regulator to define not only regulated prices, but also other contractual conditions. In particular, the Israeli regulator may be concerned about such condition like price reopening and contractual durations; take or pay and swing factors; technical performances, like ramp-up and ramp-down rates; and others.

Unfortunately, the international experience on such issues is not encouraging. Our Survey has generally not found publicly available information on such conditions. There are several reasons for this apparent failure.

1. Natural gas production is related to natural conditions of the reservoir, hence performances may be very different, for similar investment costs. It is difficult to require certain performances, which may entail significant cost increases, and it is difficult for the regulator to assess whether such costs are justified[149].

[149] In the few cases of underground storage regulation, an activity that is technically similar to production, the same problems arise. Storage site performances (including depleted fields, which the large majority of them) have rather different technical performances e.g. regarding injection and withdrawal rates. Regulators usually require transparency but do not set the performance standards.

2. In the regulatory history, price regulation has normally come first, taking for granted that the ccharacteristics of the service should be at least as available before the price regulation was introduced. Only later regulators have tried to introduce other rules, for example interms of quality of service, technical performances, contractual conditions. On the other hand, in the upstream and supply gas field this has not generally happened, because deregulation and liberalization have generally occurred before these provisions had been developed

3. In several cases, countries rely on National Oil Companies, which actually play the role of the the upstream industry regulator. This is justified by the technical complexity of the detail, as well as by the above mentioned difficulties of asssing the relationship between performances and related costs. The NOC, being itself endowed with in depth technical expertise, can perform this job better than a (usually less staffed) regulatory agency.

4. In several cases, regulation of gas supply is directly performed by Ministries, and follows more political and less transparent criteria. Ministries tend to rely on operators for more detailed technical issues.

5. Since both Ministries and NOCs in producing countries tend to maximize revenues and minimize IOC's profits, they have developed a complex set of tools to achieve such goals. However, this toolboxes usually do not include only technical conditions of supply, but extend to such issues like taxation, exploration and drilling efforts, bonuses to be paid to win the concessions, duration of the permits, development times etc. The disclosure of details is seen as damaging for the achievement of the above mentioned revenue maximization or IOC profit minimization goals, and expertise that is necessary for this approach is generally regarded as a valuable asset of NOC staff and management, not to be easily shared[150].

Considering these difficulties, for a country without a NOC, a procedure in line with transparency criteria of Western style regulation to address these issues could be as follows:

- Open a consultation about the possible parameters to be subject to regulation, focusing on a limited number;
- Once these have been identified, ask operators and other stakeholders to present proposals and related costs. This may lead to some disclosure of foreign experience as well;
- Hire a technical consultant to assess the proposals, e.g. whether the cost of adding more wells to a reservoir to improve flexibility and deliverability is reasonable;

[150] It is worth recalling that oil&gas producing countries are typically competing for exploration and development investments by IOCs. This does not solve the problems of market power, but helps achieving reasonable contractual conditions.

- Enforce a limited number of technical provisions, allowing for price increases as necessary to fund the approved investment.

Some parameters may be subject to preliminary assessment before a detailed technical assessment is carried out. For example, the regulator could assess a lower take or pay threshold by using different quantities in the same financial model, as used for cost assessment (Section 4.3 above). Decreasing the allowed quantities, or rescheduling them over a longer period, leads to a cost increase, which could be taken as a measure of the cost of requiring a lower take or pay level.

For example, the model we have used for the 2012 Report and updated here shows that a uniform 10% reduction of quantities over the 2014-2029 periods of the Tamar power generation contracts, , would entail the following cost increases:

TOP	Price 100%=100
100%	100,0
90%	104,3
80%	116,4
70%	125,0
60%	139,9

These ratios could be taken as a first measure of the “cost” of lowering take or pay constraints. Yet this values should be interpreted as cost-related maximum. Once gas can be exported, excess amounts can be sold on spot markets.

Lately, markets that have become open and competitive have led to much lower prices, but less TOP tolerance - basically contracts have turned shorter but very rigid with almost 100% take or pay. The reason is that excess or missing gas can be bought from or sold to spot markets (see section 2.7.3).

More generally, the issue of how to address the required flexibility of gas supplies is not independent of the general market design for gas in the country, which is currently unclear. At present, only some elements of a gas market design have been addressed, namely the export / domestic split, the possibility to regulate the gas price, and some other technical parameters. This is at odds with the practice of most advanced countries, notably in Europe and Latin America, where a clear market designed is usually discussed and eventually embodied into a national gas act. Even in the U.S., the strength of competition itself, pushed by thousands of different producers, did not dispense with the need to define a market design, and several Congress acts were issued for this sector, also enabling Federal Regulators to proceed towards industry unbundling as well as price and tariff regulation, actually implementing a new market design (See section 2.2).

In this respect, the government' proposal to give the system operator (for electricity) the role of a clearing house for residual quantities of gas for secondary market could help solving the problem of high take or pay commitments. The market operator could trade some quantities with the gas consumers (IEC, IPP's, industry), helping to relieve their peaking needs and establishing an embryonic balancing market. Yet, a more complete and advanced market design could foresee that, even if no national oil& gas company is established and no antitrust action is undertaken, a single buyer[151] could be established with the limited role of purchasing gas at regulated prices and reselling it at no profit to the market. This would be also the regulated supplier of a one-sided balancing market, following a model that has been used (mostly as a transitional tool) in Italy and other EU countries.

Participation of foreign sales into a balancing market would also help. The market operator (or the single buyer) could get bids from foreign market players as well. Yet if Tamar and Leviathan Consortiums are allowed to bid in such markets as a single entity, the issue of regulating their bids emerges again. Values taken from cost analysis are at best a very rough estimate of the value of flexibility. Regulation can hardly address such issues, as shown by the lack of world experience.

At best, this approach is likely to need further adjustment at a later stage, after some experience of actual delivery rates has been acquired.

As for duration of the price control and the related "reopening" clauses, this is again a relatively weak point of energy regulators, as outlined in our Survey. In fact, whereas regulators are often using incentive regulation approaches for networks, this is hardly the case for end user price controls. In fact, even in the EU, price controls are seen as temporary, and they have never been regulated along scheduled periods, with a view to reduce regulatory risk, as in the case of networks.

For both non price clauses and contractual durations (including price re-opening conditions), the practice of private contracts in competitive markets probably offers better guidance than that of regulators. The typical three-year price setting mechanism, with scheduled reviews and special reviews in case of unexpected and remarkable market upheavals, is probably the best practice to look at.

[151] Examples of such single buyers are found in our Survey, for example in Nigeria, Algeria, Egypt. Other examples are found in the past in Victoria (Australia).

Annex 1. Questions submitted to country experts

1. Which market prices are regulated (wellhead, wholesale and/or retail)?

2. Which consuming sector do have regulated prices (power generation, industry, residential & commercial, feedstock, others)?

3. Who is the regulator (Ministry, Local Governments, Government Agency, Independent Energy Regulator, Competition Regulator, Courts, or others)?

4. What is the basis for the regulation (Cost of service, including production, transportation, distribution storage etc.; local or international market price; price of competing fuels; social affordability, including for electricity that is generated from natural gas; and others).

5. With reference to the upstream part of the value chain (production and/or import), please outline the main criteria that are used for regulation, including as available:

a. criteria for capital valuation;

b. rates of return and their main component;

c. depreciation rates;

d. operational expenditure;

e. use of benchmarking techniques;

f. exploration costs and their evaluation criteria;

g. depletion fees, royalties, or user costs;

h. social or environmental fees and subsidies;

i. reference to competing fuels;

j. reference to international gas prices.

6. What are the main criteria used for price adjustment and indexation? Please outline in particular, as appropriate:

a. Adjustment frequency (if any) and trigger rule;

b. price indicators of competing fuels and/or market or other gas prices;

c. inflation index or other macroeconomic indicator;

d. ceilings and floors;

e. role of incentive or performance –based regulation.

7. Please indicate the latest available price level for the main large consumers (power generation, industry, feedstock, local distributors), and specify the date of the quote.

8. How is the structure of the regulated price for the main consuming sector? Are there…

a. Commodity charges only?

b. Capacity related charges?

c. Standing (fixed) charges?

d. Decreasing or increasing blocks?

9. What is the relevant authority for price update (e.g. company, independent energy or gas regulator, competition regulator, government agency, Ministry, etc.)? Is it the same entity issuing the pricing methodology?

10. What is the legal basis for the regulation?

11. What are the main non-price provisions of regulation that are tied to the price control? Outline in particular, as appropriate:

a. quality of service rules;

b. production performances like available capacity, ramp-up, ramp-down, swing factors;

c. take or pay clauses that may be subject to the regulation and related flexibility arrangements (e.g. make-up gas);

d. price review clauses;

e. destination clauses (by sector or country).

Annex 2 – International Gas Union's Definitions of main price formation mechanisms

Oil Price Escalation (OPE)	The price is linked, usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil and/or fuel oil. In some cases coal prices can be used as can electricity prices.
Gas-on-Gas Competition (GOG)	The price is determined by the interplay of supply and demand – gas-on-gas competition – and is traded over a variety of different periods (daily, monthly, annually or other periods). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP in the UK). There are likely to be developed futures markets (NYMEX or ICE). Not all gas is bought and sold on a short term fixed price basis and there will be longer term contracts but these will use gas price indices to determine the monthly price, for example, rather than competing fuel indices. Spot LNG is also included in this category, and also bilateral agreements in markets where there are multiple buyers and sellers.
Bilateral Monopoly (BIM)	The price is determined by bilateral discussions and agreements between a large seller and a large buyer, with the price being fixed for a period of time – typically this would be one year. There may be a written contract in place but often the arrangement is at the Government or state-owned company level. Typically there would be a single dominant buyer or seller on at least one side of the transaction, to distinguish this category from GOG, where there would be multiple buyers and sellers.
Netback from Final Product (NET)	The price received by the gas supplier is a function of the price received by the buyer for the final product the buyer produces. This may occur where the gas is used as a feedstock in chemical plants, such as ammonia or methanol, and is the major variable cost in producing the product.
Regulation: Cost of Service (RCS)	The price is determined, or approved, by a regulatory authority, or possibly a Ministry, but the level is set to cover the "cost of service", including the recovery of investment and a reasonable rate of return.
Regulation: Social and Political (RSP)	The price is set, on an irregular basis, probably by a Ministry, on a political/ social basis, in response to the need to cover increasing costs, or possibly as a revenue raising exercise.
Regulation: Below Cost (RBC)	The price is knowingly set below the average cost of producing and transporting the gas often as a form of state subsidy to the population.
No Price (NP)	The gas produced is either provided free to the population and industry, possibly as a feedstock for chemical and fertilizer plants, or in refinery processes and enhanced oil recovery. The gas produced maybe associated with oil and/or liquids and treated as a by-product.
Not Known (NK)	No data or evidence.
Hub indexation (HUB)	The price is explicitly linked to those reported at a major (physical or virtual) gas hub.

Annex 3. Common assumptions of the regulatory options for the Israeli gas market

Quantities

Gas demand by IEC, IPPs and industry (including small supplies to other sectors) as well Tamar supply are shown in the following Table A.1

Table A.3.1 - Gas demand development in Israel

	2013	2014	2015	2016	2017	2018	2019	2020	2021
Demand pow er	6,3	6,7	7,1	8,5	8	8,6	8,9	9,3	9,9
Demand industry	1,5	1,9	2,6	2,7	2,7	2,8	2,8	2,9	2,9
Demand non-energy									0,7
Demand others					0,10	0,11	0,12	0,13	0,15
Demand total	7,8	8,6	9,7	11,2	10,8	11,5	11,8	12,3	13,7
Demand no pow er	1,5	1,9	2,6	2,7	2,8	2,9	2,9	3,0	3,8
IEC	4,5	4,5	4,5	4,5	4,5	4,5	6,5	6,5	6,5
Dalia	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4
OPC	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7
Dorad	0,9	0,9	0,9	1,1	1,1	1,1	1,1	1,1	1,1
Ashdod & Ramat Negev	0,3	0,9	0,9	1,1	1,1	1,1	1,1	1,1	1,1
Alon tavor & Ramat Negev	0,3	0,9	0,9	1,1	1,1	1,1	1,1	1,1	1,1
Total available Tamar supply	8,2	9,4	9,4	10,0	10,0	10,0	12,0	12,0	12,0
Balance	0,4	0,8	-0,3	-1,1	-0,8	-1,5	0,1	-0,3	-1,7
	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand pow er	10,1	10,5	11,0	11,0	12,0	13,0	13,0	13,0	13,7
Demand industry	3,0	3,0	3,1	3,2	3,2	3,3	3,4	3,4	3,5
Demand non-energy	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7
Demand others	0,2	0,2	0,2	0,2	0,2	0,3	0,3	0,3	0,3
Demand total	13,9	14,4	15,0	15,1	16,2	17,3	17,3	17,4	18,2
Demand no pow er	3,8	3,9	4,0	4,1	4,2	4,3	4,3	4,4	4,5
IEC	6,5	6,5	6,5	6,5	6,5	6,5	6,5	6,5	0,0
Dalia	1,4	1,4	1,4	1,4	1,4	1,4	1,4	1,4	0,0
OPC	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,0	0,0
Dorad	1,1	1,1	1,1	1,1	1,1	1,1	1,1	0,0	0,0
Ashdod & Ramat Negev	1,1	1,1	1,1	1,1	1,1	1,1	1,1	0,0	0,0
Alon tavor & Ramat Negev	1,1	1,1	1,1	1,1	1,1	1,1	1,1	0,0	0,0
Total available Tamar supply	12,0	12,0	12,0	12,0	12,0	12,0	12,0	7,9	0,0
Balance	-2,0	-2,4	-3,0	-3,1	-4,2	-5,3	-5,4	-9,6	-18,2

Gas demand is taken from Ministry of Energy forecasts. However, as suggested by PUA, demand from industry is assumed to grow at a lower rate (2% per year after 2015) and the same happens for other sectors (residential, commercial and transport) which grow at 10% each year but start from very low levels. Non-energy consumption (fertilizers, methanol) is at a steady 0.7 Bcm/year after 2021.

Supplies follow those of the Tamar contracts' DCQ with IEC and five IPPs. The IEC "Option" is assumed to be implemented so that quantities increase after year 5 of the contract (i.e. starting in 2018).

IPPs have a load factor of 70%. This assumption does not ensure that total demand for gas is covered, however the exact check of the gas supply and demand balance is beyond the scope of the Report. Some supplies beyond Tamar maybe required depending on consumption seasonality, which is not addressed here. The demand –supply balance may become a more or less serious problem after 2020, depending on whether a large storage allows for a more flexible exploitation of the Tamar field. If this is not the case, seasonality must be addressed by looser take or pay conditions and a lower average load factor, which may lead to a significant cost increase. Connection to other reservoirs is another likely option, whereas the use of the FSRU (LNG ship) as storage may be more expensive.

Prices

For industry and other sectors, gas is priced after Light Sulfur Fuel Oil (LFO), on an energy equivalent basis minus 20%.

Inflation remains at 2.5% in Israel as well as the U.S.A. The NIS/$ exchange rate remains at 3.65. These assumptions have minimal effects on the purpose of this simulations, which is to compare the options rather than actual values.

Scenarios for oil and LFO prices are kindly provided by REF-E, a specialized Italian consultancy (see Table A.2).

Table A.3.2 – Oil price scenarios

Year	Brent ($/bbl)	LFO ($/ton)
2013	108,7	613,3
2014	107,8	620,2
2015	105,0	605,0
2016	103,0	593,1
2017	102,5	590,4
2018	102,5	590,5
2019	102,7	591,6
2020	102,9	592,7
2021	102,9	592,7
2022	102,7	591,5
2023	102,5	590,4
2024	102,3	589,3
2025	102,1	588,1
2026	101,9	587,0
2027	101,7	585,8
2028	101,5	584,7
2029	101,3	583,5
2030	101,1	582,4

The LNG price is consistent with that of Japan's supplies, allowing a typical spread of around -3$/MMbtu for Mediterranean supplies. LNG is used to cover small gaps in the first few years of the simulation period. For later years (since 2018), gaps are covered by other IEC supplies (e.g. Leviathan), assumed to have the same prices as Tamar. Such prices are discussed in the main text.

Simulations cover the period 2013-2030. Assuming total supplies of 230 Bcm in the period entails that current available landing and processing capacity is not enough after 2017, hence some larger CAPEX is probably required. Latest news suggest a total CAPEX for the TAMAR projects of about 6 Bn. $, and we have added further development expenditure so as to reach such total value. The debt/equity ratio has been set at 1.5, due to increasing credit difficulties. Other cost assumptions are as in the 2012 Report (subsection 1.1.2), with some variations regarding the cost of capital (WACC), which has be been updated. The calculation is as in the following Table A.3.

Total quantity		230 Bcm
Years of production		18
	Annual min. production	4.5 Bcm
	Annual max. production	14.7 Bcm
Exploration success rate		40%
Cost of Equity		**12.6%**
	Risk free rate	4.9%
	Market Risk Premium	5.8%
	Beta Levered	1.33
Cost of Debt		**7.2%**
	Risk free rate	4.9%
	Debt Risk Premium	2.4%
	Country risk premium	*1.3%*
	Tax rate	25.0%
Cost of debt with tax shield		**5.4%**
Debt structure		
D/(D+E)		60%
E/(D+E)		40%
Average resource & corporate tax rate		31.4%
WACC	**nominal**	**8.1%**

Annex 4. Indicators used in the calculation of the price of gas with the gas price formula for the Russian Federation

Indicators	Unit of measure	Source / Method for determination of the index	Period for the index determination
the arithmetic average price for heating oil (masut) with a sulfur content of 1%	USD per one metric ton	determined as the arithmetic mean between the lowest and highest values of average monthly prices for heating oil	Until nine calendar months for the month of establishing of the decreasing coefficient size by the Federal Tariffs Service of Russia
lowest and highest values of average monthly prices for heating oil (masut)	USD per one metric ton	by the Information of the quotation agencies	Until nine calendar months for the month of establishing of the decreasing coefficient size by the Federal Tariffs Service of Russia
the arithmetic average price for gasoil with a sulfur content of 0,1%	USD per one metric ton	determined as the arithmetic mean between the lowest and highest values of average monthly prices for gasoil	Until nine calendar months for the month of establishing of the decreasing coefficient size by the Federal Tariffs Service of Russia
lowest and highest values of average monthly prices for gasoil	USD per one metric ton	by the Information of the quotation agencies	Until nine calendar months for the month of establishing of the decreasing coefficient size by the Federal Tariffs Service of Russia
the official the ruble's rate to the dollar	RUB/USD	established by the Central Bank of the Russian Federation	On the last day of the calculation period of the arithmetic means of prices for masut (M) and gasoil (G)
rate of export customs duty on gas	%	Approved in the prescribed manner	the actual data at the time of the establishing of the decreasing coefficient size by the Federal Tariffs Service of Russia
specific cost value associated with the supply of gas to distant foreign countries	RUB/TCM (thousand cubic meters)	determined in accordance with paragraph 16 of the Approval	The actual data for 4 full quarters until the month of establishing of the decreasing coefficient size by the Federal Tariffs Service of Russia In the case of the decreasing coefficient size calculation the first month of the quarter, the actual data for 4 full quarters are measured from the just-completed quarter
expenses of transportation , storage and distribution of gas to distant foreign countries, outside the Russian Federation	RUB Million	actual data	The actual data for 4 full quarters until the month of establishing of the decreasing coefficient size by the Federal Tariffs Service of Russia In the case of the decreasing coefficient size calculation the first month of the quarter, the actual data for 4 full quarters are measured from the just-completed quarter
a volume of gas sales to distant foreign countries	billion cubic meters (thousand	actual data	The actual data for 4 full quarters until the month of establishing of the decreasing

	million cubic meters)		coefficient size by the Federal Tariffs Service of Russia In the case of the decreasing coefficient size calculation the first month of the quarter, the actual data for 4 full quarters are measured from the just-completed quarter
the decreasing coefficient providing a growth of gas prices rate in the settlement calendar year	unit fraction	determined in accordance with paragraph 18 of the Approval	For the regulatory period
differentiation coefficient reflecting the price variance for the 1-th zone price relative underlying zone price	unit fraction	determined by the Federal Tariffs Service of Russia in accordance with paragraph 19 of the Approval	For the regulatory period
the difference between the transporting gas average cost from gas fields to the border of the Russian Federation and the transporting gas average cost from gas fields to consumers of Russian Federation	RUB/TCM (thousand cubic meters)	determined by the formula (5) paragraph 17 of the Approval	For the regulatory period
the average distance of gas transportation, which produced JSC "Gazprom" and its affiliates, respectively, for export and the domestic market by main pipelines through the territory of the Russian Federation	km	determined by the Federal Tariffs Service of Russia as weighted averages of distances, which adopted FTS of Russia for the corresponding year for setting gas transportation tariffs for independent organizations (through the JSC "Gazprom" pipelines)	For the regulatory period
rates (unit rates) of tariff of gas transportation services by the main pipeline		Approved by the Federal Tariffs Service of Russia	For the regulatory period
calculated weighted average price*	RUB/TCM (thousand cubic meters)	Calculated by the Federal Tariffs Service of Russia on the basis of approved gas prices and gas supply volume for all price zones	For the previous period of gas prices regulation
prices change index for gas sold to consumers in the Russian Federation (except population)*	unit fraction	Approved by the Government of the Russian Federation	For the regulatory period

Source: Order of the Federal Tariff Service of the Russian Federation N 165-e/2 Jule 14, 2011 / 2 (ed. from 6 March 2014) on Approval of the Regulation on the definition of the pricing formula of gas (registered in the Ministry of Justice of the Russian Federation N 21593 10 August, 2011).

Note:
On July 9, 2014 there is a new version of the document that establishes the gas price formula - the Order of the Federal Tariff Service of the Russian Federation N1142-э July 9, 2014 on Approval of the Regulation on the definition of the pricing formula of gas (registered in the Ministry of Justice of the Russian Federation N 33165 21 July, 2014).
* These indicators are not included in the gas price formula based on the Order of the Federal Tariff Service of the Russian Federation N1142-e July 9, 2014

Table A.4.2 - Wholesale prices of gas produced by JSC Gazprom and its affiliated entities, for Russian consumers

(except for the population, as well as with the exception of gas sold to Russian consumers in respect of which applies the principles of state regulation provided for in paragraphs 15.1-15.3 "General Conditions of formation and state regulation of gas prices and tariffs for its transportation in the territory of the Russian Federation", approved by the Government decree), $ / MMBtu (without VAT (value added tax))															
№ of the price zone	Subjects of the Russian Federation	Wholesale gas prices, $/MMBtu (without VAT (value added	Wholesale prices	Limit the minimum prices	Limit the maximum prices	Wholesale prices	Limit the minimum prices	Limit the maximum prices	Wholesale prices	Limit the minimum prices	Limit the maximum prices	Wholesale prices	Limit the minimum prices	Limit the maximum prices	Wholesale prices
		from January 1, 2010	**from January 1, 2011**			**from July 1, 2012**			**from January 1, 2012**			**from July 1, 2013**			**from January 1, 2014********
1	Republic of Bashkortostan	2,18	2,49	2,49	2,74	2,70	2,70	2,97	2,78	2,78	2,96	2,97	2,97	3,16	3,06
2	Republic of Kalmyckia	2,24	2,56	2,56	2,81	2,77	2,77	3,05	2,86	2,86	3,03	3,05	3,05	3,24	3,13
3	Republic of Karelia	2,43	2,78	2,78	3,06	3,02	3,02	3,32	3,11	3,11	3,31	3,33	3,33	3,54	3,43
4	Komi Republic	1,99	2,27	2,27	2,49	2,45	2,45	2,69	2,52	2,52	2,68	2,69	2,69	2,85	2,76
5	Republic of Mariy-El	2,25	2,58	2,58	2,83	2,79	2,79	3,07	2,88	2,88	3,05	3,07	3,07	3,26	3,16
6	Republic of Mordovia	2,30	2,63	2,63	2,89	2,85	2,85	3,14	2,94	2,94	3,12	3,14	3,14	3,34	3,23
7	Republic of Tatarstan	2,22	2,54	2,54	2,79	2,74	2,74	3,02	2,83	2,83	3,00	3,02	3,02	3,20	3,10
8	The Udmurtian Republic	2,12	2,42	2,42	2,67	2,62	2,62	2,89	2,71	2,71	2,87	2,89	2,89	3,07	2,97
9	Chuvash Republic	2,25	2,58	2,58	2,83	2,79	2,79	3,07	2,88	2,88	3,05	3,07	3,07	3,26	3,16
10	Altai Territory**	2,34	2,67	2,67	2,94	2,88	2,88	3,17	2,97	2,97	3,15	3,16	3,16	3,36	3,25
11	Arkhangelsk Region***	2,10	2,40	2,40	2,64	2,59	2,59	2,85	2,67	2,67	2,83	2,84	2,84	3,02	2,92
12	Astrakhan Region	2,04	2,33	2,33	2,56	2,52	2,52	2,77	2,60	2,60	2,76	2,77	2,77	2,94	2,85
13	Belgorod Region	2,52	2,89	2,89	3,18	3,14	3,14	3,45	3,24	3,24	3,44	3,46	3,46	3,68	3,56
14	Bryansk Region	2,54	2,91	2,91	3,20	3,16	3,16	3,47	3,25	3,25	3,45	3,48	3,48	3,69	3,58

15	Vladimir Region	2,40	2,74	2,74	3,02	2,97	2,97	3,27	3,06	3,06	3,25	3,27	3,27	3,47	3,36
16	Volgograd Region	2,44	2,79	2,79	3,07	3,02	3,02	3,32	3,11	3,11	3,30	3,31	3,31	3,52	3,41
17	Vologda Region	2,26	2,58	2,58	2,84	2,80	2,80	3,07	2,88	2,88	3,06	3,08	3,08	3,27	3,17
18	Voronezh Region	2,50	2,86	2,86	3,15	3,10	3,10	3,41	3,20	3,20	3,39	3,42	3,42	3,63	3,52
19	Ivanovo Region	2,39	2,73	2,73	3,00	2,96	2,96	3,25	3,05	3,05	3,23	3,25	3,25	3,45	3,34
20	Kaliningrad Region	2,78	-	-	-	3,01	3,01	3,31	3,10	3,10	3,29	3,32	3,32	3,52	3,41
21	Kaluga Region	2,52	2,89	2,89	3,18	3,14	3,14	3,45	3,24	3,24	3,44	3,46	3,46	3,68	3,56
22	Kemerovo Region	2,35	2,68	2,68	2,95	2,89	2,89	3,18	2,98	2,98	3,17	3,17	3,17	3,37	3,26
23	Kirov Region	2,20	2,52	2,52	2,77	2,72	2,72	2,99	2,81	2,81	2,98	2,99	2,99	3,18	3,08
24	Kostroma Region	2,38	2,73	2,73	3,00	2,95	2,95	3,25	3,04	3,04	3,23	3,25	3,25	3,45	3,34
25	Kurgan Region	2,01	2,29	2,29	2,52	2,47	2,47	2,72	2,55	2,55	2,70	2,71	2,71	2,87	2,78
26	Kursk Region	2,50	2,87	2,87	3,15	3,11	3,11	3,42	3,20	3,20	3,40	3,42	3,42	3,64	3,52
27	Leningrad Region	2,41	2,76	2,76	3,04	2,99	2,99	3,29	3,09	3,09	3,28	3,30	3,30	3,50	3,39
28	Lipetsk Region	2,46	2,82	2,82	3,11	3,07	3,07	3,37	3,16	3,16	3,36	3,39	3,39	3,59	3,48
29	Moscow Region	2,50	2,87	2,87	3,15	3,11	3,11	3,42	3,20	3,20	3,40	3,42	3,42	3,63	3,52
30	Nizhni Novgorod Region	2,31	2,64	2,64	2,91	2,87	2,87	3,15	2,95	2,95	3,14	3,16	3,16	3,35	3,25
31	Novgorod Region	2,42	2,77	2,77	3,04	3,00	3,00	3,30	3,09	3,09	3,28	3,30	3,30	3,51	3,40
32	Novosibirsk Region	2,21	2,53	2,53	2,78	2,73	2,73	3,01	2,82	2,82	2,99	3,00	3,00	3,19	3,09
33	Omsk Region	2,15	2,44	2,44	2,69	2,64	2,64	2,90	2,72	2,72	2,89	2,89	2,89	3,07	2,98
34	Orenburg Region	2,09	2,40	2,40	2,64	2,60	2,60	2,86	2,68	2,68	2,85	2,86	2,86	3,04	2,95
35	Oryol Region	2,52	2,89	2,89	3,18	3,14	3,14	3,45	3,24	3,24	3,44	3,46	3,46	3,68	3,56
36	Penza Region	2,32	2,66	2,66	2,93	2,89	2,89	3,18	2,98	2,98	3,16	3,18	3,18	3,38	3,28
37	Perm Territory	2,07	2,35	2,35	2,59	2,54	2,54	2,80	2,62	2,62	2,78	2,79	2,79	2,96	2,87
38	Pskov Region	2,47	2,83	2,83	3,11	3,07	3,07	3,37	3,16	3,16	3,36	3,38	3,38	3,59	3,47
39	Ryazan Region	2,45	2,80	2,80	3,09	3,04	3,04	3,34	3,13	3,13	3,32	3,34	3,34	3,55	3,44
40	Samara Region	2,26	2,58	2,58	2,84	2,79	2,79	3,07	2,88	2,88	3,05	3,07	3,07	3,26	3,16
41	Saratov Region	2,38	2,73	2,73	3,00	2,95	2,95	3,25	3,04	3,04	3,23	3,25	3,25	3,45	3,34
42	Sverdlovsk Region	2,12	2,41	2,41	2,66	2,60	2,60	2,86	2,68	2,68	2,85	2,85	2,85	3,03	2,94
43	Smolensk Region	2,44	2,79	2,79	3,07	3,02	3,02	3,32	3,11	3,11	3,30	3,32	3,32	3,53	3,42

44	Tambov Region	2,41	2,76	2,76	3,03	2,99	2,99	3,29	3,08	3,08	3,27	3,29	3,29	3,49	3,38
45	Tver Region	2,37	2,71	2,71	2,98	2,93	2,93	3,23	3,02	3,02	3,21	3,22	3,22	3,42	3,32
46	Tomsk Region	2,16	2,47	2,47	2,71	2,67	2,67	2,94	2,75	2,75	2,92	2,93	2,93	3,12	3,02
47	Tula Region	2,50	2,86	2,86	3,14	3,10	3,10	3,41	3,20	3,20	3,39	3,42	3,42	3,63	3,51
48	Tyumen Region	1,83	2,09	2,09	2,30	2,26	2,26	2,49	2,33	2,33	2,48	2,48	2,48	2,64	2,55
49	Ulyanovsk Region	2,29	2,62	2,62	2,88	2,84	2,84	3,12	2,92	2,92	3,11	3,12	3,12	3,32	3,21
50	Chelyabinsk Region	2,16	2,46	2,46	2,71	2,66	2,66	2,92	2,74	2,74	2,91	2,92	2,92	3,10	3,00
51	Yaroslav Region	2,30	2,64	2,64	2,90	2,86	2,86	3,15	2,95	2,95	3,13	3,15	3,15	3,35	3,24
52	Moscow	2,50	2,87	2,87	3,15	3,11	3,11	3,42	3,20	3,20	3,40	3,42	3,42	3,63	3,52
53	St. Petersburg	2,41	2,76	2,76	3,04	2,99	2,99	3,29	3,09	3,09	3,28	3,30	3,30	3,50	3,39
54	Khanty-Mansijsk Autonomous Okrug - Ugra	1,62	1,85	1,85	2,03	2,00	2,00	2,20	2,07	2,07	2,19	2,21	2,21	2,34	2,27
55	The Yamalo-Nenets Autonomous District	1,37	1,57	1,57	1,72	1,70	1,70	1,87	1,75	1,75	1,86	1,87	1,87	1,99	1,93
56	Republic of Adygeya, Republic of Daghestan, Republic of Ingushetia, Republic of Kabardino-Balkaria, Karachayevo-Cherkessian Republic, Republic of North Ossetia, Chechen Republic, Krasnodar Territory, The Stavropol Territory, Rostov Region	2,56	2,93	2,93	3,22	3,17	3,17	3,49	3,27	3,27	3,47	3,49	3,49	3,71	3,59
Subjects of the Russian Federation where gas is supplied to end consumers in connection with the extension of the Unified Gas Supply System															

557	Altai Territory (Barnaul-Biysk-Gorno-Altaisk gas pipeline, section of 87 km - border of Altai Territory)	2,63	2,99	2,99	3,28	3,16	3,16	3,48	3,26	3,26	3,46	3,41	3,41	3,62	3,50
58	Altai Republic (Barnaul-Biysk-Gorno-Altaisk gas pipeline, border of Altai Territory - Gorno-Altaisk)	2,63	2,99	2,99	3,28	3,16	3,16	3,48	3,26	3,26	3,46	3,41	3,41	3,62	3,50
59	Arkhangelsk Region (Nuksenitsa-Arkhangelsk gas pipeline, section of 147 km - Mirny)	3,03	3,34	3,34	3,67	3,46	3,46	3,81	3,57	3,57	3,79	3,31	3,31	3,52	3,41
60	Arkhangelsk Region (Nuksenitsa-Arkhangelsk gas pipeline, Mirny-Arkhangelsk section)	3,27	3,60	3,60	3,96	3,74	3,74	4,11	3,85	3,85	4,09	3,58	3,58	3,80	3,68

Source: Federal Tariff Service of the Russian Federation, http://www.fstrf.ru/

Notes:

* Wholesale gas prices of output of the main gas pipeline transport. Wholesale prices are established per volume unit of gas (1000 m3) adjusted according to the following:
- temperature (t degree) +20oC;
- pressure 760 mm of Hg;
- humidity 0%;

** Except for consumers of gas supplied by Barnaul-Biysk-Gorno-Altaisk pipeline (section of 87 km-Gorno-Altaisk)

*** Except for consumers of gas supplied by Nuksenitsa-Arkhangelsk pipeline (section of 147 km - Arkhangelsk)

****Source: Federal Tariff Service of the Russian Federation, JSC Gazprom

For values calculation were used:

1 Server with the deep retrospective of data on exchange rates - OANDA.com URL: http://www.oanda.com/lang/ru/currency/converter/

2 Conversion factor of 1000 thousand cubic meters of Russian gas in MMBtu according to Gazprom data for Russian gas

Annex 5. Wholesale gas prices in the Russian Federation, 2010-2014

Table 1 - Wholesale prices for gas produced by JSC Gazprom and its affiliates, intended for subsequent sale to the population

Subjects of the Russian Federation		from January 1, 2010	from July 1, 2012	from July 1, 2013	from July 1, 2014
1 zone	Republic of Bashkortostan	1,56	2,22	2,52	2,62
2 zone	Republic of Kalmyckia	1,57	2,24	2,54	2,65
3 zone	Republic of Karelia	1,62	2,31	2,62	2,72
4 zone	Komi Republic	1,51	2,14	2,43	2,53
5 zone	Republic of Mariy-El	1,57	2,24	2,54	2,65
6 zone	Republic of Mordovia	1,60	2,27	2,58	2,68
7 zone	Republic of Tatarstan	1,57	2,24	2,54	2,65
8 zone	The Udmurtian Republic	1,55	2,21	2,51	2,61
9 zone	Chuvash Republic	1,57	2,24	2,54	2,65
10 zone	Altai Territory**	1,64	2,34	2,65	2,76
11 zone	Arkhangelsk Region***	1,57	2,23	2,53	2,63
12 zone	Astrakhan Region	1,51	2,14	2,43	2,53
13 zone	Belgorod Region	1,64	2,34	2,65	2,76
14 zone	Bryansk Region	1,64	2,34	2,65	2,76
15 zone	Vladimir Region	1,62	0,00	2,62	2,72
16 zone	Volgograd Region	1,64	2,34	2,65	2,76
17 zone	Vologda Region	1,60	2,27	2,58	2,68
18 zone	Voronezh Region	1,64	2,34	2,65	2,76
19 zone	Ivanovo Region	1,62	2,31	2,62	2,72
20 zone	Kaliningrad Region	1,88	2,33	2,65	2,75
21 zone	Kaluga Region	1,64	2,34	2,65	2,76
22 zone	Kemerovo Region	1,64	2,34	2,65	2,76
23 zone	Kirov Region	1,57	2,24	2,54	2,65
24 zone	Kostroma Region	1,62	2,31	2,62	2,72
25 zone	Kurgan Region	1,55	2,21	2,51	2,56
26 zone	Kursk Region	1,64	2,34	2,65	2,76
27 zone	Leningrad Region	1,62	2,31	2,62	2,72
28 zone	Lipetsk Region	1,55	2,31	2,62	2,72
29 zone	Moscow Region	1,64	2,34	2,65	2,76
30 zone	Nizhni Novgorod Region	1,60	2,27	2,58	2,68
31 zone	Novgorod Region	1,62	2,31	2,62	2,72
32 zone	Novosibirsk Region	1,60	2,27	2,58	2,68
33 zone	Omsk Region	1,57	2,24	2,54	2,59
34 zone	Orenburg Region	1,51	2,14	2,43	2,53
35 zone	Oryol Region	1,64	2,34	2,65	2,76
36 zone	Penza Region	1,60	2,27	2,58	2,68
37 zone	Perm Territory	1,55	2,21	2,51	2,61
38 zone	Pskov Region	1,64	2,34	2,65	2,76
39 zone	Ryazan Region	1,64	2,34	2,65	2,76
40 zone	Samara Region	1,60	2,27	2,58	2,68
41 zone	Saratov Region	1,62	2,31	2,62	2,72

42 zone	Sverdlovsk Region	1,56	2,22	2,52	2,62
43 zone	Smolensk Region	1,64	2,34	2,65	2,76
44 zone	Tambov Region	1,62	2,31	2,62	2,72
45 zone	Tver Region	1,62	2,31	2,62	2,72
46 zone	Tomsk Region	1,56	2,22	2,52	2,62
47 zone	Tula Region	1,64	2,34	2,65	2,76
48 zone	Tyumen Region	1,44	2,05	2,32	2,41
49 zone	Ulyanovsk Region	1,60	2,27	2,58	2,68
50 zone	Chelyabinsk Region	1,57	2,24	2,54	2,65
51 zone	Yaroslav Region	1,60	2,27	2,58	2,68
52 zone	Moscow	1,64	2,34	2,65	2,76
53 zone	St. Petersburg	1,62	2,31	2,62	2,72
54 zone	Khanty-Mansijsk Autonomous Okrug - Ugra	1,31	1,87	2,12	2,21
55 zone	The Yamalo-Nenets Autonomous District	1,37	1,70	1,93	1,93
56 zone	Republic of Adygeya, Republic of Daghestan, Republic of Ingushetia, Republic of Kabardino-Balkaria, Karachayevo-Cherkessian Republic, Republic of North Ossetia, Chechen Republic, Krasnodar Territory, The Stavropol Territory, Rostov Region	1,66	2,37	2,69	2,80
57 zone	Altai Territory (Barnaul-Biysk-Gorno-Altaisk gas pipeline, section of 87 km - border of Altai Territory)	2,36	3,16	3,51	3,50
58 zone	Altai Republic (Barnaul-Biysk-Gorno-Altaisk gas pipeline, border of Altai Territory - Gorno-Altaisk)	2,63	3,16	3,51	3,50
59 zone	Arkhangelsk Region (Nuksenitsa-Arkhangelsk gas pipeline, section of 147 km - Mirny)	2,50	3,46	3,41	3,41
60 zone	Arkhangelsk Region (Nuksenitsa-Arkhangelsk gas pipeline, Mirny-Arkhangelsk section)	2,66	3,68	3,63	3,62

Source: Federal Tariff Service of the Russian Federation, http://www.fstrf.ru/

Notes:

* Wholesale gas prices of output of the main gas pipeline transport. Wholesale prices are established per volume unit of gas (1000 m^3) adjusted according to the following:
- temperature (t degree) +20^{o}C;
- pressure 760 mm of Hg;
- humidity 0%;

** Except for consumers of gas supplied by Barnaul-Biysk-Gorno-Altaisk pipeline (section of 87 km-Gorno-Altaisk)

*** Except for consumers of gas supplied by Nuksenitsa-Arkhangelsk pipeline (section of 147 km - Arkhangelsk)

For values calculation were used:

1 Server with the deep retrospective of data on exchange rates -OANDA.com URL: http://www.oanda.com/lang/ru/currency/converter/

2 Conversion factor of 1000 thousand cubic meters of Russian gas in MMBtu according to Gazprom data for Russian gas

Abbreviations

€c/cm	euro cent per cubic meter
AEEGSI	Autorità per l'Energia Elettrica, il Gas e il Servizio Idrico, the Italian Energy Regulator, former Autorità per l'Energia Elettrica e il Gas (AEEG
APM	Administered Pricing Mechanism
Bcm	Billion cubic meters
CEER	Council of European Energy Regulators
CRE	Commission de Régulation de l'Énergie, the French Energy Regulator
ETP	electronic trading platform
EU	European Union
FGN	Federal Government of Nigeria
FTS of Russia	Federal Tariff Service of the Russian Federation
Gazprom	Gazprom Group
GoI	Government of India
IEA	International Energy Agency
IES	Institute of Energy Strategy
IGP	Independent gas producer
IGU	International Gas Union
IOC	International Oil Company
IPP	Independent power producer
JSC	Joint Stock Company
LNG	Liquified natural gas
Mcm	Thousand cubic me
MMbtu	Million British Thermal Units (28 cubic meters)
NOC	National Oil Company
NELP	New Exploration Licensing Policy
OECD	Organization for Economic Cooperation and

	Development
OPEC	Organization of Petroleum Exporting Countries
PSA	Production Sharing Agreement
PSC	Production Sharing Contract
PUA	Public Utility Authority (Electricity)
R&D	Scientific research and experimental developments
Rosstat	Russian Federal State Statistics Service
RSFSR	Russian Soviet Federated Socialistic Republic
UFG	Union Fenosa Gas
UGS	underground gas storage
UGSS	Unified Gas Supply System
UNO	United Nations Organizations
USSR	Union Of Soviet Socialist Republics
VAT	value added tax

References

1. AEEGSI (2014): AEEGSI Annual Report 2014, available at: http://www.autorita.energia.it/it/relaz_ann/14/14.htm
2. AER (Algemene Energieraad) (1995), Nederlands Gasbeleid: Advies aan de minister van Economische Zaken. Vastgesteld op 25 November 1995, Den Haag.
3. AER (Algemene Energieraad) (1998), Liberalisatie van de gassector: Advies aan de minister van Economische Zaken. Vastgesteld op 15 januari 1998, Den Haag.
4. Ausems, A.W.M. (1996), 'Nota de Pous 1962 en het aardgasgebouw'. In: H. 2020, Handboek Energie en Milieu. Alphen aan den Rijn: Samsom.
5. Averch, H., and Johnson, L.L., "Behavior of the Firm Under Regulatory Constraint," *US Economic Review*, Vol. LII, No. 5. (December 1962), pp. 1052-1069.
6. Berg, A.J. v.d., Boot, P.A., Dykstra, M.J. Kool, J.T.C., Schoustra, T.M.P., Wieleman, F.G.M. (1994), Van Wereldmarkt tot eindverbruiker: Energieprijzen voor de periode tot 2015, Beleidsstudies Energie no. 7, Den Haag, Ministerie van Economische Zaken.
7. CEER Status Review of Customer and Retail Market Provisions from the 3rd Package as of 1 January 2012, November 2012, available at: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab3/C12-CEM-55-04_SR-3rd-Pack-customers_7-Nov-2012.pdf
8. CEER-ACER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2012, November 2013, available at: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202013.pdf
9. China gas pricing development, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/07/NG-89.pdf
10. Correljé, A.F. (1997) 'Naar nieuwe verhoudingen in het energiebeleid', Aanpassing onder druk: Nederland en de gevolgen van de internationalisering , pp. 165-178 (eds. W. Hout, M. Sie Dhian Ho), Assen, van Gorcum

11. Correljé, A.F., (1995), 'Dutch Energy Policy and the Environment'. Presented at El petróleo y el gas: El problema energético a finales del siglo XX , Universidad Menèndez Pelayo, Santander, España 31 July - 4 august 1995.
12. Correljé, A.F., Odell, P.R. (1996) 'The politics of European Gas: Dutch play for a return to Centre-Stage', Geopolitics of Energy, Issue 18, Number 9, September 1996, pp. 7-10, The Canadian Energy Research Institute, Calgary.
13. Correljé, A.F., Van Der Linde, J.C., Westerwoudt, T. (2003), Natural Gas in the Netherlands: From cooperation to competition?, Clingendael International Energy Programme/Oranje Nassau, CIEP, The Hague. ISBN 9050310842.
14. Künneke J. Groenewegen, A.Correljé (2005) Innovations in liberalized network industries: Between private initiatives and public interest, Edward Elgar.
15. Aad Correljé (2005) Dilemmas in Network Regulation: The Dutch Gas Industry. In: R. Künneke J. Groenewegen, A.Correljé (eds.) Innovations in liberalized network industries: Between private initiatives and public interest, Edward Elgar. Pp.115-150.
16. CRE (2013): Activity Report 2012, available at: http://www.cre.fr/en/documents/publications/annual-reports/activity-report-2012
17. CRE (2014): Observatoire des marchés de l'électricité et du gaz naturel 1er trimestre 2014, available at: http://www.cre.fr/marches/observatoire-et-indicateurs-des-marches#section1
18. Decision of the Government of the Russian Federation No. 1021 of December 29, 2000 on the State Regulation of Prices for Gas, Tariffs for the Service of Transporting It and Payment for the Technological Connection of Gas-Using Equipment to Gas-Distribution Networks on the Territory of the Russian Federation
19. Decision of the Government of the Russian Federation No. 1205 of December 31, 2010 on Perfecting State Regulation of Prices of Gas
20. Decision of the Government of the Russian Federation No. 239 of March 7, 1995 on Measures to Streamline the State Regulation of Prices (Tariffs)
21. Decision of the Government of the Russian Federation No. 335 of May, 2001 on the Procedure for the Establishment of Special Increments to the Tariffs on the Transportation of Gas by Gas Distributing Organizations for the Financing of Programs for the Installation of Gas Service

22. Decision of the Government of the Russian Federation No. 534 of September 2, 2006 on experimental gas sales on the electronic trading platform
23. Energy Strategy of Russia for the period up to 2030 // App. to the public and business magazine "Energy Policy". – M.: Institute of Energy Strategy, 2010. – 172 p.
24. EZ (Ministry of Economic Affairs), (1995), Derde Energienota 1996, Den Haag, Sdu Uitgeverij.
25. EZ (Ministry of Economic Affairs), (1997), Gasstromen: discussienota, Minsterie van Economische Zaken, Directoraat-Generaal voor Energie, Den Haag.
26. EZ, various years, Oil and gas in the Netherlands, Den Haag,.
27. Federal Law No. 147-FZ of August 17, 1995 on Natural Monopolies
28. Federal Law No. 69-FZ of March 31, 1999 on Gas Supply in the Russian Federation
29. Federal State Statistic Service of the Russian Federation URL: http://www.gks.ru/
30. Federal Tariff Service of the Russian Federation URL: http://www.fstrf.ru/
31. FSR web encyclopedia http://fsr-encyclopedia.eui.eu
32. FERC, *Iroquois Gas Transmission System L.P.*, Docket No. CP89-634-000 et al, Order Making Preliminary Determination and Establishing Procedures, 52 FERC 61,091, at 61,344 - 61,345 (July 30, 1990).
33. Fuel and Energy Complex and Economy of Russia: Yesterday, Today, Tomorrow (1990 – 2010 -2030)/Under the editorship of Yu.K. Shafranik – M.: ENERGY Publishing Centre, 2012.– 462 p.
34. Fuel and Energy complex of Russia. 2000-2011/ Edited by V.V. Bushuev and A.M. Gromov – M.: Institute of Energy Strategy, 2012. – 331 p.
35. Gas Industry Company, *The New Zealand Gas Story. The State and Performance of the New Zealand Gas Industry*, 2nd Edition – April 2014, http://gasindustry.co.nz/publications/new-zealand-gas-story-second-edition.
36. Gasunie (1988), Ondergronds Rijk, Amsterdam, Uniepers.
37. Gasunie, various years, Jaarverslag Gasunie, Groningen, Gasunie.
38. Gasunie, various years, Marktverkenning lange termijn, Groningen, Gasunie.
39. Gelder, J.W. van (1997), 'Peter Sterkenburgh: We raken minder klanten kwijt dan voorspeld'. Gas (juni), p. 13.

40. Government of the Russian Federation URL: http://government.ru/
41. Holwerda, B. (1997), 'Internationale gaswereld goedgeluimd naar Kopenhagen'. Gas (maart), pp. 13-14.
42. D. Ige (2010), "Strategic Aggregator" Roles and Functions in the Nigerian Domestic Gas Market, www.gacn-nigeria.com ;
43. IGU (2014): International Gas Union, *Wholesale Gas Price Survey IGU pricing survey 2014,* www.igu.org
44. International Monetary Fund, *Energy Subsidy Reform: Lessons and Implications*, January 2013
45. Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions*, 2nd ed., MIT Press, 1988.
46. Kok, I.C., Oosterheert, R.J., Stoffer, (1994), 'Kroniek' , Energie Verslag Nederland, 1994, Petten, ECN, pp. 1-63.
47. Kort, C.J.M. (1991), 'Milieu en Europa van grote invoed op Nederlands aardgasbeleid', Staatscourant, 25/9/1991, p. 7.
48. Kunneke, R.W., Arentsen, M.J., Manders, A.M.P., Plettenburg, L.A. (1998) Marktwerking in de gasmarkt, No. 19, Beleidsstudies Energie, Den Haag, DGE, Ministerie van Economische Zaken, p. 105.
49. S.L. Levin* and A.J. M. Duncan, "Policy Considerations for the New Zealand Natural Gas Industry", New Zealand Institute for the Study of Competition and Regulation, July 2011. www.iscr.org.nz
50. Lubbers, R.F.M., Lemckert, C., (1980), 'The Influence of Natural Gas on the Dutch Economy', in The Economics and Politics of the Netherlands (ed. R.T. Griffiths), 's-Gravenhage, Martinus Nijhoff, pp. 87-113.
51. Paul W. Pindyck, Robert S. MacAvoy, *Price controls and the natural gas shortage*; AEI National Energy Project. 1975
52. Makholm, J.D. (2006), "The Theory of Relationship-Specific Investments, Long-Term Contracts and Gas Pipeline Development in the United States", NERA Working Paper, http://www.nera.com/67_5109.htm.
53. J. Makholm, The Political Economy of Pipelines, University of Chicago Press, 2012Ministry of Economic Development of the Russian Federation URL: http://www.economy.gov.ru/minec/main

54. Nigerian Electricity Regulatory Commission (NERC), *Multi-Year Tariff Order for the Determination of the Cost of Electricity Generation for the Period 1 June 2012 to 31 May 2017*, 1st June 2012, www.nercng.org
55. Odell, P.R. (1969), Natural gas in Western Europe, De Erven F. Bohm N.V., Haarlem.
56. Odell, P.R. (1995), 'The Cost of Longer Run Gas Supply to Europe', presented at SNS Day 1995: European Gas Economics in a Global Context: the Longer Run. Stockholm, October 30, 1995.
57. T.O. Okenabirhie (2009), “The Domestic Gas Supply Obligation: Is this the Final Solution to Power Failure in Nigeria? How Can the Government Make the Obligation Work?”, University of Dundee, Centre for Energy, Petroleum and Mineral Law and Policy.
58. Peebles, M.W.H. (1980), Evolution of the Gas Industry, London, The Macmillan Press LTD.
59. Petroleum Economist, various issues
60. Charles F. Phillips, *Regulation of Public Utilities: Theory and Practice*, Public Utilities Reports 1993
61. Portegies, M.J., (1969), 'Marktstrategie van het Nederlandse aardgas', Economisch Statistische Berichten, 25 juni 1969, pp. 650-654.
62. Rosneft Sakhalinmorneftegaz LLC URL: http://www.rosneft.ru/Upstream/ProductionAndDevelopment/russia_far_east/sakhalinmorneftegaz/
63. E. Sanders, *The Regulation of Natural Gas,* Temple University Press, 1981.
64. Scheer, S., Goodman, D. (13 July 2014). "Israel's Leviathan gas reserves estimate raised by 16 pct". Thomson Reuters.
65. SER (Sociaal Economische Raad) (1983), Advies inzake het Aardgasbeleid. SER Publikatie nr. 24 - 21 oktober 1983, Den Haag
66. SIGE (1995), Views of the Dutch Association of Large Industrial Energy Users (SIGE) and the ’Vereniging Krachtwerktuigen’ on the development of the structure of the energy industry in the Netherlands. Hilversum.
67. James L. Smith, *Analysis of the Fair Price of Natural Gas Produced from the Tamar Field and Sold in Israel*, June 2014; delivered by PUA

68. Stern, J. P., Allsopp, C., & Oxford Institute for Energy Studies, The pricing of internationally traded gas, 2012, Oxford University
69. Stern, J.P. (1984), International Gas Trade in Europe: The Policies of Exporting and Importing Countries, London, Heinemann Educational Books Ltd.
70. Stuurgroep Energie-projecten Rijnmond (1996), Energy 2010: Rotterdam industrial area. Capelle a/d IJssel.
71. The Portal of legal information System ConsultantPlus URL: http://www.consultant.ru/
72. The Portal of legal information System GARANT URL: http://www.garant.ru/
73. VK (Volkskrant).
74. -Vries, L. de (1996) 'Positioning of distribution company for the new trading environment', paper presented at the European Autumn Gas Conference, Kopenhagen, 6th of Novermber 1996.
75. Wieleman, F.G.M. (1982a), ’De economische betekenis van het Nederlands aardgas’. Institute for economic research discussion paper series 8218/G, Rotterdam, Erasmus University.
76. Wieleman, F.G.M. (1982b), ’De economische betekenis van het Nederlands aardgas’. Economisch Statistische Berichten, jrg. 67 (22 september), pp. 1012-1016.-Witteveen-Hevinga, T., (1998), Gas: winnen of verliezen Een aanzet tot een herbezinning op het aardgasbeleid in het licht van de volgende eeuw, Partij van de Arbeid, Den Haag.
77. World Bank Energy Sector Management Assistance Program, *Potential of Energy Integration in Mashreq and Neighboring Countries*, Report No. 54455-MNA, June 2010
78. World Gas Intelligence, Several issues (2012-14)
79. Постановление Правительства Российской Федерации от 31 декабря 2010 г. N 1205 г. Москва «О совершенствовании государственного регулирования цен на газ»
80. Постановление Правительства РФ от 07.03.1995 N 239 (ред. от 19.06.2014) «О мерах по упорядочению государственного регулирования цен (тарифов)»

81. Постановление Правительства РФ от 2 сентября 2006 г. N 534 «О проведении эксперимента по реализации газа на электронной торговой площадке»
82. Постановление Правительства РФ от 29.12.2000 N 1021 (ред. от 19.06.2014) «О государственном регулировании цен на газ, тарифов на услуги по его транспортировке и платы за технологическое присоединение газоиспользующего оборудования к газораспределительным сетям на территории Российской Федерации» (вместе с «Основными положениями формирования и государственного регулирования цен на газ, тарифов на
83. услуги по его транспортировке и платы за технологическое присоединение газоиспользующего оборудования к газораспределительным сетям на территории Российской Федерации»)
84. Постановление Правительства РФ от 3 мая 2001 г. N 335 «О порядке установления специальных надбавок к тарифам на транспортировку газа газораспределительными организациями для финансирования программ газификации»
85. Федеральный закон от 17 августа 1995 г. N 147-ФЗ «О естественных монополиях»
86. Федеральный закон от 31.03.1999 N 69-ФЗ (ред. от 21.07.2014) «О газоснабжении в Российской Федерации»