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Impact of Globalization of the Natural Gas Market on Natural Gas Prices in Power Generation and Energy Development

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Working Group on European Electricity Infrastructure [1]

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Sponsored by: International Practices for Energy Development and Power Generation

Chairs: Bai Blyden, Engineering Consultant, BBRM Group LLC, Elk Grove, CA, USA
Raymond Johnson, Manager Portfolio Development, Southern California Edison, USA
Tom Hammons, Chair International Practices for Energy Development and Power Generation IEEE, University of Glasgow, Scotland, UK

Track: New Market Structures

INTRODUCTION

The development of Liquefied Natural Gas (LNG) infrastructure that allows natural gas to be exported from gas producing regions to gas consuming regions is transforming previously regional gas markets into a global market. The panel will address the impacts of this globalization on the power generation industry that has been increasingly turning to natural gas fueled plants. Panelists from major gas producing and gas consuming regions will discuss topics such as supply, demand, infrastructure, price impacts and the possible responses of the power industry.

The Panelists and Titles of their Presentations are:

1. Luiz Augusto Barroso, Raferal Kelman and Bernardo Bezerra (PSR, Rio de Janeiro, Brasil), Hugh Rudnick (Pontificia Universidad Catolica de Chile, Santiago, Chile) and Sebastian Mocarquer (Systep Engineering Consultants, Santiago, Chile). LNG in South America: the Markets, the Prices and Security of Supply (Invited Panel Presentation Summary 08GM0540)
2. Nikolai Voropai, Victor Rabchuk, Sergey Senderov, and Natalia Pyatkova, Energy Systems Institute, Irkutsk, Russia. Impact of Natural Gas Market on Power Generation Development in Russia (Invited Panel Presentation Summary 08GM0743)
3. BinBin Jiang, Stanford University, USA, Chen Wenying, Yu Yuefeng, Zeng Lemin and David Victor. The Future of Natural Gas Coal Consumption in Beijing, Guangdong and Shanghai: An Assessment Utilizing MARKAL (Invited Panel Presentation Summary 08GM1318)

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[1] Document prepared and edited by T J Hammons

4. Michael Urbina and Zuyi Li, Illinois Institute of Technology, USA. Modeling and Analyzing the Impact of Interdependency between Natural Gas and Electricity Infrastructures (Invited Panel Presentation Summary 08GM0270)
5. Vulkan Polimac, Polimac Ltd., Godalming, UK. Generation Development Options in UK from the Aspect of Natural Gas Availability and Prices (Invited Panel Presentation Summary 08GM0277)
6. George Hopley, Commodities Research and Michael Zenker, North American Gas and Power Research, Barclays Capital, San Francisco, USA. US Flying Standby with Liquefied Natural Gas (Invited Panel Presentation Summary 08GM0351)
7. Niko Iliadis, Energy Consultant, Athens, Greece and Vassilis Triantafyllidis, Endesa Hellas, Greece. Natural Gas Market Dynamics and Infrastructure Development in South East Europe (Invited Panel Presentation Summary 08GM0283)
8. Invited Discussers

Each Panelist will speak for approximately 20 minutes. Each presentation will be discussed immediately following the respective presentation. There will be a further opportunity for discussion of the presentations following the final presentation.

The Panel Session has been organized by Raymond Johnson (Manager Portfolio Development, Southern California Edison, CA, USA), Bai Blyden (Engineering Consultant, BBRM Group LLC, Elk Grove, CA, USA), and Tom Hammons (Chair of International Practices for Energy Development and Power Generation IEEE, University of Glasgow, UK).

Bai Blyden, Raymond Johnson and Tom Hammons will moderate the Panel Session.

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BIOGRAPHIES

Thomas James Hammons (F'96) received the degree of ACGI from City and Guilds College, London, U.K. and the B.Sc. degree in Engineering (1st Class Honors), and the DIC, and Ph.D. degrees from Imperial College, London University.

He is a member of the teaching faculty of the Faculty of Engineering, University of Glasgow, Scotland, U.K. Prior to this he was employed as an Engineer in the Systems Engineering Department of Associated Electrical Industries, Manchester, UK. He was Professor of Electrical and Computer Engineering at McMaster University,Hamilton, Ontario, Canada in 1978-1979. He was a Visiting Professor at the Silesian Polytechnic University, Poland in 1978, a Visiting Professor at the Czechoslovakian Academy of Sciences, Prague in 1982, 1985 and 1988, and a Visiting Professor at the Polytechnic University of Grenoble, France in 1984. He is the author/co-author of over 350 scientific articles and papers on electrical power engineering. He has lectured extensively in North America, Africa, Asia, and both in Eastern and Western Europe.

Dr Hammons is Chair of International Practices for Energy Development and Power Generation of IEEE, and Past Chair of United Kingdom and Republic of Ireland (UKRI) Section IEEE. He received the IEEE Power Engineering Society 2003 Outstanding Large Chapter Award as Chair of the United Kingdom and Republic of Ireland Section Power Engineering Chapter (1994~2003) in 2004; and the IEEE Power Engineering Society Energy Development and Power Generation Award in Recognition of Distinguished Service to the Committee in 1996. He also received two higher honorary Doctorates in Engineering. He is a Founder Member of the International Universities Power Engineering Conference (UPEC) (Convener 1967). He is currently Permanent Secretary of UPEC. He is a registered European Engineer in the Federation of National Engineering Associations in Europe.

Raymond Johnson has an MA in Electrical Sciences from Trinity College, Cambridge University and a Ph.D. in Electrical Engineering from Imperial College, London University. He also holds MBAs awarded under a joint program at University of California, Berkeley and Columbia University, New York. His experience includes software development at Ferranti International Controls, and research and development of scheduling and trading systems at PG&E where he led a Systems Engineering team responsible for providing consulting to internal clients on resource scheduling and energy trading. In 1997 he joined the California Power Exchange where he directed the implementation of systems for start up and served as an Energy Business consultant. After leaving the PX in 2001, he started a consulting business under which he provided management consulting services on energy markets, power contract structuring and on information systems for analysis, trading, scheduling, clearing and settlement in support of energy markets. He joined Southern California Edison in 2006 where he leads a Portfolio Development team responsible for portfolio modelling, price forecasting, risk reporting, and contract valuation. He is the author/co-author of over 20 papers and publications in peer-reviewed technical journals

Bai K Blyden is Engineering Consultant, BBRM Group, LLC, USA. Bai Blyden received the degree of MS.EE from the Moscow Energetics Institute in 1979. Specializing in Power Systems, Generation and Industrial Distribution Systems with a minor in Computers**.** He is currently a Project Manager with the Cummins Power Generation Group responsible for Distributed Generation CoGen projects in California where he resides. Mr. Blyden has worked on over thirty power plants and their associated interconnections throughout his career in various capacities of Electrical Systems design, operations planning, management and construction. He has held consulting staff positions with various Utilities such as TVA, PG&E, The New York Power Authority, Entergy and TXU. He has also been a Project Engineer for major AE firms in the Power industry including Bechtel, Asea Brown Boveri, Stone & Webster and Dravo/Gibbs & Hill. While at ABB Mr.Blyden successfully led engineering teams that prepared Kansas Gas & Electric 950 MW Wolf Creek Nuclear Plant and Georgia Power's 2 x 1215 MW Plant Vogtle for Nuclear Regulatory Commission Electrical Distribution Safety Functional Inspection audits (EDSFI). He most recently served as a Project Manager on the CALPINE California Emergency Peaker Program which planned and managed the construction of eleven (45 mW) emergency GE LM6000 gas turbine Peaker units around Silicon valley during the 2001 CA Energy Crisis. He is a member of the IEEE International Practices Subcommittee and serves as consultant to GENI (Global Energy Network International). Bai Blyden is the author of several papers on African Energy Development published in various IEEE publications (1983-2004). He introduced the theoretical concept of a 'Dynamic Parameter', which he presented at MIT and at the IEEE Systems, Man and Cybernetics society conference, 1992 relating to Expert Systems and Artificial Intelligence applications for Power Plants. He has lectured extensively on African Energy Development issues to Institutions and more recently to Investment groups. Mr. Blyden is an early advocate of an Integrated African Grid and presented a conceptual framework and technical analysis for a centralized African Power pool with links to North Africa at the first IEEE Region 8 conference held in Nairobi, Kenya, December 1983.

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1. LNG in South America: the Markets, the Prices and Security of Supply

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Abstract— South America has emerged in recent years as one of the most dynamic regions for natural gas and electricity development. The continent boasts natural gas reserves and high-growth energy markets. The need to diversify away from heavy investments in hydropower and expensive oil is driving many countries to promote the use of natural gas, especially for power generation. On the other hand, challenges are being observed such as competition between hydro- and thermal generation, the breaking of cross-country natural gas agreements, competition between natural gas and other resources for power generation and electric transmission, and others. More recently, LNG started to be considered an option to ensure the adequacy of natural gas supply for power generation. Brazil and Chile are leading the implementation process of regasification facilities. However, the region has also potential to become an exporter of LNG in the medium-term once the potential gas reserves that require deep drilling become commercially available. This paper discusses the introduction of LNG in South America, focusing on the markets, the prices and the security of supply.

Index Terms-- Power system economics, electricity-gas integration, natural gas, liquefied natural gas planning.

1. INTRODUCTION

Natural gas (NG) is considered as one of the most promising sources to supply the world energy demand, with a consumption expanding at a very accelerated pace. The largest use still is for industrial heating. The second largest use is for electric power generation, which experienced a strong growth after the development of combined-cycle generation technology (CC-NG) in the 1980’s. Besides efficient, CC-NG is competitive in modules quite smaller than those of other technologies, such as coal. This has contributed to foster the implementation of power plants based on CC-NG in electricity markets worldwide, and created an interdependency between the electricity and the gas sectors.

Latin America has been in recent years one of the most intensive regions for natural gas and electricity development [1]. The region is very hydropower dependent (about 57% of the region’s installed capacity is hydro) and the need to diversify away from heavy investments in hydropower and oil is driving many countries to promote use of natural gas, especially for power generation. Examples of these developments are in Brazil, Chile and Colombia. Countries of the region have great diversity in size, electrical installed capacity, electrical power demand, and electrical transmission/natural gas network characteristics (level of meshing and geographical extension). Figure 1 shows the share of hydro and thermal power and the installed capacity in some countries of the region (2003 data).

Figure 1 – South American Electricity Markets

The economic reforms opened important sectors to the private investors that were previously reserved to the State. This reform boosted the development of an infrastructure of electricity and natural gas pipelines in the region, both in each country separately and in cross-border electricity-gas interconnections.

The introduction of NG in the energy matrix of the countries took place in a more aggressive manner at the end of the 90's, with the construction of the cross-border gas pipelines (Bolivia-Brazil, Argentina-Chile, etc) and the development of local gas production fields [1]. NG consumption for industrial and automotive use grew at quite significant rates and, in the electrical sector, the installation of gas-fired thermal generation also increased fast, representing and the biggest potential market for the NG sector. Figure 2 presents an outlook of the potential demand and current gas reserves in the region.

Figure 2 – NG reserves

While the "non-power" consumption of NG is practically constant (firm), gas consumption for thermal power plants is variable and strongly dependent on the hydrological conditions. Hydro plants are able, during most of the time, to displace thermal energy production, which are then operated in complementation mode. This is achieved through a hydrothermal coordination [4].

Over the past 3 years, Chile and Brazil decided to implement regasification plants in order to start importing LNG from 2009. Motivation for the two countries is quite similar: (i) to diversify the gas supply for the country (in case of Chile, to diversify from Argentina and in case of Brazil to diversify from Bolivia) and (ii) to create a flexible supply able to accommodate the use of gas to power generation.

The implementation of LNG in the region presents several challenges, whose description is the objective of this work.

2. LNG IN SOUTH AMERICA: MARKETS, PRICES AND SECURITY OF SUPPLY

2.1 Why LNG?

LNG is increasingly at the heart of energy policymaking in South America. The rationale behind LNG projects varies among countries and sometimes within the same country. However, there are three main drivers behind LNG import and export projects in South America.

- *Gas imbalances:* the first reason for importing or exporting LNG is related to the region's natural gas balance: there are countries or sub regions with gas surpluses and others with deficits. Brazil, for example, has a growing potential natural gas market and still not enough gas production. Given the large distances and the geographical obstacles, it is not always possible or economical to export or import pipeline gas. LNG imports are being sought as a way to increase gas supply. On the other hand, countries with abundant gas resources, such as Peru and Venezuela, are looking at LNG exports as a way to market their natural gas and monetize their reserves;

- *Security:* the second reason is geopolitical and is related to energy security and the diversification of natural gas supplies and markets. In Brazil and Chile imports from neighboring countries have proven to be unreliable. and further dependence on supply from a single country is deemed to be undesirable. LNG might become a way to diversify gas supply and some bargaining power in the discussion with regional suppliers. Similarly, Peru could export gas regionally by pipeline, but the LNG export option is considered less politically charged than pipeline.
- *Flexibility of gas supply:* the third reason for LNG imports is related to the nature of gas demand and a growing need for flexibility in gas supply. Because of the hydro predominance in the region, gas-fired dispatch is very much volatile and flexibility is an attractive attribute. However, flexibility comes at a price and it remains to be seen whether LNG is a cost-effective way of achieving supply flexibility. Specifically, in Brazil a large portion of gas demand is linked to the power sector and is highly variable because of the country's dependence on hydropower. LNG imports are deemed to provide more flexibility at a lower cost than building large pipelines.

2.2 The Markets

LNG in South America is divided into importing countries with LNG regasification plants under construction (Brazil & Chile), candidate importing countries (Argentina, Uruguay) and candidate exporting countries (Peru, Venezuela and Brazil in the future).

This means that LNG in South America is concretely summarized into Brazil and Chile as importers. Figure 3 shows the LNG terminals. These countries will be further analyzed in this work.

Figure 3 – South America LNG terminals

2.3 The Prices

The introduction of LNG will have several implications for the region's gas and energy markets, particularly in price benchmarks, energy security, and pipeline infrastructure.

LNG has an opportunity cost. Imported LNG could be more expensive than any regional gas supply and is likely to set a new price benchmark in almost all markets into which it is introduced. As LNG becomes more prominent in the energy mix, its link to global prices will create an inexorable pull on gas prices in previously isolated South American markets. LNG import prices in Latin America will also depend crucially on the timing of the different LNG projects. Until at least 2011, most of LNG production is effectively sold, and new buyers will have to rely on the secondary market. This is especially true for the Atlantic Basin. If South American countries such as Brazil are to attract deliveries of LNG in the short term, they will need to offer at a minimum a price equal to Hub plus a premium. In the current market environment, sellers are pressing for buyers to pay the highest of the Henry Hub equivalent, the National Balancing Point (Europe), and the oil price equivalent. Only in the longer term, as new liquefaction capacity comes on stream, they might they be able to negotiate contracts with more favorable terms.

2.4 The Security of Supply

As mentioned before, the first reason for importing or exporting LNG is related to the region's natural gas balance: there are countries or sub regions with gas surpluses and others with deficits. In addition, the second reason is geopolitical and is related to energy security and the diversification of natural gas supplies and markets.

3. MAIN CHALLENGES FOR LNG IN CHILE

Chile has no significant local gas supply resources. The existing ones are located in the Southern part of the country, about 3,000km away from the main demand centers. Therefore, the country started to import gas from Argentina in 1997.The Argentinean gas is the responsible for the development of the Chilean gas industry and imports were responsible until 2004 for more than 70% of the country's gas supply, which is mostly concentrated in the central part of the country. The northern part of the country depends entirely on Argentina for their gas supply.

However, as discussed in [5], since 2004 Argentina has struggled to meet its own domestic gas needs and has started cutting exports to Chile. Total annual exports to Chile have been falling since 2005 and cuts started to be frequent and recently (2007) have reached as high as 95 percent of committed volumes on several occasions, as shown in Figure 4. Restrictions have affected mainly the thermal power sector and the industrial sector, forcing power plants and industrial consumers to switch to costlier fuels.

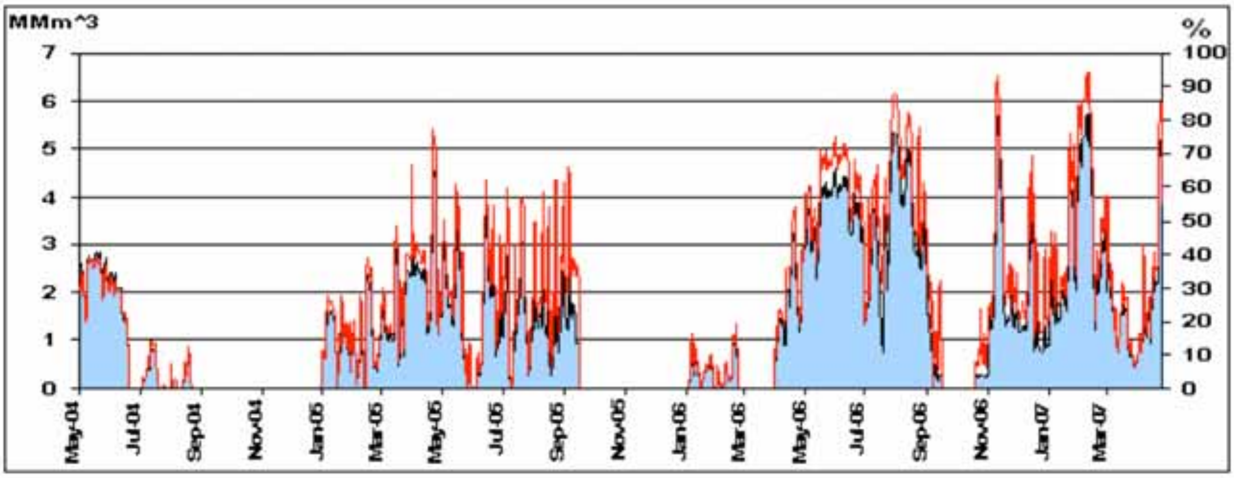

Figure 4 – Gas restrictions in Argentinean exports to Chile

In response, Chile has launched a program to import LNG not only to supply additional gas demand but also to replace decreasing Argentine exports. An LNG terminal is being constructed in Quintero, Central Chile. Next figure shows the terminal's location. Its construction is well advanced; the terminal is expected start partial operations in second quarter 2009, with full-scale operation by late 2010.

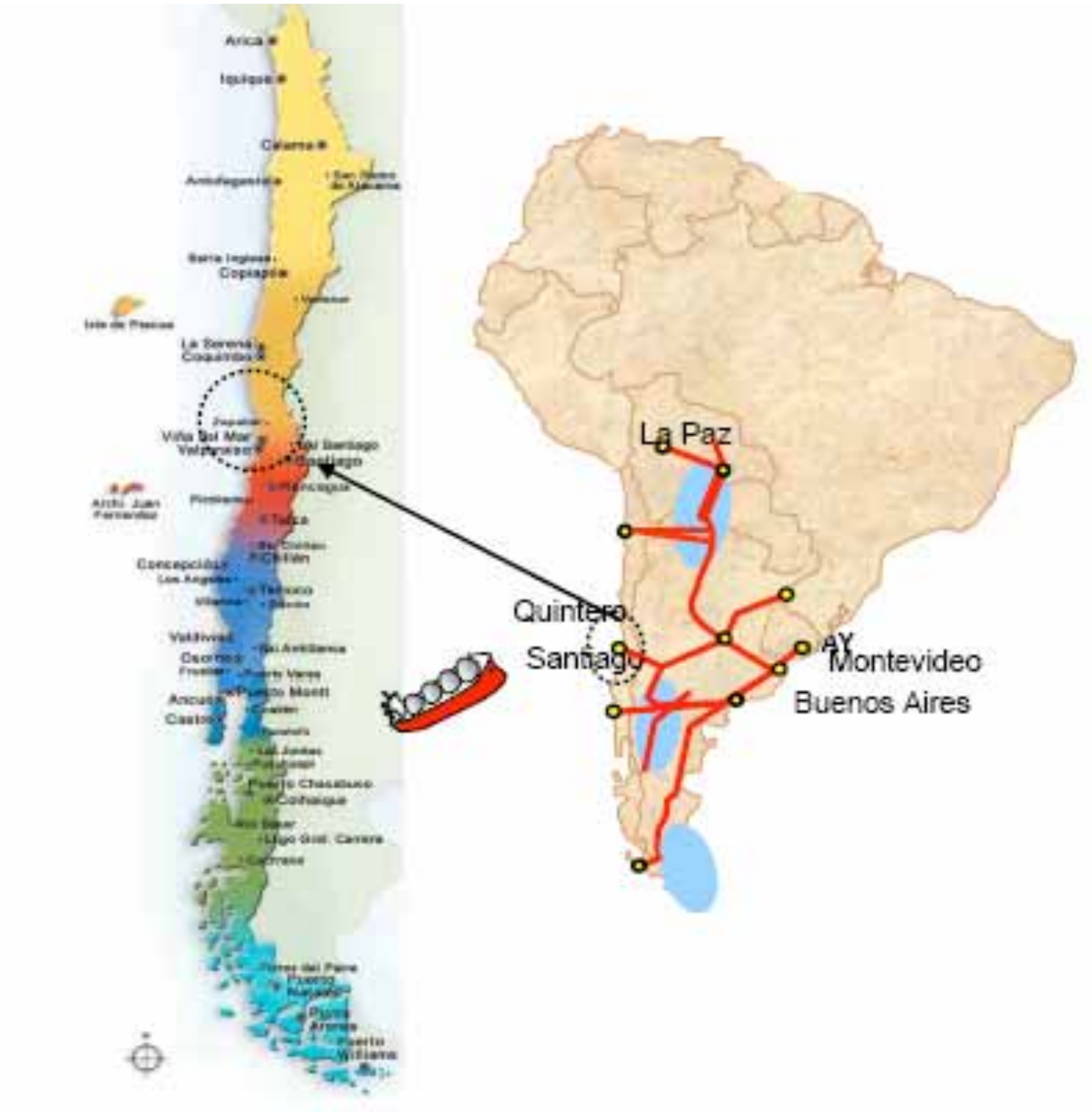

Figure 5 – Quintero's terminal location

A pool of off takers including government owned oil company ENAP, power generator Endesa Chile, and gas distributor Metrogas was created. In early 2006 the pool selected UK gas company BG Group both to supply LNG and to construct the terminal. Off takers have already contracted 6 MMcm per day of regasification capacity (final capacity could be as high as 12 MMcm per day). Other off takers (mainly power plants) is expected to soak up the additional capacity. The plant is being constructed with a possible expansion in mind (a third tank would bring capacity to 20 MMcm per day).

Plans for another LNG regasification terminal in northern Chile have also been announced, led by Co Delco, the State owned copper mining company. This system is much more dependent on gas. About 58% of capacity is gas fired, as the region has none of the hydro potential of the center and south. There are no connections between the SING and the SIC power grids, however. Nor are there any connections between the respective gas networks. The mining companies are the main off takers of gas-based electricity in the north. However, in this region LNG would face a direct competition from coal imports and coal-based power generation.

There is yet no indication of the price at which GNL Chile will buy the LNG but it is certain to be much higher than the current import price from Argentina yet lower than the price of oil products (mainly diesel oil) currently used to replace missing gas.

LNG's competitiveness with other fuels and sources of power will be critical for the development of LNG imports. Chilean gas consumers may agree to pay a premium for supply security, given the risk embedded in Argentine gas imports. However, as much of the gas is used in power generation, LNG will need to be competitive with other fuel sources (such as coal, hydro, etc). Investors in the power sector are betting that coal will be more competitive than LNG and are already building new power plants based on that fuel, with LNG being considered to play a backup function, for existing combined cycle plants, rather than a basis for generation expansion

4. MAIN CHALLENGES FOR LNG IN BRAZIL

4.1 Natural Gas Market in Brazil

In Brazil, the ingress of NG in the energy matrix took place in a more aggressive manner at the end of the 1990's, with the construction of the Bolivia-Brazil gas pipeline and the development of local production fields. NG consumption for industrial and automotive use grew at quite significant rates (induced by tax benefit policies, by increase in supply and by prices) and, in the electrical sector, the installed gas thermal generation capacity also had a fast growth, so that in Brazil it accounts today for some 8000 MW. The question of natural gas supply for thermal generation has been the object of concern by the authorities ever since the conception of the new model for the Electrical Sector [3]. A recent (2006) "dispatch test" performed by Aneel (power sector regulator) in the gas thermal power plants disclosed that such concern is actually legitimate, because about 50% of the tested capacity in the South/ Southeast-Center West Regions did not manage to produce energy due to fuel deficiency.

In an effort to increase the natural gas supply in the country, Petrobras announced recently (2006) the construction of re-gasification stations, so as to import liquefied natural gas (LNG), from 2009, to the Southeast and Northeast Regions. These gas imports would come from LNG exporters such as Trinidad & Tobago and Nigeria and Petrobras decided to implement mobile floating storage regasification units (FSRU).

4.2 The business model: LNG flexible supply

The introduction of LNG is observed with interest by the electrical sector, for three main reasons: (i) to diversify gas supply sources, (ii) a contract market with shorter ranges and greater flexibility has been emerging. This way, ships for LNG delivery may be contracted according to consumption needs and, thus, have the potential for rendering flexible the natural gas supply to thermal power plants and other clients; and (*iii*) it is possible to build thermoelectric plants located relatively close to the major LNG delivery ports, thus avoiding investment (fixed costs) in gas pipelines.

In this manner, the final cost to the consumer of thermal energy produced from LNG may become more attractive. This because the flexible supply of gas provided by LNG permits those thermal power plants is operated in the mode of complementing hydroelectric production and, therefore, that fossil fuel is saved. As discussed in [2], the final consequence of this operation is the reduction of energy cost to the consumer[2]. Actually, Petrobras announced its intention of contracting LNG to supply the Brazilian market in a flexible manner.

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[2] Thermal insertion in Brazil took place based on contracts for supply of *inflexible* gas, with 'take or pay' and 'ship or pay' clauses, which correspond to fixed payments, respectively to gas producer and to transporter. This way, the benefit of the operation and of the hydro-thermal synergy is not exploited, and the final cost of this technology becomes higher.

The business model to procure flexible LNG contracts is innovative and very challenging given the LNG volumes at stake and the current tightness of the LNG international market. The idea is to take advantage of the recently developed short-term LNG market and to sign a contract with flexibility clauses. This could be an option contract whereby an LNG provider to US market would divert ships to Brazil at Petobras's convenience.

4.3 Challenges for LNG supply

Nevertheless, although LNG may provide flexibility in gas supply to thermal power plants, it has one important characteristic: its price (*as a commodity*) strongly depends on how much in advance its order is placed. For example, a LNG order placed one year in advance can normally have a fixed price, since the vendor has the possibility of contracting adequate hedges against the oscillations of the strongly uncertain and volatile international prices. On the other hand, a LNG order placed just a few weeks in advance has a price above that of usual references, associated to the opportunity cost of displacing this gas with respect to its destination market, and increased by an "urgency rate". For instance, a LNG request for "next month" may involve the displacement of a ship intended for the United States market which has a reference price corresponding to that associated to Henry Hub. In this case, the price for the Brazilian market would be, at least, the opportunity cost of this gas (Henry Hub price) increased by a spread (e.g., 10%).

In this context, an important decision problem for the LNG buyer consists in determining, each year, the shipping schedule so as to fulfill gas demand and to minimize its purchase price. This problem becomes more complex on account of the features of the electrical sector's natural gas consumption, which is potentially high and has a strong uncertainty component, as the National System Operator has the prerogative of setting thermal plants in motion without advance notice.

At first sight, the only way to solve this conflict between anticipation of fuel order and uncertainty as to the moment of thermal plants dispatch would be the construction of physical reservoirs for LNG storage. However, the cost of these reservoirs would be very high, if the gas storage capacity were sufficient to cover the period of thermal plants operation, which could last some months. It is at this point that the concept of a *virtual reservoir* appears: instead of storing gas in a *physical* reservoir, in order to generate later electric energy, one possibility would be to pre-generate this electric energy as soon as the previously programmed LNG shipments arrive, and to store this energy in the form of water in the system hydro plants reservoirs, as *energy credits* for the future use by thermal power plants. This way, the dispatch needs would be matched to the LNG supply logic. The concept of virtual reservoir was recently introduced in the Brazilian market rules.

4.4 Virtual gas storage: gas stored in hydro reservoirs

As described above, the expectation of a LNG order for gas to be used in thermal dispatch may be frustrated by the occurrence of a more favorable hydrology that that expected. In this case, the requested natural gas would not be needed after the arrival of the liquefied gas carrier ships at the re-gasification stations. Symmetrically, a less favorable hydrology than that expected could lead to the need of an "immediate" thermal dispatch, not allowing sufficient time for the arrival of the ship carrying the required fuel.

An interesting mechanism to relieve this problem can be found in the very physical characteristic of the Brazilian hydroelectric system: the presence of reservoirs with large storage capacities provides a storage flexibility which could be used by thermal power plants to store as equivalent water, through a "forced dispatch", the delivered natural gas that otherwise would not be used. In this case, the thermal power plants would retain a credit of natural gas stored in the hydro plants reservoirs in the form of water, meaning that hydroelectric storage could be used as a buffer by thermal plants so as to permit the storage of non-utilized natural gas.

The following steps describe a simplified version of the virtual reservoir scheme:

(1) Assume that a ship has just arrived, carrying sufficient LNG to supply 2 GW average of thermal generation for one week. Assume, also, that the ISO announced that it intends to dispatch 50 GW average of hydroelectric plants next week.
(2) The thermal power plant notifies ISO that it intends to pre-generate 2 GW average; ISO reschedules hydroelectric plants generation to 48 GW average, so as to accommodate thermal plant pre-generation.
(3) ONS records in the accounts the reservoirs storage reduction *as if* hydro plants had actually generated the scheduled 50 GW. In other words, the *physical* volume of the water stored in the reservoirs will be greater than the *accounted* stored volume.
(4) The difference between physical and accounted storage (corresponding to the pre-generated 2 GW average) is credited to the thermal plant as an *energy option* ("call option") that may be actuated at any moment.
(5) Finally, assume that some time later ISO announces that it intends to dispatch 48 GW average of hydroelectric energy and 2 GW average of thermoelectric energy. As mentioned above, the thermal plant may decide to generate physically (if, by a coincidence, a new LNG ship happens to have just arrived) or to apply the option of using the stored energy. In the latter case, the thermal plant follows a procedure inverse to that of item (2): it notifies ISO that it is going to utilize its stored energy, and ISO reschedules the hydroelectric generation to 50 GW average.

The great risk for the thermal producer in this arrangement is that of water spillage from the physical reservoir: in this case, "accounted" hydroelectric energy will be spilled before the "physical" energy.

Of course, the procedure to be implemented involves more complex aspects, not addressed in this article, such as transmission restrictions, storage management for the various hydroelectric plants, compatibility with the mechanism of energy reallocation, among others. Yet, in brief, *virtual* storage utilization permits, through a *swap* operation, to accommodate the need to order LNG *without affecting* the system optimum policy and operation, thus favoring the ingress of flexible gas supply and the possibility of preparing *strategies* for its cost reduction.

5. VIRTUAL GAS STORAGE AND SMART ELECTRICITY-GAS SWAPS

Finally, the introduction of flexible LNG supply in the region can bring up several opportunities to integrate the electricity and gas markets in the region. This is because energy swaps with LNG are much more economical than the proposed point-to-point pipelines. An example of gas-electricity integration is the so-called "gas exports from Brazil to Chile without gas or pipelines". Essentially, Chile purchases 2000 MW of electricity from Brazil, for delivery to Argentina (via the Brazil-Argentina DC link). The power from Brazil now displaces 2000 MW of gas-fired thermal generation in Argentina, which frees up 10 MM3/day of natural gas supply, which is (finally) shipped to Chile.

Another example is the use of LNG against the proposed "Southern Gas Pipeline", from Venezuela to Brazil and Argentina. A more rational solution would be to send LNG from Venezuela to the Northeast region of Brazil, thus decreasing the need to send gas from the Brazilian Southeastern region to the Northeast. The surplus production is then sent by LNG to Montevideo, and from there through an existing pipeline to Buenos Aires.

Many other possibilities can be designed but, in essence, LNG brings opportunities for intelligent and economic integration of the regional energy market.

6. CONCLUSIONS

The primary challenge for South American countries is to ensure sufficient capacity and investment to serve reliably their growing economies. The region has emerged as one of the most dynamic areas for natural gas and electricity developments. More recently, LNG has emerged as an attractive option. However, South America is a latecomer to the LNG business. Other regions and countries have already incorporated this external natural gas supply source in their portfolios for many years. However, some opportunities could arise from this late arrival. In particular, the evolving rules of the global LNG market could allow for more flexible supply. This, in turn, brings opportunities for intelligent and economic integration of the regional energy market. The energy swaps with LNG are much more economical than the proposed point-to-point pipelines. An example of gas-electricity integration is the so-called “gas exports from Brazil to Chile without gas or pipelines”. Essentially, Chile would purchase 2000 MW of electricity from Brazil, for delivery to Argentina (via the existing 2,000 MW Brazil-Argentina DC link). The power from Brazil would displace 2000 MW of gas-fired thermal generation in Argentina, which would free up 10 MM3/day of natural gas supply, which would be (finally) shipped to Chile.

Finally, the ultimate amount of LNG imported will depend crucially on the development of the natural gas reserves in the region. The region has significant reserves and the challenge is how to monetize them and serve the regional and sub regional markets. The situation varies widely among LNG importers: there are countries with growing potential natural gas reserves (Mexico), which was not discussed in this work; those with very little potential (Chile) and those with substantial reserves but still not enough to supply their large market potential (Brazil). The result will likely be a mix of and local/regional gas with LNG playing a smaller, but still important role in balancing supply and demand.

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8. BIOGRAPHIES

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2. Impact of Natural Gas Market on Power Generation Development in Russia

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Abstract— The paper concerned with research of natural gas market and it's impact on power generation development in Russia

Index Terms – market - natural gas - cogeneration plants - electricity and heat production.

A large part of natural gas consumed in Russia is used for electricity and centralized heat production. Table 1 presents gas volumes consumed in 2005 in the country for electricity and heat production [1].

TABLE 1. GAS CONSUMPTION FOR ELECTRICITY AND HEAT PRODUCTION IN RUSSIA IN 2005

Type of final energy and generation sources	Gas consumption mln. tce*/ bln.m^3
Electricity supplied by fuel-fired power plants	129 / 112
Heat supplied by fuel-fired power plants	65.9 / 57
Heat supplied by industrial and residential boiler plants	81.8 / 71
Heat supplied by boiler plants of agricultural enterprises	2.7 / 2
Total:	270.4 / 243

*tce – ton coal equivalent

Thus, out of 397 bln m^3 of natural gas used in the country in 2005 electricity and heat generation required 243 bln m^3 or 61 %, the remaining 39 % was used by population and other branches: metallurgy, petrochemistry, agro chemistry, etc. Almost the same relation in shares has been observed in the recent years.

Table 2 shows the structure of fuel consumption by the generation companies of RAO "EES Rossii" in 2000-2006 for electricity and heat production. For Russia it is virtually impossible to consider separately production of electricity and centralized heat at cogeneration plants (CPs), because almost 1/3 of electricity is generated in combination with heat at thermal power plants (TPPs).

TABLE 2. STRUCTURE OF FUEL CONSUMPTION BY SUBSIDIARY GENERATION COMPANIES OF RAO "EES ROSSII" IN 2000 - 2006

	2000	2001	2002	2003	2004	2005	2006
Gas, bln. m^3	127.1	131.2	132.4	135.6	139.7	142.6	148.1
Fuel oil, mln. t	8.5	7.6	7	6.8	53	49	6.2
Coal, mln. t	120.1	109.6	106	109.3	101.2	104.4	109.2

Source: Annual reports of RAO "EES Rossii"

Conversion of data from Table 2 to standard fuel made it possible to represent the share of each mentioned resource in fuel supply for the indicated generation capacities, Fig. 1.

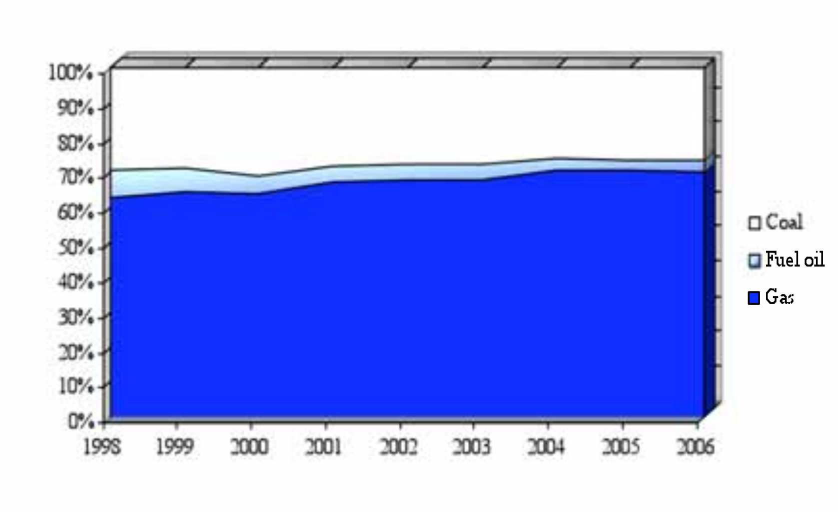

Fig. 1. Shares of individual fuel resources in fuel supply for generation capacities of RAO "EES Rossii" in 1998-2006

The analysis of data in Fig. 1 shows that over these 8 years the share of natural gas in production of electricity (and centralized heat at cogeneration plants) in the total volume of fuel used at thermal power plants increased from 63% to 70 %.

For the same period the price of gas supplied to industrial consumers and power plants increased from $10/1000 m^3 to $51/1000 m^3 (the last figure is for 2007). Note that the indicated prices are controlled and several times lower than those in the European countries and the US.

Such a situation with gas prices in Russia cannot last long – the prices will inevitably rise because of the following reasons:

- The tendency of RAO "EES Rossii" to achieve equal profitability of the gas industry in the external and domestic gas markets (in 2006 the gas price in the European countries was at the level of $250/1000 m^3);
- The price increase will be caused by the objective necessity for Russia to move to new (with very expensive development) areas of natural gas production (the Yamal and Gydan Peninsulas, shelves of the Barents and Kara Seas). This seems to be the main reason for the price increase.

The necessity to sharply increase domestic gas prices is also understood by the Government of RF. Dynamics of change of the wholesale domestic gas prices to be followed to the year 2010 is determined in its decision of 30 November 2006. Based on different factors (depletion of the main gas fields in the current gas production areas, growth of gas demands, aging of fixed production assets, growing demands of the industry for investments, etc.) the gas price level for industry and electric power industry in 2011 will approach $115/1000 m^3 – $120/1000 m^3. Besides, the possibility for including **the gas price formula** (approved by the Federal Tariff Service of RF in July 2007) in the long-term contracts for domestic consumers is examined at present [2]. (*It will take into account the primary cost of gas of a concrete gas production area in a concrete gas consumption area including the necessary charges, taxes, dues).* The average gas price calculated by this formula should be about $170 /1000 m^3 in 2007. Whereas prior to 2007 this price was hypothetic, in 10-15 years such a price will be real for the objective reasons mentioned above.

Table 3 presents the values of primary cost of gas for the main gas fields of the Yamal Peninsula (Bovanenkovskoye and Kharasaveyskoye), the shelf of the Kara Sea (Leningradskoye and Rusanovskoye) and the fields of the Gydan Peninsula in the Moscow region (i.e. in the center of the European part of Russia) that were calculated at Energy Systems Institute.

TABLE 3. THE PRIMARY COST OF GAS OF THE MAIN FIELDS IN NEW GAS PRODUCTION AREAS IN THE MOSCOW REGION, $/1000 m^3

Field	Prime cost components			Prime cost	
	Develop-ment	Production and prepration	Transport	Range of possible values	Average values
Bovanen-kovskoye	12 – 15	30 – 35	53 – 59	95 – 109	102
Kharasa-veyskoye	12 – 15	30 – 35	54 – 60	95 – 110	103
Lenin-gradskoye	18 – 20	45 – 50	60 – 67	123 – 137	130
Rusanov-skoye	18 – 20	45 – 50	64 – 71	127 – 141	134
Fields of Gydan Peninsula	15 – 18	35 – 40	64 – 70	114 – 128	121

The prime cost of gas for the concrete field (Table 3) represents the relation between the total capital and operating costs for the whole time period of infrastructure creation on the field and the total gas production for the same time period. Here the total costs are the costs for creation and operation of:

- Production and social infrastructure required for development of the considered field and later on – its exploitation;
- Systems of gas production and preparation for long-distance transportation;
- Systems of long-distance gas transportation from the field to the area of its consumption.

In Table 3 there is no analysis for gas of the Shtokmakovskoye field (the Barents Sea shelf), as far as its use in the country is obviously inexpedient and its sale in the external markets is more preferable.

The values of primary cost of gas in Table 3 were calculated on the base of the corresponding specific capital and operating costs that are reasonable only for the present day. Correspondingly, the obtained preliminary figures for primary cost of gas of new gas production areas should be considered correct only for the current gas production. At the time of actual start of gas production from the considered fields the figures can change because of uncertainty factor.

As is seen from Table 3, the most probable prime cost of gas in the Moscow region could make up currently \$100/1000 m^3 – \$105/1000 m^3 (for Yamal), \$130/1000 m^3 – \$135/1000 m^3 (for the shelf of the Kara Sea) and \$128/1000 m^3 (for the fields of the Gydan Peninsula). We can say with reasonable confidence that the specific capital and operating costs will increase with the lapse of time and hence the primary cost of gas in new gas production areas will also rise. Based on different data for the period from 2000 to 2006 the indicated specific costs increased on the whole by 70 – 100%. Even if the growth rates of specific costs for the period to 2020 are not so high and make up about 50% with respect to the present day ones, by 2020 the primary cost of gas will increase to \$150/1000 m^3 for the Yamal gas, to 200/1000 m^3 for the Kara Sea shelf and to \$180/1000 m^3 for the Gydan Peninsula.

In the foregoing we discussed only the prime cost. Hence, the mentioned average gas price of \$170/1000 m^3 (that was calculated by the gas price formula) can be considered quite real in 10-15 years. So much so, the gas share in new gas production areas in 15-20 years will amount to 70 – 75% of the total gas production in the country.

Thus, the gas price rise in the domestic market of Russia, in particular for generation companies is inevitable. This will surely involve an increase in price of electricity generated and correspondingly an increase in price of all types of industrial products and service industries.

How can this process be dampened? Actually, there are various methods but one of them suggests itself: it is necessary to try to decrease the share of a costly resource (gas) in favor of that more financially accessible (in this situation it is coal). Moreover, the increase in the diversification of fuel mix in the country (gas share is 80% of the total fuel consumption) will have a positive impact on the level of Russia's energy security.

Using all the required data (the main of which are presented below) the authors have tried to obtain a picture of change in the share of gas-fired thermal power plants in the structure of generation capacities of the country due to increase in the coal share. The data refer to:

- the increase in gas price for Russia's electric power industry from 50 $/1000 m^3 – currently to 170 $/1000 m^3 – in 2020;
- the change in relationships between coal and gas prices (in terms of standard fuel) from 1:1.1 – currently up to 1:1.6-1.8 – in 2020;
- the national electricity demand, taken on the basis of the Energy strategy of Russia up to 2020 [3];
- the technical and financial constraints on replacement of worn and obsolete generation equipment and construction of new capacities;
- the specific capital investments in the construction of new generation capacities of different types (gas- and coal-fired thermal power plants, nuclear and hydro power plants) and specific operating costs for currently operating and new capacities, etc.

A technique for electric power industry development planning which accounts for its interrelations hips with other branches of the Fuel and Energy Complex (FEC) has been actively developed in Russia [4]. It is similar to the integrated resource planning approach [5, 6]. The authors of the paper considered the approaches to the integrated planning of electric power systems and gas supply systems expansion in a market environment. Below consideration is given to the practical approach of using such techniques in the example of a multi-step planning of Russia's power industry development, taking into account the prospects for development of the national gas industry and bearing in mind the possible substantial rise in the price of gas used in the electric power industry.

Such a multi-step modeling supposes two-level studies:

- the first level – the entire Fuel and Energy Complex of the country;
- the second level – the systems of electric power and gas supply.

At the first level the territorial and production model of the national FEC is employed to determine the main relationships between the development of fuel industries and electric power industry, taking into consideration their interaction in the considered time horizon. Then, involving a more detailed mathematical model of electric power industry development, the prospective structure of generation capacities and their allocation are determined.

The next step supposes creation of scenarios of possible deviations in the gas industry development from the basic conditions (considered at the FEC level). Further the scenarios are studied from the viewpoint of their impact on electric power industry development. And then, based on the analysis of the studies and using alternately the models of FEC, electric power industry and gas industry we find the solutions of potential electric power industry development that are adaptive to the expected conditions of gas industry development (including changes in the gas prices within the set ranges). At the same time (at the FEC level) the account is taken of the conditions for expansion of all types of generation capacities and development of all fuel industries – in terms of fuel interchangeability and reserves.

The analysis of factors determining the structure of generation capacities within the multi-step modeling reveals that in addition to gas and coal prices themselves the key factors for Russia (at least up to 2020) are ***physical capabilities*** of involving gas and coal in the fuel mix of the country. In turn the volumes of such involvement will largely depend on the possibilities to produce the mentioned fuel resources in the country.

The volumes of national coal production can be increased substantially. With the investments available and with the demand for coal, its production can reach 450-500 mln t/year or 270-300 mln tce by 2020 [7] compared with the current production level of 300 mln t or 180 mln tce annually.

However, it is not easy to increase the volumes of gas production. Aside from the need to invest huge sums of money in the development of new gas production areas it is necessary to consider the time lag. For example it will take 12-13 years at best for the gas production volume on Yamal to reach 240-250 bln m^3/year (this is a maximum volume) from scratch.

In 2006 the country produced 656 bln m^3 of gas. Based on the estimates of Energy Systems Institute the gas production level in Russia in 2020 will be ***not exceed 680 bln m^3***. And this is provided that

- gas production on Yamal will start in 2010 and will then grow and reach the level of 240 bln m^3/year in 2020;
- gas production at the Shtokmanovskoye field will start in 2011-2012 reaching the maximum annual production 60-80 bln m^3/year in 2020-2025;
- the total volume of gas production in other new areas (the Sakhalin Island Shelf, Irkutsk region, the Sakha republic (Yakutia) and other regions) will reach 40 bln m^3 in 2010 and 60-80 bln m^3/year in 2015-2020.

Taking into account the above information the potential volumes of gas and coal involvement into the fuel mix of the country and potential volumes of their use for production of electricity and centralized heat at co-generation plants were compared up to 2020. The model-based studies took into consideration the fact that all gas and coal involved in the fuel mix of the country is consumed for two purposes:

- production of electricity and centralized heat;
- the use by all other categories of consumers (industry, population, housing and public utilities, etc.).
-

The results of the comparison are presented in Table 4.

TABLE 4. COMPARISON OF POSSIBLE COAL AND GAS INVOLVEMENT INTO THE FUEL MIX OF THE COUNTRY AND THE VOLUMES OF THEIR USE FOR PRODUCTION OF ELECTRICITY AND CENTRALIZED HEAT IN 2020

Natural gas, bln m^3	
Potential production	up to 680
Own needs of the industry	60
Possible import	60
Possible export	260
Domestic demand	170 (except for electricity and heat production at TPP)
Reserve*	up to 250
Reserve in mln tce	up to 290
Coal, mln t	
Potential production	up to 500
Possible import	15
Possible export	90
Domestic demand	80 (except for the electricity and heat production at TPP)
Reserve*	up to 345
Reserve in mln tce	up to 210

*Gas and coal volumes that can be used at TPP

Separation of coal and gas demand for production of electricity and heat, and for other needs allows one to reveal the extent to which the shares of these energy resources will be redistributed in the future. For example the demand for fuel at thermal power plants in 2020 can be met owing to **290 mln tce** of gas that can be supplied by the gas industry and up to **210 mln tce** of coal that can be supplied by the coal industry.

Thus, the prospective relationship between gas and coal use for production of electricity and centralized heat at cogeneration plants can make up 58% or 290 mln tce of natural gas against 42% or 210 mln tce of coal. We should bear in mind that in 2006 the gas share neared 70%. Besides, there was fuel oil in the fuel mix in 2006. For 2020 fuel oil (as a basic fuel) was not considered in the fuel mix: by that time this kind of fuel should be only used as an emergency reserve and process fuel (for example ignition of steam generators at cogeneration plants).

In conclusion we can state that the gas share at thermal power plants of Russia, despite a sharp gas price rise (from 50$/1000 m^3 currently to 170 $/1000 m^3 in 2020), can be decreased only 11-12% in favor of increase in the coal share, which to some extent will enable one to mitigate the cost rise of the electricity and centralized heat produced at TPPs in the natural gas demand zone. The above said can be real, if the future coal generation is based on clean coal, modern technologies.

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BIOGRAPHIES

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3. The Future of Natural Gas Coal Consumption in Beijing, Guangdong and Shanghai: An Assessment Utilizing MARKAL

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Abstract - There are many uncertainties regarding the future level of natural gas consumption in China. In order to obtain a clear idea of what factors drive fuel consumption choices, the study focused on three regions of China. Using MARKAL, the drivers that are considered include the level of sulfur dioxide emissions constraints set by the government, the cost of capital, price and supply of natural gas, and the rate of penetration of advanced technology. The results from the model show that setting strict rules for SO2 emissions will be instrumental in encouraging the use of natural gas. Differentiating the cost of capital for various sectors within the Chinese economy, on the other hand, may lead to a decrease in the use of natural gas as coal consumption increases. Regulating SO2 emissions also led to a significant decrease in CO2 emissions.[3]

Keywords - natural gas consumption, MARKAL, China

1. INTRODUCTION

The world's natural gas market is rapidly globalizing. Traditionally, gas supplies have been delivered entirely within regional markets—usually with little geographical distance between the source of gas and its ultimate combustion. However, a significant and growing fraction of world gas is traded longer distances via pipeline and, increasingly, as LNG. The rising role of LNG is interconnecting gas markets such that a single global market is emerging (Jensen, 2004).

Within this increasingly integrated gas market, the role of China remains highly uncertain. Today, China's share of the global gas market is tiny; with a natural gas market that is smaller than California's (CEIC, 2007), but the future demand for natural gas in China is potentially enormous. With an average gross domestic product (GDP) growth of 9.6% for the last twenty years (China National Bureau of Statistics, 2006) and no signs of slowing down, demand for energy commodities—coal and oil, notably—has been expanding rapidly. With appropriate policies, natural gas could also grow rapidly.

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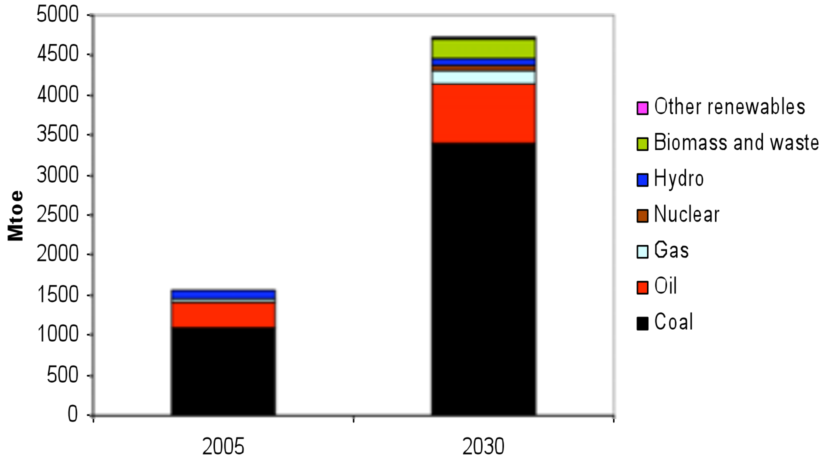


Source: BP Statistics Review 2006, IEA WEO 2005

Figure 1. Primary Energy Consumption in China for 2005 and 2030

This study explores potential drivers for increased natural gas demand within the Chinese energy system and focuses on three regions—Beijing, Shanghai and Guangdong. This regional model reflects that natural gas sourcing and the downstream natural gas market vary greatly by region due to climatic and geographical barriers. For example, Guangdong receives no pipeline gas and is dependent on LNG imports (at present from Australia), while domestic pipelines principally supply Beijing and Shanghai's gas demands. The major off-takers for the gas differ between regions as well. In Shanghai, for example, the industrial sector consumes almost all of the gas, while peaking power plants are major off-takers in Guangdong. The regional organization of this study also reflects the political realities of decision-making in China. While there are national policies on energy in China, most decisions that affect the usage of natural gas are made at the provincial and local level and driven by the economics and consumption patterns of each locale. A regional focus is therefore useful to model the nuances unique to each area.

Analyzing the drivers of gas demand in China is crucially important for three reasons. First, understanding the increasingly global gas market requires assessment of the demand for natural gas in major emerging markets, such as China and India. Second, China's gas demand has repercussions for global geopolitics. State-owned China National Petroleum Company (CNPC) is already earnestly acquiring assets and building relationships in oil and gas fields abroad. For example, high-level negotiations between China, Turkmenistan, and Kazakhstan are aimed at securing natural gas supplies from the Bagtyiarlyk gas fields, via a pipeline through Kazakhstan (Interfax, 2007). CNPC is also engaged in a worldwide search to secure more LNG supplies. If natural gas demand soars, CNPC will be under increased pressure to seek out new supplies. This competition for resources could lead to a realignment of alliances globally. Third, a significant increase in natural gas use could result in a decrease of CO_2 emissions by displacing more carbon-intensive fuels such as coal. This issue is especially pressing since China is projected to be the top emitter of greenhouse gases in the world by the end of 2007 (DOE, 2007). Gas could potentially play a role in stemming the emissions that are dominated by coal.

In analyzing the energy systems of Beijing, Guangdong, and Shanghai, we used three separate, regional MARKAL models. Given a projected level of total energy demand services, each MARKAL model solves for a least cost optimal solution (Nobel et. al., 2005) over the course of twenty years (2000-2020), utilizing a menu of technologies that is provided as an input for the models. The specific types of energy and emissions control technology are characterized by performance and cost parameters. The model solves by selecting a combination of technologies that minimizes the total system cost and meets the estimated energy demand. Our goal is not necessarily to produce an unwavering prediction of future gas use, since key input assumptions, such as the level of demand services, are highly uncertain. Rather, such models are particularly well suited to reveal how sensitive natural gas demand is to key factors. In addition, because the models allow the system to meet energy demand in the most cost effective manner, the results of the study can also help illuminate financially viable options for constraining emissions.

For this study, we identified some of the major factors that are likely to affect future demand for gas. These include:

- Rate at which more efficient end-use technology is made available;
- Stringency of local and regional environmental constraints;
- Financial reforms that affect the cost of capital for different sectors of the economy (i.e., power, industry, residential, commercial, transportation)
- Pricing and availability of gas.

The findings of the report show that the most important drivers (apart from polices that directly influence the price of natural gas relative to other fuels) which affect the consumption of natural gas are the implementation of SO_2 controls in the system and, unexpectedly, financial reforms. For very tight limits on SO_2 emissions, the model shows that a switch to natural gas in the power and industrial sectors becomes the economically optimal alternative to other fossil fuels in many cases. When the rise in gas demand is in the industrial sector, this gas displaces oil; in the power sector, where gas competes with coal, it is much harder in our baseline scenario for gas to gain a substantial share of the market. We also find that a side benefit to SO_2 emissions reduction policies is a corresponding decline in CO_2 emissions on the order of 60 million tons CO_2 for some locales (equivalent to about a quarter of the entire stock of Clean Development Mechanism projects in China)(UNEP, 2007). This suggests that a leverage point for governments in developing countries like China to start addressing global concerns about climate change is through regulation of local pollutants that yield visible and immediate benefits while also fortuitously limiting growth of CO_2.

As for the effects of financial policies on energy consumption, we found that, with differentiation of the cost of capital by sector effective in China today, the consumption of coal is particularly favored. The power sector has access to cheaper capital than other sectors within the economy, providing an incentive to build power plants with a high ratio of capital to operating costs. This arrangement favors large coal facilities, which are expensive to build and cheap to operate, over natural gas plants, which are cheap to build but expensive to operate because of the higher price of gas. While the situation is now changing due to financial reforms, it may help explain why gas has had a particularly difficult time making inroads in the power sector. This also suggests that financial reforms could have a big impact on the country's CO_2 emissions.

2. OVERVIEW: SUPPLY AND DEMAND FOR NATURAL GAS IN CHINA

1. Background

The story of China's ascent in the global marketplace is well known. Rapid economic growth has been fueled by massive domestic and foreign investments in the heavy industrial and manufacturing industries. Cheap labor, availability of raw materials, and loosely enforced environmental regulations serve as strong incentives for the development of energy intensive industries in China, mostly fueled by coal burned directly or after conversion to electricity. The government is now beginning to realize the external costs that it must pay for this mode of development. While carbon dioxide (CO_2) emissions are not likely to be regulated in the near-term future, the government has already moved in the direction of regulating local and regional pollutants such as sulfur dioxide (SO_2), which have undeniably taken a toll on the health and environment of the country. One third of the landmass of China is affected by acid rain, and the treatment and loss of productivity from respiratory illnesses caused by air pollution cost the economy more than 7% of GDP (Peng et. al., 2002). Since natural gas is the cleaner burning alternative to other fossil fuels, encouraging its use is one strategy that the government could potentially utilize to ameliorate the negative consequences of energy consumption.

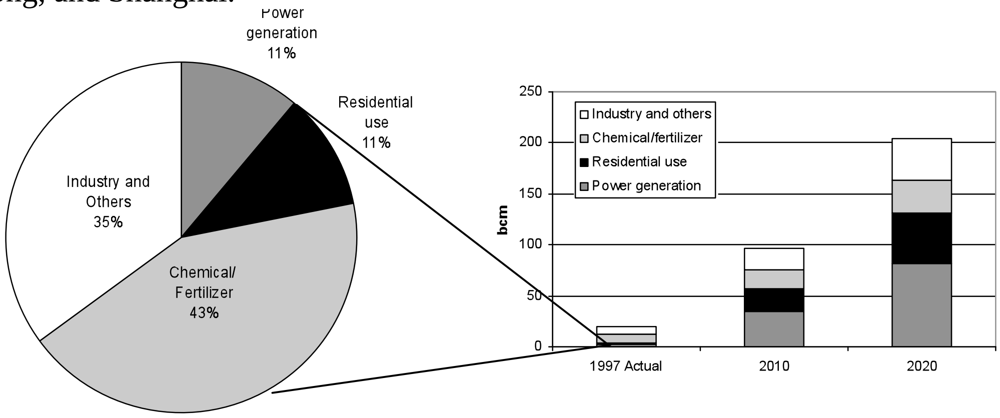
Creating the right incentives for increased natural gas use is a challenging proposition, however. Natural gas has always been an integral part of the state-owned oil industry in China. PetroChina is the largest upstream player and is also responsible for the construction of the majority of the domestic pipelines. There is no separate company that deals exclusively in natural gas. The only mention of a unified goal for natural gas is in the 11th Five-Year Plan on Energy Development developed by the National Development and Reform Commission (NDRC) of the central government. The stated goal is to increase the share of natural gas in the primary energy mix from 2% to 5.3% by 2010, and reach 10% by 2020. However, there are no guidelines for how such ambitious goals can be achieved. As a result, provinces sometimes are expected to reach unrealistic targets without assistance from the central government. The lack of structure and support for the development of natural gas usage is partly responsible for the small part that gas plays in China's energy mix.

NDRC sets gas prices based on an affordability criterion utilizing the cost-plus approach to pricing.[4] These are the prices that the gas distribution companies have to pay. The local pricing bureaus approve fees charged by gas distribution companies to end-users. The price for natural gas therefore varies by province and sector. Residential users pay the highest price, followed by chemical producers, then power generators, and finally fertilizer manufacturers. Consequently, the suppliers (Sinopec and PetroChina) typically prefer to sell at a higher price to the residential sector rather than to the subsidized industries, especially in a tight market. An overall goal of the NDRC is to increase gas prices by an average of 8% annually to balance out the increasing dependence on foreign imports of energy resources such as gas (Interfax, 2007).[5] At the same time, there is some tension between this goal and the objective of boosting natural gas use to increase fuel diversity and reduce environmental impacts (Interfax, 2007).[6] There are plans to change the natural gas pricing mechanism to be 40% weighted on the international crude oil prices, 20% on international LNG prices, and 40% on international coal prices. While this does not bode well for an increased consumption of natural gas, the rising price of coal may blunt the effects of these changes.

[4] Well-head [regulated] + pipeline mark up cost + local distribution mark up cost = sales price to customer

Demand

The major off-takers of natural gas in China are the chemical and fertilizer, industrial, power generation, and residential sectors (Figure 2). In time, IEA predicts that the power sector will assume a larger percentage of overall demand, consuming 39% of the gas in 2020 compared to 11% in 1997. Residential consumption is also estimated to increase to 25% of total gas off-take in 2020 from 11% in 1997. The consumption of gas by the chemicals and fertilizer sector is predicted to fall from 43% to 16%. Although these numbers describe the national market, regional demand can look quite different. Most noticeably, the chemical/fertilizer natural gas demand is non-existent for the fairly urbanized areas in and around Beijing, Guangdong, and Shanghai.



Source: IEA, "World Energy Outlook." 2006

Figure 2. National natural gas consumption in China by sector

Beijing

In Beijing, end-use consumption of gas is dominated by space heating (60%), residential use (22%), commercial use (14%), industry (3%), and automobiles (1%) (Chen et. al., 2007). Because space heating is such a large component of the consumption needs, one of the challenges for the system is how to accommodate the seasonality of the demand and how to deal with the extra supply in the summer. However, because Beijing is particularly motivated to rid the air of pollutants such as sulfur dioxide (SO_2), nitrogen oxides (NOx), and total suspended particulate matter (TSP) before the 2008 Olympics, the government is likely to support policies which encourage the use of natural gas. Although no firm polices are in place to do this, the Beijing government has forecasted optimistic future natural gas consumption levels (12% of end-use energy mix by 2020; the current level is 7%) (Chen et. al., 2007).

Guangdong

Guangdong's situation is especially affected by the scarcity of local coal resources. This province is thus poised to become the biggest natural gas demand center in China. It faces high costs and unreliability associated with the transportation of coal from remote areas. Consequently, Guangdong is often the first among the provinces to explore alternative energy supply options. China's first LNG terminal, Guangdong Dapeng, was completed in 2006. Guangdong has also initiated several nuclear power plant projects. The major consumers of natural gas in this region include peaking power plants that would otherwise be run by expensive diesel generators (Zeng et. al., 2007).

Table 1: Natural gas demand in three regions

Region	Dominant uses in status quo	Current natural gas demand	Availability of competing fuel alternatives	Existing gas infrastructure
Beijing	Space heating; Residential and commercial use	2.4 bcm	High (coal)	West –East Pipeline (WEP)
Guangdong	Power generation; residential/commercial use; industrial processes	3.5 bcm	Low	LNG terminal
Shanghai	Power generation; co-generation, Transition from city gas for residential/commercial uses	4.3 bcm	High (coal)	West –East Pipeline (WEP); existing residential city gas pipe system

Source: Chen et. al., Zeng et. al., Yu et. al. 2006

Industrial and residential/commercial demand is also projected to increase. The high level of development and income in the region means that its residents and officials have the financial and infrastructure capacity to put a premium on environmental protection. Natural gas is a more attractive fuel option for this region than in other parts of China due to these factors.

Shanghai

About 32% of the natural gas demand in Shanghai comes from six energy intensive industries (Yu et. al., 2007)[7]. Industry is therefore poised to be the largest user of natural gas in this region, although some construction of natural gas-fired power plants is under way. Shanghai experienced a rapid increase in residential and commercial natural gas consumption in recent years due to the fact that much of the infrastructure that is needed to bring gas to each household was already in place (This network of pipes enabled the distribution of synthetic gas, also known as town gas, infrastructure, coal remains dominant in the energy sector before natural gas was made available). Shanghai also has one of the most comprehensive policies in support of natural gas market development in China. For example, the municipal government was the first in the country to subsidize the cost of natural gas conversion. Simultaneously, fees for SO_2 emissions have tripled from 0.20 RMB/kg to 0.60 RMB/kg in 2005 (Yu et. al., 2007). However, with its cheaper fuel prices and entrenched infrastructure, coal remains dominant in the energy sector.

Supply

Most of the onshore gas supplies are controlled by PetroChina, a listed subsidiary of China National Petroleum Company (CNPC), China's largest state-owned enterprise (The offshore supplies are controlled by the China National Offshore Oil Company, CNOOC-another state-owned company.)

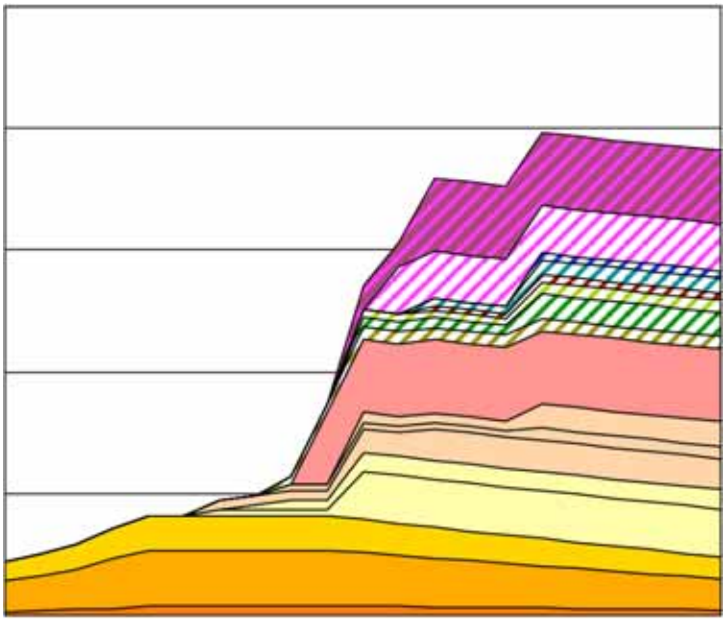
In addition to piped natural gas, imported liquefied natural gas (LNG) is another source of natural gas that China has tapped into and is planning to rely more upon in the future. Only the Dapeng Shenzhen LNG terminal in Guangdong is operational currently; two more in Shanghai and Fujian have been approved by

[7] Figure calculated by author from data from Yu Yuefeng, Zhang Shurong, and Hu Jianyi. using the total natural gas demand, percentage of natural gas in total gas use, and the total gas consumed in industry.

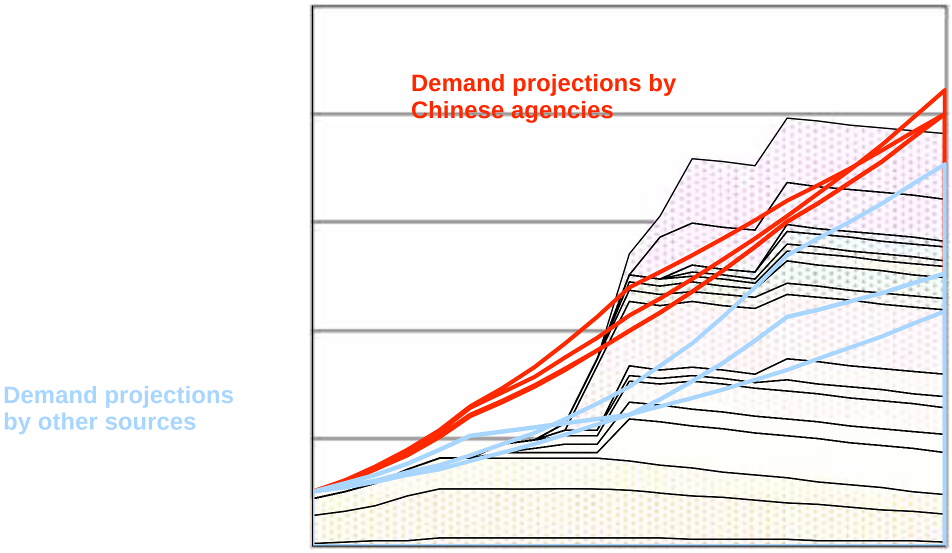
the government and are likely to go forward. There is no foreseeable barrier to the construction of the other LNG terminals if demand continues to grow, although the growth in demand is slower than predicted originally (Petroleum Economist, 2007). A third source is international pipelines from Turkmenistan, Russia and Kazakhstan. Of these, the pipeline to connect Turkmenistan and Xinjiang seems to be the most promising option, although talks have stagnated on the question of gas prices. The Kazakh and Russian supplies appear less likely to be realized at the moment. Supply from Russia's Kovykta gas field are a perennial source of interest yet also perennially stalled due to lack of strategy and commitment by Russia's Gazprom.

The top graph in Figure 3 "stacks" the supplies, with the most likely on the bottom and shaded in solid and the more speculative on top and hatched in shading. The bottom chart indicates countrywide demand estimates from official Chinese agencies (such as the National Development and Reform Commission (NDRC), China National Petroleum Company (CNPC), and China National Offshore Oil Company (CNOOC)) and western sources overlaid on top of the supplies. The Chinese sources all arrive at similarly high estimates for natural gas use, perhaps due in part to a desire to approach government targets, while outside sources show lower and more varied projections. They suggest that the full range of plans to develop major international gas projects are based on overly optimistic demand projections. Uncertainty surrounding the gas demand estimates makes infrastructure planning difficult. The 100 billion cubic meters (bcm) difference between the highest and lowest estimates for gas demand is more than nine times the capacity of the West-East pipeline. This is the essential dilemma of developing a natural gas market. As earlier studies have shown, one of the major challenges in developing large-scale gas infrastructures is assuring adequate demand (Victor, Jaffe, Hayes, 2006). The study at hand does not look at the whole country, and thus our projections are only a subset of the national total, but the projections are consistent with the full range of demand projections for the country.

Supply



Demand



Source: PESD estimates 2007, CNPC/Sinopec/CNOOC company reports 2007, ERI, IEA 2004 Chinese agencies: NDRC, China Energy Development Report 2003, CNPC, CNOOC
Western sources: BP, EIA/DOE 2003, AIE/WEO 2002

Figure 3. Potential Natural Gas Supplies and National Demand Projections

2. Scenarios

The pivotal policy driver for each of the scenarios within the study in China is the implementation of sulfur dioxide (SO_2) constraints upon the energy system. We use SO_2 as a proxy for the full range of local pollutants and future studies might model those other pollutants. SO_2 is a reasonable target due to local governments' concern with proximate pollution. The governments of Beijing, Shanghai, and Guangdong have already voiced their commitment to controlling this pollutant. Additionally, data for SO_2 is the most complete and accurate of all the pollutants that are monitored in China (compared to data for NOx, PM 10, PM 2.5, CO_2).

To examine the influence of SO_2 constraints, we developed three "core" scenarios. In the base case reference scenario (R), we assume no changes are made to the status quo. The model operates on a least cost optimization paradigm so that it solves for the most economically favorable solution. In this situation, we expect coal to out-compete gas in all sectors due to the lower fuel cost. Some emissions control programs are already in place on the national and regional levels; the reference case scenario only includes policies that are currently implemented, as well as highly likely extensions of those policies. From this starting point, there are two main scenario developments.

Scenario P is the case in which the output SO_2 emissions are reduced by 40% from the reference case and is defined as the "plausible" scenario. This scenario tests what can happen if SO_2 emissions were capped at a level 40% below what is currently expected in the status quo. Scenario "Ag" is the case in which SO_2 emissions are reduced by 75% from the baseline. This is defined as the "aggressive" scenario and is less likely to represent the future than scenario "P", but is not entirely out of the question. Having developed the core scenarios we then developed the "MoreGas" scenarios ("M"). The goal is to find out how the system would react to sensitivity parameters with a plausible SO_2 constraint <u>and</u> more gas supply available to the region (such as might be available from a successful effort to develop international pipelines and price gas favorably). With the "MoreGas" scenarios, it is possible to determine the relative effects of gas availability and pricing versus the other drivers in the model.

Within each of the core scenarios, we also wanted to find out how gas demand would vary with two other factors. First, we changed the rate at which efficient, advanced technology is allowed to enter the market (the "Fast" scenarios). Second, we wanted to find out if specifying different costs of capital for each of the sectors would make an impact in consumption patterns (the "Diffcost" scenarios). We also combined the factors with each other in ways shown in Table 2.

In all, we looked at twelve scenarios. These scenarios allow us to explore four broad hypotheses:

A. Policies, which constrain total SO2 emissions from the entire system lead to, increased natural gas consumption.
B. The rate of technological diffusion significantly influences the amount of natural gas consumed within the system.
C. Varying the cost of capital for different sectors has an effect on energy consumption patterns.
D. Gas prices and the availability of gas are important factors in determining which sector consumes what volume of natural gas.

Below, we organize the results of the study according to the four hypotheses.

Table 2. Summary of Scenarios in this Study

Primary Ru	Assumptions	Secondary Runs	Assumptions
Reference ("R")	Status quo emissions control		1.5% annual market share growth of new demand technology 10% discount rate for all sectors No gas supply from Russia (LNG availability unconstrained)
Plausible ("P" scenarios)	40% SO_2 reduction	P: Reference Assumptions	Same as reference
		P_Fast: Faster Penetration of Demand Technologies	3%, 5% annual market share growth of new demand technology
		P_Diffcost: Different costs of capital	5.8% for power sector 10% for industrial 25% for residential and commercial
		P_Moregas: High availability of cheap gas	Gas supply from Russia available (LNG availability unconstrained)
Aggressive ("Ag" scenarios)	75% SO_2 reduction	Ag: Reference Assumptions	Same as reference
		Ag_Fast: Faster Penetration of Demand Technologies	3%, 5% annual market share growth of new demand technology
		Ag_Diffcost: Different costs of capital	5.8% for power sector 10% for industrial 25% for residential and commercial
		Ag_Moregas: High availability of cheap gas	Gas supply from Russia available (LNG availability unconstrained)
Plausible w/ more gas availability ("C" scenarios)	40% SO_2 reduction + Moregas	M_Fast: Faster Penetration of Demand Technologies	3%, 5% annual market share growth of new demand technology + Gas supply from Russia available (LNG availability unconstrained)
		M_Diffcost: Different costs of capital	5.8% for power sector 10% for industrial 25% for residential and commercial + Gas supply from Russia available (LNG availability unconstrained)
		M_Exp: More expensive oil and gas	Gas supply from Russia available (LNG availability unconstrained) at a more expensive price

A. Constraints on SO_2 emissions

Figure 4 shows projections of natural gas consumption for the reference (R), plausible (P, 40% reduction in emissions), and aggressive (Ag, 75% reduction) scenarios from 2000 to 2020 in all three areas. The estimates for consumption vary widely depending on which SO_2 constraint is implemented in the system. From 2000 to 2020 in the reference base case, natural gas consumption increases by about six times in Beijing and fifty times in Shanghai. Guangdong goes from zero gas consumption to around 5 bcm. The natural gas consumed in 2020 in the aggressive scenario for all three regions is close to 50 bcm greater than the amount consumed in the reference scenario. These results suggest that a tighter SO_2 constraint leads to more gas demand. While these results shed some light on the sensitivity of the model to SO_2 policies, a deeper understanding of the system comes from looking at the projections within each of the three city-regions.

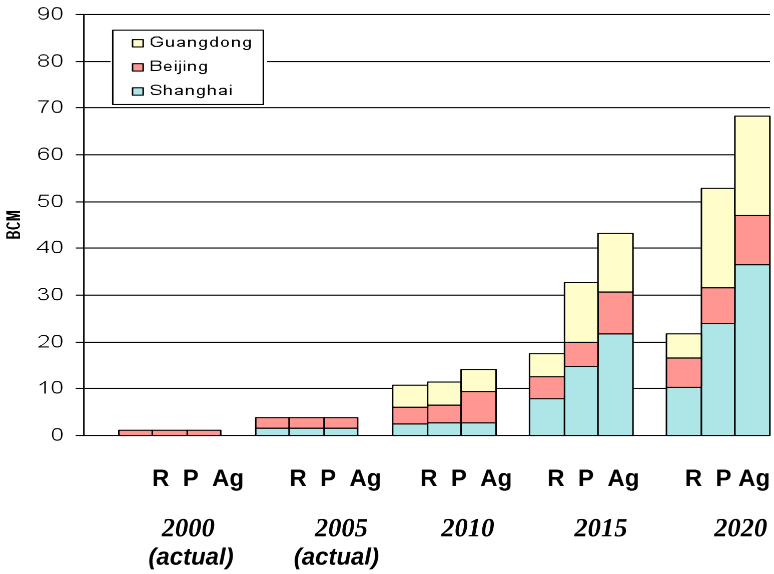


Figure 4. Natural gas consumption for all study areas: Comparison of results for reference and SO_2 constrained scenarios

Elsewhere we have explained how our projections relate to official provincial targets. In general, we found that provincial government targets were reasonably close to those projections. Before making this comparison, we hypothesized that the projections made by each government would far exceed calculated numbers since official targets are based on an ideal rather than a plausible set of assumptions. Beijing targets appeared slightly optimistic, falling about 1 bcm higher than the most aggressive model projections in 2020. In both Guangdong and Shanghai, the government projections are within the bounds of our highest and lowest scenarios. This shows that official provincial targets appear to be feasible goals for the most part if sufficient efforts are made to encourage gas use.

Beijing

The natural gas fields near Beijing were developed before supplies were made available to Shanghai and Guangdong. The result was that Beijing residents had connections to natural gas supplies before either of the other two regions. However, the model results suggest that Beijing will consume less gas in 2020 than the other two regions for all scenarios. What stands in the way of rapid development of the natural gas?

First, natural gas demand is highly seasonal. 60% of the consumption (in 2003) comes from space heating, which is not required during the summer (*Source: Beijing Statistics 2004, Beijing Statistic Bureau, China Statistic Publishing Company, 2004)*. Expensive infrastructure to deliver gas continuously is especially costly to operate when it is under-utilized for significant periods of time during the year. The Shanghai government has engaged with this problem by encouraging the use of natural gas air conditioners to sustain the level of natural gas consumption during the summer when heating demand does not exist, but no such measures have been implemented in Beijing.

Second, reductions in pollutants thus far have been accomplished largely by closing down coal-fired power plants and installing generators in neighboring cities. ESP and FGD have also been installed in coal-fired power plants. Due to such efforts, the low hanging fruit in decreasing local SO_2 emissions has already been picked, and further decreases in SO_2 emissions could be achieved through continuing the current, cheaper option of desulfurization and importing electricity from outside regions rather than by forcing a fuel switch from coal to natural gas. It is for this reason that there is very little difference in gas consumption between the reference scenario and the plausible scenario in Beijing (Figure 5).

Starting in 2010, natural gas fired power plants account for all of the additional gas consumed in scenario "P" compared to the reference case scenario, with demand 24% higher than the levels consumed for the reference case scenario by 2020. This tells us that when the system is forced to reduce its SO_2 emissions by 40%, the most cost efficient sector in which to implement fuel switching is the power sector. For scenario "P", the increased gas use comes from the Taiyanggong electric and thermal plant. The relative increase of gas use for this scenario is minor compared to other scenarios because, overall, the main strategy for controlling emissions is to clean existing fuel systems. The system does start to change more drastically when the SO_2 constraint becomes tighter. In scenario "Ag", the gas consumption in the industrial and residential sectors increases along with demand in the power sector. In addition to Taiyuangong, a combined cycle natural gas plant comes online, and more gas is consumed in existing gas power plants that were already operating in the plausible scenario ("P"). For 2010 and 2015, the power plants are still the main source of fuel switching in Beijing. In 2020, industrial coal and oil boilers, used primarily for process heat, are replaced by natural gas boilers. For more lenient SO_2 emissions standards, it is cheaper to desulfurize coal-fired power plants rather than fuel switch from coal to gas. The opportunities for cost-effective desulfurization are exhausted by 2020.

Although there is pressure for the government to reduce pollutants such as SO_2 and NOx and to increase energy efficiency for the upcoming 2008 Olympics in Beijing, there are no specific policies to promote natural gas use, although the Beijing Gas Supply Group, the organization that is responsible for supplying natural gas to the area, is partially subsidized by the government. Despite the lack of official orders, the Beijing government is still optimistic about the future of natural gas use, assuming that natural gas will account for 12% in end-use consumption by 2020, according to the Olympic Energy Action Plan and the Beijing City Master Plan 2004-2020.

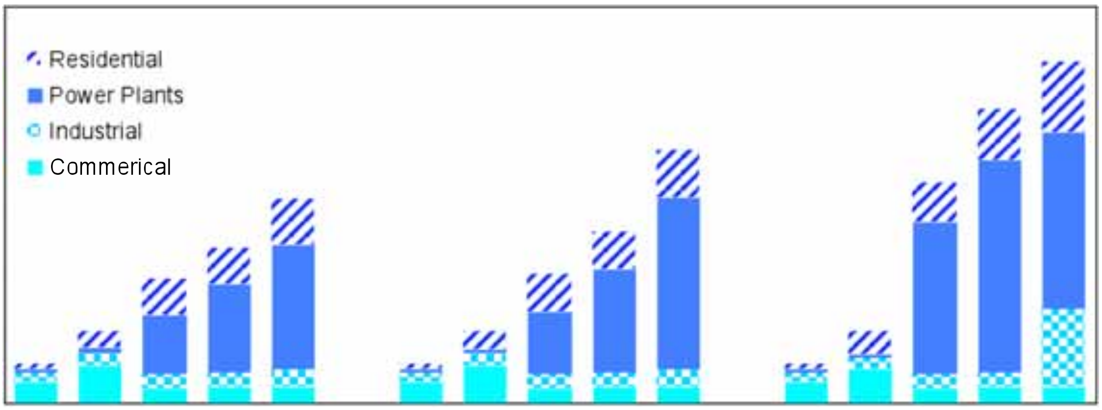


Figure 5. Natural gas consumption in Beijing for reference, plausible, and aggressive SO_2 constraint scenarios

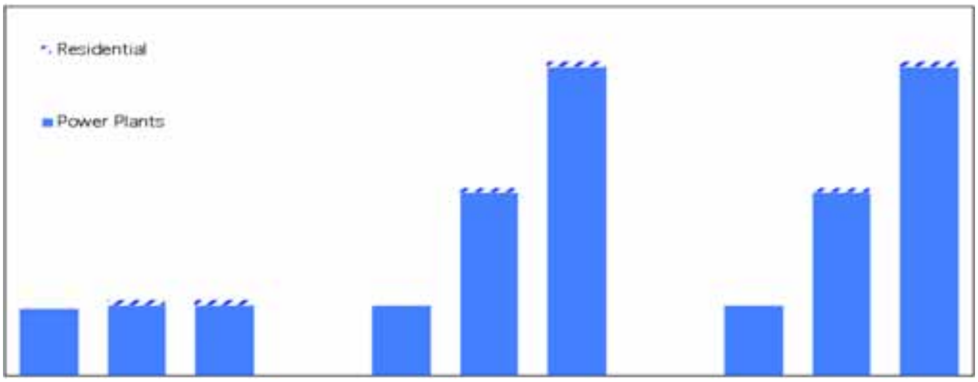
For comparison, our "R" and "P" scenarios yielded 8% and 9% gas penetration, respectively. The "Ag" scenario, which reduces SO_2 by 16% from the baseline, is the most extreme case and goes far beyond the Olympic games for pollution control. The implication of these results is that while the goal set by the government is not impossible to achieve, such an outcome will not be realized without much tighter environmental policies that are well-enforced and specific policies to promote gas.

Guangdong

Guangdong is the southernmost of the three regions, where, in contrast to Beijing, space heating is rarely needed. Its economic growth is the most rapid in China, and it emits more pollutants than any other region. Guangdong, unlike Beijing and Shanghai, does not have easy access to coal. There are no indigenous sources; so all coal must be imported from other regions of China or from abroad, resulting in high prices. This poses a special opportunity for the use of natural gas. Guangdong also is currently not able to intercept piped natural gas from the West-East Pipeline (WEP) due to geographic constraints. Guangdong therefore relies on LNG to meet some of its energy demand and is home to China's first LNG terminal (completed in 2006).

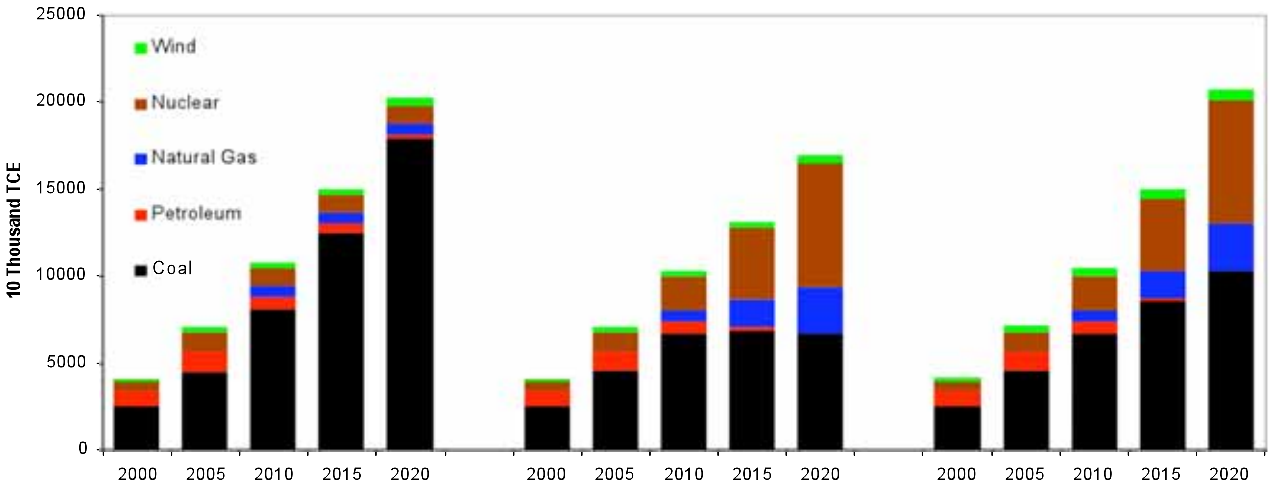
In the reference scenario "R", the level of natural gas consumption stays constant from 2010 onwards. Consumption is capped at the level corresponding to the volume of LNG imported from Australia under a cheap contract (approximately \$3/mmbtu, compared with the \$5 to \$7 typical of current LNG contracts). Any volume of gas above this amount would be sold at the new, higher price. Since there is no incentive for the system to spend more money than what is necessary in the reference scenario, the amount of gas consumed stops at the volume limit of the contract. Gas is unable to compete with coal and nuclear in meeting new demand for power. In the reference scenario, nonetheless, most of the gas is consumed by power plants, with the residential sector taking a miniscule portion. When a 40% mandatory decrease in SO_2 emissions is imposed on the system in the plausible scenario, the consumption of gas increases for 2015 and 2020, although there is no increase in uptake before 2015. For this plausible scenario, the amount of gas consumed is no longer constrained by the volume of LNG under the Australian contract because the system has no choice but to pay higher prices in order to meet the SO_2 constraint. All of the increased gas demand comes from power plants. In particular, gas-fired combined cycle plants replace oil. Gas also finds use in co-generation and replaces coal in two ways: small, inefficient peaking coal plants that are less than 135 MW, and one large coal-fired base load power plant. The environmental constraints also push forward the construction of an integrated coal gasification combined cycle (IGCC) plant.

At the same time that gas consumption is increasing, nuclear power is also on the rise. Nuclear provides base load generation, while gas is used for peaking, so there is no direct competition between the two. Nuclear generation increases 14 times above 2020 reference scenario levels. Nuclear power development is uniquely far along in Guangdong, with a few plants that are already under construction in the area. However, without a policy push to decrease SO_2 emissions, coal is still the preferred fuel since a coal plant facing modest limits to SO_2 is cheaper to build than a nuclear unit.



Reference ("R0") *Plausible ("P")* *Aggressive ("Ag")*

Figure 6. Natural gas consumption in Guangdong for reference and plausible SO_2 constraint scenari



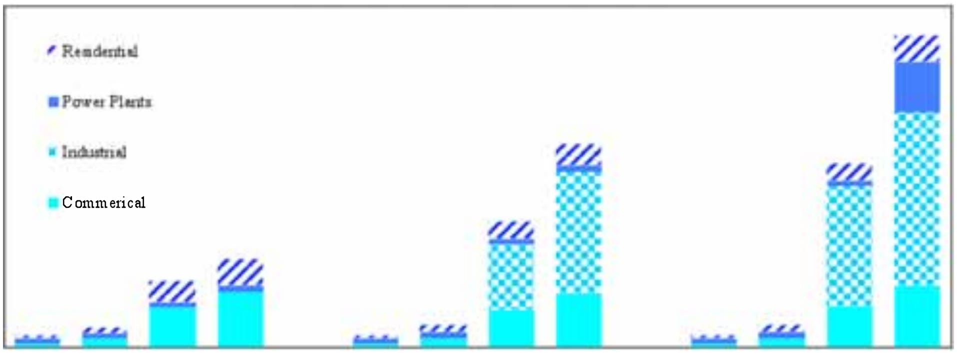
Reference ("R") *Plausible ("P")* *Aggressive ("Ag")*

Figure 7. Fuel consumption in Guangdong Power Sector for reference and plausible SO_2 constraint scenarios

Natural gas consumption does not increase when a more stringent limitation is applied to the system (75% SO_2 reduction, scenario "Ag") due to the operation of a new IGCC unit in Guangdong starting in 2010. The additional energy demand in the model is therefore met by coal rather than natural gas. This suggests that even though the coal prices in Guangdong are higher than in other parts of China, it is still cheaper than natural gas, which makes clean coal operations competitive. The caveat to this outcome is that the actual cost of IGCC units may be higher than the one assumed in the study ($1400/kW), which is much cheaper than western estimates, although twice the cost of conventional coal plants. In reality, construction of IGCC units may be delayed due to the unavailability of the technology. If so, our estimation were that advanced (ultra-supercritical) coal along with pollution control equipment, and some expansion in nuclear, would be favored over gas for base load power.

Shanghai

Shanghai's economy is dominated by energy intensive industries that thrive in and around the city. Six industries comprise 50% of the city's total energy demand—smelting/rolling of ferrous materials, oil processing, coking, nuclear fuel processing, textiles, and chemical production. In contrast to Guangdong, not much natural gas is used for power plants. This is mostly due to the fact that there is an abundant and relatively cheap supply of coal available for firing base load plants. When the 40% SO_2 constraint is imposed on this system, there is an increase in the consumption of natural gas appearing in 2010. Almost all of this growth stems from the industrial sector. Rather than building new power plants that run on cleaner burning gas, it is much less costly in Shanghai to meet the SO_2 constraint by switching existing boilers in the industrial sector from higher sulfur heavy fuel oil and coal to natural gas (Figure 8). Similarly, many of the coal boilers and kilns in the six energy intensive industries get switched to natural gas fuel to meet SO_2 constraints. Replacing old, inefficient coal technology with natural gas boilers minimizes the cost of fuel switching. As a result, an increase in gas consumption in the power sector becomes attractive only after opportunities in the industrial sector are exhausted. In addition, Shanghai has access to domestic piped natural gas that is priced lower (for now) than LNG, which facilitates the switch to natural gas.



Reference ("R") ***Plausible ("P")*** ***Aggressive ("Ag")***

Figure 8. Natural gas consumption in Shanghai for reference and plausible SO_2 constraint scenarios

B. Effects of the rate of technological diffusion in demand technologies

It is instructive to consider how the rate at which advanced, efficient demand side technologies diffuse into the market can affect natural gas demand. For our study, there are two assumptions for the size of the initial market share of demand technologies in different sectors. For "new" demand technologies that have longer life cycles and are more expensive to purchase, such as industrial equipment and mass transportation infrastructure (boilers, kilns, and buses), we assume a 5% share of the entire market in 2010. A 7% initial share of market is assigned to demand technology in the commercial and residential sectors, such as air conditioners, cooking stoves, heating appliances, and lighting.[8] We created different scenarios by changing the rate at which this initial share grows. After consulting a range of sources[9], a 1.5% annual growth market share starting in 2010 seemed reasonable for the reference case. For the scenario in which a faster rate of technological diffusion is expected, we used a 5% annual share growth. A 3% annual share growth was also tested to approximate the sensitivity of the model but there were no significant changes in fuel consumption in any of the regions so the results are not included in the study. The table below lists the runs that are discussed in this section.

In Beijing, under modest environmental constraints, faster technology diffusion reduces coal consumption by 6% and natural gas consumption by about 57% in 2020 relative to the base case diffusion scenario.

[8] Our assumptions came from a study that numerated the initial market shares of fluorescent light bulbs in several other studies: U.S. National Energy Modeling System database (NEMS), A joint study between the Energy Foundation and China National Institute of Standardization (EF/CNIS), A joint study between Guan Fu Min in Qingdao, China and Lawrence Berkeley Laboratory (Guan/LBL).

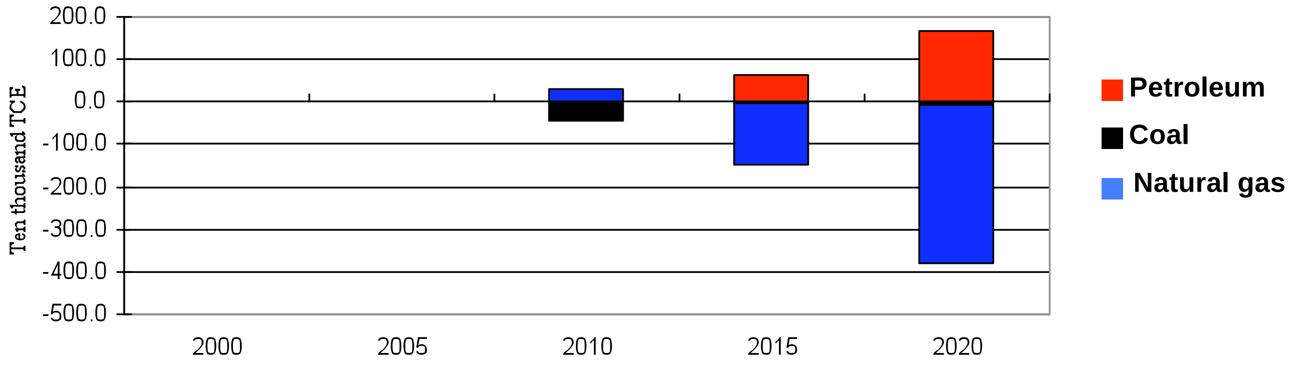
[9] See above

Natural gas use decreases when more advanced technologies are introduced into the market because greater end use efficiency affects energy demand where gas tends to be used, such as in cooking, heating water, and space heating. In the scenarios with technology diffusion, these natural gas using technologies are replaced by newer technologies that do not utilize natural gas, such as a heating network for cooking and heating water (fueled by coal-fired sources). The main assumption driving these outcomes is that advanced coal utilizing demand technology is likely to flood the market before natural gas equipment gets there. The speculation is that because coal-powered technologies have been out on the market for a longer period of time, there has been more time to develop more efficient versions of this equipment that can reach the market before new gas consuming technologies are introduced. Thus the availability of efficient technologies that are not fueled by natural gas is detrimental to the expansion of the gas market. As expected, the residential sector was especially affected by the fast scenarios due to the assumption of higher initial market share of advanced end-use technologies.

In Guangdong, under modest environmental constraints, coal consumption increases when the rate of technology penetration is increased. This is due not only to the replacement of old equipment with more advanced commercial coal stoves and boilers but also to increased consumption by these technologies. In the industrial sector, new coal boilers and kilns replace older versions and also contribute to the increased consumption of coal. Higher chain efficiency for coal makes this fuel more competitive. Oil consumption decreases slightly as improved LPG stoves and heaters that require less fuel to do the same amount of work in the residential sector replace older models. Electricity and natural gas consumption do not change much between the reference penetration (P) and the high technology penetration rates (P_Fast). The technology diffusion trends are further magnified when the system is placed under a stringent environmental constraint (Ag, Ag_Fast). Such tight constraints also favor gas over coal.

In Shanghai, starting in 2010 there is a small decrease in the consumption of coal within the residential sector and a slight increase in the consumption of gas as old, inefficient coal burning appliances are retired. In 2015, we see natural gas consumption decrease within the residential sector as more efficiency in end use cuts demand and oil products became more competitive. The same trend on a greater scale occurs in 2020. The increased share of oil surprised us. Although in open markets oil is more expensive than gas (by heat content), refined oil products are made available to the domestic market at a subsidized cost supported by the central government, which could explain the system’s overall reliance on oil in the residential sector. While this resilience for oil is interesting, it is useful to keep in mind that the total change in energy consumption between P and P_FAST here is only about 2.5% of the total amount of energy consumed within the system. In short, rate of technology diffusion is not a significant factor in determining fuel consumption patterns in our model.

Overall, increasing the rate of technological diffusion may help to reduce the overall energy intensity of a system, but it does not generally encourage natural gas consumption. In fact, in all three regions, we find that natural gas consumption, especially in the residential sector, actually decreases. This is because most of the new technologies utilize coal (or oil in the case of Shanghai) rather than natural gas. Thus when the technology penetration rate is increased, more efficient demand favors coal and oil.



Source: Yu, 2007, Shanghai Jiaotong University/PESD study

Figure 9. Differences in Primary Energy Consumption in Shanghai (P vs. P_FAST)

C. Effects of Differing Costs of Capital across Sectors

An often-overlooked aspect of the energy system is the financial realities that govern the flow of capital. Most importantly, the costs of capital offered to different sectors in the economy are highly variable. In particular, the cost of capital for building state-owned power plants has been much lower than for private projects and business. The purpose of this section is to simulate varying costs of capital reflective of the past reality of the Chinese financial system (P_Diffcost) and to compare that with a behavior under a uniform cost of capital across all sectors. For our reference runs, we replicate what has done many times in other models, which is to assume that there is a uniform discount rate across all sectors (10%) reflecting the assumption that the cost of capital is uniform. For the scenarios that vary the cost of capital, however, we attempt to simulate the actual differentiated lending rate system under which the Chinese economy has been operating under by assigning different lending rates for each sector in MARKAL. Taking into account these different discount rates should, we expect, lead to a significantly different energy system.

The power sector is viewed as a "pillar" industry by the government, which affords the industry special treatment such as indirect subsidies and access to political favors. One way indirect subsidies are distributed is via the China Development Bank, which at the time of the model runs was providing capital to government connected enterprises at a rate of 5.8%.[1] This same arrangement is not extended to the industrial sector, which is still given a 10% discount rate. The residential and commercial sectors experience significant barriers to obtaining loans at all – which we simulate by applying a 25% discount rate.[2] One rationale that the government uses to justify preferential relative treatment of the large industrial players is that many are state-owned enterprises employing large numbers of people. The manufacturing companies within the industrial sector have also been the driving force behind China's economic development. The government therefore has a stake in maintaining the financial health of this important sector, and these enterprises (especially owned by the state) reinforce this view through their political connections. This multi-tiered cost of capital system is reflective of the reality of the Chinese economy and representative of the strategy that the Chinese government has employed since making a transition from a planned to a market economy: "Let go of small enterprises and engage with large enterprises" (Zhang, 2006). Smaller players in the market are always allowed to privatize first while larger entities are carefully "guarded" by government subsidies and regulations. The exact effective discount

[1] Discussions with Pan Jiehua (CASS), Kejun Jiang (ERI), and Tao Wang (BP), November 2006, People's Bank of China website (www.pbc.gov.cn), Global Financial Data (www.globalfinanicaldata.com)

[2] Discussions with Pan Jiehua (CASS), Kejun Jiang (ERI), and Tao Wang (BP), November 2006

rates vary constantly, but after consulting experts, official statistics, and various rules and regulations of the People's Bank of China, we chose these tiers as more or less representative of the differentiated cost of capital structure that may be plausible in China.

Table 3. Different assumed costs of capital by sectors

Sector/Industry	Effective Lending Rate
Power plants and other public service entities	5.8%
Industrial sector	10%
Residential	25%
Commerical	25%

In Beijing, coal consumption in the modest environmental constraints scenario is higher in the case of differentiated costs of capital between sectors. That is because gas-fired power plants have low fixed costs and high O&M costs, whereas coal-fired power plants require high fixed investments but have low O&M costs. Thus coal consumption increases by about 17%, while natural gas consumption decreases by about the same percentage. The same story holds true when environmental controls are set tighter for Ag0 and Ag_Diffcost scenarios. The SO_2 constraints are not sufficient to induce fuel switching in favor of natural gas because cheap capital makes advanced coal technology such as flue gas desulfurization (FGD) even more economical (prices for FGD are already low in China). The exact numerical results for Beijing are reported in detail elsewhere.[1]

Table 4. Investment Costs for Various Types of Power Plants in China (2006)[2]

Technology	$/kW (300MW)
Pulverized coal-fired power plant	600-676
PC w/ FGD	620-1100
Combined cycle natural gas	500 – 600
Ultra supercritical coal	1000-1100
IGCC	1000-1300

Source: Chen ET. al, Yu et. al., Zeng et. al., 2006

A similar story plays out in Guangdong. Coal consumption is higher under differentiated costs of capital representing the status quo. Advanced coal plants with pollution control equipment (FGD, ESP) are built at the expense of LNG-fired power plants.

In fact, the situation on the ground is already playing out in this way due to rising LNG prices in recent years (Interfax, 2007).

In Guangdong, the coal consumption is a dramatic 88% higher under differentiated costs of capital, with natural gas consumption decreasing by about 40%. For illustration, Figure 10 shows the results. By contrast, there was little change in the amount of coal consumed as a function of capital cost assumptions in Shanghai. This is explained by the fact that the vast majority of natural gas consumed there is within the industrial sector, for which the cost of capital does not change between the reference case and the "Diffcost" runs. We are mindful that China is in the midst of accelerating reforms that are making state enterprises more competitive and also improving access to capital across the economy. It is possible to

[1] Figures 15 (pp. 33) in Jiang et. al "The future of natural gas vs. coal consumption in Beijing, Guangdong, and Shanghai: An assessment in MARKAL" (2007) Program on Energy and Sustainable Energy, Stanford University, Working Paper #62

[2] Cost in Beijing, Guangdong, and Shanghai

see a future where the varied cost of capital are less extreme than shown here, but our results help illustrate the sensitivity of the models and also help explain the capital intensive nature of the industrial energy development so far.

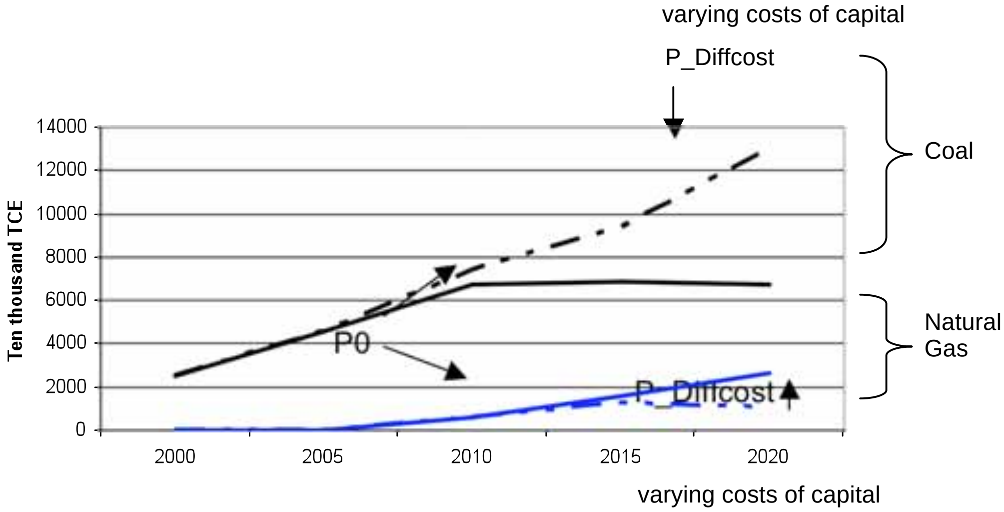


Figure 10. Coal and Natural Gas Consumption in the Guangdong (Power Sector)

D. Effects of gas supply

Obviously, gas cannot be consumed unless supply can be assured. Figure 3 showed that some of the potential natural gas sources are international pipelines. While China and Russia signed an agreement in March 2006 to develop potential pipelines between China National Petroleum Company (CNPC) and Gazprom (Interfax, 2007), and similar plans with Kazakhstan and Turkmenistan were codified in August 2007, it is not certain that these plans will actually be carried out. International projects are inherently challenging to complete because they are rarely motivated purely by economics and are sensitive to political moods and relationships between the relevant governments (Andrews-Speed, 2002). China also has a plethora of LNG terminal projects planned, seven of which have been approved. In the following scenarios, we explore gas consumption patterns in a world where international gas does not get piped to China and one in which there is additional international gas supply available. The availability of gas supplies affects the price of gas and thus, in turn, affects demand.

Table 5. Gas Availability Scenario

Name of run	Gas supply
Ag	Only domestic pipeline and LNG terminal in Guangdong
Ag_Moregas	Domestic pipeline, international pipeline, LNG terminal in Guangdong

Beijing is not sensitive to the availability of gas in either the plausible or aggressive scenarios. This presumably indicates that the use of natural gas is not hindered by the availability of the supply. Indeed, because there is a domestic pipeline that supplies the city, and also because Beijing is the capital, it already gets preferential treatment when gas is allocated. The relatively low demand for natural gas in this area, as indicated by Figure 4, is also relatively easy to satisfy.

Guangdong is more responsive to the availability of gas only if additional gas (and lower gas prices) combines with tight rules on SO_2. Figure 11 shows the major consumers of natural gas by sector in both the Ag and Ag_Moregas scenarios (there is no movement for this scenario under the plausible SO_2 constraint conditions). Along with this, the black bars also indicate bounds for different types of supplies available to Guangdong. The main difference between Ag and Ag_Moregas is that for Ag_Moregas, an additional source of piped gas becomes available to Guangdong at a cheaper price than expensive LNG.

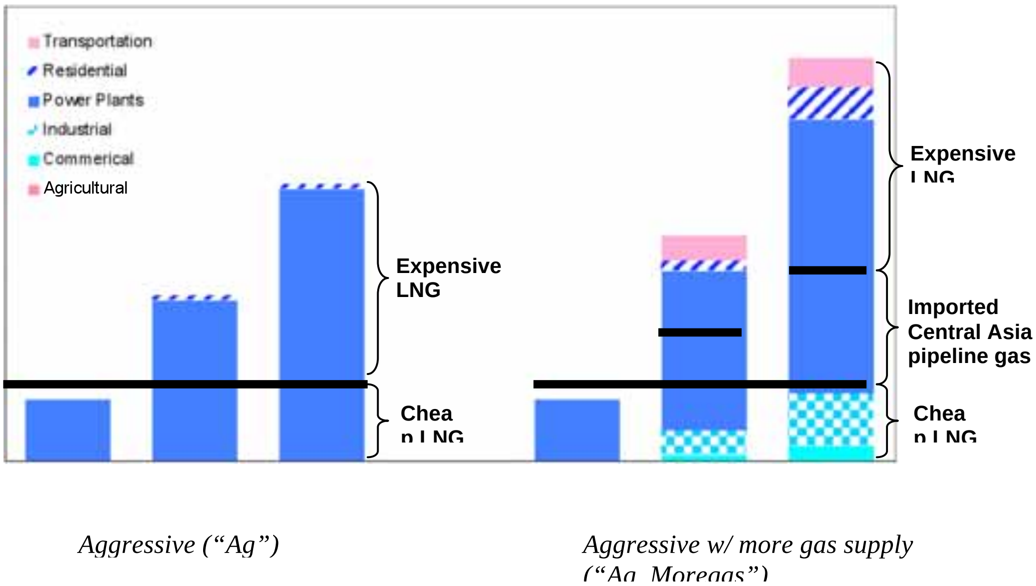
Even though the amount of expensive new LNG that is consumed does not decrease in “Ag_Moregas”, the major consumers of gas change in this scenario. What we see here is that the additional cheaper supply of gas allows major off-takers *outside* of the power sector to consume gas. The transportation, residential, industrial, and commercial sectors all dip into the natural gas supply once it becomes available. When cheap gas supplies are limited, almost all of the gas is funneled into power generation in order to meet the requirements of the SO_2 emission constraints.

In Shanghai, greater availability of cheap gas does not significantly change the consumption patterns (<0.1%) in the industrial sector. Given Shanghai’s abundant domestic gas supply (Shanghai, like Beijing, has access to gas from the West-East pipeline) at favorable prices, it was not expected that supply constraints would drive scenarios in this situation.

Table 6. Gas prices and supplies for in Moregas Scenario

Gas supply	Price[10]	Supply limit
Cheap LNG	$5.50/MMBtu (regasified to delivery)	5.1 bcm
Imported Central Asia	$7.12/MMBtu	5 bcm in 2010 10 bcm in 2020
Expensive LNG	$9/MMBtu (regasified to delivery)	No limit

In summary, as a supply-constrained market, Guangdong is the only region that is sensitive to the availability of new supplies of gas. This sensitivity hinges on a set of assumptions—notably the availability of a piped natural gas from the second West-East pipeline from Central Asia in 2010 that will face political, financial, and geographic challenges. When new sources become available, there is a diversification in the use of the natural gas that extends beyond the original power plant off-takers. If an international gas pipeline is built for Guangdong, the fuel will be cheaper than any new LNG contracts that the government will be able to obtain and will have a significant impact on energy consumption patterns.



Source: Gas volume estimates for MARKAL model, Mark Hayes, 2007

Figure 11. Gas Supply Options for Guangdong and Natural Gas Demand by Sector

[10] Present day prices

The gas demand in Beijing and Shanghai, on the other hand, is not affected by additional sources of gas because these regions are already connected to existing pipelines that deliver adequate gas supplies. especially with regard to how to bring developing countries to the climate negotiation table. Developing countries are wary of emission caps that may hinder economic growth. However, they are more strongly motivated to engage in discussions related to local and regional pollution. Perhaps a stringent SO_2 policy could be a more acceptable scenario compared with one that addresses CO_2 emissions directly. The caveat to these results is that while the carbon dioxide savings come from fuel switching in a particular region, there is no guarantee that demand could not also be met by importing electricity from power plants outside the city, particularly if emissions controls are less stringent elsewhere. Most likely, any imported electricity will be coal-fired – although in the past Guangdong has imported substantial quantities of electricity from large government hydroelectric projects. This implies that while carbon dioxide emissions are decreasing in one area, they could be increasing in another, diluting any benefit. We do not expect that this effect will be significant in the cases modeled here, it could become a much more important issue in the future, particularly if imported electricity becomes cheaper than developing regional energy resources.

For reference, in Figure 13 we show the similar effect of SO_2 controls in Shanghai. The total emissions of this city are lower than Guangdong and contribute to the less dramatic reduction of CO_2 as a result of putting in SO_2 controls.

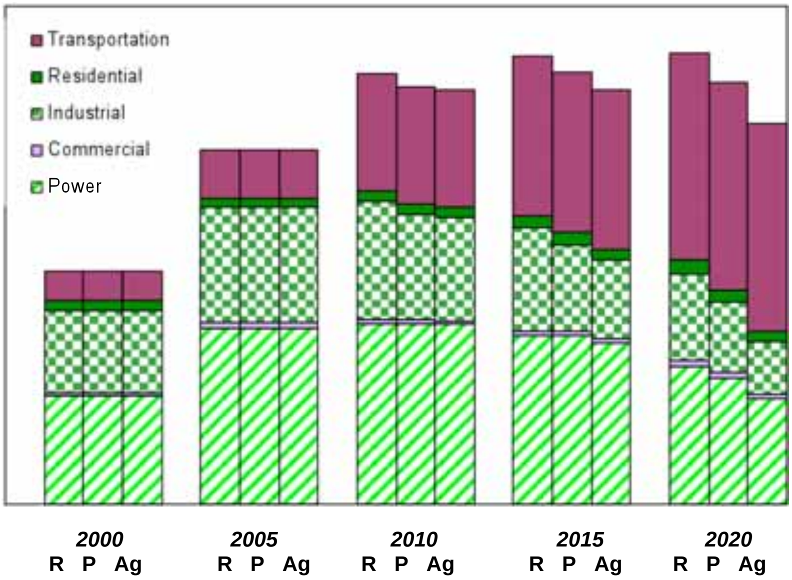


Figure 12. CO_2 Emissions from Guangdong in the Reference, Plausible, and Aggressive Scenarios

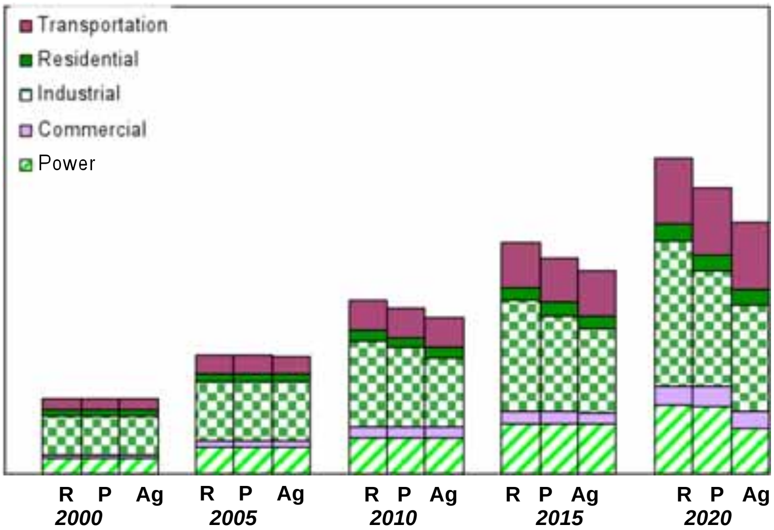


Figure 13. CO_2 Emissions from Shanghai in the Reference, Plausible, and Aggressive Scenarios

The effect of financial reform on CO_2 levels is also striking. When the cost of capital is made uniform across sectors, the amount of CO_2 reductions that occurs in the system is close to that of when *aggressive* SO_2 constraints are implemented. This reinforces the idea that there are alternative ways of thinking about controlling CO_2 emissions other than forcing developing countries to put restrictions on their factories and power plants. Standardizing lending rates across sectors, for example, is already a goal that the Chinese government is moving towards because it is in line with the greater goal of moving the economy towards a stable market economy. Utilizing leverage points such as this one to negotiate with China and other developing countries on the carbon emissions will be the key to creating a practical climate regime.

6. CONCLUSIONS

The study suggests five key findings on the competitiveness of natural gas in China over the next two decades:

First, demand size and uncertainty influence supply infrastructure. Growth in gas demand in China could lead to a surge of natural gas imports, as demand is likely to far outstrip domestic supplies in certain parts of the country. Guangdong province is a particularly extreme case that relies completely on imports. This supply constraint provides an impetus for the Chinese government to seek out new supplies, such as a large international pipeline from Russia, Kazakhstan, or Turkmenistan, and more LNG regasification terminals. At the same time, demand is highly uncertain, making it challenging to determine the appropriate rate at which to build out infrastructure.

Second, gas demand is highly dependent on financial policies. The current Chinese financial system provides extremely low costs of capital for the power sector. This makes the construction of capital-intensive coal-fired power plants especially attractive. Because coal and natural gas are in direct competition as the fuel source in most cases, this diminishes the opportunity for more natural gas combined cycle plants to be built. In Guangdong, for example, the MARKAL model would predict almost 50% lower coal consumption by 2020 if a 10% lending rate were available to all sectors. While policies related to the banking system do not usually factor into considerations for planning an energy system, our study shows that this is an important aspect to consider in creating the right incentives for a sustainable energy plan.

Third, the industrial sector can in some cases be more attractive for fuel switching than the power sector. The study found that looking outside of the power sector for fuel switching opportunities could prove to be a cost effective option. According to the model, a switch from coal to natural gas boilers would be cheaper than forcing a switch in power plants in the case of Shanghai where the industrial sector is currently dependent on inefficient coal boilers. Replacing an inefficient coal boiler requires much less upfront capital than converting a power plant from coal to natural gas. When there are enough boilers in the industrial sector to make a difference in emissions, this is an especially attractive alternative.

Fourth, the fuel mix for electricity generation is unlikely to change dramatically. In all of the scenarios that were tested in the model, coal remains the dominant fuel in the energy mix. Coal is simply too cheap and abundant to leave unused (China has the world's third largest coal reserves). Aggressive sulfur reductions do shift the electricity mix somewhat towards a greater role natural gas, but sulfur reductions can often be met more cheaply through fuel shifts in the industrial sector and by installing end-of-pipe solutions on coal plants.

Fifth, non-climate policies could have a large impact on carbon emissions. While China is unlikely to accept binding carbon dioxide emissions reductions targets in the near future, very large CO_2 reductions might be realized as a side benefit from other policies enacted for reasons other than climate concerns. For example, in the case of China, a cap on SO_2 emissions could have a significant effect on CO_2 reductions by promoting the use of cleaner burning fuels and more advanced technology. An SO_2 policy might be more palatable to the Chinese government because it addresses immediate local concerns about air quality and health that directly affects its citizens.

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4. Modeling and Analyzing the Impact of Interdependency between Natural Gas and Electricity Infrastructures

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***Abstract*—**With increasing investment in natural gas powered generation technologies, limitations in gas delivery capabilities are becoming increasingly relevant to operational planning for electric power systems. Thus it is essential to model and analyze the impact of the interdependency between natural gas and electricity infrastructures. This paper tries to convey the idea that, through an integrated modeling of the two infrastructures, critical energy infrastructure vulnerabilities can be identified, which provides useful information for future planning of natural gas delivery system and electric power system. The IEEE 118-bus power system and an assumed natural gas delivery system are used to illustrate the impact of interdependency between natural gas and electricity infrastructures.

***Index Terms*—**Interdependency, Natural Gas Infrastructure, Electricity Infrastructure, Infrastructure Vulnerability

1. INTRODUCTION

The nation's energy security and sustainability, depending primarily on its energy infrastructure's security and sustainability, are of critical importance to the nation's economic competitiveness and the improvement of people's daily lives. Natural gas infrastructure and electricity infrastructure are two essential elements of the nation's energy infrastructure. The loose interdependency of the two was not seriously studied during the regulation era of the electricity industry. The electricity industry restructuring since the 1990's, along with increasingly severe global warming issues, require the adoption of power generation techniques that makes economic sense and is environmentally friendly. Such requirements have resulted in rapid deployments of gas-fired combined cycle generating units. It is reported that the majority (up to 90%) of the electric power plants that were built in recent years and will be built in the future are fueled by natural gas [1, 2]. By 2030, generation by natural gas is expected to increase by 230%, the greatest relative increase of any generation technology [3].

Such rapid deployments have intensified the physical and economic interdependencies between natural gas and electricity infrastructures, which have introduced additional challenges for managing the security of such interdependent infrastructures. Specifically, the emergence of large quantity of gas-fired units necessitates a more extensive gas supply and transmission infrastructure which could greatly increase the vulnerability of gas pipeline infrastructure from the security viewpoint, and increases the demand thus market prices of natural gas from the economic viewpoint. There has been evidence that natural gas usage for electric power in summer may have a noticeable impact on working natural gas in storage and winter gas availability.

On the other side, the limitations of the gas delivery system become increasingly relevant to power system operations with the increased reliance on natural gas. An interruption or pressure loss in gas transmission systems could lead to a loss of multiple gas-fired electric generators that could dramatically jeopardize the power system security. In the event of outages in gas transmission or power transmission systems, inconsistent control, monitoring, and curtailment procedures in the energy infrastructure could further constrain operations and may lead to cascading outages and even blackouts. The 2006 reliability study performed by NERC emphasizes the importance of natural gas delivery to system reliability, and calls for increased study of the reliability and adequacy of systems as a result of unexpected fuel transportation contingencies [4].

The bottom line is that the two infrastructure systems have become highly interdependent [5]. For instance, gas market prices have a direct impact on unit commitment and economic dispatch in security-constrained power system operation. Changes in gas prices may mean the difference between using gas-fired units, or units which rely on coal or other fuels. Additionally, in situations where the demand for natural gas and electric power peak simultaneously, as during periods of extreme cold weather, low operating pressures may lead to spikes in gas prices, and even curtailment of gas generators. This was the case during an outage that occurred in February of 2006 in Colorado [6]. Record low temperatures caused a high demand for gas for residential heating purposes. Gas pipeline pressures and supplies were low, so in order to maintain service to residential customers, as is common practice for gas utilities, several gas-generating customers were curtailed, resulting in a loss of more than 1,000 MW of generation. As a result, the electric utility was forced to shed 85 MW of interruptible and 428 MW of firm load. More than 323,000 customers were without power for several hours. Finally, of utmost importance in the study of the interdependency is the effect of gas outages on the electrical system. An outage in a single pipeline can force multiple gas generators to go offline. An example of such an outage occurred in July of 2002 at the Collins generating facility near Chicago, IL [7]. A pressure spike resulting from efforts to repair a leak caused four of the five generators at the facility to go offline, resulting in a total loss of 2,019 MW of generation. This outage did not result in load shedding; however, it demonstrates the large capacities that can be lost in the event of a relatively small gas disruption.

These cases demonstrate the need for a combined model for power and natural gas delivery systems. To the best knowledge of the authors, there has been no existing commercial tool with the capability of modeling natural gas and electricity infrastructure simultaneously. In the existing literature, very few have studied the interdependency of natural gas pipeline system and electric power network. In [5], a model of the natural gas delivery system is proposed. This model is limited in that it does not model the gas flows directly, but simply assumes a pre-determined relationship between gas components and the power system. Essentially, gas-fired generators rely on the operation of specific components of the gas delivery system, so in the event of an outage, fuel supplies to specific units are either cut off, or are limited by a pre-specified amount. In practical systems, however, such relationships are not easily anticipated. It may be impossible to determine universal rules for how an outage of a gas delivery system component may affect gas availability throughout the system. Ref. [8] presents a model for the natural gas delivery system with the objective of minimizing the cost to the gas supplier to supply the gas demand. The cost to supply power is related to the cost of gas; however, there is no direct coordination between the gas supplier and the scheduling of the electrical system. Therefore, it will be assumed that the gas supplies are constant values determined separately by the gas supplier.

This paper introduces a framework for modeling the interdependency between natural gas and electricity infrastructures and analyzes the impact of such interdependency on the economics and security of electric power system operation. This paper extends the work presented in [9].

2. MODELING THE INTERDEPENDENCY BETWEEN NATURAL GAS AND ELECTRICITY INFRASTRUCTURES

2.1 Gas Network Model

Pipeline Flow

The basic model for pipeline flow in the natural gas delivery system presented in [6] is used in this paper. Gas pipelines are defined as either passive, for pipelines without a compressor, or active. For passive pipelines, the gas flows are determined only by the pressure difference. For active pipelines, a compressor allows the flow to exceed the pressure difference. Additionally, for active pipelines, the gas can only flow in one direction. A detailed mixed-integer-programming (MIP) based formulation can be found in [9].

Gas Contracts

In this paper, gas contracts are modeled as interruptible, where the gas customer pays only for the amount of gas used, or take or pay, where the gas customer pays a fixed cost in advance for a specified amount of gas. In both cases, the total gas usage must be less than or equal to the contract amount. For interruptible contracts, the gas customer pays a fixed per-unit price for the amount of gas used. For take-or-pay contracts, however, the gas customer pays a single fixed amount regardless of the gas actually used. Mathematical formulation for modeling gas contracts as described above can be found in [9].

2.2 Electrical Network Model

The short-term operation of the electrical network can be simulated using a security-constrained unit commitment (SCUC) model. The objective of SCUC is to determine a day-ahead UC for minimizing the system operating cost while meeting the prevailing constraints listed as follows:

1. Power balance
2. System spinning and operating reserve requirements
3. Minimum up/time limits, ramping up and down rate limits, startup and shutdown characteristics of units
4. Must-on and area protection constraints
5. Fuel and multiple emission constraints
6. Transmission flow and bus voltage limits
7. Load shedding and bilateral contracts
8. Limits on state and control variables
9. Scheduled outages

A complete model can be found in [10, 11, 12].

2.3 Gas Pipeline and Electrical Network Interdependency

The coupling constraints between the gas and electrical network are the flow conservation constraints: the total gas entering a node is equal to the sum of the gas leaving the node and the total gas withdrawal. Unlike other models for gas/electricity interdependency, the inclusion of the flow conservation constraints enables gas usage limits to vary as a function of gas flow limitations instead of being fixed values. Thus, the current operating limitations on gas usage are directly represented in the problem, unlike [5], where it was necessary to estimate the gas usage limits beforehand. Mathematical formulation for the gas flow conservation constraints can be found in [9].

2.4 Solution to the Integrated Gas Network and Electrical Network Model

The addition of gas pipeline network modeling to SCUC will increase the size of the optimization problem in terms of number of variables and constraints. In this paper, SCUC with gas pipeline network modeling is decomposed into two sub problems: unit commitment (UC) and network analysis (NA). The UC problem is formulated for various types of generating units including thermal, combined-cycle, fuel switching, hydro, pumped storage, and renewable resources (wind or photovoltaic). The gas pipeline network model is incorporated as additional constraints in the UC problem for considering interdependency on gas network. A MIP approach is applied to calculate the hourly unit commitment. The NA sub problem conducts security analysis based on the UC solution and coordinates with the UC problem through shift factor based method [13] or Benders decomposition [10, 11].

3. ANALYZING THE IMPACT OF INTERDEPENDENCY BETWEEN NATURAL GAS AND ELECTRICITY INFRASTRUCTURES

3.1 Previous Study

In [9], a simple four-node natural gas delivery system and a simple three-bus electric power system are modeled to illustrate the interdependency between natural gas and electricity infrastructures. Four cases were presented in [9]. The base case shows how the natural gas delivery system can limit the availability of fuel to natural gas fired units. The system is forced to operate in a sub-optimal state as a result of insufficient pressure differences that limits the necessary gas flows to areas further from the supply. The compressor impact case demonstrates how compressors can reduce the dependence on high pressures in order to achieve sufficient gas supplies. Two gas outage cases demonstrate the impact of gas pipeline outages on the electric system operation. Of particular interest is that modeling the two systems simultaneously exposes a critical vulnerability in the system: shedding of electric load has to be called to relive security violation. Such vulnerability is not evident by studying the gas or electrical systems separately.

3.2 Study System Description

Further study has been performed on the IEEE-118 bus system based on the work in [9] to gain more insights. Part of the results is reported in this paper. The IEEE 118-bus system shown in Fig. 1 contains 54 thermal generators, 36 of which are fueled by natural gas. Additionally, there are 9 fuel-switching units that use gas and oil, and 12 natural gas-fired combined-cycle units. The standard IEEE-118 bus system does not provide any information on gas delivery system. For the purpose of this study, a natural gas delivery system is constructed to supply the gas-fired units, as shown in blue in the background of Fig. 1. The gas delivery system contains three parallel pipelines, connecting 6 gas nodes. Compressors are in use on the pipelines between nodes 1 and 2, nodes 2 and 4, and nodes 3 and 5. There are two gas supply points, at gas nodes 1 and 4. The following three cases are studied. Case 1 serves as a base case and studies the impact of gas flow constraints on electrical system operation. Case 2 considers only gas pipeline outage and studies the impact of electrical transmission constraints. Case 3 considers both gas pipeline and electrical transmission outages.

3.3 Case 1 – Base Case

In the base case, the interior diameters of all gas pipelines are 36 inches. The simulation study is run for 24 hours for the system with and without gas flow constraints. The differences in gas usage as a result of considering the gas network are depicted in Fig. 2, with net increases shown in blue and net decreases shown in red. The total gas usage does not change significantly, however, at node 5 there is a significant decrease in usage as a result of restrictions in the gas supplies. This decrease is offset by increases at other nodes.

3.4 Case 2 – Gas Pipeline Outage

In this case, the natural gas pipelines between nodes 5 and 6 are disconnected, cutting off gas to node 6 entirely. Electric load shedding is required, as depicted in Fig 3. The load shedding is primarily limited to buses with generators fueled by gas from node 6, and this location dependence is the result due to the natural gas limitations combined with the electrical transmission network. If the electrical transmission constraints are ignored, as shown in Fig. 4, there is no longer a location correlation as power to the loads can be transferred from any generator. By distributing the load shedding throughout the system, the total loss of load in this case is reduced by 20%.

3.5 Case 3 – Combined Gas Pipeline and Electrical Transmission Line Outage

In this case, the natural gas pipelines between nodes 2 and 3, as well as electrical transmission line 33 between buses 25 and 27, is disconnected. When considering either outage alone, no load shedding is required. Each outage, however, stresses the gas delivery system in a similar way, requiring more gas usage at nodes 1 through 4, while causing decreases in gas usage at nodes 5 and 6. When combined, therefore, a significant amount of load shedding is now required, limited to bus 32, as shown in Fig. 5.

4. CONCLUSIONS AND FUTURE WORK

As the electricity industry becomes more and more dependent on natural gas-fired generation, limits in the natural gas delivery system are becoming increasingly relevant to power system operation. This paper presented a combined model for electric and natural gas systems for study the impact of such interdependency on electric power system operation. For the 118-bus system, in the gas pipeline outage only case (Case 2), it was demonstrated how a gas outage combined with electrical transmission limits affect the ability to supply the electric load throughout the system. In essence, when the transmission system is sufficiently robust as to allow power transfer from more remote locations, the effect of gas outages on the electrical system is minimized. In Case 3, combined outages in the electrical and gas systems were considered. When considered separately, the outages were not critical, i.e. they did not result in load shedding, however, when the outages occur simultaneously, the system load could no longer be fully supplied and load shedding has to be prescribed. Exposing these critical vulnerabilities demonstrates the value of the combined model.

The incorporation of natural gas network modeling presented in this paper is only a start to comprehensively analyze the interdependency between the natural gas and electricity infrastructures. The gas network model used in this paper is still a very simplified model. For instance, gas storage is not modeled; only gas usage for electric power production is considered; other non-power gas usages, such as residential and commercial, and the associated impacts are not modeled. A more detailed gas network model should be included for a more realistic study on a practical system, for which the availability of data may be an issue. In addition, this paper considers the impact of the interdependency between natural gas and electricity infrastructures mainly from the perspective of power system operation. Future work should also consider the impact of such interdependency on the gas network operation.

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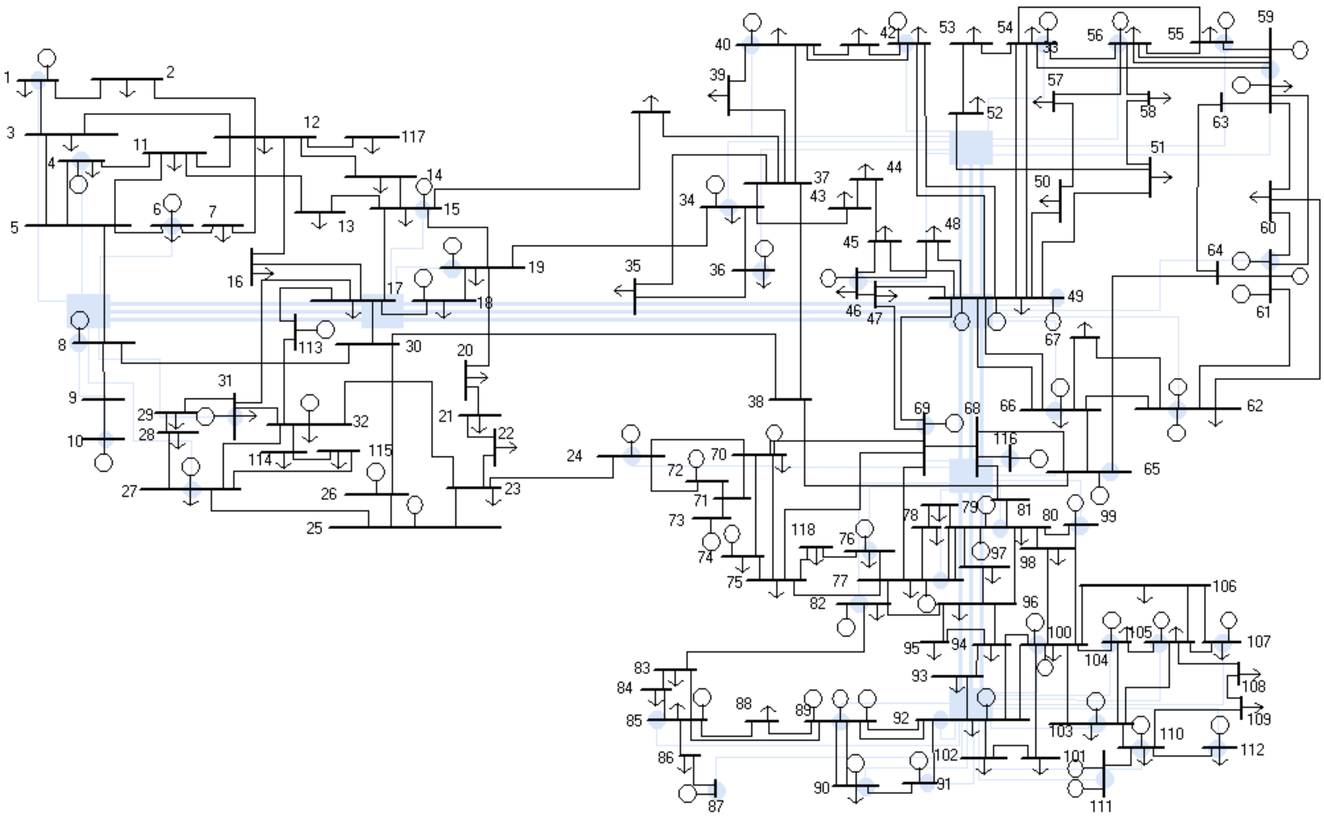

Fig. 1. IEEE 118-bus system (light blue in the background shows the assumed natural gas delivery system)

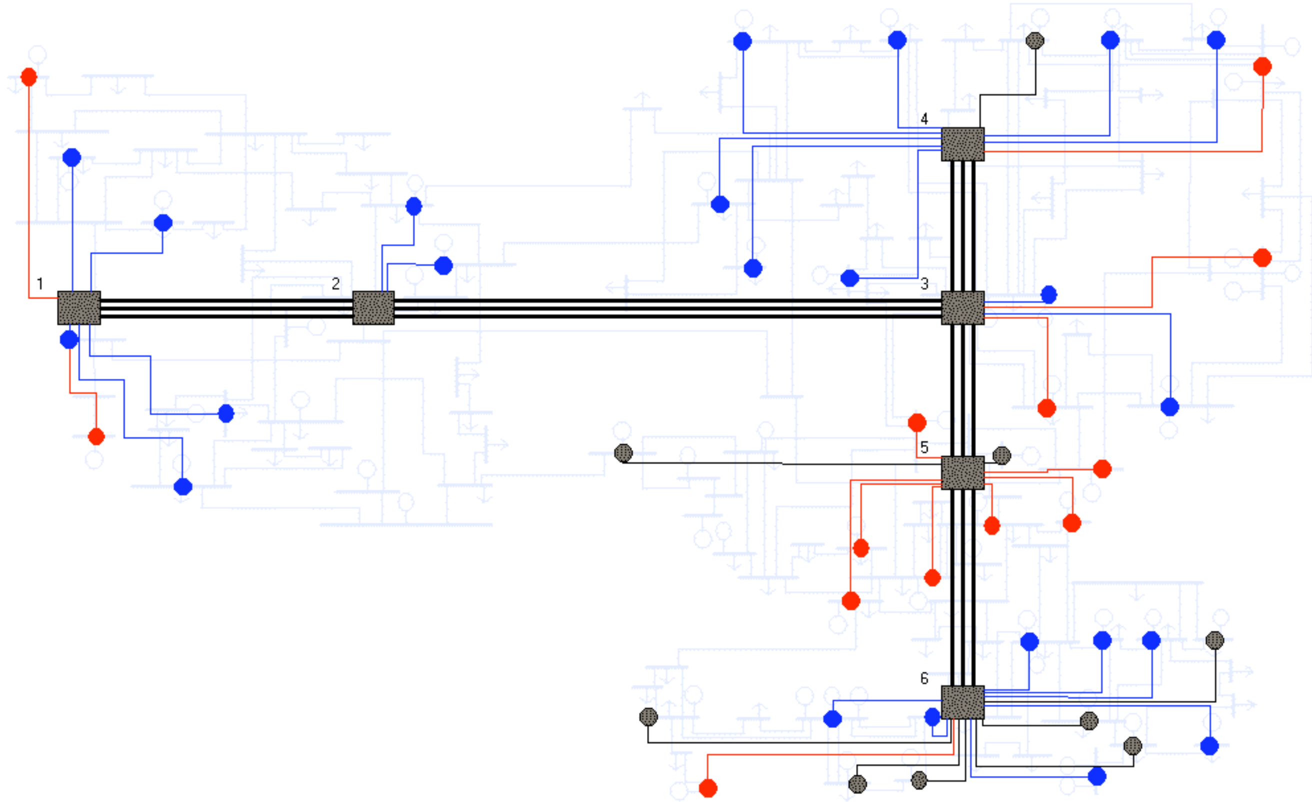

Fig. 2. Depiction of the differences in natural gas usage as a result of modeling the base-case gas delivery network (Case 1). Nodes where there is a net increase are shown in blue, while net decreases are shown in red.

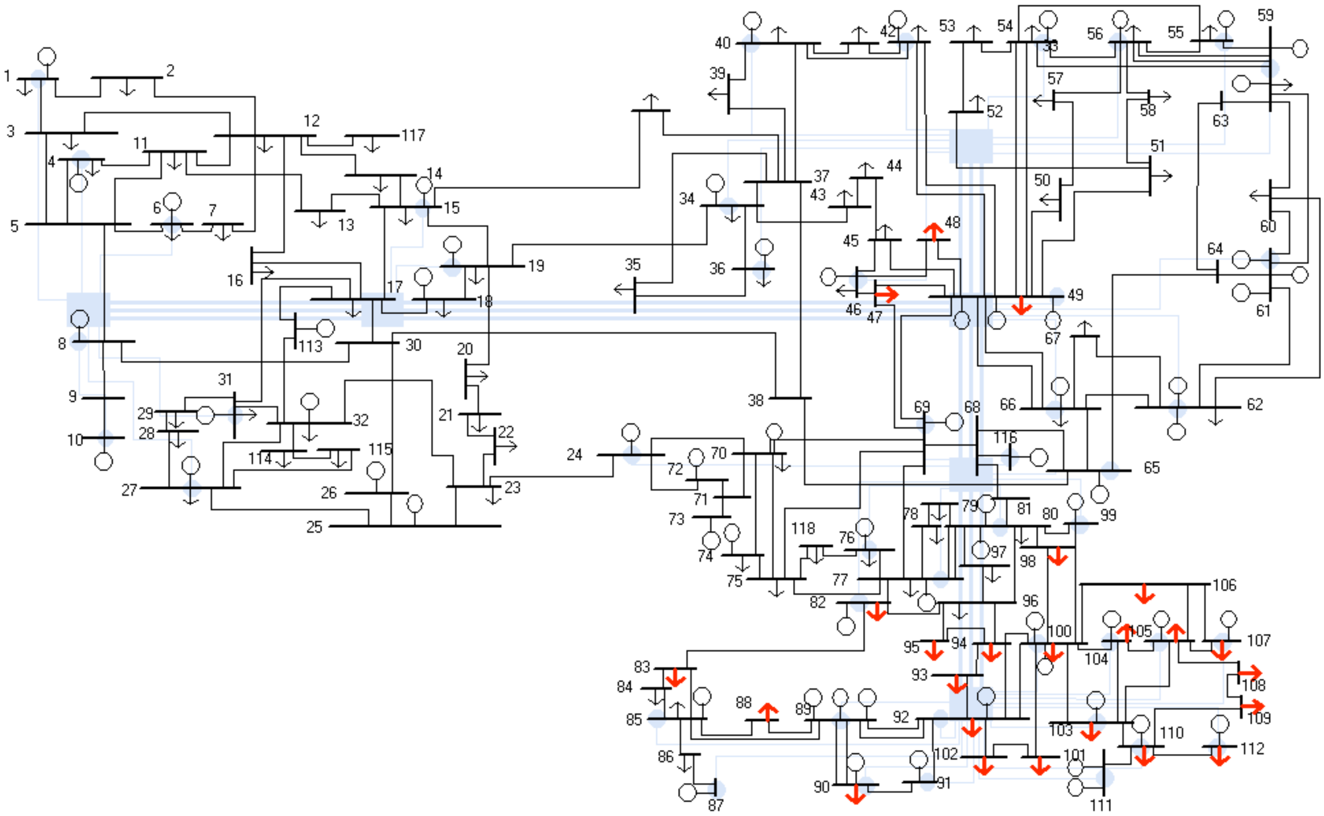

Fig. 3. Load shedding with gas pipelines between nodes 5 and 6 on outage (Case 2)

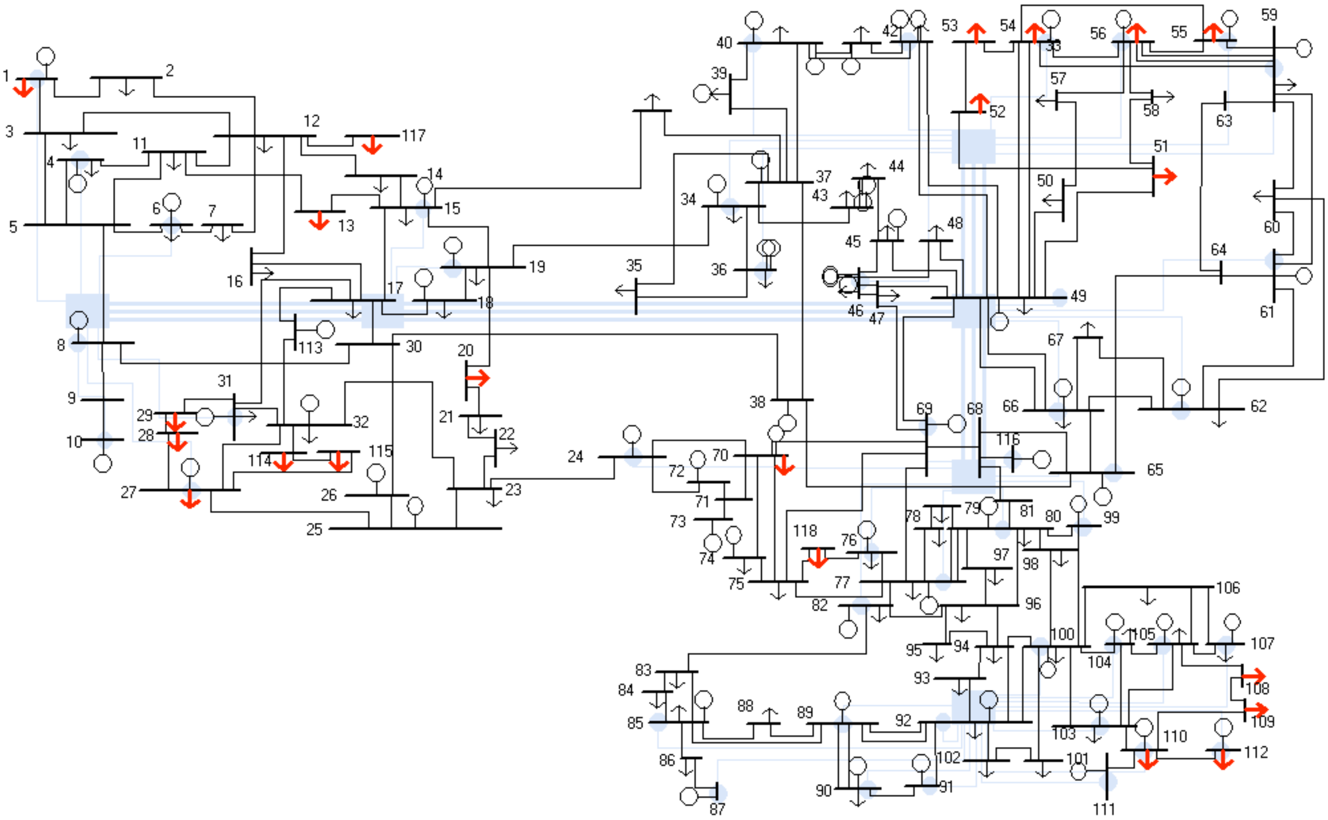

Fig. 4. Load shedding with gas pipelines between nodes 5 and 6 on outage (Case 2), without considering transmission flow limits

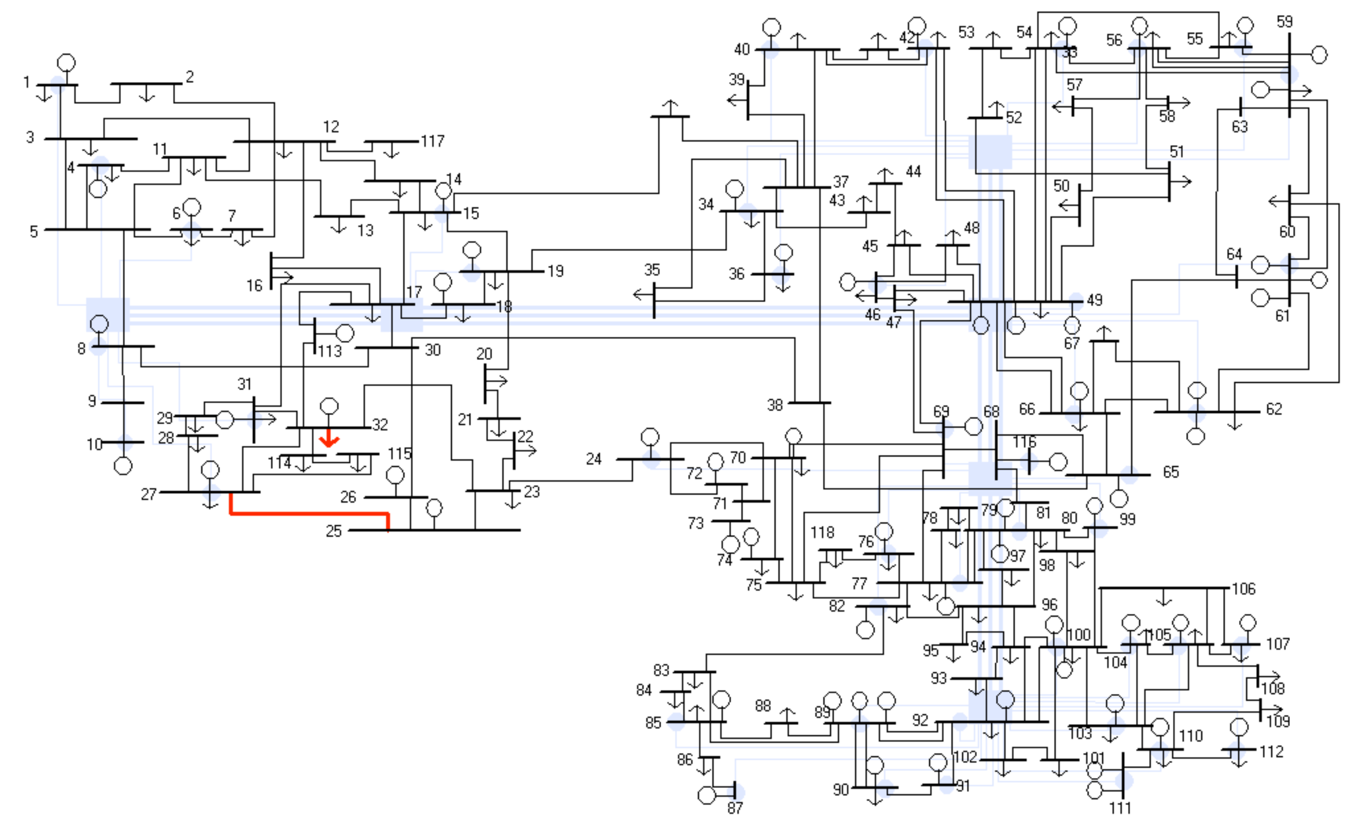

Fig. 5. Load shedding with a combined outage on gas pipelines between nodes 2 and 3, as well as electrical transmission line 33, between buses 25 and 27 (Case

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5. Generation Development Options in the UK from the Aspect of Natural Gas Availability and Prices

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Abstract: Continuous requirement for additional electrical generation is evident in developed and developing world. Governments also face pressure to tackle pollution and global warming issues. Apart from technical and economic consideration country's generation planning has a strategic component that influences diversity of use of prime energy resources.

Tendency in West Europe to use more natural gas for heating and electrical generation could be boosted by further development in the European gas market. Considerable number of new pipeline and gas storage projects as well as constructive regulatory activities indicates that the gas supply could be significantly increased.

Developing a competitive and regulated gas market supported with significant infrastructure investments and fulfilled environment requirements provide the right framework to encourage increase in use of gas in the UK. From the energy resources diversity aspect it appears that there is sufficient room for growth of CCGT and CHP plants to keep the right balance of the generation mix.

Keywords: Power Generation Planning, Generation mix, Natural Gas, Gas Market, Energy Efficiency, CCGT (Combined Cycle Generation Turbine), CHP (Combined Heat and Power), GHG (Green House Gasses) emissions reduction.

1. INTRODUCTION

Significant changes in energy demand have been noticed in relation with the modern society development and trends. It is evident that the demand grows in both developed as well as developing countries in relation with various social and economic factors in each of them. Factors such as population growth, improved standard of living, climate change and industrial developments affect the energy demand, which in turn raise concerns about the availability of the energy sources and the effect of its consumption on the environment. For those reasons governments and the responsible institutions are continuously tackling those issues from various aspects with the aim to secure the energy sources, transport and distribute it safely to the end consumer.

Rapid increase in local energy demand creates difficulties in securing a fast and efficient response. Various options to provide power are available from use of sustainable energy sources to combination of heat and electricity. Gas meets most of the current requirements for clean and efficient source to provide heat and power and is often considered as the most suitable. This provides new opportunities for further development and restructuring of the gas market in Europe and North America.

One of the main aspects in this paper is the effect of gas market reforms on the power sector in particularly on generation mix in combination with industrial and heating requirements. Optimum generation mix considers the choice of fuel supply on a long-term basis via the analysis of remaining reserves and predicting the market trends.

2. ENERGY DEMAND AND SUPPLY IN EUROPE AND UNITED KINGDOM

Annual energy demand growth projection in Europe is expected to be between 1.0 and 1.2 per cent in the next twenty years. On the other hand, the local electricity production has a relatively low prospect for growth, apart from a number of locations in Norway with the ongoing projects over the next few years. It is therefore expected that the local sources will be insufficient to meet the demand in the medium and long term. This combination of demand growth and local supply decline creates a need for a half a million billion cubic meters of new supplies in Europe.

Significant new supplies to Europe and UK are required and consideration has been given to pipelines from the North (Russia and Norway), East (ex Soviet countries via South East European corridor) and South (North African countries) as indicated in Fig.1 Gas Installations in Europe.

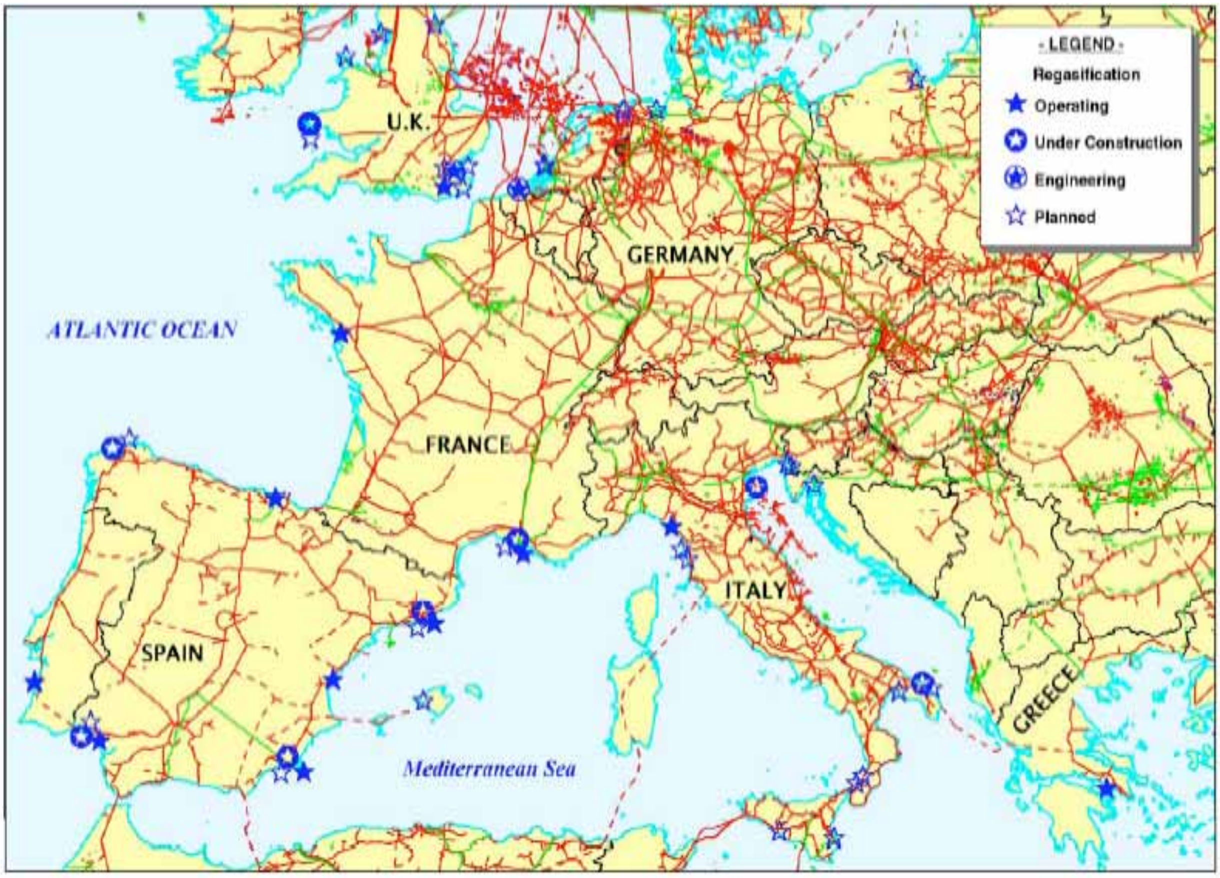

Figure 1. Gas Installations in Europe

It is expected that gas would come from new developments in West Siberia (Yamal from 2012) and the Russian Barents Sea, pipelines through the Black Sea, the SEE (South East European) countries and over the Mediterranean Sea from Africa to Italy.

Due to the expected benefits that it will bring in terms of sufficient supply and regulated prices, Europe is expected to increase its participation in the global gas market. Perhaps the most important aspect of the future gas market is the significant development in competition for securing new supplies and the resulting growth in inter-regional trade. It is in this environment that Europe finds itself competing to attract investment for the necessary new gas supplies.

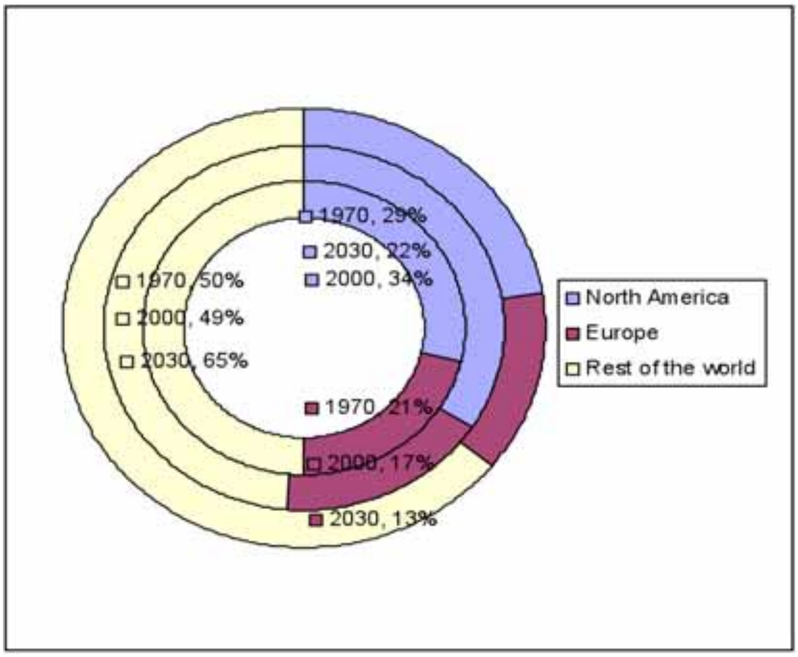

Figure 2. Share of electrical generation

The electricity sector is one of the largest sectors of most European countries and could claim up to a half of the total capital investment. On average, the electrical generation claims one third of countries total fuel consumption. On the other hand the total power generation of the developing world (including Asia, Latin America and Middle East) is expected to be over 60 per cent of the world's total. Fig. 2 Share of Electrical Generation shows how the electrical power generation has been divided between North America, Europe and countries that effect economic growth in terms of demand. [1]

From the projection of fuel inputs to power generation, coal and gas today represent about 66% of fuel inputs, and by 2030 it is expected that it will reach over 70%.

3. GAS MARKET – BRIEF OVERVIEW

The main participants in the gas industry are suppliers, infrastructure owners, distributors and consumers. Most of the existing contracts for supply of gas to the distributors in Europe and UK are long term contracts based on steady increase in demand. The current pressure to supply local areas with gas and electricity at a new development pace requires fast response from the suppliers, which is difficult to achieve at competitive prices under the existing contract terms. Hence major changes are expected in restructuring of those contracts to reflect the dynamic changes in heat and electricity demand. The new open market would also need to adjust by providing prompt changes in price in accordance with the demand and supply.

The changes in the gas supply industry are already visible in that the suppliers now tend to target more then one market. In an open market the consumers would equally have a choice of suppliers that would therefore result in reduction and optimization of prices.

4. GENERATION OPTIONS IN UK

4.1 Planning principles

The following diagram Fig.3 illustrates a relationship between the main factors in the countries economy at various levels.

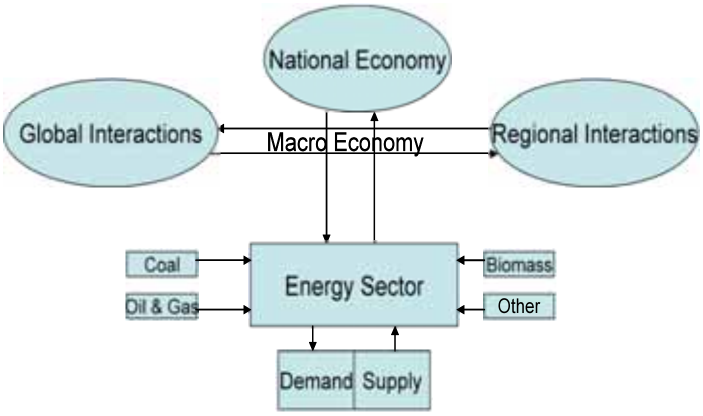

Figure 3. Macro Economy Factors

It is evident that a macro economy based strategy is related to national economy with strong ties with the energy sector with a strong influence and interactions at regional and global levels.

Electricity is a major sub-sector of Energy, which together with other sectors such as agriculture, transport, health and education greatly affects the national economy. Electricity is irreplaceable in many areas like computers, large servers (internet hotels) etc. It also plays a strong role in expansion of other sectors and therefore its development is of crucial importance for a country's economic growth.

The main generation planning principle is to provide supply to meet the predicted demand in the most economic way in accordance with the adequate security and safety standards. Integrated Resource Planning (IRP) [2] is a recognized process that identifies a mix of resources to meet the future electricity service needs of the consumers, economy and the society. Different energy source options are compared using various techniques such as discounting process with the assessment of long-term costs and benefits.

The following Table 1. illustrates various sources of energy participating in generation in UK and Europe [3]. There is a significant effort to increase the use of sustainable sources but it appears that a target of 10% is too high for the UK.

Table 1. Electricity Generation in UK and Europe

	N	CL	P	NG	H/W	B	Other	Total
	%	%	%	%	%	%	%	'000 GWh
UK	22	34	2	37	2	1	-	386
EU	33	25	6	17	15	2	2	2671

N-Nuclear; CL-Coal Lignite; P-Petrol; NG-Natural Gas; H/W-Hydro/Wind; B-Biomass

Generation development in UK is currently under the influence of a several institutions that are arguing over their favorite source of energy.

Nuclear technology, although present in the UK since the first nuclear reactors were installed in the world, has been put aside for decades due to the moratorium on building new NP (Nuclear Plant). Compared to similar installation in Europe, there are some views that UK should revisit its current position. Serious of proposals have been published recently on nuclear waste storage, which is one of the main obstacles aside from the immediate danger related to safe operation of the plant. The current trend is to prepare grounds for reconsideration of use of nuclear power.

Consideration has also been given to use of coal and lignite with new technologies that would purify the fuel and increase the plant efficiency. Exchange of experience with countries using those technologies in Europe, such as Poland and Russia, may lead to reopening of some coal mines and result in maintaining coal's share of current electricity production in UK.

The UK is committed to reducing the emissions of GHG by 2010 as per Kyoto protocol. The mechanisms to import clean energy from the countries with high margins (mainly developing countries in Eastern Europe) are also on the agenda. However it is unlikely that renewable sources will meet the target because they have proved to be expensive. As an alternative to those sources of energy the experts in UK are trying to increase efficiency through implementation of CHP plants. This would result in significant gas demand from the new gas market where it is expected that UK play an important part.

Future electricity generation technologies will aim at achieving clean emissions in order to reduce the impact on environment, high efficiency and short lead times to minimize uncertainties and risks. Gas turbines combined cycle (CCGT) as well as CHP fully comply with this requirement. CHP technology is more common in Sweden, Netherlands, Germany and Austria due to the high demand in heat for longer winter periods.

The main advantages of the gas turbine generation could be summarized:

- There is more choice for the location for gas Power Plant that could be beneficial for the Transmission and Distribution (T&D) system in lower losses and more stable system.
- Gas plants and CHP can operate in peak shaving mode due to its fast response on demand to provide power
- CHP, which is capturing waste heat and reusing it in an industrial process, is considered as the most efficient type of generation

On the other hand the main disadvantages is that the availability and prices of gas will always be associated with risks related to disintegrated markets and political stability of the countries with the gas source as well as countries associated with gas transmission.

4.2 CHP Plants in UK

Although the efficiency of majority of power plants has improved in the last few decades from as low as 27%, most of the thermal plants worldwide produce electricity with very low efficiency i.e. of the order of 33%. This has recently prompted even more concerns regarding high emissions of global warming gasses due to the GHG effect with evident local, regional and likely global implications. Due to those climate change initiatives, the focus on modern electricity generation has shifted towards improving energy efficiency and reduction of pollution.

Table 2 illustrates the advantages of gas over fuel oil and coal in terms of air pollution emission. [3]

Table 2. Air Pollution Emission

Fuel	**SO2**	**NOx**	**CO2**	**PM**
Coal	**0.081**	**0.018**	**3.57**	**0.106**
Oil	**0.06**	**0.017**	**3.13**	**0.004**
Gas	**none**	**0.012**	**2.07**	**none**

[in mill tons/m.t.o.e of fuel]. PM-Particulate matter; SO2 sulphur dioxide; CO2 carbon dioxide; NOx nitrogen oxide

According to environmental agencies new CHP plants in the UK can deliver cost-effective carbon savings between 4 and 6 million tonnes by 2010 and up to 8 million tonnes by 2015.

From the technical point of view they provide fast response to generate into the system, which fits nicely in the new regulated and more dynamic gas market. Gas turbines are generally more reliable than pure sustainable sources. They are also suitable to operate as embedded generation that is currently the trend in the UK.

There is also a possibility of limited fuel storage.

One of the issues that need to be mentioned is high cost of maintenance of gas pipes, associated with leaks and costs in minimizing the risks of terrorist attacks. The negative impact would reflect on the environment and financial damage to the unsupplied market.

5. UK LEGISLATION AND POLICY

5.1 Energy Review

The UK Government's report has issued the Energy Review ‘The Energy Challenge’ on 11 July 2006. The main objective is to meet the two major long-term challenges in UK energy policy namely the climate change by reducing carbon dioxide emissions and deliver secure, clean energy at affordable prices, as UK moves to increasing dependence on imported energy.

A package of proposals was announced in the Energy Review document. Many of the issues are complex and a series of public consultations is being held. These will ultimately lead to meeting the preset goals of reducing carbon emissions and a secure energy supply.

The consultation on the new measures on gas security of supply has been held from 16 October 2006 - 12 January 2007. This consultation on gas security follows up on the commitment in the Energy Review report to consult with both industry and consumers on:

- the effectiveness of current gas security of supply arrangements
- their robustness as UK moves to higher dependence on gas imports over the next 10-15 years
- whether new measures are needed to strengthen them.

It is stressed and explained in the Review report that it is continued to be believed that well-functioning markets are the most effective mechanism for ensuring adequate investment in gas infrastructure.

The document considers in more details the security of gas supply and examines the extent to which the current policy framework is likely to deliver security of supply.

It also assesses the new challenges faced as the flexible sources of gas in the UK decline and discusses views on the costs, benefits and risks of some possible adjustments to the current commercial and regulatory framework to strengthen the ability to rise to that challenge.

A number of other consultations have been launched to help address security of energy supply and climate change challenges with the selection of a few listed below.

- New nuclear policy framework, October 2006
- Energy Efficiency Commitment April 2008-March 2011, October 2006
- Proposals on banding, and amending the Renewables Obligation, December 2006 (part 2) and January 2007 (part 1)
- Measures to reduce carbon emissions in large non-energy intensive business and public sector organizations, January 2007
- Energy billing and metering, February 2007
- Resilience of Overhead Power Line Networks, March 2007
- Distributed energy, A call for evidence, January 2007
- A consultation on Offshore Natural Gas Storage and Liquefied Natural Gas Import Facilities. This consultation considers the need for, and provides views on, changes to existing legislation with regard to the storage of natural gas in non-hydrocarbon features (e.g. salt caverns), the storage of natural gas in hydrocarbon features (e.g. partially depleted oil and gas fields) and the unloading of Liquefied Natural Gas (LNG) offshore.
- Offshore Natural Gas Storage and Liquefied Natural Gas Import Facilities: consultation, February 2007

On 15 December 2006, the Department of Trade and Industry (DTI), now Department for Business, Enterprise and Regulatory Reform (BERR), issued new Guidance to power station developers to maximize the use of CHP where feasible. In issuing this Guidance the Government is signaling its strong commitment to CHP, whilst recognizing that it is up to the market to bring forward the most competitive proposals to help ensure security of supply. This Guidance gives developers access to information on regional heat customers through Defra’s interactive heat maps. The Guidance also includes clearer instructions on what information is required from developers. The issuing of this Guidance was a commitment in the Energy Review and it is accompanied by a Regulatory Impact Assessment.

The outcome of these pieces of work has been fed into the Energy White Paper in 2007.

5.2 Energy White Paper

The White Paper, published on 23 May 2007, sets out the Government’s international and domestic energy strategy to respond to these changing circumstances, address the long term energy challenges we face and deliver our four energy policy goals:

- to put ourselves on a path to cutting CO2 emissions by some 60% by about 2050, with real progress by 2020;
- to maintain the reliability of energy supplies;
- to promote competitive markets in the UK and beyond;
- to ensure that every home is adequately and affordably heated.

It shows how the measures set out in the Energy Review Report in 2006 have been implemented, as well as those announced since, including in the Pre-Budget Report in 2006 and the Budget in 2007.

Some of the measures in this White Paper require further public consultation. Alongside the White Paper consultations on nuclear power, the Renewables Obligation and guidance on the 1965 Gas Act have been launched.

The available UK Government reports outlined the measures to stimulate wider adoption of CCGT and CHP and stress the benefits of investing in CHP technology due to:

- exemption from the Climate Change Levy
- firms investing in CHP technology are eligible to incentives under the Enhanced Capital Allowance scheme
- CHP are exempted from business rates re-evaluation
- furthermore biomass and waste were eligible for incentives under the Renewable Obligation schemes.
- carbon saved through CHP installations would be rewarded under the European Emissions Trading scheme

CHP plants are currently in the focus of energy experts as the alternative to failure of meeting the targets related to sustainable energy. Total CHP generated energy in UK in 2005 was 27TWh of electricity and 51TWh of heath. The UK government predicted that just over 10% could be generated out of total predicted energy of 350TWh with the trend to grow up to 17% as an ultimate potential. On the other hand other countries in Europe such as Germany, reports they expect CHP plants to meet 25% of the overall demand. With an open gas market in Europe UK would surely consider higher utilization.

6. CONCLUSION

Local energy sources can neither meet the demand growth in the developed countries nor in Central and Eastern Europe. Electricity generation forms an important part in a country’s development strategy; therefore it comprises a generation mix of energy sources that takes into account availability, market trends and political stability.

The advantages of gas turbines over other sources are numerous from fast response to system requirements to acceptable ecological characteristics with low NOx and no SOx emissions. In terms of efficiency, CCGTs are considered the best of all thermal power plants with efficiencies up to 60%. Further improvements, which is the trend in the UK as well, is to combine the gas turbine with use of sustainable sources of energy that would reduce the emission of GHG (green house gasses) and improve efficiency up to 80% by connection to districting heating and providing heat to industrial processes.

The latest analysis of generation mix in the UK indicates that it will be difficult to meet the target of 10% set for use of sustainable/renewable sources. Discussions have been reopened on use of nuclear power as well as fossil fuels.

Liberalization of the European Gas Market opens the opportunity for gas to participate in UK's generation mix in developing more CHP in addition to already implemented CCGT.

However, dependence on gas imports to replace UK reserves is most likely to be both pricey and vulnerable to the loss of supply due to political instability. It is considered prudent to plan for such a foreseeable situation by consideration of the following.

- Build modern Nuclear to replace the existing operational, but old stations – which could provide deficit that other low CO_2 technologies cannot provide.
- Allow power generation from abated emission, modern coal power stations, as well as providing incentive to utilize more coal mine methane in gas engines.
- Continue promoting 'renewable' fuels and wind, wave and solar, whilst keeping in perspective the relatively low percentage of their overall contribution.
- Minimize output from existing gas fired power stations to retard the rate of consumption of Britain's own reserves – this may mean returning to a higher percentage of power generation from coal, having "clean coal" technology.
- Adequately fund development of tidal and under sea current technologies, for predictable power generation.
- Government policy with regard to the structure of the energy markets should aim to remove the short-term price horizons in those markets that are a major bar to capital investments that depend on long tern return periods.

In conclusion competitive market when combined with investments, environment requirements and stabile, predictable regulation, provides the right framework to encourage the growth of gas and CHP plants in order to contribute to the right balance in generation mix in European countries including UK.

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8. BIOGRAPHY

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He gained the experience by working for major consultancy companies in UK and is currently operating as Polimac Ltd. The projects he was working on stretch from Australia to North America including technical analysis and major transmission and distribution system planning.

Vukan has carried out work for the regulators as well as assessed environmental aspects of technical projects.

Vukan has published a number of papers in Europe and USA on system planning, climate change issues, innovative approach to maintenance and technical aspects of environmental issues. His recent presentation at Sheffield University covered aspects of Linear Infrastructure projects.

He is also a member of the CIGRE Working Group C1.11 Asset Management - Performance Benchmarking. E-mail: vukan.polimac@polimac.co.uk

6. US Flying Standby with Liquefied Natural Gas

George Hopley, Michael Zenker

Abstract - US and Canadian gas consumers are averse to long-term physical contracts—the traditional mechanism for securing LNG in the world market. While North America will become increasingly reliant on LNG, without committing to this form of natural gas supply, it may not be available if needed in the years ahead. We highlight the risk that in any given period, LNG flows could fall to low levels, even zero, depending on events outside of North America.

Index Terms – Natural Gas; LNG;
[11]

I. INTRODUCTION

The US and Canadian natural gas market is wedded to spot transactions. This is partly a reaction to costly experiences unwinding long-term, reserve-based, bundled supply and transportation contracts that were well above spot prices a few decades ago, and partly a reflection of just how comfortable market participants have become in relying on the spot market whenever they need to buy or sell physical gas. The advent of financial hedging has allowed market participants to lock in prices, while continuing to conduct physical gas transactions on the spot market.

The liquefied natural gas (LNG) industry, by contrast, is wedded to long-term contracts. Two drivers are responsible. First, long-term contracts with credit-worthy off-takers were necessary to underpin the large capital investments for the first several LNG projects. Second, buyers who must depend on LNG and are thereby displacing other fuels, require dedicated upstream resources; liquefaction trains and tankers for assurance the gas will be there when needed. Want to draw a laugh at a gathering of overseas LNG buyers? Ask them to depend on “the market” rather than contracts to meet their needs.

There has been little progress bridging the commercial tendencies of these two worlds. The US and Canada (and the UK) attract supply with price, while Europe and Asia attract new supply with long-term contracts. But with most market observers (including Barclays Capital) expecting that LNG will need to fill a growing void in the North American supply picture in the years ahead, will price alone attract what North America requires? Maybe not.

Recent history has already demonstrated that flows of LNG to the US are not simply a function of the relative attractiveness of North American spot prices. The lack of US and Canadian commitment to LNG clashes with the obvious dependency that these countries will have on this new supply. Hoping that LNG will be there when needed is akin to flying standby for LNG – standby for a ship these markets must catch.

II. POWER SECTOR ALONE ASSURES THE NEED FOR LNG

Gas demand growth is challenging the gas industry to keep pace with new supplies. Even with moderate demand growth from the residential, commercial and industrial sectors in the years ahead, power sector demand growth alone will boost the need for gas. Electricity consumption has grown at an annual average rate of 1.3% per year so far this decade. With the latest round of new power plant capacity more than 90% gas-fueled, natural gas is serving a large and growing share of power sector demand growth. The outlook is for more of the same, with natural gas slated to serve the lion’s share of power plant additions ahead. Power sector use of gas should add an average of 0.75 bcf per day of gas demand each year in the rest of the decade ahead (Figure 1).

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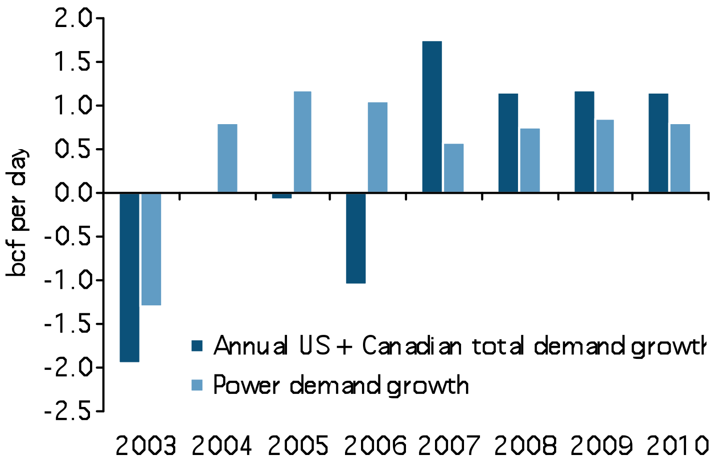


Source: EIA, Barclays Capital

Figure 1. Gas Consumption in the Power Sector

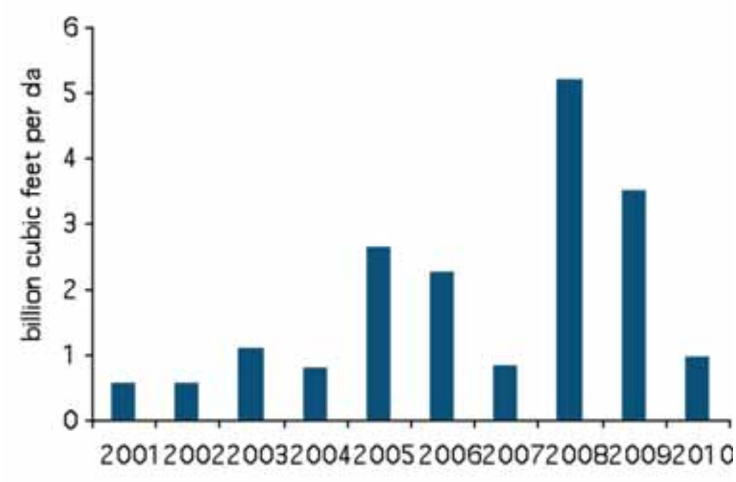
III. MEXICO TAKES A DIFFERENT PATH

Before focusing on this LNG dilemma, it is noteworthy that long-term contracts are being signed in North America – in Mexico. Facing the same gas-centric build-out of their power sector, and an acknowledgement that domestic gas resources would not meet power consumption growth, the power utility of Mexico turned to term LNG contracts to serve their growing appetite for natural gas.

IV. GLOBAL LNG SUPPLY BOOM IS UPON US

The expected reliance of the US and Canada on LNG conveniently parallels two significant events in the LNG industry. The first is a boom in global LNG supplies. These have grown 9 bcf per day since the start of the decade and are set to grow an additional 9 bcf per day by the end of the decade (Figure 2). The expected 5 bcf per day of LNG supply additions in 2008 would be the largest single year of supply additions in the industry’s history.

This boom in global LNG supply was facilitated by the second significant event – the intermediation of energy companies as supply off-takers for many new liquefaction projects. Sensing a growing global need for new LNG supply, a number of new supply projects were launched, with energy companies – rather than end-users – contracting for the new supply. The companies were often monetizing their own gas with the LNG projects. There is essentially no unsold LNG supply from liquefaction projects that are under construction. While committing to LNG supply without an end-use buyer may seem risky, the large, liquid US market provides a handy destination of last resort for any supply that does not otherwise find an end-user by the time the liquefaction project comes on line. This wave of LNG contracts without an end-user contract convinced some market observers that a significant share of this new supply would be focused on the US market, especially as US prices grew ever higher.



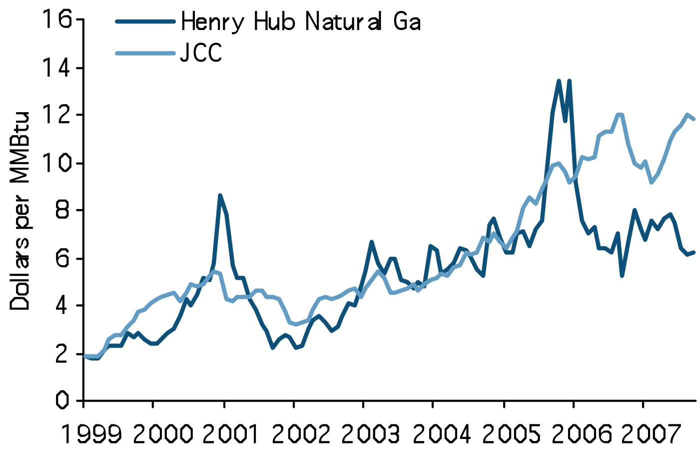
Source: EIA, Barclays Capital

Figure 2. Global LNG Supply Growth

V. OIL-INDEXATION, YEN AND EUROS ARE BETTER THAN HENRY HUB AND THE DOLLAR

We believe energy company intermediaries never intended to hold vast quantities of LNG supply for spot market sales. With global prices for natural gas remaining robust, and with strong demand growth for natural gas in non-North American markets, a growing number of new long-term contracts have allowed these energy companies to commit this LNG to end-users. Of course, these long-term end-user contracts allow the companies controlling the supply to reduce their risk, at prices that have proven to be desirable.

Beyond a wave of new, long-term LNG contracts to non-North American end-users, two additional powerful trends are driving LNG away from US shores. First, typical European and Asian long-term LNG contracts are linked to oil prices. With oil selling at an increasing premium to natural gas (Figure 3) oil-linked LNG in non-US markets carries an automatic premium to Henry Hub at current market levels. Many countries that import LNG do not have functioning gas markets; thus, prices must be linked to another commodity, typically oil. Oil-linked LNG provides buyers and sellers an opportunity to hedge. The second trend is the strength of the yen and euro compared with the US dollar, with the dollar declining 9% against the yen over the past three years, and falling 25% against the euro. While not all contracts are paid in local currency, any that are carry that added value as well.



Source: EIA, Barclays Capital

Figure 3. Growing Oil Premium to Natural Gas (Japanese Crude Cocktail (JCC) oil prices compared with US Henry Hub)

VI. STANDBY FOR LNG

With US and Canadian end-users averse to long-term physical contracts for LNG the risk remains that, without committing to LNG, it may not be available if needed in the years ahead. We believe it is unlikely that none would be available on a spot basis for a given sustained period in the years ahead, when we compare forecast non-North American gas demand with global LNG supply. Yet, there remains the risk that in any given period, LNG flows could fall to low levels, even zero, depending on events outside of North America. The point is clear: the US and Canada do not have control over LNG flows into their markets. Just like flying standby, if you want a seat, you need a reservation.

Does this mean that US and Canadian buyers should rush out to contract for LNG? Perversely, no, not now, owing to:

- Financial hedges combined with flexible, short-term physical supply offers fewer headaches for buyers and sellers.
- Some LNG contracts include marine risk (as part of force majeure); LNG tankers do not enjoy hurricanes, for example. This risk creates a challenge for some buyers.
- An energy supplier is more likely to offer a buyer portfolio gas rather than specifically LNG under a US-destined long-term physical contract.
- LNG is not necessarily cheaper than portfolio gas.
- If utilities continue to be judged on their purchase prices against the spot market, then a drought of LNG that pushes spot prices higher for everyone presents no inherent risk for a utility so judged.
- As discussed above, an increasingly smaller amount of LNG remains uncommitted. The opportunity available to sellers of Pacific LNG, for example, is a JCC-linked price. Never mind the challenge of overcoming US sentiments about long-term physical gas contracts. We know of no utilities that are interested in signing oil-linked LNG contracts.
- A long-term contract represents a tremendous contractual liability of a buyer’s balance sheet.

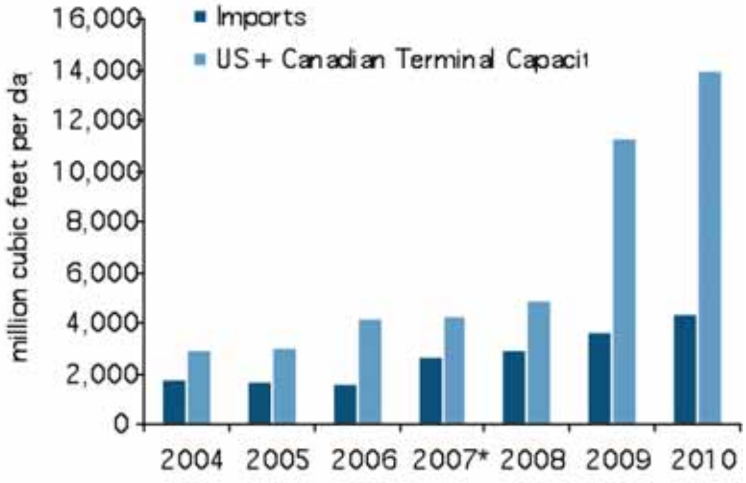
In response to these issues, some utilities have a free-rider approach: let others bring the LNG to market, enjoy the downward price pressure that results, and buy it on the spot market.

A few years ago, when energy companies were signing the wave of off-take commitments discussed above, they in turn mounted a global selling effort to place this supply, and a buyer’s market reigned. This was a time when firm LNG could have been purchased in North America at US-indexed, fixed, US-like, and even index-minus prices. The aversion to term contracts, however, largely prevented the signing of these contracts.

The tide has changed, and committing to LNG now means competing with global prices. Welcome to the sellers’ market for LNG.

VII. LNG IMPORTS TO REMAIN DE-LINKED WITH US SPOT PRICES

Our view is that global LNG supply growth will moderately outstrip non-North American consumption, allowing deliveries to the US to grow. Make no mistake, regasification capacity and shipping capacity pose no restriction to US imports. Regasification capacity, which will likely register substantial growth in 2008, should further outstrip available supply to fill it (Figure 4). Should economic growth boom overseas, particularly in Asia, then LNG deliveries to the US would dwindle far below the amounts shown in Figure 4. Conversely, faster pace of LNG supply growth or more moderate rates of gas demand growth in the other fifteen LNG consuming countries would boost deliveries to North America.

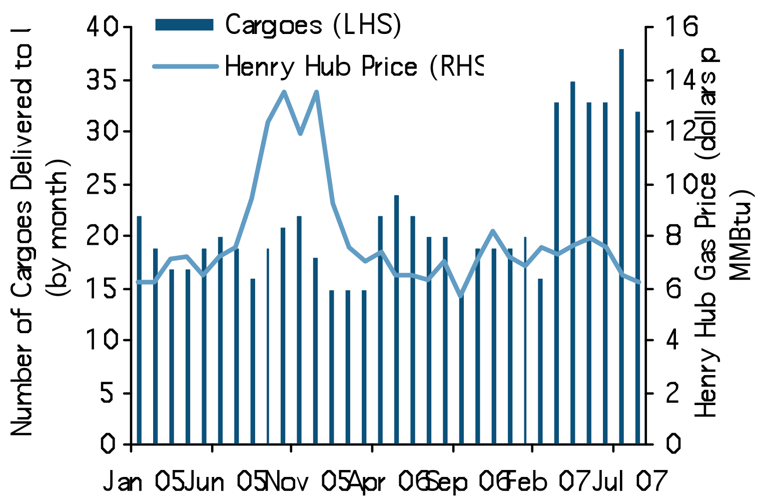


*Note: *Estimated. Source: EIA, Barclays Capital*

Figure 4. US and Canadian LNG Imports versus Regasification Capacity

It would be incorrect to simply add up all non-North American LNG supply contract volumes and assume these will not be available to the US and Canada. End-use LNG buyers contract for more supply than needed, allowing surpluses to be marketed in the spot market. Many energy companies that are more accustomed to spot gas market risk and have LNG supply positions have an interest in securing a stronghold in the US LNG market, in part because it offers diversity in their portfolio. New LNG contracts offer greater flexibility to divert cargoes. The large storage market in the US provides a ready destination for surplus volumes. There have even been modest signs of interest in buyers securing LNG supply, notably in California. Thus, a growing slice of LNG supply can be marketed on a spot basis to buyers.

In competition for these supplies will be any market in need. Asian markets, which typically clear on volume and not price, have shown a penchant to out-bid these spot cargoes away. European buyers have shown more price responsiveness, while the UK market operates much as the US and Canadian market, with spot pricing.



Source: EIA, NYMEX, Barclays Capital

Figure 5. US LNG Imports versus Gas Prices (Henry Hub)

This standby method of purchasing LNG attracts it to the US at some times, and not at others, as would be expected. Figure 5 illustrates the historical relationship between US pricing and LNG deliveries. As the figure shows, spot prices are obviously not the primary driver of flows into the US. Note the general trend in increased deliveries in 2007 was due to more available spot LNG supply, not stronger US prices. Thus, the machinations of the non-North American buying community determine flows into the US. These buyers have confirmed seats, and often first call on remaining seats, while the US and Canada remains on standby.

VIII. CONCLUSIONS

With US and Canadian end-users averse to long-term physical contracts for LNG the risk remains that, without committing to LNG, it may not be available if needed in the years ahead. We believe it is unlikely that none would be available on a spot basis for a given sustained period in the years ahead, when we compare forecast non-North American gas demand with global LNG supply. Yet, there remains the risk that in any given period, LNG flows could fall to low levels, even zero, depending on events outside of North America. The point is clear: the US and Canada do not have control over LNG flows into their markets. Just like flying standby, if you want a seat, you need a reservation.

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[2] New York Mercantile Exchange (NYMEX), available at www.nymex.com.

BIOGRAPHIES

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7. Natural Gas Market Dynamics and Infrastructure Development in South East Europe

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Abstract— In this article we expose the status and outlook of the market dynamics and its related infrastructure in the South East Europe (SEE). An important emphasis is given in the actual coalitions that will assist in the faster and more robust development of the gas sector in SEE, the existing infrastructure, the future projects that are under development on under study and the regulation that is needed in order to guide all the above. The ultimate goal to these developments is the creation of a common financial market in the SEE region. We close this article by stating some of the most sensitive factors that have to be taken into consideration in order to smoothly accomplish the common market between the countries.

Index Terms— Gas physical and financial market, gas interconnection projects, southeast Europe, Istanbul forum.

1. INTRODUCTION

South East Europe (SEE), during the last 5 years has demonstrated significant potential for development in the field of energy. More specifically, important projects and studies both in electricity and gas sector have taken place attracting investors of international activity. In the last 2 years, the strategic development in the abovementioned sectors have entered a significant period where the infrastructure and regulatory decisions from the SEE countries will define the energy map for the years to come.

2. CONTEXT AND STATUS

2.1 Common Market Concept – The Gas Forum in Istanbul

The countries of South East Europe are characterized by a low-level gas penetration. The use of power for heating is widespread in many of the region’s urban areas. This has been identified as a problem in the “Framework for Development of Energy Trade in South East Europe” as power is a relatively inefficient means of providing heat, and the use of power for heat in South East Europe exacerbates energy affordability problems. From an environmental perspective, substituting gas for power for purposes of heating would result in lower greenhouse gas emissions given that the dominant form of power generation in the region is and will continue to be lignite based.

One obstacle to increased gas penetration is the lack of gas market in the region. The prevailing of Russian gas monopoly has implications both for gas pricing and security of supply. Introducing competition to Russian gas through development of a gas market in the region would bring both price and security benefits. There is then scope for increased competition / diversification through transporting of Caspian gas across Turkey to SE Europe.

Recognizing the above-mentioned needs an Energy Community Treaty was created to develop a regional gas market. This Treaty is organized by European Commission and basically requires that SEE countries undertake gas sector reforms through development of regulatory frameworks and industry unbundling with a view to increased gasification in each state and establish an integrated regional energy market and progressively ensure its integration into the European

Community's Internal Energy Market.

The Istanbul Gas Forum was established in order to support development of a SE Europe Gas market and follow the implementation of the Treaty. The Gas Forum in Istanbul is to the countries of South-East Europe what the European Gas Regulatory Forum in Madrid is to the EU countries. The aim is to facilitate development of a regional gas market and bring Caspian gas into the Balkans region, the key element being to establish a surer supply of gas for the Union. This is not only because Europe will have access to new sources from the east but also because the new market will operate according to the EU's own rules reflected in the newly-created energy community in South-East Europe.

The Energy Community Treaty that was signed in Athens represents the achievement of the largest internal market for electricity and gas in the world, with effectively 34 participating parties: the 25 European Union Member States and Croatia, Bosnia and Herzegovina, Serbia, Montenegro, Albania, the Former Yugoslav Republic of Macedonia, Romania, Bulgaria, and UNMIK Kosovo. Negotiations with Turkey are ongoing. Moldova, Ukraine and Norway have applied to join, but for the moment are observers.

With respect to the regional natural gas market, the participants commit themselves to establish common rules for all market activities mainly for transmission, distribution, supply, storage of natural gas and adopt the rules relating to the organization and functioning of the natural gas sector, access to the market, the criteria and procedures applicable to the granting of authorizations for activities and the operation of systems as those laid down in Directive 2003/55/EC, and will provide a timetable for doing so.

The Gas Forum in Istanbul comprises representatives of the European Commission, governments, regulators and transmission system operators of the countries of South East Europe, the Council of European Energy Regulators (CEER), the European Transmission System Operators (ETSO), representatives of donors, gas producing companies, and consumers. The Forum is co-chaired by the European Commission and a representative of the president in office.

The Gas Forum has created a regional plan with the following objectives:

- To implement national gas market reform in all signatory countries
- To implement international best practice in the wholesale gas markets and to facilitate cross-border trade
- To create regional and national gas markets, in part to reduce the environmental impact of existing thermal plants; and,
- To secure supplies for the region and the EU through the creation of a seamless integrated market between Vienna and Ankara.

2.2 Actual Situation of the Gas Market in SE Europe

The countries of the South East Europe are neither major natural gas producers nor consumers. Although the region does hold some fossil fuel deposits, these resources are not significant on a world scale. The gas market in the region is relatively underdeveloped considered as a whole, but this masks wide difference between the Eastern Balkans through into Turkey, and the Western Balkans through into Albania. In the Eastern Balkans and Turkey, gas use is either mature (Romania) or rapidly developing (Turkey and Bulgaria). In the Western Balkans, gas supply to Albania, Bosnia and Herzegovina, Croatia, FYROM, Montenegro, Serbia and UNMIK Kosovo is either underdeveloped or non-existent or has fallen into disuse (Montenegro and UNMIK have no gas infrastructure at all).

In the weighted average share of gas in primary energy supply is very close to that of EU Members average. However this average hides significant variances throughout the region.

Romania has the largest share in the region where Albania, Bosnia & Herzegovina and FYROM have the lowest share (excluding Montenegro and UNMIK as no gas usage).

Natural gas is mainly used in industry and partly in power generation in the region (except in Bosnia and Herzegovina in which it is used in residential and commercial sectors and in Turkey in which it is used mostly for power generation).

Most of the countries import natural gas only from Russia. Only Turkey has diversified their sources of supply, and only Romania, Croatia and Serbia have some domestic reserves.

Regarding the legal regulatory framework of the region; all the countries in the region have their respective independent Regulators. Most of the countries in the region have opened their markets, by completing their legal framework, creating conditions for participation of the private sector and identifying at least some eligible threshold. However, competition has not been fully introduced into region yet as the current monopolistic structures still prevails in most of countries.

Most of the Transmission System Operators and Distribution System Operators are in the process of legal and managerial unbundling. Accounting unbundling is foreseen for almost all activities. Access to domestic pipelines is regulated in most of the countries in the region. However, as far as the transit network is concerned, access is in principle regulated in some countries of the region and is negotiated in others.

In most Countries, postage stamp methodology is being or is expected to be used for transmission. Tariffs are mostly determined and/or approved by Regulatory Authorities. However it is not yet clear whether such tariffs, as well as other features of third party access regimes in the region (with the exception of Romania) are suitable for the development of competition. In fact they are not used due to the lack of competitors.

While several pipelines physically link several countries, their transit rights are almost entirely attributed to long-term contracts for import from external sources. As a consequence, none of the countries has access to the other’s market or facilities that may boost security of supply, like domestic production fields, storage plants and LNG terminals.

2.3 Final Goal: Creation of a Financial Common Market similar to the NW Europe

The above-mentioned status and efforts have ultimately as a goal to reach. This is described by the creation of a financial common market similar to the one that NW Europe has. Such a result will lead to all the benefits of a common market. Nevertheless a series of considerations have to be made and a steps to be taken in order to make the latter possible.

Firstly, improving the balance between energy supply and demand is crucial to improve and sustain economic development in South Eastern Europe. This requires a strong legal commitment by the countries of the region towards market oriented reforms, regional integration and sustainable development, and investment security. This will offer significant advantages both in terms of improved utilization of existing supply and production capacities, but also in fostering more cooperation and integration in the region, which would result in economic growth, stability and investment.

Secondly, the security of supply of the European Union is based on diversifying supply of gas and in being politically able to counter threats to energy disruption in the European Union. By connecting this strategic area with the internal energy market, this will assist in assuring both the European Union’s security of supply and that of the region.

The destruction of the energy infrastructure in the region during the wars of the 1990s and the economic fall-out following the break up of the East-West divide have had tremendous effects on the security of supply in this region.

The Energy Community Treaty was consciously modeled on the European Coal and Steel Community that is the basis of the European Union. The Treaty seeks to allow the states of postwar South East Europe to agree on one area of policy and then to develop in a shared outlook. The Energy Community Treaty is a key element of the EU strategy in South East Europe and an effective pre-accession tool as it aims to extend the benefits of the Internal Energy market before the states of the region may become members of the European Union.

The European Union is in the process of rapidly completing the internal electricity and gas markets. There are strong arguments for extending the internal electricity and gas markets outside the borders of the European Union, but the creation of a level playing field and equivalent environmental and safety standards is a central element for a wider European electricity and gas market to function effectively. The process of inclusion of such countries goes considerably beyond simple questions of open trade between the European Union and its neighbors under more general international trade obligations. It involves the active creation of a real integrated market, free of any barriers. Practically, in South East Europe that means creating a local regional market and designing it so that it seamlessly will fit into the general framework of the European Union's Internal Energy Market.

The final goal is to achieve the fluidity level of the electricity and gas markets of NW Europe where many energy trading transactions occur every day promoting the gas to gas competition and resulting to the lowest European gas prices in the wholesale gas markets such as the prices in UK, Holland and Belgium.

To achieve this goal the Energy Community Treaty has three operational parts:

- Firstly, the treaty will extend the application of the energy, environmental, renewable, competition and other parts of the acquis communautaire (legislation and rules decided at EU level). This will create a level playing field, though there will have to be credible, effective and policed transition dates.
- Secondly, the treaty will create regional mechanisms that extend into the European Union to allow for deeper integration of local energy markets. This will for example mean enabling regulation allowing for accelerated infrastructure development, in particular for gas pipelines (especially new connections to the Caspian Sea and the Middle East).
- Thirdly, given that the idea of a common energy market is central to the Energy Community, there is agreement to work toward common policies for external trade, mutual assistance and the removal of internal energy market barriers.

The Energy Community Treaty provides that the states will:

- implement electricity and gas tariff reform plans;
- implement all necessary technical standards, such as grid codes, accounting systems and information exchange for the operation of the grid;
- implement effective third party access to infrastructure;
- create National Regulatory Authorities and transmission system operators;
- develop local solutions to pressing problems of regulation, energy poverty and social equity, and
- implement the gas and electricity directives.

3. ACTUAL INFRASTRUCTURE

3.1 Transmission, Storage and Distribution Capacity

Natural Gas Transmission network is relatively underdeveloped in the region. Only Romania has well developed transmission network. Bulgaria and Croatia have slightly developed transmission networks where in Albania, Bosnia-Herzegovina and FYROM is very limited and partly developed in Serbia and Turkey.

The NG Transmission infrastructures are owned and operated by state companies. On the other hand network in the EU-ECSEE Countries is well developed, excluding Greece.

Bulgaria, Croatia, Romania, Serbia and Hungary have underground storage with a total working Gas capacity of 7’500 mcm from which only Romania and Hungary have 6’000 mcm of storage working gas capacity. Turkey and Greece have LNG Terminals. Turkey has 2 LNG Terminals and Greece 1.

NG Distribution networks are relatively underdeveloped in the region. The distribution lines per capita index are significantly high in Croatia and Serbia. In all other Non-EU ECSEE Countries the distribution network is under fast development. The distribution companies are mostly privately owned. Infrastructure in Hungary only is very well developed.

Sizeable total market is 47.5 bcm/year in Non-EU ECSEE Countries and 103.4 BCM/year in EU-ECSEE Countries (Italy, Hungary, Austria and Greece).

In the Non-EU ECSEE Countries, the weighted average share of gas in primary energy supply is 23.8%, which is very close to that of EU Members average (24%). Gas markets in Austria, Hungary and Italy feature high levels of per capita consumption and low expected growth rates; hence they can be regarded as mature markets. Among Non-EU ECSEE Countries the only relatively mature gas market in the region is Romania. On the other hand per capita gas consumption in Greece and Non-EU ECSEE countries except Romania is in general significantly smaller.

Greek, Turkish, Serbian, Bulgarian and Croatian gas markets are expected to develop rapidly. In the remaining countries of the region gas consumption has either just started recently or is very little developed. Turkey and Romania consume 83% of the total consumption.

Natural Gas is mainly used in industry and partly in power generation in the Non-EU ECSEE and Greece. In more mature EU-ECSEE Countries consumption patterns are more mixed.

3.2 Regulatory Framework, Market Transaction and Players

Most of the countries in the region have opened theirs markets, and identifying at least some eligible threshold. However, competition has been introduced into EU ECSEE Countries and Romania (except Bulgaria), but in all other countries current monopolistic structures still prevail.

All the countries in the region have their respective independent Regulators. TSOs and DSOs are in process of legal and managerial unbundling. Accounting unbundling is foreseen for almost all activities. Access to domestic pipelines is regulated in most of the countries in the region. However, as far as the transit network is concerned, access is in principle regulated in some countries of the region and is negotiated in others.

In most Non-EU-ECSEE Countries, postage stamp methodology is being or is expected to be used for transmission. Tariffs are mostly determined and/or approved by Regulatory Authorities. However, it is not yet clear whether such tariffs, as well as other features of Third Party Access regimes in Non-EU ECSEE countries and in Greece (with the exception of Romania), are suitable for the development of competition. In fact they are not used due to the lack of competitors.

The average declared market opening is 61% in Non-EUCSEE countries. This may be compared with 94% of EU-ECSEE Countries.

All Non EU-ECSEE Countries started to open their markets except FYROM and Bosnia & Herzegovina. In EU-ECSEE countries all countries opened their market.

The Wholesale supply monopoly exists in most countries. No pipe-to-pipe competition and the Gas industry are regulated in all countries. The major players are the vertical integrated national gas companies in most countries.

3.3 Actual Technical Problems for Infrastructure Development

The inadequate gas infrastructure in all domains (transmission, distribution and storage) is based on the following:

- The domestic resources are limited (except Romania),
- No diversification of external supplies, including LNG where appears the phenomenon of the NIMBY problem,
- Non-EU ECSEE countries as well as Greece have no access to each other's markets or facilities that may boost security of supply, like domestic production fields, storage plants and LNG Terminals,
- The geology of the region where the major part of the territory in the region is covered by high mountain chains, and
- Poor experienced construction and manufacturer local companies in the gas industry (piping manufacturer, special machinery for construction etc.)

4. FUTURE DEVELOPMENT

4.1 Gas Projects Development

The energy industry, represented by OGP (International Association of Oil & Gas Producers), made a detailed presentation on the natural gas export potential from the Caspian basin and the Middle East to South-East Europe. OGP believes that the Caspian Region holds 6% of the world's natural gas reserves, with 12’240 bcm, representing 178 years of gas supply at the current rate of production (148 bcm/year). Forecasts predict that production will double in 15 years. OGP also presented statistics and forecasts for Iran which possesses 27’500 bcm of natural gas but which consumes slightly more than the 85.5 bcm of which produces on annually. Together, Iran and Iraq could supply more than 100 bcm/year to the export potential of the Caspian Region. Currently the gas production from the Caspian Region is between 80 and 100 bcm/year. In comparison, the EU consumes approximately 500 bcm/year, 55% of which is imported.

Infrastructure feasibility studies until now have dealt with four projects. The first being the Nabucco project linking Turkey with Austria via Bulgaria, Romania and Hungary. According to the World Bank, it is the most advanced of the projects and is "not considered to be in competition with the other projects". A second project is to link Bulgaria with Serbia and a third, piloted by Edison Gas is to link Turkey with Italy passing through Greece but not Albania. In competition with this is a fourth project, piloted by the Swiss utility EGL with the intention of linking the Greek network with Italy, but this time via Albania. A fifth project, the "West Balkan connector" still in the study phase, will connect Greece with Slovenia via the FYROM, Serbia, Bosnia-Herzegovina and Croatia. All these projects will be examined by the World Bank and judged according to the benefits that they could offer the region. Consultants for the World Bank also proposed a list of twenty cities for detailed study as regards potential for gas distribution network development.

A lately announced project by the Russian Gas Giant Gazprom and ENI is the South Stream Pipeline. This pipeline will cross the Black Sea from East (Russian Cost) to the West (Bulgarian Cost) bypassing Turkey and connected to the Bulgarian Gas Grid. From this grid it will be spitted into two sub-streams: The south sub-stream will be connected to the gas grid and with the usage of the IGI Interconnector will bring Russian gas quantities to Italy and then to Europe. The north sub-stream will be routed to Austria via Serbia, Romania and Hungary. This last project will be in competition with the “Nabucco” project.

The List of the 10 major Gas Projects in SE Europe is as follows:

TABLE I – B AJOR PROJECTS IN SE EUROPE

Planed/Proposed Gas Routes	Length (km)	Capacity (bcm/year)	Sponsor	Cost (mill)	Stage

1	South Caucasus Pipeline	960	7,1 - 22	BP-Statoil	900 $	In Operation
2	Turkey-Greece Interconnector (TGI)	285	3,6 - 12	Botas-DEPA	280 $	In Operation
3	Greece-Italy Interconnector (IGI)	804	8 - 12	Edison-DEPA	1300 $	Advanced Study (exp2011)
4	Nabucco (TR-BUL-ROM-HUN-AUS)	3400	25 - 30	Botas-Bulgargas-MOL-OMV	4400 €	Advanced Study (exp2012)
5	Hungary-Romania Interconnector	55	0,5-2	Trnasgaz	20$	
6	Serbia-Bulgaria Interconnector	230	3	Bulgargaz-NIS		Study
7	Trans Adriatic (N) (BUL-M-AL-IT)			EGL+		Study
8	Trans Adriatic (S) (GR-AL-IT)	570		EGL		Study
9	Western Balcan Corridor			Relevant Countries TSO		Study
10	South Stream (RUS-BUL-GR-SER-HUN-AUS	900	30	Gazprom-ENI	1000 €	

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4.2 Regulation and Liberalized Market Development

Most benefits can only be achieved through a single common market, as most national markets in the region are too small.

Some of these benefits are:

- Negotiating for import supplies,
- Diversifying of gas sources,
- Ensuring security of supply through use of storage, interconnection and LNG facilities of each country,
- Exploiting economies of scale in gas transportation,
- Matching excess supply with excess demand markets in the short and long run, and
- Developing new long distance transmission infrastructure.

Consistently with the experience of the EU market opening according to the Directives 98/30/EC and 2003/55/EC, further research and regulatory effort should in particular address the following issues, with a view to ensure their necessary harmonization and their compatibility for a common market:

- Authorization and licensing regimes for existing and new transportation infrastructure,
- Technical standards and other obstacles to cross border exchanges, in comparison with the EASEE-gas process in the EU,
- Legal, fiscal and tariff barriers to cross border trade including destination clauses and other commercial restrictions
- Independence and responsibilities of national market regulators,
- Stability, predictability and accountability of the regulatory framework,
- Regulated access to transmission, distribution and (at least in the medium term) storage and LNG facilities,
- Impact of existing and new long term contracts on competition in the region,
- Infrastructure capacity information and allocation criteria,
- Infrastructure financial viability under competitive conditions,
- Implementation of cost-reflective (preferably entry-exit) pricing mechanisms of transmission,
- Economically sound fair and non discriminatory public service obligation criteria,
- Legal and management unbundling of transmission and distribution operations,
- Criteria for release and availability of unused capacity,

- Promotion of gas consumption through environmentally consistent fiscal and regulatory policies,
- Increased cooperation and trade among ECSEE countries, and
- Promotion of measures to ensure security of supply on a non-discriminatory basis

5. CONCLUSIONS

In this article we have presented the actual status of the gas market in the SEE. More specifically we have given the emphasis on the actual coalition that assist the development of the gas market, the existing infrastructure, the future projects and the regulation that is currently set in palace. We have stretched the importance of the existence of a common market in order to assist the infrastructure development in the region. In the same order of importance, the balanced development of infrastructure will enable the creation of a common financial market.

Nevertheless, there is a fine geopolitical balance defined by US and Russian interests that are directly depicted from the projects under construction or study. More over the provenance of funds from very different sources such as international organizations, countries, investment funds and utilities define an uneven order of priorities that might have a negative effect on the overall development of projects. Hence there is a very delicate task submitted to all commissions, forums and boards that govern and supervise the process of development where a set of technical specifications and plans defining the projects have to be combined with tensed geopolitical situation.

6. REFERENCES

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7. BIOGRAPHIES

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