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World Natural Gas Markets and Trade: A Multi-Modeling Perspective

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WORLD NATURAL GAS MARKETS AND TRADE: A MULTI-MODELING PERSPECTIVE

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GUEST EDITOR

HILLARD G. HUNTINGTON
Executive Director, Energy Modeling Forum
Stanford University

THE ENERGY JOURNAL

SPECIAL ISSUE

WORLD NATURAL GAS MARKETS AND TRADE: A MULTI-MODELING PERSPECTIVE

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Preface

It is a great pleasure to introduce this Special Issue of *The Energy Journal* which focuses on modeling of natural gas markets. The issues that are addressed are complex, the analyses intricate, and the findings often subtle and nuanced. The authors draw upon an extensive tool-kit ranging from equilibrium models to game theory to non-stationary econometric models in an ambitious effort to improve our understanding of these markets. Even a casual review of these papers will bear substantial fruit for the reader. A deeper reading will yield a plentiful harvest indeed.

The volume consists of papers by twelve research teams that participated in a recent Stanford University Energy Modeling Forum (EMF) study of international natural gas markets and trade. A number of the papers apply a world or regional model to one or more important strategic or policy issue. Others discuss important analytical issues, such as market power, interregional natural gas prices or North American supply conditions.

This Special Issue would not have been possible without special funding from StatoilHydro and the encouragement and advice of their Natural Gas Market Analysis Department. EMF and study participants wish to express their deep appreciation for this support. Public dissemination of the ideas embodied in this volume is essential if models are to become more credible and useful for decisionmaking.

Broad-based, independent research requires continued support over extended periods of time. The Forum also wishes to gratefully acknowledge the generous and long-standing support of the following organizations: American Petroleum Institute, Aramco Services, BP America, California Energy Commission, Central Research Institute of Electric Power Industry (Japan), Chevron, Duke Energy, Electric Power Research Institute, Électricité de France, EnCana, Environment Canada, Exxon Mobil, General Motors, Lawrence Livermore National Laboratory, Ministry of Economy, Trade and Industry (Japan), Natural Resources Canada, Southern Company, SUEZ Energy North America, U.S. Department of Energy and U.S. Environmental Protection Agency.

Adonis Yatchew
Editor-in-Chief, The Energy Journal

Natural Gas Across Country Borders: An Introduction and Overview

*Hillard G. Huntington**

In the last several years, market forces and institutions have transformed international natural gas markets in fundamental ways. Natural gas today is relatively easy to transport over water, and an increasing volume of purchases flow through the spot market. As trade grows, regional prices start to move with each other. Although one does not need formal modeling to describe these new developments, it is also evident that the modeling process improves our basic understanding of how these trends reshape the natural gas outlook.

1. INTRODUCTION

Around the globe, natural gas consuming markets are adjusting to limits on their own resources and the need for additional supplies from beyond their borders. These conditions have ushered in a flurry of new building of pipeline infrastructure and liquefied natural gas (LNG) plants.[1] As natural gas trade grows and expands into new producer and end-user markets, regional prices will adjust to the

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* Executive Director, Energy Modeling Forum, Stanford University; email: hillh@stanford.edu.

The author gratefully acknowledges the helpful comments of a unanimous referee. He also appreciates many useful insights from the very open and productive collaboration of the Energy Modeling Forum 23 working group participants, many of whom are authors in this special issue. Importantly, the usual disclaimers apply; the views in this chapter are the author's responsibility.

1. Jensen (2003) discusses the prospects and key market barriers to the evolving liquefied natural gas trade, while Victor *et al* (2006) evaluate political economic trends underlying this market transformation. The latter also includes two chapters by Hartley and Medlock (2006a, 2006b) that describe their initial efforts to represent world natural gas markets with the same model they discuss in this volume.

new market balances.[2] Strong, well-integrated natural gas markets will have significant implications for the success of policies geared towards mitigating greenhouse gas emissions. Decision makers and analysts can no longer ignore the interregional and dynamic interrelationships that are growing within this industry.

This volume includes papers prepared by international natural gas modelers and other natural gas experts who participated in a recent Stanford University Energy Modeling Forum (EMF) study on this topic. A previous report discusses the main conclusion of the EMF working group (Energy Modeling Forum, 2007). Each modeling team simulated scenarios with standardized assumptions and reported back to the group common output variables. Comparison of these results led directly to a range of different conclusions about the future natural gas market as well as the current state of the available analytical frameworks. For the most part, the scenarios represented constraints on various supply options (like Russian or Middle Eastern export capacity) or more vigorous demand or economic growth around the world.

Two results from this study appeared to be quite pronounced and bear some repeating here. First, restricting the total amount of natural gas trade may not be the best approach for achieving energy security. There appeared to be broad agreement that security could be achieved more effectively by expanding an efficient, integrated natural gas market. This development would particularly be the case if it fostered many different supply options with varying risks of being interrupted by surprise events or geopolitical interests. And second, long-run price paths will tend to be more resilient to (and change less with) shifts in underlying supply constraints or demand growths in the future than they are today. The key determining factor in each model was the response of producers and consumers to price deviations from one scenario to another. Higher responses created smaller adjustments in these long-run price paths. Generally, a model that showed smaller price changes for one set of exogenous changes in market conditions also indicated smaller changes in other cases.

Rather than asking each modeling team to repeat exactly what they did in the study, the editor decided to ask them to produce an interesting paper based upon their model. Thus, the range of issues is wider than what the working group considered in the study. Since much of the work and interesting discussion also included other analyses that did not quite fit neatly into a "model", we have supplemented these modeler papers with supporting analyses that provide a broader appreciation of this growing trend in the natural gas industry.

2. Market integration began in the United States, after nearly six decades of complicated field price regulation and controls on transmission access (MacAvoy 2000). De Vany and Walls (1993) and Walls (1994) noted the trend towards price convergence between some U.S. regions after the Federal Energy Regulatory Commission established more open transmission with Order 436 in 1985 and resolved take-or-pay contracts with Order 500 in 1987. Beltramo, Manne, and Weyant (1986) offered an early spatial model for the North American model and discussed implications for Canadian export policies.

2. MODELING FOR INSIGHT

The volume begins with a contribution by Robert Stibolt, who reflects upon his long experience in supporting corporate decisions about large energy projects. An energy model cannot be credible and useful in a corporate setting unless it is based upon certain principles. Stibolt discusses in turn these principles, starting with a perspective that is decision-focused, embraces uncertainty, is fact-based, can navigate the complexity of systems, and recognizes the important distinction between insight and unattainable precision. Reflecting upon the most recent experience on Wall Street, he argues that the financial collapse demonstrated not so much a failure of models as a failure of thought. Models provide useful insights, but they do not replace thought nor can they be used indiscriminatingly for establishing precise forecasts. The danger lies not with using models but rather in using them without careful attention to their limitations.

The second article by Dale Nesbitt and Jill Scotcher follows this same theme by demonstrating how a simple spatial framework can generate powerful conclusions about integrated energy markets. They initially show the fallacy of applying network pricing to any pair of supply and demand regions in an energy market. Network pricing requires that the particular supply-demand flow is within the realm of being economically competitive. Next they show that local supply or demand perturbations in one region will have global effects and permeate throughout all regions if the market is well integrated. Transportation costs also significantly influence the outcomes, but perhaps in unexpected ways. A global reduction in transportation costs may raise prices in many production areas and reduce prices in many demand centers. If the story stopped there, it would be interesting but hardly surprising. The Nesbitt-Scotcher analysis shows that lower transportation costs shifts the relative advantage of different transportation links. Links that were previously high cost now gain a relative advantage with a uniform percent reduction in transportation costs. And finally, the analysis shows how specific constraints alter the conclusion relative to a workably competitive market. A congested transmission system or a monopolist controlling a segment of the transmission line can push prices up well above competitive levels. This paper unfolds some of the mystery behind spatial models, which the other papers in this special issue use to explore a range of pressing industry problems.

3. COMPETITIVE WORLD MARKETS

The next four papers explore a range of interesting results from world natural gas models. The first three models represent regional supplies and demands in workably competitive markets. The various nodes are linked by explicit pipeline and LNG infrastructure. Natural gas trade and regional prices are inextricably linked in these systems. Increased trades along certain corridors cause supply and demand conditions to rebalance. More trade causes a realignment of regional prices. Gas on gas competition emerges as a driving factor in world natural gas markets.

Finn Aune, Knut Rosendahl and Eirik Sagen use a numerical model of international energy markets (coal, oil and electricity as well as natural gas) to explore key features of the growing natural gas trade. These authors expect lower LNG costs to continue expanding LNG trade and spot purchases into demand regions like the United States and Europe with growing import requirements. Their framework contains considerable detail on regional natural gas production and international gas transport. A key finding in their analysis is the critical role of Middle Eastern natural gas supplies. Unconstrained by political factors, regional natural gas prices around the world may not experience much upward movement from current levels. If policies and other factors restrict the development of these Middle Eastern supplies, however, consumers around the world will see substantially higher prices.

Justine Barden, William Pepper and Vineet Aggarwal analyze the effects of higher oil prices on world natural gas markets. Higher oil prices lead to higher production and consumption of natural gas regardless of constraints on future gas-to-liquid (GTL) capacity additions. When GTL capacity can be easily built, however, higher oil prices cause more natural gas production to be shifted towards the production of diesel fuels. Natural gas prices rise under these conditions, causing reductions in natural gas consumption by powerplants and industrial users, who instead shift to less expensive fuels. Oil and natural gas prices will be more closely linked in the long run when the development of the GTL infrastructure is relatively less constrained.

Russia currently supplies large volumes of natural gas to Europe, is well-situated to satisfy rapidly expanding demand in Northeast Asia, and has extraordinary potential for developing new resources in the future. Peter Hartley and Kenneth Medlock explore the likelihood that Russia will dominate this industry's future with a large model of the world natural gas market with considerable detail on competing supply and demand regions. They conclude that Russia's advantageous position does allow them to influence natural gas trade flows and gain excess rents in the near term. The difficulty will be that these efforts will be offset by significant and sustained losses in the longer term. The developing global market for natural gas implies that disturbances in one location are spread across the globe in the same way as articulated in the article by Nesbitt and Scotcher. Interregional competition will become intense if Russia exerts its market power too aggressively. Additionally, producers will delay their investment strategies to extract resources more fully in later periods. They also highlight the Middle East as a possible counterweight to Russia. Coordinated action by Russia and the Middle East could therefore be a much more significant threat to the energy security of the rest of the world. These conditions emphasize that the countries of Western Europe, Northeast Asia and North America have a common interest in promoting the development of an efficient worldwide market with multiple natural gas supply options.

In contrast to the competitive markets represented in other world modeling systems, Ruud Egging, Franziska Holz, Christian von Hirschhausen and

Steven Gabriel discuss the results of simulating a more collusive behavior by some natural gas producing and exporting countries. This possibility is widely discussed in the popular press by reference to a country grouping called the gas producing and export countries (GASPEC). These authors employ a dynamic, strategic representation of world gas production, trade, and consumption between 2005 and 2030 that allows capacity investments to be determined endogenously by market conditions. Their results suggest a much stronger impact on European and North American delivered natural gas prices (15-20%) than in the workably competitive frameworks. Their analysis reveals that much of the consumer surplus transferred away from these major demand centers flows to natural gas producers outside of the cartel. These producers receive higher natural gas prices that result from the strategic behavior of cartel members.

4. STRATEGIC BEHAVIOR WITHIN EUROPEAN MARKETS

The Egging, et al, analysis provides an interesting transition to the European natural gas models, which invariably discard the assumption of workably competitive markets in favor of strategic behavior by one or more sets of actors. The adoption of this modeling framework by European groups reflects as much current energy market conditions as it does any deep-set philosophical orientation about modeling. Natural gas trade within Europe is dominated by a few major gas-producing regions. Russia contributes about 30 percent of current supplies to the continent (depending upon how one defines "Europe") and nearly half of all supplies to one of the principal countries, Germany. In addition, large, strategic firms often dominate transactions within individual countries like France and Germany. It is difficult to argue the benefits of a workably competitive framework in markets where trade and internal operations are often managed by strategic interests.

Wietze Lise and Benjamin Hobbs explore many of these issues further with a dynamic spatial model that encompasses endogenous decisions about when and how much to increase transport and storage capacity. They explore the opportunity for large gas producers to exercise market power in a world with higher oil and natural gas prices. Using a dynamic gas market model that accounts for demand, supply, and investments in pipeline transport, LNG, and storage, they explore the competition between regions as well as the dynamics of transportation and storage capacity adjustments that can influence market power opportunities in regions with growing demand. They conclude that Russia has the most incentive to exercise market power. This strategy will increase regional price differences within Europe and encourage pipeline and storage construction across the continent. They repeat and emphasize a theme developed by Stibolt in the opening article. Structural and parameter uncertainty pervade many equilibrium models. As a result, they should be used to explore basic insight from considering different scenarios and assumptions rather than to develop point projections.

Franziska Holz, Christian von Hirschhausen, and Claudia Kemfert simulate the European natural gas market effects through 2025 associated with the

EMF 23 reference case and alternative scenarios. They use a strategic model of European gas supply that evaluates competition at several layers: upstream natural gas producers, traders in each consuming European country (or region), and final demand. They report modest changes in the overall natural gas supplies to Europe, indicating that current worries about energy supply security issues may be overrated. Future LNG trade will likely increase faster than other European natural gas imports. This expansion means that Russia will not significantly increase its dominance of the European imports. Even so, the Middle East will continue to be a rather modest supplier, while the United Kingdom market will successfully transform itself from a natural gas exporter to a market with diverse supplies of imports. Congested pipeline infrastructure, and in some cases LNG terminals, will remain a feature of the European gas markets, although these problems will diminish somewhat.

Declining indigenous resources in the United Kingdom and the Netherlands will force the European natural gas market to become more dependent on a small number of large exporters, who may respond by exercising their market power. Gijsbert Zwart explores this two-way interaction between resource constraints and market power. Finite resources means that producers who extract now will reduce their future opportunities to sell later. If large producers can escalate market prices above marginal costs, their decisions will have different implications for pipeline gas suppliers, indigenous European resources and LNG infrastructure. The article focuses considerable attention on the short and long-run implications of the growing LNG trade within Europe. Constraints on LNG availability may lead to short-term reductions in output by competing suppliers, if they believe that these constraints will endure and drive future prices and returns higher. When large producers exert less market power, indigenous resources are depleted slightly faster. Zwart concludes by emphasizing the future need to incorporate the LNG market endogenously to conditions in both European and other regional markets.

5. ATLANTIC PRICE CONVERGENCE

The next two articles focus on the relationship between North American and European natural gas prices over the last 10 years, a period when LNG trade was expanding and markets were becoming more integrated. The ability to divert cargo from one market to another should result in some convergence of prices in the two major markets.

The weekly prices evaluated by Brown and Yücel indicate coordinated movement in natural gas prices across the Atlantic. These results could be evidence that LNG shipments were directly causing this apparent price arbitrage. Before accepting this hypothesis, however, the authors consider the relationship between natural gas and crude oil prices on each side of the Atlantic. They find a long-run relationship between the two fuels in each market. Although natural gas and crude oil prices do not equate at any particular BTU price, natural gas prices

do move with crude oil prices. Any short-run deviation from the long-run attraction between the two fuel prices would cause natural gas prices to adjust gradually over time. This latter result suggests the possibility that crude oil prices may be the facilitating mechanism that makes natural gas prices on both sides of the Atlantic appear coordinated.

The daily price series used by Anne Neumann are also consistent with regional price convergence across the Atlantic. She applies a methodology (Kalman filter) that allows the coefficient for price convergence to vary over time, because market integration evolves over time rather than occurs immediately in one period. Henry Hub prices for the United States and National Balancing Point prices for Europe converge towards the law of one price, where the price difference is largely due to transportation and transaction costs. Like Brown and Yucel, she also adjusts for the price of oil. She removes the effect of residual fuel oil prices from the original natural gas prices and provides a decorrelated time series for each natural gas price. A convergence process is less evident with these decorrelated series, but she concludes that there still is some evidence that natural gas prices on both sides of the Atlantic do move together directly as a result of the expanded LNG trade. That is particularly the case in the winter months. Taken together, these last two papers suggest that one must account for the relationship between natural gas and crude oil prices in trying to establish price convergence for natural gas.

6. RESERVE APPRECIATION FOR DOMESTIC SUPPLIES

North America's recent natural gas experience underscores the important role played by domestic supplies, particularly those produced from shale formations. If domestic supplies are more available and respond more strongly to price than expected otherwise, these developments could reduce the net demand for new imports through pipelines and LNG projects. Although data on shale developments is relatively limited, one of the cheapest and most important sources of supply is reserve appreciation, i.e., reserve growth in known fields. Kevin Forbes and Ernest Zampelli employ a rich database from the United States Minerals Management Service (MMS) to estimate the growth in reserves from over 500 known gas fields in the federal offshore waters of the U.S. Gulf of Mexico (GOM) over the period 1975 through 2003. As of 2003, these fields had annual production of approximately one trillion cubic feet (Tcf) or more than twice the level of LNG imports into the United States. They estimate the annual growth rate in a gas field's natural gas reserves as a function of the age of the field, its initial size, the real price of natural gas, water depth, and a set of unobserved field-specific factors that do not vary with time. These unobserved factors represent a particularly challenging econometric problem, because they are strongly collinear with the set of individual constant terms for each field that also do not change over time. They adopt a three-stage estimation process that estimates fixed field effects in the presence of time-invariant variables. The results strongly suggest that the age

of the field is not the sole factor in explaining its annual reserve growth. They conclude that estimating oil and gas reserve growth using the standard geological assumption that the age of the field is the only critical factor may yield a distorted assessment of future energy supplies.

7. CONCLUDING REMARKS

The modeling activity described within this volume provides a useful perspective on the state of knowledge about existing natural gas markets and where our understanding is likely to improve. The current state of best-practice modeling in this industry shows promise, particularly in its representation of regional competition between competing resource areas and demand centers and the critical role played by transportation infrastructure. At the same time, this modeling is expanding and improving its representation of real world markets in several ways. One important factor will be future natural gas demand and its substitutability for other more carbon-intensive fuels in a world increasingly concerned about mitigating greenhouse gas emissions. A second important consideration is the shift from comparative static analysis to dynamic models with endogenous investment decisions. This second theme permeates many of the papers that address issues, such as resource depletion, dynamic strategic behavior, pipeline infrastructure, and the building and extension of LNG facilities. As these modeling techniques develop, the model-using community will benefit from much richer analytical frameworks for sorting through the major issues in these vastly complicated markets.

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A Practitioner's Perspective on Modeling Prices and Trade in a Globalizing Natural Gas Market

*Robert D. Stibolt**

This paper advances some principles for practical application of natural gas models that were used during the EMF 23 study. These principles emphasize a decision-focused perspective, embrace uncertainty, demand consistency of model results with observable facts, are capable of navigating the complexity of systems, and distinguish insight from unattainable precision. The principles are designed to foster the assistance of better decision making by models and modelers.

1. INTRODUCTION

In its September 2007 Report 23, *Prices and Trade in a Globalizing Natural Gas Market*, the Stanford Energy Modeling Forum (EMF) has once again pursued a challenging agenda seeking to combine leading edge thinking on economic theory with practical application in order to provide insights that actually improve both energy policy and corporate strategic decisions. As the executive representing Suez Energy North America,[1] Inc. in the study group, the emphasis on getting from theory to practical insight was paramount. GDF Suez, after all, is a company with large positions within the LNG value chain for whom such insights are critical to strategic success. At the same time, industry practitioners must recognize that sound theory is an essential pre-requisite for practical success.

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* JP Morgan Global Commodities Market Risk. Email: Bob.Stibolt@Stanfordalumni.org.

The author thanks an anonymous referee, Dr. Dale Nesbitt, and Dr. Hill Huntington for useful comments. The views expressed are those of the author and do not represent those of JP Morgan.

1. This company has been renamed GDF Suez Energy North America, Inc. following the merger of GDF and Suez into GDF Suez completed in July 2008. The revised designation will be used throughout the balance of the paper. The author as of June 15th, 2007 has left GDF Suez Energy North America, Inc. to join The Bear Stearns Companies Inc. as Senior Managing Director and Chief Risk Officer for Bear Energy LP. He has subsequently joined JP Morgan Global Commodities Group as a Managing Director.

The purpose of this paper is to advance some principles for practical application of energy models that were used during EMF 23. These principles, which are arguably more philosophical than technical in their nature, include an unbending decision-focused perspective, recognizing and embracing uncertainty, fact-based rather than subjective, able to navigate the complexity of systems, and unequivocally recognizing the important distinction between insight and unattainable precision. Models grounded in these principles have in fact been applied in the energy industry and the best of them have been systematically successful in helping companies make better decisions. The principles offered here are designed to foster the assistance of better decision making by models and modelers.

It is said that economics is the science of negative feedback.[2] Prices always adjust to equate supply and demand. Quantities and capacity additions adjust in the face of prices. Proper market modeling and interpretation must always represent the negative feedback in markets. Although there may be positive feedback and amplification for some period of time, and protracted positive feedback often catalyzes overconfidence in models and results, over the medium and long-term there is significant negative feedback in economic systems. Markets tend to undermine the apparent stability of extrapolated trends. How many analysts in the month of July 2008 said that oil and gas prices were never going to drop from $140/BBL and $13/MMBtu because the forwards were up in the stratosphere and avowed energy experts were singing dirges about the limits of resource availability? Many – and while a few may have dissented from the conventional wisdom, the majority did not. Less than three months later in October 2008 oil and gas prices have declined dramatically to levels predicted by models with negative feedback.

The most recent experience on Wall Street, characterized by the severe impairment in the value of securitized debt portfolios far exceeding anything that the models for these securities anticipated, has sparked further commentary on the failure of models.[3] However, the more thoughtful commentary on the subject seems to have recognized that the present difficulties have not so much been a failure of models but rather a failure of thought. Models provide useful insights but do not provide a substitute for thought and must always be applied with careful attention to their limitations. The illusion of precision that from a practical, fact-based perspective was not realistic was arguably a significant cause of model failure. The amplification of model risk through errors that are compounding rather than diversifying – always an issue in navigating the complexity of systems – was another significant cause.

2. This commentary on negative feedback in markets as well as the high supply/low supply example and further observations on scenarios and Monte Carlo models discussed later were all suggested by Dr. Dale Nesbitt, President of Altos Management Partners, Inc. following his review of early drafts of this paper. Dr. Nesbitt has demonstrated both deep theoretical insight and practical expertise over the many years I have worked with him on energy modeling problems as a client at three different Fortune 500 energy companies.

3. For example, see Bloomberg Report, January 2008

There are perhaps useful lessons that energy modelers can learn from having observed the Wall Street experience even though the models that "failed" were not energy models per se. Brief summaries of each of the five aforementioned modeling principles and how they apply to prices and trade in a globalizing natural gas market follow.[4]

2. DECISION FOCUS

Several market trends relevant to future company and government infrastructure investment decisions were highlighted by the study, which consequently turned it into much more than just an "academic" exercise. Of most interest from a practitioner's perspective were those trends on which the several models included in the study came to a consensus. One important example of this is the conclusion that by 2020, given the geographical configuration of the world natural gas resource base, LNG imports will capture a greater percentage market share in North America than in Europe.[5] Along with this comes the related conclusion that North American delivered gas prices will be higher than in Europe.[6]

The evolution of this trend would not be apparent at all from observations of today's market conditions, which are characterized by natural gas prices higher in Europe and Asia than in North America with higher LNG imports into Europe and Asia. The changing dynamic of the Atlantic Basin gas market has significant implications for where investments in LNG re-gasification terminals need to be made and it appears that EMF 23 has played a useful role in better informing such investment decisions.

In the case of GDF Suez Energy North America, Inc., one of the firms providing financial support to EMF 23, these implications have translated into concrete actions in the form of investments estimated at more than one billion U.S. dollars to develop floating LNG terminals serving both the New England (Neptune) and southeast Florida (Calypso) natural gas markets.[7] During 2007, GDF Suez was, at 742 billion cubic feet, the largest importer of LNG volumes into both Europe and North America and with the completion of Neptune, Calypso, and the Fos-Cavaou terminal in France will have a total of 7 LNG terminals operating in Europe and North America. In addition, GDF Suez operates 15 LNG tankers with another 5 currently under construction. Given the size and significance of LNG to their strategy, a strong understanding LNG markets is critical.

4. A presentation on these made at the June 2006 EMF meeting in Berlin is available through the EMF.

5. Energy Modeling Forum (2007, p. 6, Figure 4 and p. 10, Figure 7).

6. P. 22, Figure 17.

7. In addition to benefiting from the insights out of EMF 23, GDF Suez Energy North America, Inc. runs its own modeling cases using the MarketBuilder software developed by Dr. Dale Nesbitt, President of Altos Management Partners Inc. and MarketPoint Inc. This same software is also used by the Rice World Gas Trade Model (RWGTM, but designated as "RICE" in EMF 23), one of and in the author's opinion among the best of the models reviewed by EMF 23.

3. UNCERTAINTY VS. PRECISION

Of course, even with a consensus view established it would be folly to treat baseline model results as a somehow infallible forecast of future market evolution. Decision focus also requires a thoughtful consideration of uncertainty and how market conditions might evolve differently. One method for addressing uncertainty that has gained especially wide acceptance in the energy industry is scenario analysis.[8]

Although EMF 23 explored only a handful of scenarios, the scenarios it did explore served both to illustrate how a scenario-oriented approach might be applied more broadly and proved to be of some interest per se in the sense of non-trivial impacts that would change the baseline conclusions.

An example of such a scenario is restriction of Russian gas supply, either because of political gaming (e.g. CPB Model) or the fact of higher estimated costs limiting competitiveness (e.g. RICE Model). In this scenario, the ratio of European to North American LNG imports increases significantly relative to the baseline along with a corresponding change in pricing. The consequences of this scenario for a strategy limited to investment in North American re-gasification would be quite dire. Industrial companies considering such investments, whether energy marketing intermediaries or end-users, would be wise to both undertake a comprehensive assessment of the risk that this scenario might occur as well as develop a more diversified strategy mitigating the risk.

Scenario analysis is not risk or uncertainty analysis, but it is nevertheless a technique oriented in that basic direction. Consider a deterministic model in which you run two scenarios characterized as "high supply" and "low supply". In the high supply (deterministic) scenario, every economic player in the model makes investment, operation, and retirement decisions assuming high supply. The decisions predicted by the model are such that every player in the model behaves under the deterministic supposition that there is high supply. All the decision makers execute a high supply-specific investment, operation, and retirement strategy. Consider the low supply case. In the low supply deterministic scenario, every economic player in the model makes investment, operation, and retirement decisions assuming low supply. The decisions predicted by the model are such that every player in the model behaves under the deterministic supposition that there is low supply, and the decisions every agent makes are completely different from the decisions made in the high supply case. Each scenario has an entirely different decision space for every agent. Yet consider what a real world market with true uncertainty is: There is a common set of investment decisions in the high and low supply case. Agents have to make one set of decisions in the face of forward high supply-low supply uncertainty. Agents today make their investment decisions, the coin is flipped, and the outcomes occur. One set of decisions – two prospective outcomes. That is the way uncertainty truly works. In that world, economic agents trade risk as well as

8. As outlined, for example, in Schartz (1991).

commodity, and the price of each affects the price of the other. Framed with this distinction, it seems reasonable to conclude that scenario analysis is but a halfway house, indeed a valuable but approximate halfway house, on the way to truly probabilistic market models. There is a strong need for intrinsically probabilistic models, but EMF had none and we are not aware of any in the market.

Even with a "probabilistic model" such as a Monte Carlo model that samples from probability density functions and then plays out each sampled scenario, the foregoing problem is not alleviated. Indeed, every individual scenario has all the agents thinking deterministically within that sampled scenario. Furthermore, if there is a single probability distribution within a model, there is de facto an explicit assumption that every agent in the model sees and agrees on a common probability distribution over the uncertain lottery within the model. Agents in Monte Carlo models are not allowed to have different information sets or probability distributions. They are all forced by construction to have the same information set. This is a severe limitation when one thinks of the real world in which there are a plethora of information sets. The only way to overcome that would be for each and every individual agent to have a different probability distribution over uncertain outcomes. If there were 1000 agents in your model, you would have to sample individually for each agent from his or her private probability distribution. That simply is not conceptually or computationally tractable. However, it is the way uncertainty works.

It is well to consider that economic/market models under uncertainty are not a technology that is with us today, within EMF or elsewhere, and scenario analysis is a useful halfway house toward that desirable objective.

Scenarios of the type, often seen with colorful names that are assembled subjectively by people in groups or panels, are far less useful than the types of scenarios addressed here. Scenarios here are completely and totally consistent scenarios under a given set of assumptions. The assumptions comprising the scenarios are assembled, but the model computes consistent agent behavior under that set of assumptions. Analysts are not allowed to postulate both the answers and the scenario assumptions. The model gives the answers for the given scenario assumptions. This is as it should be. The function of the model is to compute the incentive compatible, consistent, integrated market impact. That is what models are good at – calculating an incentive compatible solution for all the agents under a given set of assumptions, i.e., a scenario. Modelers should never give in to subjective scenarios, nor should decision-makers.

4. FACT-BASED MANAGEMENT

In the modern world of information overload, both the availability of information that is truly reliable and the discipline to effectively use it in making decisions has become an enormous challenge. Here, "truly reliable information" can be defined by a number of characteristics, including that it has been validated to a significant degree by empirical methods, is consistent with theories that have

in turn been so validated, and remains open to the possibility of falsification as the result of new and deeper evidence.

Of course, the knowledge and discipline required to adhere to such a high standard can be an inconvenient impediment to fast action, hierarchical status, and the perceived comfort and safety in following the herd. Consequently, information quality is often not considered in practice or built into organizational processes. Research in management science has recently more fully explored such decision information quality with some interesting conclusions and insights beginning to emerge.[9]

Although the focus is inherently narrower, the same information principles apply within the discipline of energy modeling. One could reasonably frame the question as simply: Can the model explain what we actually observe? A somewhat more formal technique for answering this question is back-testing, which has been one of the more successful empirical techniques for testing model validity (and, therefore, validating the quality of information models provide for decisions). The fundamental idea of back-testing is to set up the conditions within the model to match what in fact they were at a designated time in the past, run the model, and then compare model forecasts for the subsequent period to what was actually observed within the same period.

Of course, back-testing is an imperfect test in that actual history represents only one of multiple possible scenarios that might have occurred with slightly different initial conditions. In order to partially mitigate this issue, a good back-test should include tests starting at more than one and ideally as many as reasonably possible designated times in the past. However, even with the testing of just one (historical) scenario, useful insights will almost certainly emerge. A model forecast and, more broadly, a business strategy that fails the back-test must be called into question. Back-testing of energy trading strategies, specifically those based on technical analysis, could have saved many energy companies a great deal of money had it been employed.[10]

There are more elaborate methods for back-testing models, including most importantly techniques based on the combination of synthetic scenario generation with back-testing. Though more elaborate, these methods rely on essentially the very same principles and will not be fully described here.

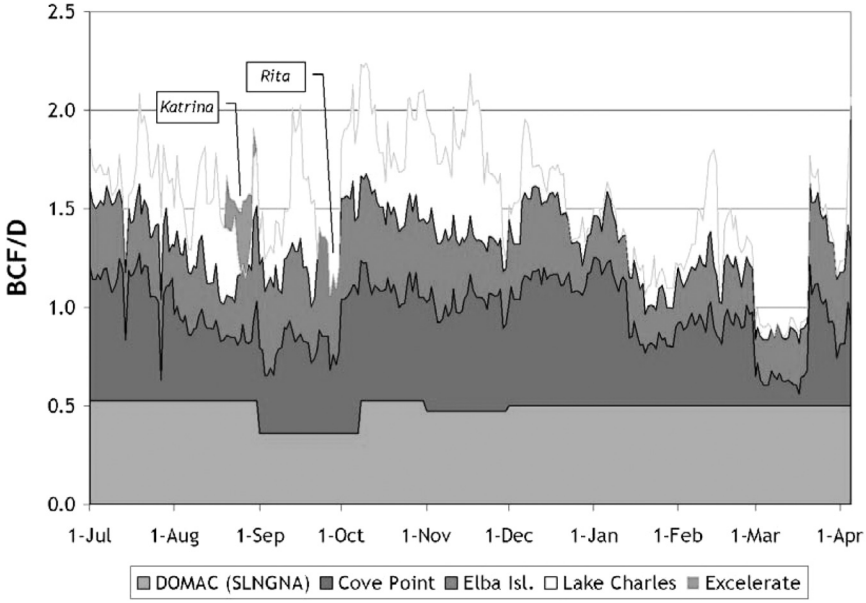
Two back-tests relevant for world natural gas markets that were discussed in some detail by EMF 23 working groups, though not specifically addressed in the executive summary, were locational volume and pricing relationships and oil/gas relationships.

Historical volume relationships of interest are displayed in Figure 1. These show a hierarchy of deliveries with baseload volumes into Distrigas of Massachusetts (DOMAC), which represents the most constrained and highest priced market in the US. As we progress from the northeast US to the Mid-Atlantic

9. e.g. Pfeffer and Sutton (2006).
10. e.g. Stibolt (1987).

(Cove Point, Maryland), the southeast US (Elba Island, Georgia), and then to the Gulf Coast (Lake Charles Louisiana and Excelerate) we observe a progression in the mix of baseload and swing supply shifting from pure baseload in the northeast to essentially pure swing in the Gulf Coast. Models with sufficiently refined locational detail should pick up this dynamic as it is driven by the profile of demand and shipping distances. The Rice World Gas Trade Model is an example of one that does, so that its locational dynamic has in that sense been partially validated by a back-test.

Figure 1. Daily U.S. LNG Imports (2005–2006)

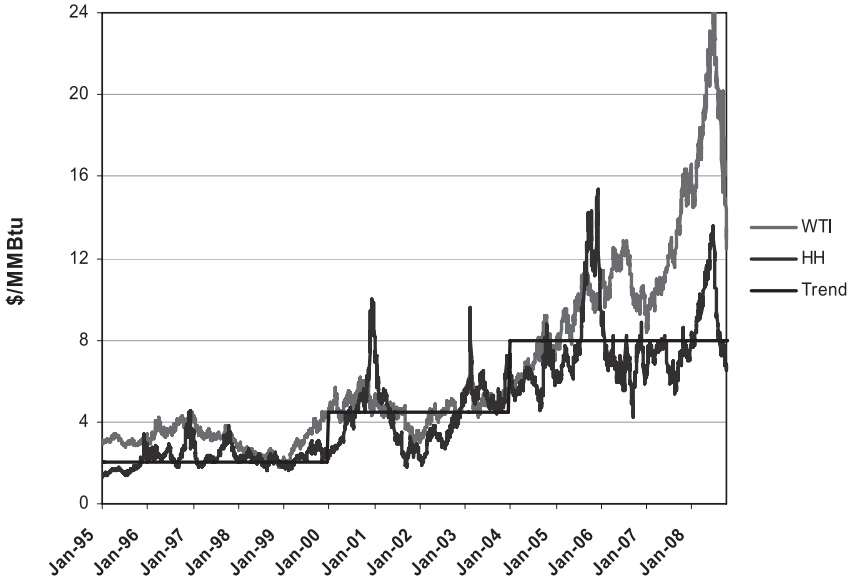


In the case of oil/gas pricing relationships, history as displayed in Figure 2 shows what appears to be a reasonably strong relationship. There is a solid theoretical rationale as to why this should be the case as well – specifically, the geological, geophysical, exploratory drilling, field development, and production engineering resources required for both oil and gas production are both scarce and can be shifted from one activity to the other.[11] In an industry where production decline sets in rapidly in the absence of continuing capital investment this would

11. Strong empirical support for this relationship is demonstrated using various statistical techniques in two recent papers on the subject. See Villar and Joutz (2006) and Hartley, Medlock, and Rosthal (2007).

suggest that the relationship between the output prices should remain connected.[12] Tested against various oil price scenarios the models in EMF 23 generally captured this behavior, so this represents an example of another back-test passed.

Figure 2. Historical Energy Price Series, WTI (Crude) and Henry Hub (Natural Gas)



Tests of model validity should be routinely repeated and expanded where possible as a matter of best practice for their successful application.

Having advocated back-testing as a valuable exercise, let me also address some possible problems with it. If not done honestly and correctly, back-testing can be highly misleading and quite at odds with decision focus. A common misapplication is to substitute a simpler ”historical validation” test that attempts to best match known history (which itself contains intrinsic measurement error) over

12. The underlying premise accepted here is that price formation is driven by fundamental supply/demand factors. There has recently been significant political discourse surrounding the impact that index fund investments in oil, oil products, and natural gas futures might have on the prices of these commodities. Since the funds holding these contracts never take physical delivery i.e. they sell the contract instead, they can have no impact at all on pricing at the time of delivery. By “rolling” the contract (i.e. selling spot and buying forward) index funds can in fact maintain a structurally long position (which from their standpoint is a diversifying investment rather than a speculative trade), but since every futures contract must have both a buyer and a seller, their structural long position must be exactly offset by structural shorts. Typically, these structural shorts are producers hedging near-term production, which decreases their risk, strengthens their balance sheets and, therefore, at the margin should theoretically increase supply. This would imply that lower rather than higher prices should result from futures trading activity.

the entire period reviewed by adjusting the parameters of a multidimensional, multiple degrees of freedom model. This is not the same at all as a true back-test, which is framed so that at every point in time at which the model is tested only information that was available at that time can be incorporated. Indeed, models typically have sufficient degrees of freedom to reasonably match any history once you have the complete history. The mere demonstration that a model "fits history" is far from a convincing test. Since historical validation can be manipulated in practice to give fundamentally dishonest and non decision focused results, we want to avoid this type of approach.

A further consideration in judging the validity of even properly framed back-tests should be an assessment of the fundamental reasonableness or cogency of the model's design per se. For example, do the model's free parameters and input variables correspond to conceptually reasonable and cogent representations of the real world processes being modeled or are they simply arbitrary parameters and variables with no discernible interpretation or connection? An example of such a cogent parameter would be the "efficiency of exploration" parameter estimated in certain oil and gas discovery process models – a parameter that provides an estimate of how much better than random drilling an exploration process has been. The estimated value of this parameter has a distinct meaning that can be reasonably interpreted in light of the actual geoscientific processes by which oil and gas is discovered.[13]

5. NAVIGATING THE COMPLEXITY OF SYSTEMS

This category represents perhaps the greatest value models add for the practitioner, albeit with the caveat that the practitioner must be sufficiently knowledgeable and experienced in how to interpret modeling results. In complex systems there is only a low probability that unguided human intuition can get to right answers or even valid insights. "Business intuition" is arguably the most overrated attribute of senior energy executives and is particularly susceptible to hindsight bias.[14]

Real world systems typically have numerous linkages creating complexity that often results in surprising counter-intuitive behaviors when the system is perturbed. Without the discipline in thinking that models enforce foreseeing these counter-intuitive behaviors becomes a far more difficult challenge.

Another problem of complexity – one that challenges the very best of models – is that of cascading errors – errors that compound rather than offset. The simplest example of this is a present value calculation where an error in the risk-adjusted rate used to discount cash flows compounds rather than diversifies the error. A more complicated example – one that is more systemic in nature – is the correlation behavior of energy spread options, which are fundamental to the en-

13. Stibolt (1988). See also Kaufman (1986).
14. Kahneman and Tversky (1979).

ergy industry.[15] The tails of the probability distributions underlying such options tend to be associated with scenarios characterized by various degrees of market distress that almost by definition imply chaotic behavior and the break-down of correlation. Thus, the simple model of correlated behavior fails just when the value implications are highest and risk mitigation is most difficult. Furthermore, these distressed market effects tend to cascade systemically – often leading to much greater levels of loss than models embedding an implicit assumption of portfolio diversification would have predicted.[16]

While there is no "silver bullet" answer to the problem of cascading errors, an awareness of the issue at least can help the practitioner avoid overstating the precision of what even the very best model can do.

6. INSIGHT VERSUS PRECISION

An awareness of both the power and limitations of models ultimately leads the practitioner to the right place – one in which a balance has been struck between the power of strategic insight into complex systemic behaviors that models help to unveil and the inherent limitations on the precision of forecasts. Strategic insights out of models are often far more important than the model results per se, especially to the degree that they feed into a formal process of strategic feedback.

There is something of a paradox in our use of models in that real world deviations from model results are often indications of genuinely profitable opportunities. This is perhaps turning things around somewhat from the customary pattern of thought, but the process actually works. Economic theory suggests that we should not see twenty dollar bills lying on the sidewalk. Therefore, when we do see such a bill we should probably pick it up. From the practitioner's perspective, becoming twenty dollars wealthier is not a failure, but a success.

A more sophisticated version of this is encountered in inter-temporal locational competition. The best models of inter-temporal locational competition[17] are able to identify the timing of and locations where new facilities (whether power plants, LNG re-gasification terminals, or gas pipelines and storage) should be built. These models are also powerful in understanding how various constraints impeding optimal siting might change the dynamic and what the second best opportunities would then be. Value is added by identifying the best sites and getting

15. e.g. the power plant's "spark spread" or "heat rate" option to convert natural gas to electric power or the refinery's "crack spread" option to convert crude oil to gasoline and heating oil.

16. Arguably, cascading risk in the form of correlation break-down and other systemic effects has been a significant element in the "credit crisis" where numerous banks have reported losses far exceeding what their Value at Risk (VaR) measures deemed possible.

17. From the author's perspective, these include many of the models discussed in this volume. He has personally worked with the North American Regional Electric (NARE), North American Regional Gas (NARG), and World Gas Models developed by Altos Management Partners using MarketBuilder software and the Rice World Gas Trade Model also developed using MarketBuilder software.

there first to capture the rent. It is indeed the twenty dollar bill on the sidewalk and it is interesting how often, even without constraints, it has not been picked up.

Of course, real asset markets are not efficient in the way that liquidly traded securities markets are, which is of course the ultimate source of the value arbitrage that a well-run industrial company captures. Thus, the possibility of value capture identified by the models is very real from the practitioner's perspective. At its very best, the involvement of models in the decision process becomes one of strategic feedback. This process, which is closely akin to the feedback loop between the theoretical and experimental activities in the natural sciences, is one in which decisions based on the opportunities identified using the model are implemented, the quality of those decisions and implications for model structure are subsequently evaluated based on back-testing, models are improved or enhanced, and then new opportunities are identified. As previously noted, this process pays close attention to opportunities unveiled by the discrepancy between model forecasts and observed market conditions.

EMF 23 involved many hours of working sessions in which many of the issues raised here were seriously considered and broadly discussed by experts representing a wide spectrum of knowledge and experience in the energy industry. Arguably, the opportunity to participate in this process was from a practitioner's perspective every bit as important for understanding the value opportunities implied by the modeling work as was seeing the final report. Perhaps it is not too far-fetched a hope for the future that the impact of such forums involving academic, industry, and government representation can lead to systematically better decisions in energy.

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Spatial Price and Quantity Relationships in World and Continental Commodity Markets

Dr. Dale M. Nesbitt and Dr. Jill N. Scotcher***

Modeling world or continental natural gas, oil, coal, or electricity requires a representation of the spatial nature of such commodity markets—multiple interconnected and/or independent source points, intermediate points, and consumption points. Spatial commodity models, properly constructed, expose the underlying economic fundamentals—prices, basis differentials, flowing quantities, and why prices and quantities embrace certain relationships but not others. This paper examines spatial market equilibrium from a methodological perspective and puts forth results that explain interrelationships of prices and quantities of commodity throughout a market of competing/complementary supply chains. The objective is to allay common "myths" by counterexample and at the same time posit some realities both methodologically and by example.

1. BACKGROUND

Samuelson (1952) introduced a number of insights regarding prices and quantities in spatial commodity networks. Based on welfare maximization, Samuelson (1952) showed that under carefully specified conditions, a linear programming problem characterizing the spatial aspects of the multiregional economic system is embedded. Samuelson (1952) neither claims nor implies that "Competitive markets exhibit netback price relationships among regional prices." We disprove netback relationships by example herein. Samuelson (1952) does not imply that "Everyone benefits when transportation congestion is eradicated." We disprove that by example. Samuelson (1952) does not imply that "Supply

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* Corresponding author: President, Altos Management Partners, 334 State Street, Suite 204, Los Altos, CA 94022, (650) 948-8830. Email: dale.nesbitt@altosmgmt.com.

** 4590 Malabar Place, Castro Valley, CA 94546, (925) 842-0277.

region prices must be lower than demand region prices by at least the magnitude of intervening transportation cost from supply to demand." That too is disproved by example. Samuelson (1952) does not imply that "Transportation cost drives a wedge between supply and demand prices, and it doesn't matter how high it gets." That too is demonstrably incorrect. Samuelson (1952) never asserted that "Linear programming is an adequate model of market equilibrium." This paper disproves by example misconceptions about prices and flows in such systems by generalizing the Samuelson model to a Walrasian form and applying comparative statics.

2. WALRASIAN EQUILIBRIUM IN A SYSTEM WITH TWO SUPPLY REGIONS AND TWO DEMAND REGIONS INTERCONNECTED BY A TRANSPORTATION GRID

Consider the spatial structure in Figure 1 in which there are two supply regions at the bottom of the diagram (Supply Regions 1 and 2), each containing a linear indirect supply function:

$$p_1 = 1 + \frac{1}{2}q_1 \qquad p_2 = 1 + 2q_2 \tag{1}$$

which is easily invertible to create direct supply functions.[1] There are two demand regions at the top of the diagram (Demand Regions A and B), each containing a linear indirect demand function:[2]

$$p_A = 5 - q_A \qquad p_B = 5 - \frac{1}{2}q_B \tag{2}$$

which is easily invertible to create direct demand functions.[3] There is a transportation system interconnecting each supply region with each demand region.[4] We postulate that the throughput capacity of each transportation link is unbounded (no transportation "congestion") with no barriers to entry, constant returns to scale, no transportation losses, and fixed volumetric costs specific to each route or link in the grid in Figure 1 (depicted inside the triangles).[5] Figure 1 distinguishes

1. Both regional producers are assumed to be price takers with no monopolistic-oligopolistic market power.

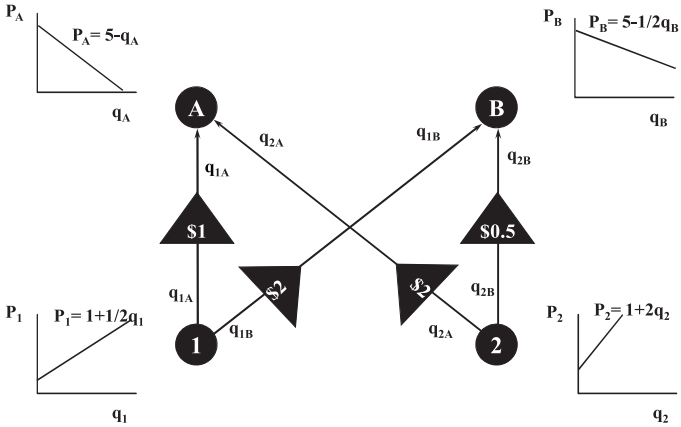
2. Both regional consumers are assumed to be price takers with no monopsonistic-oligopsonistic market power.

3. The results here are not particularly dependent on the specific mathematical forms of the demand curves. We have chosen linear forms for computational simplicity. The results herein generalize to integrable nonlinear demand curves derived from utility maximization or alternatively to nonintegrable nonlinear demand curves inferred from statistical or judgmental methods.

4. Extension to larger numbers of supply and demand regions with more interconnecting transportation links is straightforward. Virtually all commodity markets have an analogous structure, be they coal, oil, natural gas, copper, gold, grains, precious metals, livestock, etc.

5. We later relax this no-congestion assumption to analyze what congested transportation means for spatial markets.

Figure 1. Spatially Distributed Markets—Two Consumption Points and Two Production Points Connected by Transportation Grid



four interconnected markets (one each at locations 1, 2, A, and B) each with its own distinct price.[6]

We develop the system of equations/inequalities that characterizes Walrasian equilibrium for Figure 1. The supply and demand relationships are obvious. Using transportation link 1-to-A as an example, seen in Figure 1 to cost \$1 per unit with unlimited capacity available, two conditions must be satisfied:

1. A positive quantity of commodity flows from Region 1-to-A only if the price differential across the 1-to-A transportation link is equal to or larger than the transportation cost of \$1, i.e., $q_{1A} > 0 \Rightarrow p_A - p_1 \geq \$1$
2. If the price differential across the 1-to-A link is strictly less than the cost of transportation of \$1, zero commodity will be transported across that link because the cost of such transportation is higher than the market is willing to pay, i.e., $p_A - p_1 < \$1 \Rightarrow q_{1A} = 0$.

We write the two foregoing equations for the 1-to-A link (and analogously for the other three links):

6. Our formulation ignores long term contracting or oil indexed contracting such as has occurred in LNG markets in recent years. Such contracts are an artifact of scarce LNG liquid supply coupled with scarce storage capability in import areas such as Asia and Europe, which are both likely to abate fairly quickly in world markets. We anticipate an end to oil indexed contracts in LNG. With the massive arbitrage already in LNG markets and spot prices substantially below oil prices, we believe this formulation is representative of LNG as well as other commodities delivered by pipeline.

$$
\begin{aligned}
&q_{1A}(p_A - p_1 - 1) \geq 0 \quad \text{with} \quad q_{1A} \geq 0 \quad p_A - p_1 - 1 \geq 0 \\
&q_{1B}(p_B - p_1 - 2) \geq 0 \quad \text{with} \quad q_{1B} \geq 0 \quad p_B - p_1 - 2 \geq 0 \\
&q_{2A}(p_A - p_2 - 2) \geq 0 \quad \text{with} \quad q_{2A} \geq 0 \quad p_A - p_2 - 2 \geq 0 \\
&q_{2B}(p_B - p_2 - .5) \geq 0 \quad \text{with} \quad q_{2B} \geq 0 \quad p_B - p_2 - .5 \geq 0
\end{aligned}
\tag{3}
$$

Quantity balances for markets A, B, 1, and 2, which must hold in all four markets under Walrasian equilibrium, are the following:

$$
\begin{aligned}
q_A &= q_{1A} + q_{2A} \\
q_B &= q_{1B} + q_{2B} \\
q_1 &= q_{1A} + q_{1B} \\
q_2 &= q_{2A} + q_{2B}
\end{aligned}
\tag{4}
$$

Twelve equations/inequalities characterize Walrasian equilibrium in Figure 1, equations (1)-(4). The unknowns are the four prices p_A, p_B, p_1, p_2; the four quantities q_A, q_B, q_1, q_2; and the four transportation link flows q_{1A}, q_{1B}, q_{2A}, q_{2B}.

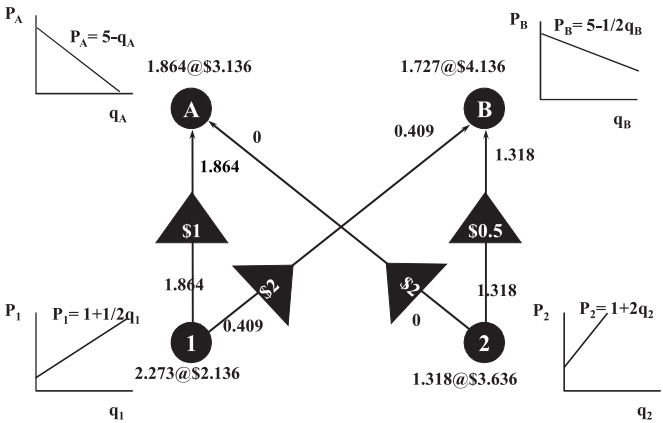
2.1 Reference Case

The reference case equilibrium is displayed in Figure 2, which can be verified by substituting the numbers directly into equations (1)-(4). The figure depicts the prices and flows through the various transportation links. We array the results from Figure 2 in Table 1 to facilitate comparisons of the reference case to subsequent cases. Figure 2 disproves any notion that "netback relationships" hold across transportation links in spatial markets. A netback calculation begins with the observed price in a demand market (e.g., the price \$4.136 in demand Region B). Thereafter, the netback calculation subtracts the transportation cost \$2 entering from supply Region 1 to demand Region B from the price \$4.136 in demand Region B and argues that the result should be the price in supply Region 1. According to netback logic, \$4.136 - \$2 = \$2.136 should be the price in supply Region 1. Netback reasoning is problematic for market prices, as we shall see from the four netback calculations in Figure 2:

- B back to 1: \$4.136 - \$2 = \$2.136, which is the market price in region 1.
- B back to 2: \$4.136 - \$0.50 = \$3.636, which is the market price in region 2.
- A back to 1: \$3.136 - \$1 = \$2.136, which is the market price in region 1.
- A back to 2: \$3.136 - \$2 = \$1.136, which **is not** the market price in Region 2. The netback calculation \$1.136 is well below the true market price \$3.636 in region 2.

Alas, netback pricing does not work in this simple two supply-two demand region setting and thus cannot be argued to work in larger, more complex,

Figure 2. Prices, Quantities, and Flows in the Reference Case



or more general settings[7]. Netbacks cannot be argued to work in any setting. Spatially distributed market prices do not obey netback relationships. This has been

Table 1. Walrasian Quantities and Prices – Reference Case

	Quantity		Price
q1A	1.8636	pA	$3.1364
q2A	0.0000	pB	$4.1364
q1B	0.4091	p1	$2.1364
q2B	1.3182	p2	$3.6364
q1	2.2727	pA-p1	$1.0000
q2	1.3182	pA-p2	-$0.5000
qA	1.8636	pB-p1	$2.0000
qB	1.7273	pB-p2	$0.5000

misunderstood since Samuelson (1952), who was very careful to state that the complementary slackness conditions in his embedded linear programming model governed prices, not netbacks.

Notice in Figure 2 there is zero commodity flow from 2 to A, a link across which the netback calculation does not work. The netback calculation does not work along this path from 2 to A because the path is not competitive; nobody wants to use it. Netback calculations hold along transportation links that experience positive flows at equilibrium, but not zero flows.

7. A theorem disproved by example in any setting is a theorem disproved in every setting.

That netbacks do not work is not heretical or unusual in the real world. Gas transportation cost from British Columbia to Florida does not affect the price differential from British Columbia to Florida. Power transmission cost from Louisiana to Maine does not set the price differential between Louisiana and Maine. Neither route is economically competitive. Examples abound where netbacks do not work. In large spatial networks, predicting which transportation links are economically competitive and which are not is an impossible combinatorial problem that cannot be solved without a Walrasian model, certainly not using netbacks or historical price extrapolations.

There are several other insights from the reference case in Figure 2. First, suppliers who commit to netback pricing contract should expect to **lose money** relative to what they could otherwise get. Netback prices along noncompetitive transportation routes are **lower** than market prices in those supply regions. This is what noncompetitive transportation cost means—high cost. Suppliers have no idea ex ante what transportation routes will be competitive; therefore, they are likely to be selling in their supply region at too low a price if they make netback agreements.

Secondly, if a transportation system is mobile and fungible (such as LNG or crude oil tankers), there is no reason for netback pricing. Owners of mobile vessels can exploit the mobility of their transportation system, and a market pricing rather than netback pricing system should emerge (e.g., an FOB system). An FOB system is today germinating with LNG; it has always governed oil. Both transportation owners and suppliers get fair market value and do not leave money on the table.

Owners of transportation grids, particularly regulated power and gas grids, have implemented postage stamp or other non-route-based ratemaking to thwart arbitrage of the transportation system. Owners despise trying to predict which specific segments of their system will be competitive and used, yet they want to recover the entire cost of their system based on whatever portion of their system is actually used regardless of where commodity actually flows. They convince regulators to set the rates high enough to recover their entire system cost on whatever portion of the system the market elects to use. We illustrate postage stamping below.

2.2 Higher Upstream Supply in One Single Supply Region (High Supply Case)

What would happen to prices in all four markets in Figure 1 if technological innovation, a new resource discovery, or a new LNG liquefaction facility were to increase supply in one single region, i.e., what if the supply curve in Region 2 were shifted outward and to the right? Assume in particular that the new supply curve in Region 2 has the equation $p_2=1+3/2q_2$ rather than the old equation $p_2=1+2q_2$, all else equal to the reference case, thus representing a highly localized supply increase in Region 2. Most agree that one should expect a price depression

in Region 2 (where the additional supply occurs) relative to the reference case. However, would one expect price depressions to ripple outward from the point of initiation (supply Region 2) abated or unabated in magnitude as they go? People usually infer (without benefit of analysis) that as a commodity is displaced by additional supply in Region 2 and as the displaced commodity seeks alternative markets, secondary displacements induce smaller price effects. Tertiary displacements are thought to be more modest still. People seem to postulate therefore that price depressions are largest in primary markets, lower in secondary markets, and lower yet in tertiary markets. They postulate that price ripples proliferate outward, diminishing in magnitude relative to displacements that preceded it. Such intuition is incorrect.

Table 2 depicts the Walrasian equilibrium in the high localized supply case in the four left hand columns and calculates the differences between the high localized supply case and the reference case in the four right hand columns (high localized supply case minus reference case).[8] The most striking insight lies in the final column—localized high supply causes the *same* magnitude of price reduction in *every* market. There is no damping in magnitude as one moves away from Region 2 in which the increased supply occurs. The price depression resulting from the increase in supply in just one localized region (Region 2) is exactly the same magnitude, namely -$0.07754, in every one of the four regions. The price drops by the same magnitude everywhere throughout the spatial network as a result of the new supply in just one localized region. The new solution in Table 2 is governed by 11 of the original 12 equations/inequalities that governed Figure 1. The only equation that differs is the new supply curve in Region 2. Even one single equation in a system can have profound effect on the solution. Even one

Table 2. Quantities and Prices and Differences from Reference Case – High Localized Supply Case

High Localized Supply Case

	Quantity		Price		Quantity Difference		Price Difference
q1A	1.9412	pA	$3.0588	q1A	0.0775	pA	-$0.0775
q2A	0.0000	pB	$4.0588	q2A	0.0000	pB	-$0.0775
q1B	0.1765	p1	$2.0588	q1B	-0.2326	p1	-$0.0775
q2B	1.7059	p2	$3.5588	q2B	0.3877	p2	-$0.0775
q1	2.1176	pA-p1	$1.0000	q1	-0.1551	pA-p1	$0.0000
q2	1.7059	pA-p2	-$0.5000	q2	0.3877	pA-p2	$0.0000
qA	1.9412	pB-p1	$2.0000	qA	0.0775	pB-p1	$0.0000
qB	1.8824	pB-p2	$0.5000	qB	0.1551	pB-p2	$0.0000

8. Price netback calculations continue not to hold in the high localized supply case just as in the reference case.

localized increase in supply can have a profound effect on nodal gas prices around the world.

How could this be, the same magnitude of price depression everywhere? Keep in mind, our model has assumed no transportation restrictions, i.e., unlimited volumetric availability. The fact that price drops by the same magnitude in all four markets as a result of a localized supply increase in just one single region depends in part (but only in part) on the assumption of unlimited transportation. Identical logic would apply to spatial markets much larger in size as long as there are no transportation limitations—price depressions will decrease by the same magnitude throughout that entire spatial market regardless of the size, extent, or location of the supply increase.

There is no damping in the magnitude of price decrease traveling outward from Region 2. Price decreases by exactly the same magnitude in Region A even though Region 2 does not send any product at all to Region A in either the reference case or the high supply case. Completely disconnected regions experience precisely the same magnitude of price decrease as do connected regions. Commodity displacement induces the same price decrease in a demand region that is not served from a specific, local supply increase as one that is served. This case disproves any assertion that the existence of a direct, interconnecting transportation link is a prerequisite for a supply change to induce a price depression in another region. Displacement of commodity anywhere in a spatial network is sufficient to guarantee an identical price depression everywhere throughout a spatial network (assuming no transportation limitations or scale economies).

In reality, one might observe different magnitudes of price depression in different regions when supply in one localized region increases. This might occur because of transportation bottlenecks, decreasing returns to scale (or no connections at all) between regions, or differential losses across transportation links. Real world spatial markets can have transportation bottlenecks or decreasing returns to scale, and these can cause price damping as one moves further from the original point of supply increase. In the real world, we expect price damping to be modest in magnitude because transportation systems tend not to be grossly undersized relative to market need. Quite the contrary, regulators and regulated companies tend to oversize transportation. Transportation tends to be oversized because "pipe is cheap compared to gas" and because of Averch-Johnson (1962) incentives.

Increased supply in Region 2 not only changes price, but it also changes flows throughout the entire network. Quantity differences in Table 2 indicate commodity displaced. Negative signs denote quantity reductions caused by the entry of the new supply at Region 2, and positive signs denote net increases. There is 0.077 more demand at A and 0.155 more demand at B. Reduced prices stimulate more demand in both end use demand markets, and by an aggregate total of 0.077+0.155=0.232. Total commodity flow through the transportation grid increases by this amount because supply must exactly equal demand. Aggregate

production across all supply regions must increase by this amount 0.232.[9] Table 2 shows 0.155 lower production in Region 1 and 0.388 higher production in Region 2. Because supply region prices are both lower, supply is actually depressed in Region 1 (in which there is no supply increase). Increased supply in Region 2 compensates for the entire demand increase PLUS the supply suppression in Region 1. Increased supply in Region 2 (additional commodity at every level of marginal cost) displaces production that would otherwise have occurred in Region 1 into Region 2. New, low cost supply in Region 2 eradicates a portion of the higher cost commodity from Region 1 that was produced in the reference case. Low cost supply defeats high cost supply independent of the geographical location of the high and low cost supply.

Another non-theorem is evident: Supply increases do not necessarily cause formerly unused transportation links to flow. Just because there is new supply upstream from a transportation link (e.g., the link from 2 to A) does not mean that the link from 2 to A will flow because of the new surfeit of supply. Flow may happen, but there is no guarantee. In this localized high supply case, new supply flows along exactly the same old transportation links as always but in larger volumes. New supply does not necessarily germinate new transportation routes.

In the real world, there has been speculation as to what would happen to commodity prices if new LNG facilities were built around the world. A new LNG liquefaction facility represents an increase in the local supply curve in the region in which it is constructed, precisely analogous to our localized high supply case. Per our result, as new LNG liquefaction facilities are introduced, commodity price will be reduced in *every* supply and demand region in the world, supply will be suppressed in *every* other supply region in the world, and demand will be stimulated in *every* other region of the world. The LNG transportation system is highly mobile and not undersized relative to whatever flow might be required. Unlimited transport capacity at route-dependent transportation costs seems an appropriate representation of LNG (and crude). In such a situation, there is little damping of price depression resulting from increased localized LNG supply such as that in Region 2 here. Price depressions travel undamped to every producing and consuming region in the world, stopping nowhere, and affecting producers and consumers everywhere. Lower prices suppress local supply everywhere outside the new LNG supply region, new LNG displacing local supply that would otherwise have to be produced. Spatial networks are displacement oriented, and displacement anywhere drives prices down everywhere. This result heralds the fact that no LNG exporter is immune from price decreases resulting from every other LNG exporter.

9. If we allowed for commodity losses in transportation, the result could be different. Increased supply upstream from a low efficiency, bottlenecked, or constrained transportation system could actually cause aggregate consumption losses to increase at the same time that prices decrease throughout the system. We have omitted losses from the analysis here.

2.3 Higher Downstream Demand in One Demand Region (High Localized Demand Case)

What happens if demand were stimulated in one of the two localized demand regions? This might result from influx of population or industry, a new use, emergence of a developing country into an industrialized condition, or rapid GNP growth in a specific country. The results are analogous to the high regional supply case. Prices in a high localized demand case are higher in every market, and by exactly the same magnitude, whether or not those markets are connected to the region in which the demand curve has increased. Analogous to supply, demand has a ubiquitous and equal price stimulation effect throughout the entire spatial market—every supply and demand region in the world. Netback calculations continue not to work, and the increase in demand does not necessarily alter which transportation links are used. If China or India increase demand, they pull up prices by an equal amount worldwide.

2.4 Pro Rata Lower Transportation Cost Along All Routes (Low Transportation Cost Case)

Much attention has been given to the possibility of reduced transportation costs for pipelines, LNG tankers, electric power systems, crude oil tankers, etc. Relatively huge pipelines from the Arctic to demand markets (e.g. the 6 Bcfd gas pipeline from Prudhoe Bay into the Alberta market) spreads fixed and operating costs over more and more throughput and therefore reduces volumetric cost. More efficient, less costly liquefaction, shipping, and regasification reduce LNG supply chain costs to market. To create a low transportation cost case, we reduce the cost of transportation by a factor of one half on all the transportation links in Figure 1, holding supply and demand curves constant across all supply and demand regions (e.g., reduced LNG shipping cost per mile). Table 3 gives the results in this case and differences from the reference case.

Another non theorem emerges: reduced transportation cost across the board does not reduce prices everywhere. It does not bestow everyone a win. The reduction by one half in transportation cost actually increases price in supply Region 1 and demand Region A (in Region 1 quite substantially). The high transportation cost ($2) in the reference case discouraged transportation from supply Region 1 to demand Region B. Reduction in that transportation cost directs commodity from 1 to B that was not flowing in the reference case. As this occurs, the price in demand Region B decreases. There is more supply coming into demand Region B than before, and there is a corresponding price reduction in demand Region B. There is also a price reduction in supply Region 2 because it has a harder time competing with the surfeit of inflow from supply Region 1 at the lower transportation cost. Consumers who formerly benefitted from contiguity to low cost supply lose out. Consumers who formerly were far from supply win. Producers who formerly saw their prices suppressed by high outbound transportation costs

Table 3. Quantities and Prices and Differences from Reference Case – Half Transportation Cost Case

Half Trans. Cost							
	Quantity		Price		Quantity Difference		Price Difference
q1A	1.8409	pA	$3.1591	q1A	-0.0227	pA	$0.0227
q2A	0.0000	pB	$3.6591	q2A	0.0000	pB	-$0.4773
q1B	1.4773	p1	$2.6591	q1B	1.0682	p1	$0.5227
q2B	1.2045	p2	$3.4091	q2B	-0.1136	p2	-$0.2273
q1	3.3182	pA-p1	$0.5000	q1	1.0455	pA-p1	-$0.5000
q2	1.2045	pA-p2	-$0.2500	q2	-0.1136	pA-p2	$0.2500
qA	1.8409	pB-p1	$1.0000	qA	-0.0227	pB-p1	-$1.0000
qB	2.6818	pB-p2	$0.2500	qB	0.9545	pB-p2	-$0.2500

win. Producers who formerly served captive markets in contiguous demand regions lose. Any notion that lower transportation cost will be ubiquitously heralded is incorrect. The aggregate quantity transported is higher in the low transportation cost case.

The low transportation cost case disproves by example theorems that would prescribe how, where, and whether lower cost transportation would reduce prices uniformly in demand regions or supply regions. When faced with any change in transportation cost, whether universal or local, the entire spatial system changes. Consider that not every country or geographic region in the world would be an economic beneficiary if the cost of LNG shipping (or the cost of commodity transportation via pipeline) were to decrease universally. Not every producer in the world would be a beneficiary. Some producers would see higher prices, and some producers would see lower prices under reduced transportation cost to market. An erroneous belief that a universal reduction in transportation cost reduces all prices and increases quantity consumed in all end use regions is just plain wrong.

If transportation were to become free and ubiquitously available (as in the next section), a supply-rich country such as Russia would export a huge quantity of commodity, and Russian domestic price would rise as such exports increased. In the past, commodity price in Russia has been low because of stranded supply, poor transportation networks, high costs of transportation, and perhaps restriction. Low outbound transportation cost to export points would elevate domestic prices. By contrast, if transportation costs fell to zero, United States and other high cost suppliers would experience lower prices and lower profits, would produce less, and might even exit the business, being replaced by offshore lower cost providers. United States consumers would benefit from the lower cost of the imported commodity. Winners under lower transportation costs are producers in abundant supply regions and consumers not near supply-rich regions. Losers are producers in

scarce supply regions and consumers in supply-rich regions. High transportation costs are actually advantageous to producers in countries with scarce resources like the United States. High inbound transportation costs actually shelter producers in high cost countries with scarce resources by allowing a higher domestic price and high indigenous cost commodity to get to market.

2.5 Equal Transportation Cost (Postage Stamp Transportation)

Suppose that the cost of all transportation links were equal to a common value no matter where the commodity originates or terminates, a "postage stamp" pricing arrangement. Under postage stamp pricing, there is no way to arbitrage the transportation system--prices in the two demand regions are equal, and prices in the two supply regions are equal. In the special case in which transportation is postage stamped at zero cost (completely free transportation), the quantities and prices are those in Table 4. Zeroing transportation altogether has benefited customers in Region B and hurt customers in Region A. It has benefited suppliers in Region 1 and hurt suppliers in Region 2. Not everyone benefits.

If the postage stamp rate were raised from 0 to $1, total demand is suppressed from 5.45 down to 4.09. There is price increase in the consumption regions from $3.1818 to $3.6364. There is price decrease in the supply regions from $3.1818 to $2.6364. Higher transportation cost imposes price increases and demand suppression on consumers and simultaneously imposes price decreases and supply suppression on producers. When regulators load costs onto transportation, they suppress both demand and supply. Indeed, someone has to pay for it, and both producers and consumers have to do so. There is no free lunch with transportation. Indeed, if transportation rises to $4 in our example, demand will be suppressed to zero and the market will be stultified.

Table 4. Quantities and Prices and Differences from Reference Case – Zero Transportation Cost Case

Zero Transport Cost							
Quantity			Price	Quantity Difference			Price Difference
q1A	-	pA	$3.1818	q1A		pA	$0.0454
q2A	-	pB	$3.1818	q2A		pB	-$0.9546
q1B	-	p1	$3.1818	q1B		p1	$1.0454
q2B	-	p2	$3.1818	q2B		p2	-$0.4546
q1	4.3636	pA-p1	$0.0000	q1	2.0909	pA-p1	-$1.0000
q2	1.0909	pA-p2	$0.0000	q2	-0.2273	pA-p2	$0.5000
qA	1.8182	pB-p1	$0.0000	qA	-0.0454	pB-p1	-$2.0000
qB	3.6364	pB-p2	$0.0000	qB	1.9091	pB-p2	-$0.5000

2.6 A Single Congested Transportation Link (Congestion Case)

In recent years, there has been a literal fixation on insufficient transportation infrastructure in place between certain supply and demand markets, e.g., insufficient power line capacity to move power between western and eastern PJM; not enough LNG ships running from Australia to Baja to carry the quantity of gas the market wants; insufficient pipeline capacity to move Russian gas into eastern Europe—the dreaded word "congestion" in the parlance of regulators. (Congestion means undersized transportation capacity relative to what the market wants to use.) What if one of the transportation links in the reference case is congested, i.e., not as much capacity exists along a link as was utilized in the reference case? As we shall see, congestion can allow the owner of transportation rights on a congested link to earn rent, i.e., the price difference across a congested transportation link will be seen to exceed the cost along that link.

To simulate congestion, we return to the reference case in Figure 1 and impose an upper bound on the transportation link from supply Region 1 to demand Region A. In particular, we assume an upper bound of 1.400 units flowing on this link (lower than the 1.864 units that flowed in the reference case). Such an assumption creates congestion along the transportation link from supply Region 1 to demand Region A and changes all prices and flows throughout the network. See Table 5 for the results of this case and comparison to the reference case.

We begin by examining all four netbacks in this congestion case

$$\text{A netback to } 1: p_A - \$1 = \$3.600 - \$1 = \$2.600 > \$2.033 = p_1$$

$$\text{B netback to } 1: p_B - \$2 = \$4.033 - \$2 = \$2.033 = p_1$$

$$\text{A netback to } 2: p_A - \$2 = \$3.600 - \$2 < \$3.533 = p_2$$

$$\text{B netback to } 2: p_B - \$0.50 = \$4.033 - \$0.50 = \$3.533 = p_2$$

Table 5. Quantities and Prices and Differences from Reference Case – 1-toA Congestion Case

Congestion 1-A

	Quantity		Price		Quantity Difference		Price Difference
q1A	1.4000	pA	$3.6000	q1A	-0.4636	pA	$0.4636
q1B	0.6667	pB	$4.0333	q2A	0.6667	pB	-$0.1030
q2A	0.0000	p1	$2.0333	q1B	-0.4091	p1	-$0.1030
q2B	1.2667	p2	$3.5333	q2B	-0.0515	p2	-$0.1030
q1	2.0667	pA-p1	$1.5667	q1	-0.2061	pA-p1	$0.5667
q2	1.2667	pA-p2	$0.0667	q2	-0.0515	pA-p2	$0.5667
qA	1.4000	pB-p1	$2.0000	qA	-0.4636	pB-p1	$0.0000
qB	1.9333	pB-p2	$0.5000	qB	0.2061	pB-p2	$0.0000

With congestion two netbacks (B back to 1 and B back to 2) work, but two (A back to 1 and A back to 2) do not work. In the reference case, three netbacks worked and one did not. Under congestion, the two netbacks that work do so because there is no congestion along these specific links entering demand Region B and both flows are positive. These two transportation links are used by agents in the market because they are economically competitive; agents are willing pay for these links.

Under congestion, netback A back to 2 does not work and yields a price at 2 that is lower than the market price at 2, just as in the reference case. This 2-to-A transportation link is too expensive to utilize even in this congested case. Agents choose not to use this link; there is zero flow along this link; and the market will not pay for any use of this transportation link notwithstanding the presence of congestion elsewhere in the network. Another non theorem emerges by example—congestion does not necessarily fill slack transportation. The 2-to-A link was empty in the reference case and remains empty in the congestion case. The netback calculation along this link is just as incorrect in the congestion case as it was in the reference case. Congestion does not render netback calculations correct nor "fill up the empties."

The other netback that does not work is the one along the congested link, 1-to-A. The netback from A back to 1 is $3.600-1=$2.600, yet the market price of commodity in supply Region 1 is only $2.033. The netback from A back to 1 gives a higher, not a lower, value than the market price in Region 1. The fact that the netback price is higher than the market price implies that owner of transportation rights along the 1-to-A link (for which he or she only had to pay $1) would own an asset worth $3.600-$2.033=$1.567. There is a rent to be realized here. Even though there is no market power by assumption in this example, the owners of the congested 1-to-A transportation link would be able to earn $0.567 in rent, i.e., in "windfall profits" by virtue of owning shipping rights on that link whose cost is only $1. The key insight is this—scarcity caused by congestion changes prices and flows at every one of the markets, not only those directly upstream and downstream from the congestion. Congestion of any single link anywhere in the system has global effects on every market and every link throughout the entire system. Congestion is not at all a local phenomenon. Congestion allows rent to be earned by owners of the congested transportation link even in the absence of market power. Owners of rights on congested transportation links would not be expected to embrace transportation system expansion.

Congestion has been the subject of controversy in natural gas and power. California consumer advocates have argued that the existence of rents along congested inbound pipelines is evidence of "market manipulation" or market power by pipeline owners. Our example shows this to be specious; congestion breeds rents for owners of a congested transportation link even without market power. Market power is not a precursor for congestion, nor is congestion an indicator of market power.

It is insightful to compare the prices in the congestion case with the prices in the reference case as tabulated in the right hand columns in Table 5.

Congestion on the 1-to-A transportation link increases price downstream from the site of congestion (demand Region A) as compared to the reference case. Congestion of transportation causes elevation of price downstream from such congestion. Customers downstream from points of congestion are losers because of such congestion. Winners under congestion include suppliers with preferred positions downstream from such congestion who can bypass such congestion.

Congestion is also seen to decrease price upstream from the point of congestion and in turn upstream from those points. Because of congestion, supply is rendered abundant in regions upstream from such congestion because the commodity is "backed up" by the lack of transportation capacity to the downstream market in which the commodity is scarce. With congestion, there is too much supply vying to get through a "pinch point" to high value downstream markets, and such vying causes low prices upstream from the congestion point. Congestion sends the signal to producers upstream from the congestion point: "Don't build here! Don't add capacity here! Debottleneck the congestion point downstream so that we get increased market access!" We observe this type of phenomenon in LNG and other commodity markets. Consider that the fair market value of natural gas in Alaska is close to zero because there is severely congested outbound capacity. Prices throughout the world are higher than they would otherwise be because of the bottleneck in Alaska. The same holds true for Russia, Iran, Venezuela, Iraq, and Saudi Arabia, all of which have congested outbound transportation and as a result suffer low indigenous prices. Prices would be substantially elevated in the event of the addition of LNG or other export facilities.

Congestion of the type postulated here creates incentives to add transportation capacity along the congested route or build new capacity directly in the downstream demand region in search of the rents along the congested link. Region A is the stereotypical "downstream from a congestion point" area. It is an area of high price and high margins for new entrants. Developers would be incented to build power plants in that region, not regions upstream.

2.7 Market Power Exercised Along the 1-to-A Transportation Link

Transportation of liquids, gas, and power was for a long time in the United States regarded as a natural monopoly requiring regulation and intervention. Such is assuredly not true for LNG or crude oil shipping and may not be true for backbone interstate gas, oil, and power transmission. This section considers what happens if one of the links were owned by an unregulated monopolist. Suppose there is a single owner of the 1-to-A link who fully exercises his or her market power. How much transportation rent will he or she capture? To what degree would he or she be motivated to restrict flows and alter prices? We answer this by making a series of substitutions in equations (1)-(4) to eliminate the four prices p_A, p_B, p_1, p_2 and the four quantities q_A, q_B, q_1, q_2 and express everything in terms of the four transportation link flows q_{1A}, q_{1B}, q_{2A}, q_{2B}:

$$q_{1A}(3-\frac{3}{2}q_{1A}-\frac{1}{2}q_{1B}-q_{2A})\geq 0$$
$$q_{1B}(2-\frac{1}{2}q_{1A}-q_{1B}-\frac{1}{2}q_{2B})\geq 0$$
$$q_{2A}(2-q_{1A}-3q_{2A}-2q_{2B})\geq 0$$
$$q_{2B}(3.5-2q_{2A}-\frac{1}{2}q_{1B}-\frac{5}{2}q_{2B})\geq 0$$

The first equation is the profitability to the owner of the 1-to-A link, so a Stackelberg monopolist who owned that link would maximize the first equation subject to the second through fourth equations acting as constraints. The solution, which tells what an untrammeled 1-to-A Stackelberg monopolist would do, is summarized in Table 6. Following are the netbacks, which do not work in this case either:

$$\text{A netback to 1}: p_A - \$1 = \$4.0682 - \$1 = \$3.0682 > \$1.9293 = p_1$$
$$\text{B netback to 1}: p_B - \$2 = \$3.9293 - \$2 = \$1.9293 = p_1$$
$$\text{A netback to 2}: p_A - \$2 = \$4.0682 - \$2 = \$2.0682 > \$3.4293 = p_2$$
$$\text{B netback to 2}: p_B - \$0.50 = \$3.9293 - \$0.50 = \$3.4293 = p_2$$

Notice that the rent along the pipeline 1-to-A has climbed all the way to \$2.1389 – 1 = \$1.1389. This rent is approximately twice as high as the former congestion case. Notice further that the monopolist has cut transportation throughput to such a degree that the price in ALL four regions—the two supply regions and the two demand regions—all increase when the pipeline monopo-

Table 6. Quantities and Prices and Differences from Reference Case – 1-toA Stackelberg Monopoly Case

Monopoly 1-A

	Quantity		Price		Quantity Difference		Price Difference
q1A	0.9318	pA	\$4.0682	q1A	-0.9318	pA	\$0.9318
q2A	0.0000	pB	\$3.9293	q2A	0.0000	pB	-\$0.2071
q1B	0.9268	p1	\$1.9293	q1B	0.5177	p1	-\$0.2071
q2B	1.2146	p2	\$3.4293	q2B	-0.1035	p2	-\$0.2071
q1	1.8586	pA-p1	\$2.1389	q1	-0.4141	pA-p1	\$1.1389
q2	1.2146	pA-p2	\$0.6389	q2	-0.1035	pA-p2	\$1.1389
qA	0.9318	pB-p1	\$2.0000	qA	-0.9318	pB-p1	\$0.0000
qB	2.1414	pB-p2	\$0.5000	qB	0.4141	pB-p2	\$0.0000

list restricts throughput. The monopolist wreaks havoc on all regions and makes money by so doing.

With a monopolist, the sheer magnitude of cutback is seen to be large. Keep in mind, the monopolist must not be able merely to cut production, he or she must actually unilaterally garner increased revenue and profit as a result of such cutback. Monopoly rents do not emanate from "cutting back." Monopoly rents come from making more profit on the reduced throughput than one would have made on the entire original flow before cutting back. Monopoly is not cutting back; monopoly is unilaterally monetizing any cutback. Monopoly rent has been poorly understood in the sense that people forget that the profits from cutback have to exceed the profits from no cutback.

3. CONCLUSIONS

There is no such thing as a local or localized price or quantity effect resulting from changes in a spatial network. Alas, conventional wisdom seems to assume that all price effects are local and if they proliferate outward, they are significantly attenuated as they go. We have shown that changes to demand, supply, and transportation in one region are transmitted to every geographic region throughout the spatial system, and are felt in equal magnitude if transportation is abundant. In spatial energy markets, nothing is local. All localized changes immediately proliferate throughout the entire interconnected set of supply and consumption markets to become universal changes. Even though prices are nodal in spatially distributed markets, they are systematically and strongly interlinked. No market with existing or prospective transportation is an island. Conventional wisdom seems ubiquitously to pine for netbacks to always work. Alas, they do not; and entities who rely on them can suffer systematic price discounts, which is undesirable and unnecessary. There are no rules of thumb to calculate or explain prices. One has to solve equations explicitly and completely, and one cannot sidestep the need for models to do so. There are no shortcuts or experts here.

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Globalisation of Natural Gas Markets – Effects on Prices and Trade Patterns

Finn Roar Aune, Knut Einar Rosendahl** and Eirik Lund Sagen****

The regional natural gas markets are expected to gradually become more integrated. The major driving forces are lower LNG costs, more spot trade, and increased need for imports into the US and other key markets. In this paper we examine various scenarios for a future global gas market, particularly focusing on natural gas prices and trade patterns. We use a numerical model of the international energy markets, with detailed modelling of regional gas production and international gas transport. Scenarios with different assumptions about future demand and supply conditions are simulated. Our results suggest that trade between continents will grow considerably over the next couple of decades, and that prices in the main import regions will remain around current levels. However, significant constraints on exports from the Middle East may alter this picture.

1. INTRODUCTION

The natural gas markets in different regions are gradually becoming more integrated. This globalisation process is due to several reasons. First, the costs of transport (especially LNG – Liquefied Natural Gas) have fallen significantly over the last 1-2 decades (except for the last few years), and constitute a much lower share of the wholesale price of gas than 15-20 years ago (Brito and Hartley, 2007). Second, gas reserves in the main consuming areas are gradually reduced compared with annual consumption,[1] which implies an upward pressure on domestic

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* Statistics Norway, Research Department, Kongensgt. 6, N-0033 Oslo, Norway. E-mail: finn.roar.aune@ssb.no.

** Corresponding author. Statistics Norway, Research Department, Kongensgt. 6, N-0033 Oslo, Norway. E-mail: knut.einar.rosendahl@ssb.no.

*** Statistics Norway, Research Department, Research Department, Kongensgt. 6, N-0033 Oslo, Norway. E-mail: eirik.lund.sagen@ssb.no.

1. In the EU, the ratio has fallen from 9 to 6 years since the year 2000 (BP, 2008).

prices and increased imports of gas. With a larger share of gas reserves located in a few geographical locations such as Russia and the Middle East, intercontinental trade becomes more profitable. Third, an increase in the share of spot trade means that short-term price differences between regions may be more easily exploited by re-routing the gas (especially LNG), cf. IEA (2006).[2]

In this paper we look into future scenarios for a globalised natural gas market. Using a detailed numerical partial equilibrium model of the international gas, oil and coal markets, we explore how regional gas prices and trade patterns may develop until 2030 under different scenarios about future market conditions. Not surprisingly, we find that intercontinental trade will grow considerably over the next decades, reducing the upward pressure on gas prices in import regions such as Europe and North America. This result depends crucially, however, on the absence of constraints in the expansion of the gas industry in the Middle East. If the growth in gas production from this region is suppressed, we may see quite higher prices from 2020 onwards, and less intercontinental trade.

Our numerical analysis builds on the assumption that the international gas markets are liberalised and integrated. This is in contrast with the results in Siliverstovs et al. (2005), who find no sign of price integration between the North American market and the European/Japanese markets in the period 1994-2003. Their findings may reflect that the gas markets in continental Europe and North-East Asia are not yet fully liberalised. On the other hand, the gas markets in North America and the UK have been liberalised for more than a decade, with prices linked to liquid spot markets, and Neumann (2007) finds increasing convergence of spot prices in the US and the UK based on data for 1999-2007. Moreover, the EU has adopted two directives on gas liberalisation over the last decade (EU, 1998, 2003), although the speed of implementation has been quite slow in several key countries (Haase, 2008). With rapid growth in international spot trade, gas suppliers may find it easier to sell their gas in new markets, especially in the short term. Jensen (2004) claims that a moderate level of spot trade may be sufficient to balance the regional markets. Thus, we believe that the international gas markets are heading towards a globalised market, although with region-specific prices.

Whereas gas consumption in OECD regions has grown slowly over the last decade, consumption outside OECD and the former Soviet Union has increased by more than 5 per cent annually since mid 1990's (BP, 2008). In China, gas consumption more than tripled from 1997 to 2007. A similar picture is seen on

2. In contrast to the more liquid crude oil market, LNG spot (or short-term) trade is often defined as contract transactions with terms of one year or less (Morikawa, 2008). Although cargo-by-cargo spot transactions seem to remain limited for the LNG industry, Trinidad has for several years made swap LNG deals to arbitrage from US-Europe price differences. In March 2008, Oman was the first Middle East country to redirect LNG cargoes from Europe to a more profitable Asian market (Energy Business Review, 21. March 2008). In addition, transactions known as "Equity LNG" and "Branded LNG" have entered the business, meaning that a non-consuming buyer enters a mid/long-term contract without specifying the cargo destination.These contracts, which could be interpreted as spot or short-term transactions, accounted for 37% of the LNG contract volumes for the combined Europe and US deliveries in 2007 and may reach 64% by 2015 (Morikawa, 2008).

the supply side, where gas production in the OECD has been rather constant since the turn of the century. On the other hand, production both in the Middle East and in Africa has more or less doubled over the last decade. Although intercontinental trade has been modest so far, some arbitrage trading has occurred in the Atlantic Basin, and the Middle East has to some extent become a swing supplier to both South and East Asia and the Atlantic Basin. So far, most of the LNG from the Middle East has been shipped eastwards, to India, Japan and South Korea, and only about 15 per cent to the Atlantic Basin (BP, 2008).

Besides the studies presented in EMF (2007) (and in this special issue), there have been few previous numerical analyses of globalised natural gas markets. One exception is Rosendahl and Sagen (2009), who examine the effects of transport cost reductions on gas prices in different regions (using the same model as in this paper). They show that gas prices in some import regions may increase when transport costs decline, e.g., because of different choice of transport mode or because of different transport distances between trading regions. Numerical analyses of the European gas market are found in Golombek et al. (1998), Boots et al. (2004) and Egging and Gabriel (2006), whereas MacAvoy and Moshkin (2000) and Gabriel et al. (2005) simulate the North American gas market.

In the following section we briefly describe the numerical model FRISBEE. Then we go on to present the simulation results of future scenarios in Section 3. Finally we conclude.

2. MODEL DESCRIPTION

We use a numerical model of the international energy markets called FRISBEE.[3] It is a recursively dynamic partial equilibrium model with 13 global regions, cf. Table 1. Supply and demand of fossil fuels and electricity are modelled in each region. FRISBEE accounts for discoveries, reserves, field development and production of oil and natural gas, distributed on regions and field groups. Supply of coal and electricity are modelled in less detail. There are three demand sectors in the model: 'Manufacturing industries', 'Power generation', and 'Others' (including households). All markets clear each year, and annual, regional supply, demand, prices and trade flows are among the outputs of the model. Seasonal variations in demand and supply are not included in FRISBEE, which means that variations in e.g. trade directions over the year are not captured by the model. The base year of the model is 2000, and it is programmed in GAMS (Brooke et al., 2005).

3. See Aune et al. (2005) for a more extensive presentation of the FRISBEE model. Aune et al. focus on the oil market, but natural gas supply (and demand) is modelled quite similarly as oil supply, so most of the model description carries over. Rosendahl and Sagen (2009) also provide a (more brief) description of the gas market modelling.

Table 1. Regions in the FRISBEE Model

Industrialised regions	Regions in transition	Developing regions
Canada (CAN)	Caspian region (CAR)	Africa (AFR)
OECD Pacific (OEP)	Eastern Europe (EEU)	China (CHI)
USA	Russia/Ukraine/Belarus (RUB)	Latin America (LAM)
Western Europe (WEU)		OPEC-Middle East (OPM)
		Rest-Asia (RAS)
		OPEC-Africa (OPA)

Natural gas demand is a function of the end-user prices of all energy goods. The own price elasticities for 'Manufacturing industries' and 'Others' are on average around -0.3 in the long run (around -0.1 in the short run). Cross-price elasticities are in general small. In the long run, gas demand is particularly dependent on income growth – (per capita) income elasticities are on average around 0.6. The elasticity of population is set equal to one. Finally, a moderate, exogenous energy efficiency rate is assumed (0.25% p.a. within OECD and 0.5% p.a. outside OECD). Fuel demand in the 'Power generation' sector is driven by existing capacities and generation costs (including fuel prices) for different technologies, as well as the electricity price. Substitution possibilities are thus much higher in the power sector than in the two end-user sectors.

Traditionally, the natural gas markets in Europe and to some degree Asia-Pacific have been dominated by only a few large players, both upstream and downstream, and the markets have been highly regulated. As the gas markets become more integrated, the potential for upstream market power diminishes.[4] Moreover, liberalisation processes are taking place both in OECD and non-OECD regions (IEA, 2006), and this is gradually reducing the market power of large, downstream companies. The extent of spot trade is growing fast, and gas price indexation is partially replacing the oil price link in long-term contracts (Cornot-Gandolphe, 2005).[5] Consequently, although it might be seen as a simplification of the current market structure, in our future scenarios for the global natural gas markets we assume fully competitive and liberalised markets.

FRISBEE distinguishes between (oil and gas) fields in production, undeveloped fields and undiscovered fields. Data on field characteristics are based on an extensive database of global petroleum reserves in the year 2000, and data on production costs are based on the same source. Supply from developed fields in the model is set so that marginal operating costs equal producer prices net of

4. Gas exports from Russia (the world's largest gas holder and exporter) constitute only 5 per cent of global production (BP, 2008), and there are concerns about Russia's ability to stabilize its future export volumes (Sagen and Tsygankova, 2008). The potential for market power increases if several countries form a cartel, which is one of the alternative scenarios we consider.

5. Although there is no formal link between oil and gas prices in the model, prices of fossil fuels (and electricity) are partially connected through the (small) cross-price elasticities, and through the competition between different power technologies (cf. Hartley et al., 2008).

gross taxes. Operating costs are increasing functions of production, but are generally low unless production is close to the fields' production capacity; then they increase rapidly. The cost functions are calibrated based on data on production costs in different locations.

Oil and gas companies may invest in new fields and in reserve extensions of developed fields. Investments decisions are driven by expected net present values (NPV), which are calculated for four field categories in each of the 13 regions.[6] Expected NPV depends on expected prices (adaptive), a pre-specified required rate of return (set to 10 per cent in real terms), unit operating and capital costs, and net and gross tax rates. Unit capital costs are convex in the short term, and increase when the pool of undeveloped reserves declines (for new fields), and when the recovery rate rises (for reserve extension).

New discoveries are modelled in a simpler way. The amount of discoveries depends on expected prices and expected undiscovered reserves in each region (USGS, 2000).

All arbitrage opportunities are assumed to be exploited in the model, so that price differences between two regions never exceed the corresponding transport costs. Unit costs of LNG and pipelines are assumed to be constant in this analysis. Both capital and operating costs are included in the cost figures, except for pipeline capacities existing before 2007 (where only operating costs matter). Total transportation costs are linear functions of the distance between the regions. No geopolitical or other constraints are restricting investments in new transportation capacity in the model. Each year the cheapest transport technology between a pair of regions is chosen (i.e., LNG or pipeline). Thus, a region may import both via LNG and pipeline transport, but not from the same region. Data on unit transport costs are mainly based on OME (2001).

3. FUTURE SCENARIOS FOR A GLOBALISED GAS MARKET

In this section we present different scenarios for a globalised natural gas market towards 2030. Obviously, there are many uncertainties about how this market will evolve, not only to what degree the regional markets will be integrated. Thus, the quantitative results should be interpreted with caution. Perhaps most interesting is the comparison between scenarios, which will demonstrate the effects of some potentially important driving forces. Table 2 provides a brief overview of the different scenarios.

6. Classification of categories differs across regions, e.g. according to onshore vs. offshore, deep vs. shallow water, field size.

Table 2. Overview of Scenarios

Scenarios	Key assumptions
Reference Scenario	Based on EMF (2007) and EIA (2006)
High Demand Scenario	GDP annual growth rate increased by 0.5%
Constrained Export Scenario	Exports from Russia and OPEC-Middle East constrained at 2005 levels + volumes under construction
Middle East Cartel Scenario	Exports from OPEC-Middle East are set so as to maximise export revenues from this region

3.1 Reference Scenario

The Reference Scenario assumes a rather constant real oil price between $50 and $60 per barrel, and an annual average growth in world real GDP of 3.8 per cent (growth rates vary between regions). The global gas market is assumed to behave competitively, without any constraints in production, transport or distribution of gas. Costs of producing gas from a specific field are exogenously reduced over time (0.5-1.5 per cent p.a.), but unit costs may still rise because the cheapest fields are extracted first. Transport costs are held constant (in real terms) at 2003 levels. Even though costs of LNG have declined considerably since the beginning of the 1990's, costs have increased lately, and it is hard to know whether further technological progress may push the unit costs further down in years to come. Energy and environmental policies are fixed at their base year levels, which mean that we disregard any effects from the Kyoto protocol and any future climate agreements on the gas market. Policies to reduce CO_2-emissions vary a lot, and may in general have ambiguous effects on gas demand, so it is difficult to say how this could have affected the numerical results. Although we refer to this scenario as the Reference Scenario, it is not necessarily the most realistic one (more like a benchmark scenario).

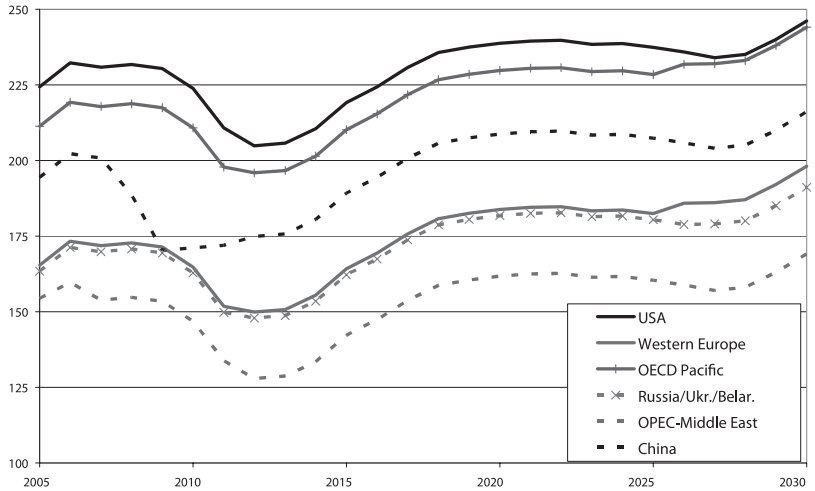
Figure 1 shows how the wellhead prices develop in selected regions up to 2030 in the Reference Scenario. We notice that the prices increase modestly in all regions in the second half of this time period, but prices in 2030 are only 10-20 per cent higher than in 2005 (in real terms). This result reflects that there are sufficient gas reserves in the world (at affordable costs) to meet the expected demand growth over the next couple of decades. However, as the cheapest reserves are extracted first within each region, the prices of natural gas will tend to rise further into the future (despite new discoveries and moderate technological progress).[7]

The figure further shows that the price differentials between regions are rather constant through time. The explanation for this is that the price differential between a pair of trading regions is equal to the unit costs of transport between these two regions, and these costs are assumed to be constant in the Reference

7. Significantly more new discoveries or more rapid technological progress in energy production (either for gas or for close substitutes) may counteract this upward pressure on the gas price (which is due to gas being a non-renewable resource).

Scenario. Import regions that are far away (in terms of transport costs) from key export regions will typically face higher prices than import regions that are closer. That's why prices in the US and OECD Pacific are higher than in Europe.

Figure 1. Wellhead Gas Prices in Selected Regions in Reference Scenario
$\$_{2000}$/toe

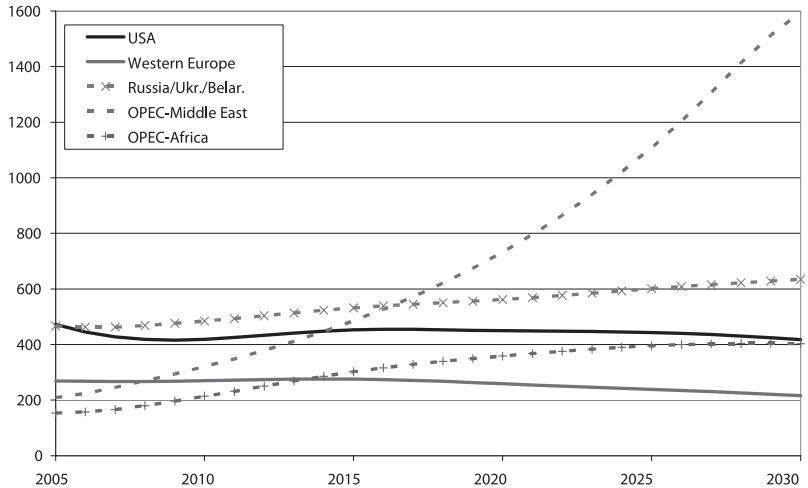


Figures 2-3 show the development in gas production and consumption in selected regions in the Reference Scenario. The most striking result in Figure 2 is the dramatic increase in gas production in OPEC-Middle East. Annual growth from 2005 to 2030 is 8-9 per cent, which is due to a very large resource base combined with relatively low production costs. Although actual growth since 2000 has been in the same range (BP, 2008), it may be questioned whether such high growth rates are sustainable for 2-3 decades. Thus, two of the alternative scenarios we consider assume lower growth rates (either explicitly or implicitly). Production in OPEC-Africa also grows considerably, especially in the first half of this period, but the growth potential is much more limited than in the Middle East. Russia, which holds a quarter of the global gas reserves, also increases its production, but only modestly due to high production costs compared with e.g. the Middle East.

Another interesting observation from Figure 2 is that gas production in the US and Western Europe is only modestly reduced up to 2030 (by 12 and 19 per cent from 2005, respectively). This is particularly interesting as the R/P-ratio (reserve over production) in the US was only 11 years at the end of 2007 (BP, 2008). Remaining reserves in the US have actually increased each year since 1998 according to BP. This is mainly due to upgrading of non-conventional gas resources, which counteracts the more significant reduction in conventional gas production. The future growth in non-conventional gas extraction in the US will

have significant bearings on global trade patterns in the coming decades. Lower than predicted growth potential could lead to much more imports of LNG, whereas higher than predicted growth rates could make North America self sufficient for a longer period of time.

Figure 2. Production of Gas in Selected Regions in Reference Scenario. Mtoe/year



Consumption of natural gas increases in all regions in the Reference Scenario, but there are significant regional differences (see Figures 3a and 3b). Among OECD regions, consumption grows much stronger in Europe (and Canada due to tar sand production) than in the US and OECD Pacific. This may be explained by consistently lower prices in Europe than in the other OECD regions (cf. Figure 1), which makes gas power more competitive (especially compared to coal) in Europe than in the US and Japan.

The strongest growth in gas consumption is clearly seen outside OECD, particularly in China where consumption more than quadruples from 2005 to 2030 (though from a rather modest level). Other parts of Asia, Latin America and Africa also experience high growth rates. Gas demand in Russia grows faster than in OECD regions, but slower than outside OECD. We have assumed that Russian end-user prices are gradually increased in line with official governmental plans, and this dampens the demand growth somewhat.

In the Reference Scenario, there is a gradual increase in transatlantic trade over the time horizon. In 2020 annual trade over the Atlantic is 114 Mtoe per year, and this increases to 325 Mtoe per year in 2030. The volumes of trade depend highly on the assumptions about costs of LNG. As costs of liquefaction have risen significantly since 2003 (i.e., our benchmark for transport costs), the

Figure 3a. Consumption of Gas in Selected Regions in Reference Scenario. Mtoe/year

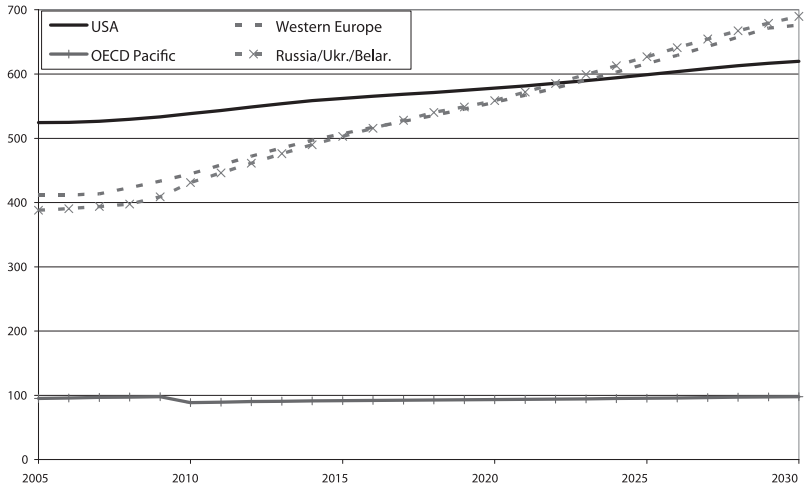
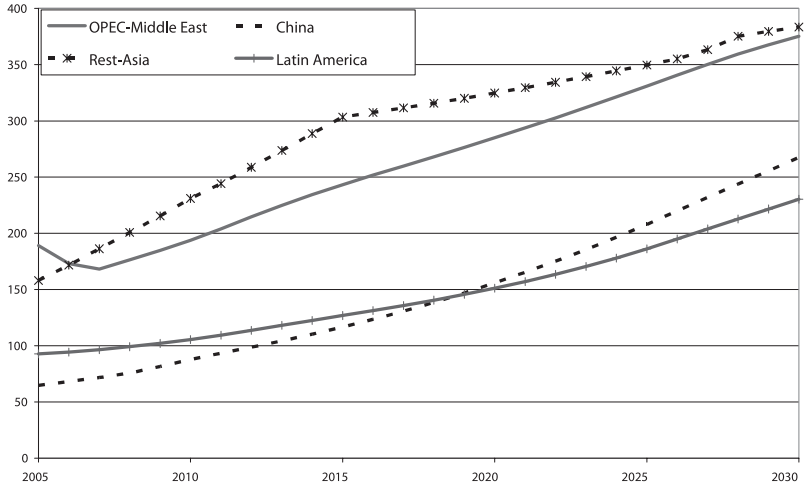


Figure 3b. Consumption of Gas in Selected Regions in Reference Scenario. Mtoe/year



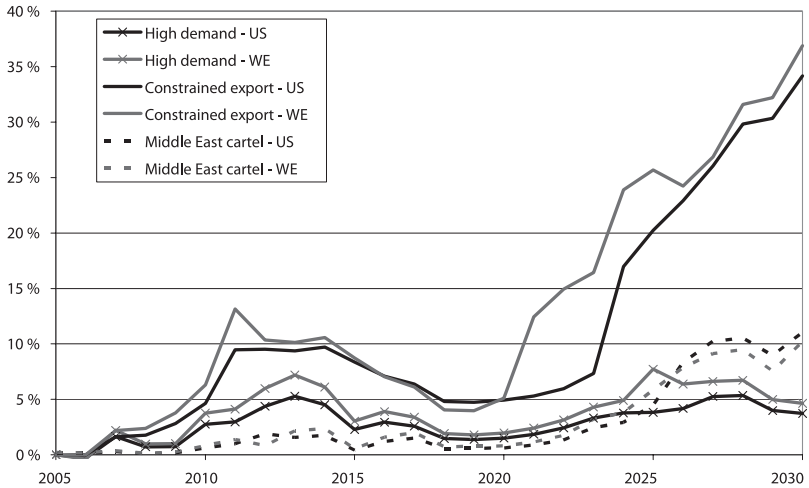
Reference Scenario may overestimate the development in transatlantic trade.[8] On the other hand, FRISBEE only models annual prices and volumes, and thus short-term arbitrage options are not taken into account.

3.2 Alternative Scenarios

In this subsection we focus on three potentially important driving forces for the international gas markets. These are economic growth, supply constraints and market power (see Table 2). We want to examine to what degree these factors may influence the outcome of the gas market.

Figure 4 shows how gas prices in the US and Western Europe are changed in the three alternative scenarios (compared with the Reference Scenario). As expected the prices increase in all scenarios, either because of higher growth in demand or because of reduced gas supply. In particular, a constraint on exports from the Middle East and Russia at current levels (including volumes under construction) leads to significantly higher prices after 2020. This is not surprising, given the production growth in OPEC-Middle East in the Reference Scenario (see Figure 2). However, such a constraint seems rather pessimistic, unless there is a significant change in the (geo)political situation in the Middle East.

Figure 4. Percentage Changes in Gas Prices in Selected Regions in Alternative Scenarios (Compared to Reference Scenario)

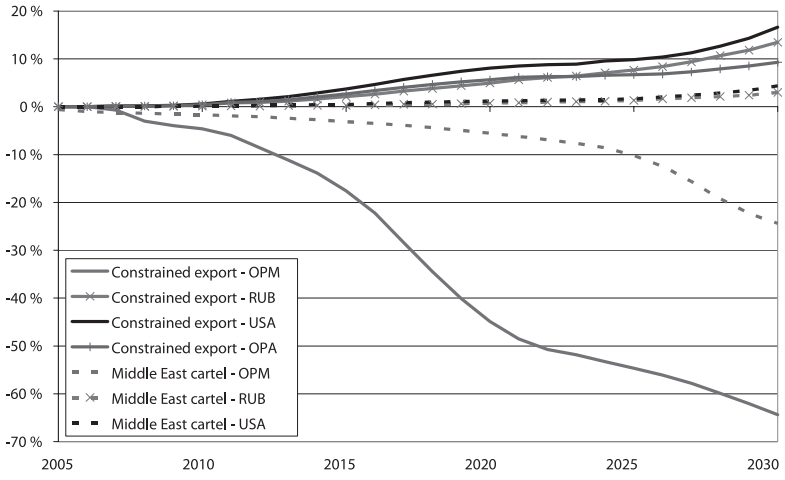


8. Rosendahl and Sagen (2009) look into the effects on prices and transatlantic trade of different assumption about costs of LNG and pipelines.

On the other hand, cartel behaviour by the OPEC countries in the Middle East has only small effects on the gas prices, at least until 2020.[9] The reason is that OPEC-Middle East reduces its supply (and export) only moderately in the Middle East Cartel Scenario; cf. Figure 5. This indicates that there is limited potential for market power in a fully integrated global gas market, unless a larger group of countries joins the Middle East in this respect (e.g., Russia or OPEC countries in Africa). In a less integrated global market, however, OPEC-Middle East may find it more profitable to cut back on supply in order to push prices upwards in some import regions.

As seen in Figure 5, Russia actually increases production in the Constrained Export Scenario, even though its export is constrained at current levels. The explanation is simply that Russia's export is gradually falling in the Reference Scenario, as growth in domestic demand outpaces its supply growth. This is in line with previous studies by e.g. Sagen and Tsygankova (2008). When exports from OPEC-Middle East are constrained, prices in import regions increase, and thus Russia finds it profitable to increase its export. We further see that production in other regions such as OPEC-Africa and the US increase in this scenario. US production rises by more than 10 per cent after 2025, which means that the US import share of gas in 2030 is reduced from one third in the Reference Scenario to only 4 per cent in the Constrained Export Scenario. In Western Europe the corresponding import share is reduced from two thirds to about 50 per cent.

Figure 5. Percentage Changes in Gas Production in Selected Regions in Alternative Scenarios (Compared to Reference Scenario)*

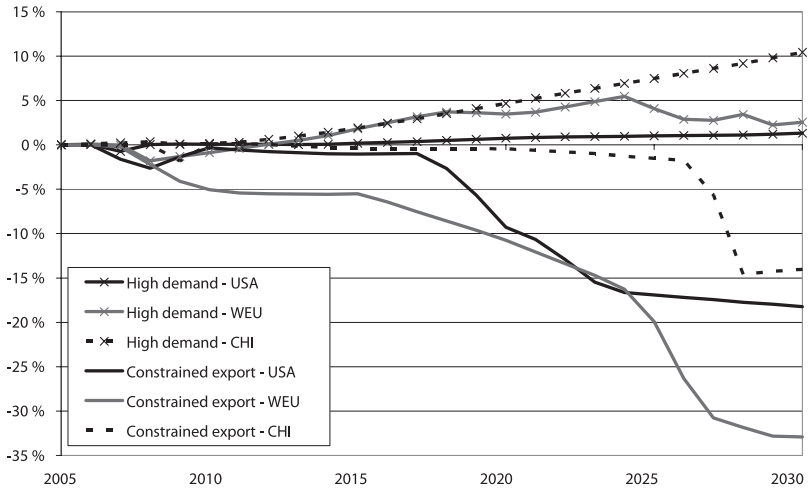


*OPM: OPEC-Middle East; RUB: Russia/Ukraine/Belarus; OPA: OPEC-Africa

9. In the Middle East Cartel Scenario OPEC-Middle East introduces a fixed export duty so as to maximize the sum of producer surplus (including export revenues), domestic consumer surplus and government income.

The reduced import share in the Constrained Export Scenario is not only due to increased domestic production, but also to reduced consumption, cf. Figure 6. In particular, with higher prices as a result of constrained supply from the Middle East, natural gas loses significant market shares in the regional power markets. Both in the US, Western Europe and China the *growth* in gas power production is reduced, and eventually the level of production starts to fall, too. Coal power production increases correspondingly.

Figure 6. Percentage Changes in Gas Consumption in Selected Regions in Alternative Scenarios (Compared to Reference Scenario)

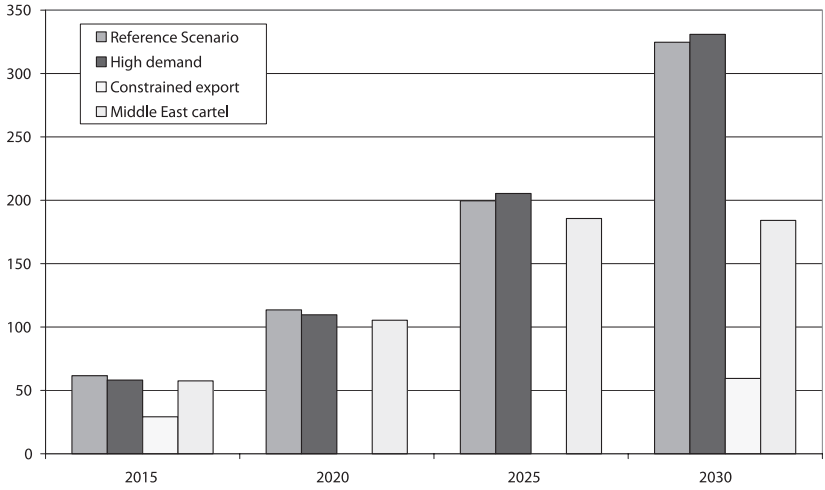


In contrast, in the High Demand Scenario, with higher GDP growth, natural gas demand grows faster, particularly in China. Demand growth in OECD regions is only moderately increased. Although global GDP in 2030 is 13 per cent higher than in the Reference Scenario, global consumption of natural gas is merely 3 per cent higher. The increased prices of gas are the main explanation for this modest effect.

Gas trade across the Atlantic Ocean develops quite differently in the various scenarios, see Figure 7. In the Reference Scenario there is a significant growth, particularly after 2015 when production in OPEC-Middle East gets very large. Transatlantic trade in the High Demand Scenario is almost similar to the Reference Scenario, as most of the demand growth takes place in Asia. On the other hand, in the Constrained Export Scenario there is little or no trade across the Atlantic as increased prices in North America stimulates own production and more imports from Latin America. Eventually, however, imports from across the Atlantic Ocean are needed to balance the American market despite high prices also in Eurasia. In the Middle East Cartel Scenario, there are small trade differ-

ences from the Reference Scenario until the end of our time horizon, which is consistent with the price and production changes observed in Figures 4 and 5.

Figure 7. Annual Gas Trade Across the Atlantic Ocean (to North America) in Different Scenarios. Mtoe/year



The evolution of global LNG trade follows a similar pattern as transatlantic trade. In 2015 LNG trade between regions amounts to 4-5 per cent of global gas production. In the Reference and High demand scenarios this share grows to 8-9 per cent in 2030, versus 6 per cent in the two scenarios with some constraint on gas export from the Middle East. In addition to trade across the Atlantic, LNG is also shipped to some extent from Latin to North America, and between the Asian regions.

4. CONCLUSIONS

Globalisation of natural gas markets will substantially increase the level of intercontinental trade, and prices in different regions will become more integrated. Without significant constraints on exports from the Middle East, prices in import regions may remain around or just above current levels. These are the main results from our numerical simulations of the international gas markets.

The key to the future natural gas markets lies in the Middle East. We have seen that a constraint on the export of gas from this region at current levels (including volumes under construction) may lead to much higher prices of natural gas after 2020. Consumption of gas will grow considerably slower, particularly in the power market, leading the way for further increases in coal power production.

However, such a constraint on export is not profitable for the Middle Eastern gas producers. If they behave like a gas cartel, maximising their joint

consumer and producer surplus (including export revenues), they are more likely to choose a moderate reduction in their production growth. In this case, prices of gas are hardly increased until after 2020, when there is a moderate price increase compared to our Reference Scenario. Expanding the cartel to include other countries such as Russia or OPEC countries in Africa may increase its market power. However, we find that Russia's export is gradually declining, reducing its potential gains from any cartelisation.

There are several uncertainties about the future gas markets that are not analysed in this paper. We have already mentioned the costs of LNG, which will be determinant for the globalisation process. Another crucial factor is the international focus on climate change and energy security, which may lead to significant policy measures affecting the gas markets. When it comes to climate change, natural gas is a cleaner fuel than other fossil fuels, but obviously not as carbon-free as renewables and nuclear. Thus, a moderate climate policy may stimulate gas consumption, whereas a strong policy may have the opposite effect in the long run as carbon-free technologies make significant progress.

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The Impact of High Oil Prices on Global and Regional Natural Gas and LNG Markets

Justine Barden, William Pepper**, Vineet Aggarwal****

Oil prices are notoriously hard to predict, but they are an important input in many energy and economic models. This paper explores the effects of different oil price assumptions on natural gas markets (production, consumption, prices in different regions) in the International Natural Gas Model (INGM). Three cases from the INGM are presented: a reference case, a high oil price case and a second high oil price case, where gas-to-liquids (GTL) capacity additions are constrained. The results show that regardless of constraints on GTL capacity additions, higher oil prices lead to higher production and consumption of natural gas. However, when GTL capacity is allowed to expand, higher oil prices generally lead to higher natural gas prices and to less gas consumption in the electric power and industrial sectors as they switch to cheaper fuels and more natural gas is diverted to the production of GTLs.

1. INTRODUCTION

Natural gas markets have historically been regional with some linkage with international petroleum markets. However, as natural gas transportation capacity, including pipeline capacity and the capacity to produce, transport and receive liquefied natural gas (LNG), continues to expand, regional gas markets are increasingly becoming linked and moving toward a global market for natural gas. The linkages between natural gas and oil markets, and their future evolution, present a more complicated picture.

Oil and gas markets are linked in several ways. Natural gas competes with oil in several consumption sectors, making oil and gas substitutes. Natural

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* US Energy Information Administration.
** Corresponding author, ICF, International; email: BPepper@icfi.com.
*** ICF, International.

gas liquids (NGLs) are produced alongside natural gas and are then stripped from the wet gas stream, with the NGLs sold into oil markets and the dry gas sold separately. The GTL process uses natural gas as a feedstock to produce low-sulfur diesel and other oil products. Further, oil and gas compete for exploration and drilling resources, and many current natural gas contracts base the contract price of natural gas on market oil prices. These last two linkages between oil and gas markets, however, are not accounted for in the INGM.

The INGM attempts to represent oil and gas competition in several demand sectors as well as the market affects of NGLs and GTLs. These multiple linkages between oil and gas markets lead to a complicated relationship between oil and gas prices in the model. Higher oil prices, generally, should stimulate increased consumption of natural gas in sectors where it can be substituted for oil. If this were the only way in which oil prices affected natural gas markets, one would expect the market price of gas to always rise in response to increased oil prices, as increased gas demand drives up the gas price and increases gas supply to meet the elevated demand, thus balancing the market. However, higher oil prices also lead to higher NGL prices and spur increased production of NGLs, and of their byproduct, dry natural gas.

Because of how NGLs link oil and gas markets, higher oil prices can lead natural gas prices to either increase or decrease depending on the regional gas supply/demand situation. If the elevated gas demand attributable to the higher oil prices is less than the increased gas supply attributable to the higher NGL prices, then for natural gas markets to balance, the gas price must come down to further spur demand. If the opposite is true, and the increases to gas demand are greater than to NGL and gas supply, then gas prices will rise in response to oil prices, as would generally be the case with substitute goods.

Higher oil prices can also spur increased demand for GTLs, thus elevating demand for natural gas as a feedstock for the process. This increased demand for natural gas can push up natural gas prices, leading to lower consumption in other sectors which then limits the upward pressure on gas prices, as consumers switch to competing fuels. However, the affect of GTLs on gas markets is limited by the extent to which global GTL capacity can reasonably expand.

GTL facilities require large upfront capital expenditures and potentially many years to recover the investment. Also, there are fewer commercial scale GTL facilities in the world and fewer under construction than there are LNG facilities, or other types of gas assets. This means there is less information on and greater risk surrounding what it takes to construct and bring online a commercial scale GTL facility. This also means there are fewer experienced personnel to complete such a job. Additionally, because of the significant energy losses in the GTL process, sustained low natural gas prices and high product prices are required to support the investment. The alternative GTL scenario is a response to these considerable risks and the significant affect of the GTL capacity expansion assumptions on the way the model responds to alternative oil price scenarios.

2. DESCRIPTION OF THE MODEL

The International Natural Gas Model (INGM) was developed to enhance the Energy Information Administration's (EIA) long-term assessment of world natural gas markets. The INGM simulates the natural gas and LNG markets from production, through processing and transportation, to end-use for 60 nodes which are detailed in Barden et. al, Table TA-1 and summarized in Table 1, below. The nodes are generally defined based on their current or potential significance in the world gas markets, as a major producer, consumer or transit location for natural gas. INGM uses a linear program (LP) to simulate gas markets with an objective of maximizing the cumulative discounted sum of producer and consumer surplus in developing the market equilibrium, capacity investment decisions, and capacity utilization (see Hogan, 2002). The INGM simulates demand for natural gas and utilization of the capacity in three seasons: Winter, Summer, and Spring/Fall. Utilization of capacity can vary between these seasons.

Table 1. INGM Regions

Aggregate Reporting Region	Number of INGM Nodes	Notes
OECD North America	19	Includes 13 nodes for the U.S.
OECD Europe	4	Turkey and the Iberian Peninsula are separate
OECD Asia	4	Australia's Northwest Shelf and Australia/New Zealand Demand are separate
Non-OECD Europe and Eurasia	8	Includes 6 nodes for Russia, including 3 that are supply only nodes
Non-OECD Asia	11	Includes 3 nodes each for China and India
Middle East	6	Saudi Arabia, Iran and Qatar are separate
Africa	4	North and West Africa are separate
Central and South America	4	Brazil is separate

The key components of the model include natural gas and NGL resources by node, natural gas processing and transport capacity, and demand for natural gas and other fuels. Natural gas resources must be discovered and developed in INGM, creating reserves which then can be produced. The rate of discovery and development is a linear function of remaining economically recoverable resources, which is a function of the natural gas price and solved simultaneous with the natural gas prices. The percentage of economic resources that can be developed is constant over time. The base rate of production of reserves (the P/R ratio) is also constant over time but the model can increase the P/R ratio at a cost.

INGM accounts for removal of NGLs and the gas used in processing. The resulting dry gas can then be transported through a pipeline to a consuming node, converted to LNG, or consumed at the node. Natural gas that is transformed into LNG must, in an additional step, be transported by tanker along pre-defined

tanker routes and then regasified for use or pipeline transport at the destination node. Dry natural gas can also be converted to a liquid fuel at a GTL plant. Finally, natural gas seasonal storage is simulated to address seasonal variations in regional production and consumption.

The capacity and utilization of the gas processing, LNG liquefaction, LNG regasification, tankers, pipelines, storage, and GTL facilities are all modeled similarly. Capacity must exist or be added before it can be utilized. Capacity additions incur initial development costs, annual fixed costs, and variable costs depending upon the utilization of the capacity. The period from the initial decision to add capacity until the first date of utilization of the capacity, is usually five to six years for land-based assets and four years for LNG ships but varies depending on the type of capacity. The investment and operating costs for LNG and GTL facilities are provided in Table 2. The utilization of the capacity will result in energy use/losses which vary considerably by the asset type and within the asset type (e.g. pipeline fuel use).

Capacity for any asset type will be added and utilized, endogenously, if the value of the capacity is equal to the discounted cost of constructing and operating the capacity, including the cost of the natural gas used as feedstock (GTL plants) or consumed by the asset. Once capacity is constructed, the utilization of the capacity depends on the variable operating costs including the cost of the natural gas fuel or feedstock. It is possible for capacity to be built, utilized for a number of years, and then left un-utilized due to changing economics.

Table 2. Investment and Operating Costs for LNG and GTL Plants

Parameter	Liquefaction Plant	Small GTL Plant	Units
Capacity Increment	0.585	0.184	PJ/day output
Planning & Approval Period	2	2	Years
Planning & Approval Costs	0.5	0.5	$MM/yr
Investment Period	3	3	Years
Investment Costs	358.8	344	$MM/yr
Maximum Life	100	100	Years
Fixed O&M Costs	86	0	$MM/yr
Variable O&M Costs	0.093	0.976	$/GJ
Retirement Costs	0	0	$MM
Process Efficiency	92%	65%	

Demand for NGLs and GTL products are assumed to be unconstrained globally but demand for natural gas in the power generation and end-use sectors are modeled using a logit formulation based on starting demand estimates provided by EIA from their WEPS+ modeling system. The INGM allows for interfuel competition using the following equation:

$$S_{r,f,t} = (P_{r,f,t} + PA_{r,f})^{\alpha} / \sum_{f'} (P_{r,f',t} + PA_{r,f})^{\alpha} \quad (1)$$

Where $S_{r,f,t}$ is the share (fraction) of demand served by the fuel *f* in region *r* in year *t*, $P_{r,f,t}$ is the price of the fuel ($2006/GJ) for the region and year, PA_r is a calibration variable for the region and fuel and reflects both the ability to use the fuel for the sector (e.g., natural gas in road transport) and the regional access to the fuel, and α is the price elasticity which takes the values of -0.88 for the residential sector, -1.22 for the commercial sector, -2.06 for the transport sector, -1.54 for industrial cogeneration, -0.92 for industrial feedstock uses, -0.66 for other industrial uses, and -2.00 for power generation sector. The high elasticity for the transport sector is offset by large regional price adjustments for natural gas for that sector.

3. DESCRIPTION OF THE CASES

The INGM reference case is based on the reference case in the EIA's *International Energy Outlook 2008* (*IEO2008*), the U.S. Department of Energy's long-term assessment of world energy markets through 2030. The *IEO2008* consumption projections were used as starting demand numbers for the INGM reference case. The world oil price path assumptions for the reference case are also based on the *IEO2008* reference case. That said, the *IEO2008* reference case oil price path was devised in mid-2007, when oil was trading at about $70 per barrel—substantially lower than the $140 per barrel observed only a year later. In the INGM reference case, the 2008 average nominal oil price is set at $100 per barrel, falling to $93 for 2009, and continuing to decline to $68 in 2016 before gradually increasing to a 2030 nominal price of $113 per barrel ($74 per barrel in real, inflation-adjusted 2006 U.S. dollars). The price trajectories for the three cases are shown in Figure 1 and in Barden et. al., Table TA-2.

The INGM allows the user to place constraints on the expansion of pipelines, LNG facilities, and GTL facilities. In the short run, 2006 to 2015 (or sooner depending upon the capacity type), constraints have been used to reflect the status of current projects in planning and their potential to be fully developed. In the medium- and long-run, capacity expansions are constrained when the speed at which the new capacity expansions occur may be limited—not by supply or demand—but by the ability to develop potentially massive amounts of capacity in a short period of time. For example, pipeline expansions from the Russian-Caspian Region are limited to 1 petajoule per day (PJ/day) per year through 2020. Expansions of GTL facilities are limited to 0.37 PJ/day per three year period for key producing regions. In most cases, however, capacity expansions are not limited in INGM for the medium and long run. The constraints on pipeline, processing asset, LNG, and GTL capacity expansions are provided in Barden et. al., Tables TA-3, TA-4a, TA-4b, and TA-4c .

The 2006 beginning of year reserves and undeveloped resource assumptions are provided in Figure 2 and in Barden et. al., Tables TA-5 and TA-6, and

Figure 1. Crude Oil Price Assumptions

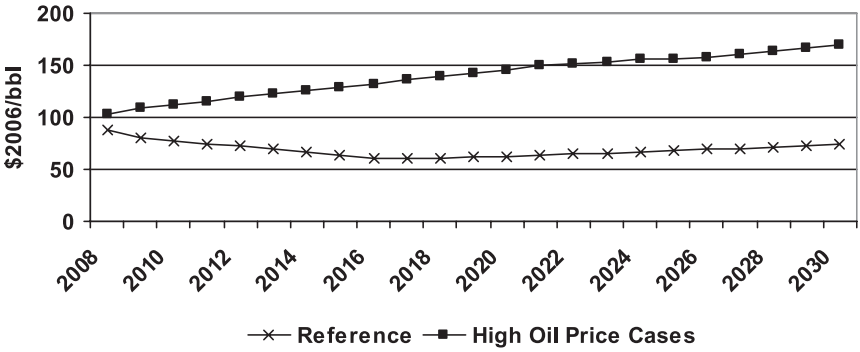
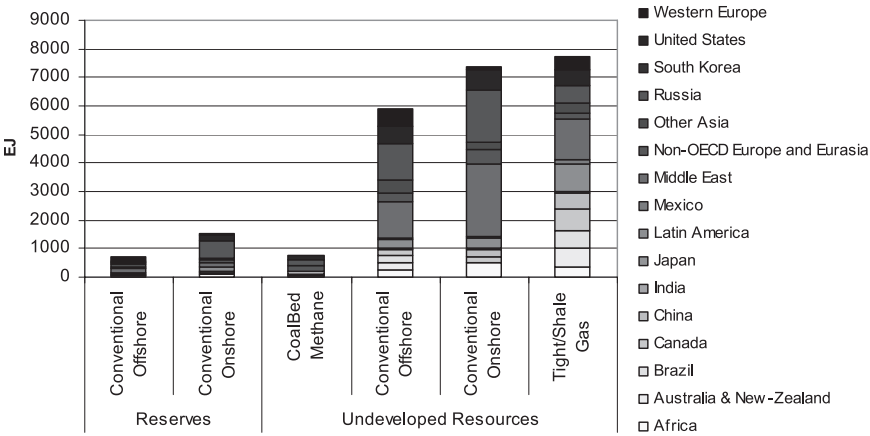


Figure 2. Reserve and Undeveloped Resource Assumptions



are based on a number of sources, including the U.S. Geological Survey (USGS, 2005a; USGS, 2000) and the U.S. Minerals Management Service (MMS, 2006) for conventional resources, and Holditch (2006), Kawata et al. (2001), Rogner (1997), UNEP (2002), and USGS (2005b) for unconventional resources. The conventional resource data from the USGS and MMS includes information such as field size, drilling depth, water depth (if offshore), and impurity content. This information was combined with a drilling/production model and used to estimate the cost of exploiting the resource. The sources for unconventional resources were combined with estimates of recovery rates and exogenous estimates of development costs to estimate the cost of exploiting the resource. The cost estimates and

resources estimates for both conventional and unconventional resources were then input into the INGM as supply curves.

For unconventional resources, the Holditch reference provides estimates of gas-in-place after a study of the Rogner, Kawata and Fujita publications. The article further asserts that the volume of undiscovered resources is around 10% of the total gas-in-place for the United States We increased this estimate based on recent activity with U.S. shale gas, where resource finds and development are increasing more quickly than was expected in the past yielding undiscovered unconventional resources of 8500 EJ globally. In order to develop extraction cost curves for these resources, we used average nodal field size distributions and well depths from conventional resources. Unconventional resources are discovered, developed, and produced like conventional resources using a linear formulation with a constant fraction of economic undeveloped resources that can be developed in each year and a P/R ratio that can be increased with an increase in cost.

The first sensitivity, heretofore referred to as the HWOP case, modifies the reference case assumptions, using a higher oil price path. This price path reflects the higher crude oil prices observed in mid-2008, and increases the estimates for future world oil prices consistent with a view of the markets that crude oil prices will stay high and increase even more in the future.

In the HWOP case, the average nominal oil price is set at $127 per barrel for 2008 and $133 for 2009, with prices increasing continuously but gradually from that point, reaching a 2030 nominal price of $266 per barrel ($169 per barrel in real 2006 U.S. dollars). Price assumptions for NGLs and GTL products are adjusted accordingly. The constraints on GTL capacity additions are the same in the HWOP case as in the reference case. The second sensitivity, from here on referred to as the HWOP_LGTL case, modifies the HWOP case by restricting GTL capacity builds after 2015 to only those builds the model chose to make in the reference case.[1]

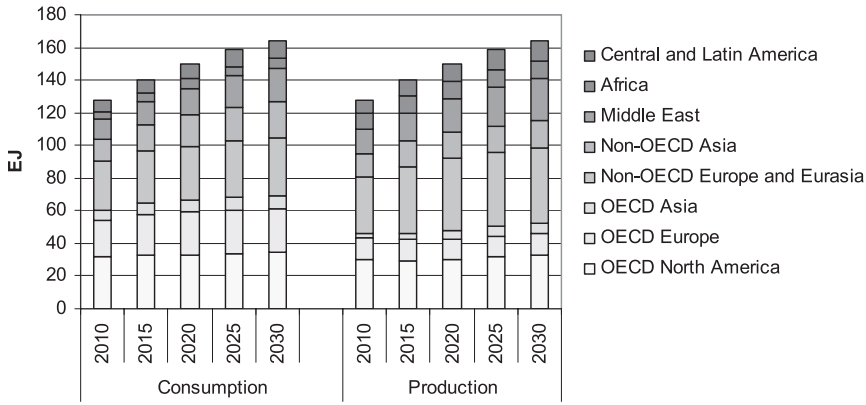
4. RESULTS

4.1 Overview/Global Perspective

The reference scenario describes a world where natural gas consumption and production increase significantly through 2030 with most of the growth in consumption occurring in the developing economies and the growth in production dominated by a few exporting regions that have significant natural gas resources. As shown in Figure 3, over two thirds of the increase in global consumption of natural gas occurs among emerging economies outside of the Organization for Economic Cooperation and Development (non-OECD): Asia, the Middle East, Africa, and Latin America. Moreover, nearly three-quarters of the growth in natu-

1. The LGTL case did allow for increased builds prior to 2015 for three regions reflecting current project plans.

Figure 3. Regional Consumption and Production of Natural Gas for the Reference Case



The consumption includes processing losses, own use, pipeline fuel use, and storage fuel use. The production excludes gas reinjected for pressure maintenance.

ral gas production occurs in the non-OECD Europe and Eurasia, the Middle East, and Latin American producing regions.

The majority of additional production from Russia and non-OECD Europe and Eurasia is transported to consuming regions through pipelines. Some of the additional gas production in the Middle East is transported to market through pipelines, but a larger share of natural gas from the Middle East and Northern Latin American producers is transported in the form of LNG. Annual LNG shipments are expected to increase from 8 exajoules (EJ) in 2007 to over 10 EJ by 2015 in the reference scenario and stay relatively constant through 2030. The reference scenario has limited exports of natural gas from Saudi Arabia, due primarily to the country's strategy of using natural gas for domestic electric power and industrial uses.

4.1.1 Demand

In the reference scenario, total consumption of natural gas, excluding reinjected gas, increases from 128 EJ in 2010 to close to 165 EJ by 2030, as shown in Figure 4. Nearly two thirds of the growth in consumption is in the industrial and power generation sectors. The percentage growth is greatest in the GTL sector, which accounts for 17 percent of the growth in total gas consumption. The transportation sector has the next highest percentage growth, but the share of global consumption in 2030 is expected to be low due to assumptions that the transport fleet will not change dramatically by 2030.

Figure 4. Global Natural Gas Consumption by Sector for the Reference Scenario

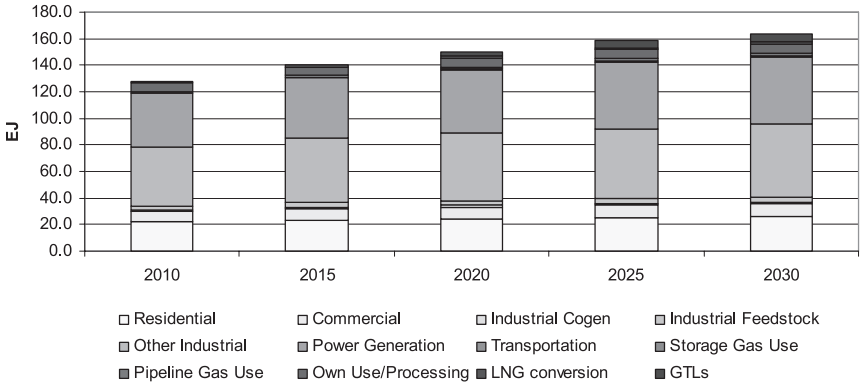
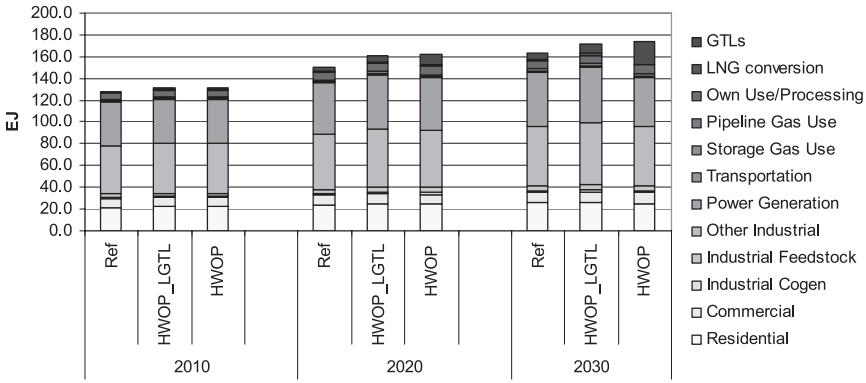


Figure 5. Natural Gas Consumption by Scenario and Sector



Higher world oil prices in the two alternative scenarios make GTL conversion more attractive and the use of natural gas for GTL conversion increases significantly unless constrained, driving up the price of natural gas in the producing regions and in many consuming regions. This actually results in non-GTL natural gas demand declining in many regions versus the reference case despite the much higher crude oil prices. The largest reduction in gas consumption is in the power generation sector. Figure 5 shows global natural gas consumption by sector in the reference scenario and the two higher world oil price scenarios. The consumption projections for all three of the scenarios can be found in Barden et. al., Table TA-7.

In the HWOP_LGTL scenario, where GTL capacity expansion is limited to the capacity expansion in the INGM reference scenario, the natural gas consumption increases in all end-use sectors, but with gas use in some sectors rising more than in others. The largest impact on natural gas consumption is found in the "Industrial Feedstock" and "Other Industrial" sectors.[2] This is because, excluding the transportation sector, these sectors account for the greatest use of liquid fuels and have the greatest potential for natural gas to displace petroleum liquids.

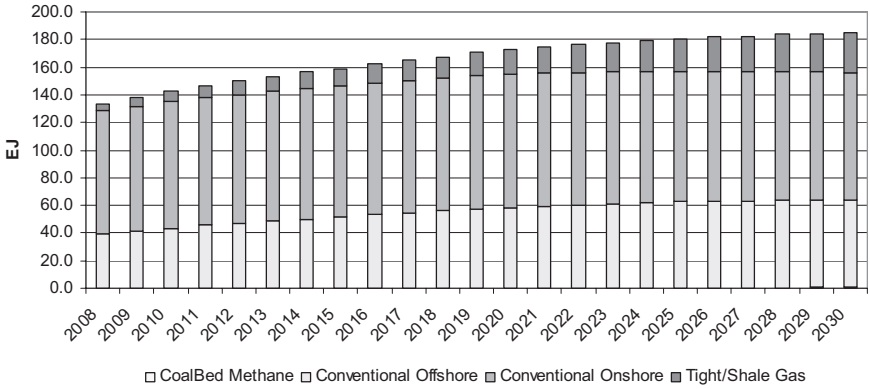
4.1.2 Production by Sector

In the reference scenario, the increase in global natural gas production comes from both conventional off-shore and tight/shale gas production (see Figure 6). Conventional natural gas production increases from under 130 EJ in 2008 to over 150 EJ by 2030. However due to reporting of current reserves, some unconventional production is included in conventional production in the model.[3] Hence, the reported production from the model would tend to underestimate current unconventional production and overestimate the percentage increase over time.

The increase in tight/shale natural gas production in the INGM reference scenario occurs globally, as shown in Figure 7, and helps limit the growth in imports of natural gas and LNG for OECD North America and OECD Europe.

In the high crude oil price scenarios, the higher crude oil prices not only

Figure 6. Reference Scenario Global Production by Sector



2. The industrial sector end-use consumption is disaggregated into industrial co-generation, industrial feedstocks, and other industrial. Natural gas uses in processing, transport (LNG and pipeline) and for GTL conversion are all modeled separately.

3. Current estimates of reserves do not differentiate between conventional and unconventional forms of natural gas but EIA estimates that 8 TCF of 2006 production in the U.S. is from unconventional sources (EIA, 2008). Unconventional natural gas production is currently more limited outside of North America

Figure 7. Reference Scenario Regional Production of Tight/Shale Gas

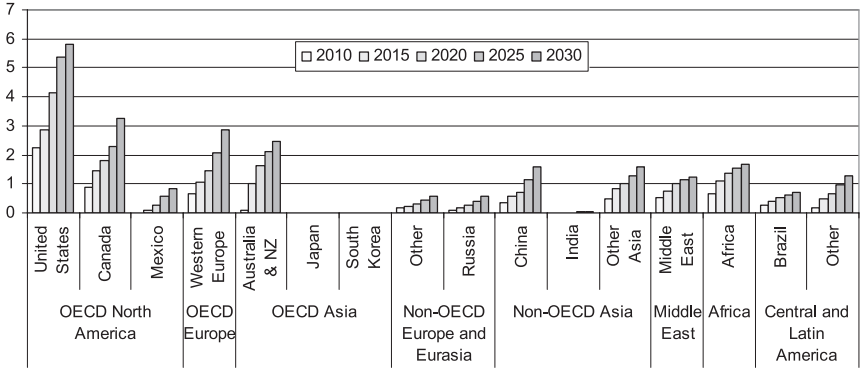
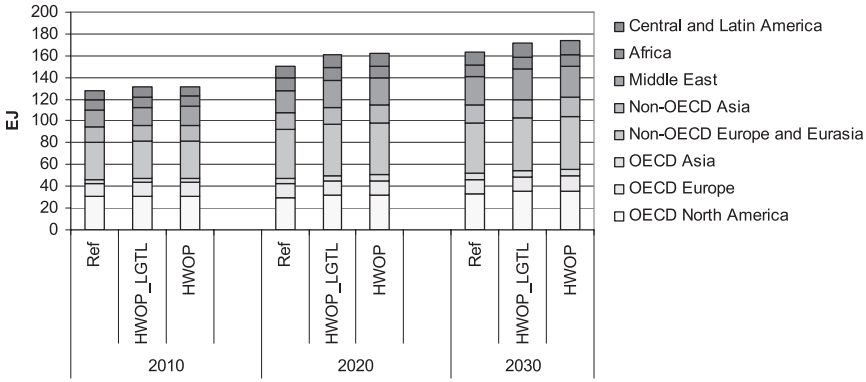


Figure 8. Regional Natural Gas Production



Production is net reinjected natural gas

increase demand for natural gas but also increase the value of the NGLs in the natural gas from conventional onshore and offshore resources[4], resulting in increases in production in all the regions as shown in Figure 8. United States and Canadian natural gas production increases in both of the high world oil price scenarios, despite small decreases in natural gas prices in those regions.

In both of the high world oil price scenarios, the Middle East represents 30% or more of the increase in production in 2030 relative to the reference scenario and the non-OECD Europe and Eurasia represents over 24% of the increase. This is consistent with significant increases in natural gas prices in the producing nodes in those regions, especially in the HWOP scenario. Production increases

4. Tight gas and coal bed methane are modeled with no NGL production.

significantly in OECD-North America due in large part to the higher value received for NGLs.

4.1.3 Equilibrium/Prices

Comparing the HWOP_LGTL case with the reference case we see the complicated relationship between oil prices and gas markets, where higher oil prices can lead to either higher or lower natural gas prices depending on the node and the supply/demand situation for the node. In North America, for instance, prices decline reflecting the fact that most of the incremental supply in the HWOP_LGTL scenario is from domestic production and the value of the wet gas is greater due to the higher prices of the NGLs. In Russia, in contrast, the price impacts are mixed. The prices in the Russia-Sakhalin and Russia-East regions rise due to increases in domestic natural gas demand and increases in exports to China. The prices in other nodes in Russia decline considerably, reflecting the increased value of the NGLs and the limited domestic and export markets for the additional natural gas production. The prices in Qatar increase due to growing GTL capacity prior to 2016, but prices in the rest of the Middle East decline due to the NGL effect on supply. Prices in Japan and other parts of Asia increase because of higher LNG prices.

The full impact of the HWOP scenario, where GTL expansion is not constrained, is different than in the HWOP_LGTL scenario. The ability to convert the natural gas and sell the GTLs at much higher prices results in increased natural gas prices at most of the nodes, with significant increases in exporting regions. In Qatar and Russia-Sakhalin, the increase in the average natural gas price from 2015 to 2030 is over $5.00 per gigajoule (GJ). Other producing regions in the Middle East, Russia, and the other nations of non-OECD Europe and Eurasia do not increase as much since, even with the GTL expansions allowed, the capacity additions are still constrained.

The impact of the high world crude oil prices on consuming regions varies as shown in Figure 9 and in Barden et. al., Table TA-8. In the U.S. and Canada, the NGL effect is greater than the effect of the crude oil prices on demand, and the domestic production increases result in slightly lower natural gas prices. In Europe and Asia, the prices tend to be higher relative to the reference scenario, by anywhere from $0.40/GJ to $1.00/GJ, since they import a larger share of their natural gas, and the prices in these regions are responding to increases in natural gas demand, including gas use for GTL production.

4.1.4 Liquefied Natural Gas

Globally, high oil prices lead to more GTLs and less LNG in the market as consumption of natural gas for GTLs increases in those nodes where it can, including most LNG exporting nodes. Production increases in the LNG exporting regions cannot keep up with the increases in consumption of natural gas for GTLs

Figure 9. Nodal Natural Gas Prices in 2030

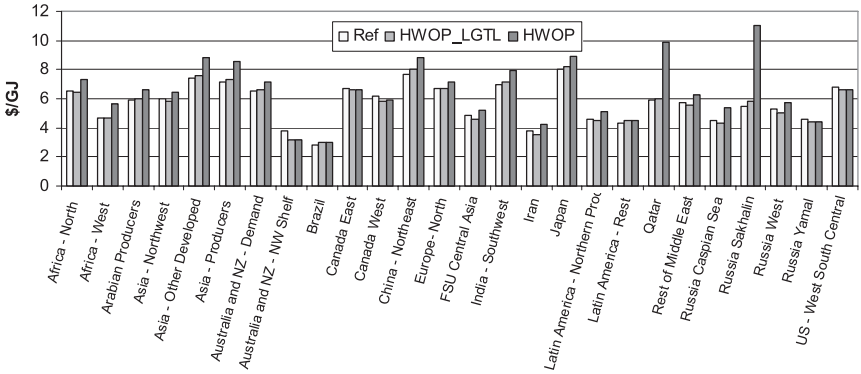
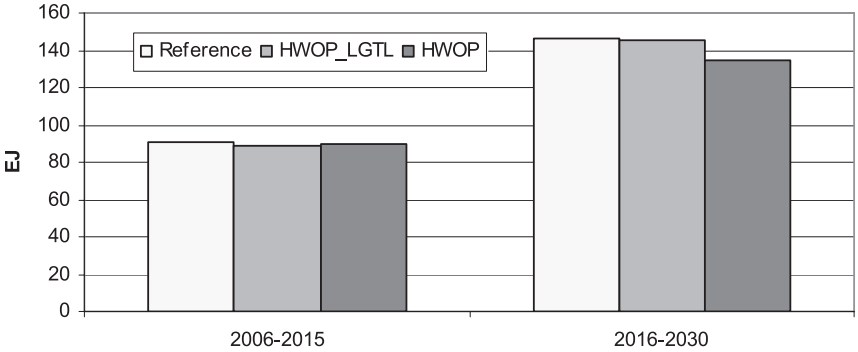


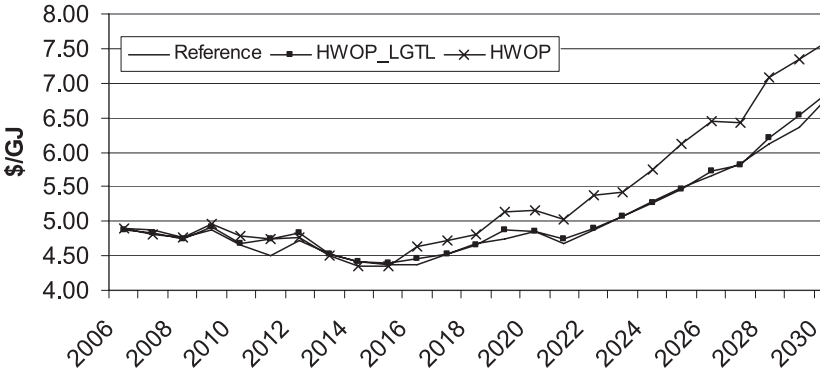
Figure 10. Cumulative LNG Production



and, in response, LNG production in the high oil price cases falls below that of the reference case, as shown in Figure 10. LNG exports still grow over the model period in all scenarios, but growth is strongest in the reference scenario.

In the HWOP_LGTL scenario, total LNG production is only slightly reduced from the reference case. Domestic production increases are sometimes more than adequate to meet increased natural gas demand in this scenario without significant or, in some cases, any increase in imported LNG. An example is the decline of natural gas prices in North America where increases in gas production are spurred more by the value of the associated liquids than by increased gas demand. In the HWOP_LGTL scenario, the average global LNG price varies little from that in the reference case throughout the model projection period, as shown in Figure 11. As can also be seen in Figure 11, this is not the case when GTL capacity additions are not constrained (i.e., the HWOP scenario).

Figure 11. Global Average LNG Price



In the HWOP scenario, where GTL expansion is allowed, the effect on the LNG markets is more substantial. In some LNG exporting nodes, the new GTL facilities act as a demand shock every three years, temporarily increasing prices and depressing other demand for natural gas, as well as LNG production.[5] As new GTL capacity comes online, immediate declines in LNG production are seen. However, LNG production generally increases in the succeeding two years, partially recovering before the next GTL capacity addition. In later years (after 2025), natural gas production is better able to keep up with the GTL capacity additions, and as new GTL facilities come online, the initial decline in LNG production is lower than in earlier years (2016 to 2025). This pattern is evident in the Africa West node, as shown in Figure 12. The cumulative effects of successive declines in LNG production, followed by only partial recovery after each GTL capacity addition, add up to a significant loss of LNG from some nodes compared to the reference scenario.

In the HWOP scenario, LNG production increases in some nodes, even as it decreases in others, limiting the total decline in LNG production versus the reference case. As natural gas prices in the LNG exporting nodes rise above those in the reference case in response to increased GTL production, LNG prices rise too. The Chinese consuming region (nodes China-Northeast and China-South) provides the best illustration of the variations that occur in the LNG market across the different scenarios. While in many of the nodes, natural gas prices respond little to the increase in oil prices unless GTLs are allowed to increase, in the consuming areas of China, the three scenarios each yield a distinct natural gas price path, see Figure 13.

5. The pattern of three year shocks is based on the scenario assumptions which include constraints on GTL builds where 0.37 PJ/day capacity can be built every three years.

Figure 12. LNG and GTL Production in Africa West in the HWOP Scenario

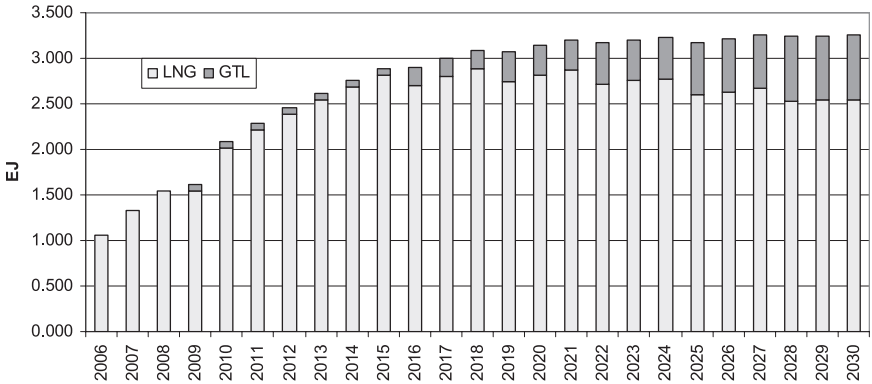
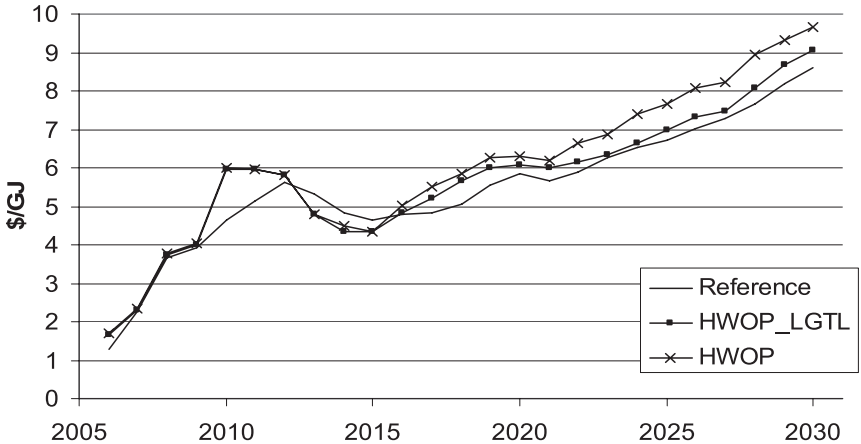


Figure 13. Average Natural Gas Prices in China's Consuming Areas



Natural gas prices in both of the high oil price cases disconnect from the reference case after 2009, first reflecting increased prices on LNG and then as Chinese production increases reflecting the increased value of the NGLs. After 2015, the natural gas prices in the two high oil price scenarios begin to diverge, as the increased GTL production in the HWOP scenario leads to higher global LNG prices than in the HWOP_LGTL scenario where GTL expansion is constrained. Additionally, beyond 2015, natural gas prices in the consuming areas of China are still higher than prices in the reference case. High oil prices, even without the effect of increased GTL production, generally cause LNG demand to rise in

Asia, where many countries are unable to increase production to meet increased demand. Also, as previously mentioned, global LNG production in the HWOP_LGTL scenario is slightly reduced, increasing the net demand for natural gas and hence its price. In response, LNG and natural gas prices in China rise above those in the reference scenario.

5. CONCLUSIONS AND FURTHER WORK

The model provides reasonable responses to high oil price scenarios, although some results were unexpected. With higher oil prices, natural gas demand rises as consumers switch from oil to natural gas whenever possible. If GTL capacity can expand significantly in response to high oil prices, then natural gas prices will rise more than if there are limits on GTL expansion. Also, the increased gas consumption for GTL use and the higher natural gas prices reduce demand in other sectors, especially the power generation sector, where less expensive alternatives to natural gas are available. The most unexpected result from the model was that natural gas prices fall in some regions in response to higher oil prices. This is, however, reasonably explained because natural gas production increases in these regions are driven more by the high value of the associated natural gas liquids than by increased demands.

The results presented here are part of testing the INGM model and do not represent the opinions or projections of the EIA. Further model enhancements are planned, including the capability to implement carbon tax scenarios to assess the impact of potential global greenhouse gas legislation on world natural gas markets. In the future, the model is to be used for world natural gas supply projections for the *International Energy Outlook* and to support LNG supply projections for the *Annual Energy Outlook*, both published annually by the EIA.

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Potential Futures for Russian Natural Gas Exports

Peter R. Hartley and Kenneth B. Medlock III***

Russia is a dominant supplier of natural gas, especially to Europe, and has the resources to become even more dominant in the future. Nevertheless, we show that Russia's ability to influence the world natural gas market is limited in the longer term by competition from alternative suppliers.

1. INTRODUCTION

According to the U.S. Energy Information Administration (EIA), Russia is the largest natural gas supplier, with dry gas production in 2006 of 23.2 trillion cubic feet (tcf) representing over 20% of global output. Russia could also significantly expand production. The *Oil and Gas Journal* (OGJ) reported Russian proved natural gas reserves of 1,680 tcf in 2007, and the United States Geologic Survey (USGS) reports a mean estimate of undiscovered, technically recoverable natural gas resources of 1,168 tcf and an additional 358 tcf of potential reserve growth in existing fields, yielding a total of more than 3,200 tcf of recoverable natural gas resource.

In 2006, Russian exports, primarily to Europe, equaled 7.8 tcf. Europe as a whole now relies on Russia for about one-quarter of its natural gas supply with the reliance of some countries even higher. For example, Russia supplies over one-third of Germany's requirements, and East European and Baltic countries, which were closely integrated with Russia in the Communist era, are even more dependent.

Gazprom produces more than 80% of Russia's natural gas and controls access to Russia's domestic natural gas pipeline system. While renegotiating export prices to Ukraine in the winter of 2006, when demand in both Ukraine and

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* George and Cynthia Mitchell Professor of Economics and Rice Scholar, James A. Baker III Institute for Public Policy, Rice University.

** Corresponding author. Fellow in Energy Studies, James A. Baker III Institute for Public Policy and Adjunct Assistant Professor of Economics, Rice University. E-mail: medlock@rice.edu

Western Europe was high, Gazprom temporarily reduced supply to Ukraine.[1] While the principal motivation may have been a desire to raise Ukrainian prices closer to European netback parity, the move was widely interpreted as an attempt to interfere in Ukrainian politics. In addition, the event substantially raised energy security concerns among European consumers.

Concern is also mounting over Russia's ability to meet its future contractual commitments. Although Russian natural gas production was about 10 percent below 1992 levels by 1997, it was above 1992 levels by 2005. Nevertheless, strong growth in domestic demand and exports has required Russia to increase its imports of gas from Caspian states. This, however, may not be sustainable, and prompted the Ministry of Industry and Energy to state in October 2006 that Russia could face a natural gas shortage as early as 2010.

Growth in domestic production requires new investments, but Gazprom is restricted in its ability to use external capital. In addition, Gazprom has difficulty generating internal investment funds since more than 70% of its production is sold domestically at highly subsidized prices (currently approximately $0.80 per thousand cubic feet (mcf) according to EIA (2008)).

In late 2006, the Russian government proposed a gradual increase in natural gas prices to market-based levels and in May 2008, the government approved tariff increases of up to 28.6% in 2008, followed by 19.9% in 2009, 28% in 2010, and 40% in 2011. Fearing the inflationary consequences, the government has stopped short of the original goal of complete liberalization by 2011, at least for the industrial sector.

Even with price increases, gas production may not be sufficient to satisfy demand in the short-term. In addition, a commitment to raise future prices may perversely discourage production in the near term. To the extent that Gazprom can sell less natural gas domestically at current low prices (for example, through quantity rationing or by ceding market share), it will have more gas to sell at future higher prices.

Russian natural gas production in 2006 was 2.4 percent above 2005 output, but Gazprom's share declined from 85.9% to 83.9%. Novatek, Lukoil, and Rosneft collectively had total production capacity of about 6.4 tcf per year in 2006, or about one-third of Gazprom's output. The production share of independent producers is expected to increase in coming years as the Ministry of Industry and Energy has stated that Russian independent producers are expected to supply more than half of the country's industrial needs by 2015 (Blagov (2007)). However, growth of output from these independents may require investments in pipeline capacity, and, perhaps more importantly, full access to Gazprom's existing pipeline infrastructure.[2]

1. The incident is being repeated in January 2009.

2. Access is vital to expanded use of associated gas, rather than simply flaring it, and both former President Vladimir Putin and current President Dmitry Medvedev have publicly demanded that Gazprom facilitate third party access.

Over half of Gazprom's production comes from mature fields in West Siberia that are declining at an average rate of 0.7 tcf per year according to a recent International Energy Agency report (IEA (2006)). Gazprom therefore needs to develop new fields. According to Glazov (2007), total domestic production must increase substantially by 2030 to meet projected domestic demand and contracted exports. This will have to come from a combination of Gazprom's own production, the production of independents, and imports from Caspian states.

In 2005, Gazprom entered a joint venture to construct the offshore pipeline Nordstream to transport gas through the Baltic Sea from Russia to Germany.[3] Gas supply is projected to come from the Yuzhno-Russkoye oil and gas reserve in the Yamal Peninsula, and the Ob-Taz bay and Shtokmanovskoye fields.[4] In 2007, Gazprom also announced plans to develop two other fields in the Yamal peninsula to supply existing pipelines through Ukraine and Belarus and financed partly by projected revenues from the price increases to those countries. Finally, Gazprom has also announced plans to upgrade production and transmission systems in Eastern Siberia with a goal of exporting to China (Gazprom (2008)). Despite these announcements, the projects are not much beyond the planning stage and, therefore, the future of Russian gas exports remains uncertain.

In this paper, we use the Rice World Gas Trade Model (RWGTM) to compare the behavior of the world natural gas market in a Reference Case with corresponding outcomes under three scenarios for disruptions to Russian production and exports:

Scenario 1: Yamal peninsula and Kara Sea resources remain undeveloped

Scenario 2: Russian exports are severely, but only temporarily, reduced in 2010, perhaps for political reasons

Scenario 3: Asian pipeline infrastructure from Russia remains undeveloped

2. THE RICE WORLD GAS TRADE MODEL

The RWGTM is a dynamic spatial equilibrium model of the world natural gas market grounded in geologic data and economic theory (see Hartley and Medlock (2006) for more detail).[5] The RWGTM proves and develops reserves from existing fields and undiscovered deposits, constructs pipelines and LNG delivery infrastructure, and calculates prices to equate demands and supplies while maximizing the present value of producer rents within a competitive framework.

The resource data underlying the model is based on the USGS World Resource Assessment 2000 and data for existing reserves from the OGJ database. Capital and operating costs for resource development were derived using data from the National Petroleum Council (NPC (2003)). The costs of constructing

3. Gazprom's partners in the project are BASF/Wintershall, E.ON Ruhrgas and N.V. Nederlandse Gasunie.

4. See http://www.nord-stream.com/en/ for more detail.

5. The model is constructed using the *MarketBuilder* software from Altos Management Partners. For the sake of brevity, we limit our discussion herein of the technical aspects of the model.

new pipelines and LNG facilities were estimated using data for past projects available from the EIA, IEA and various industry reports.

Demand for natural gas varies exogenously with economic development, population growth and the price of competing fuels, and responds endogenously to the equilibrium price of natural gas. Data used in estimating the demand relationship were obtained from the EIA, the IEA, the World Bank, the United Nations, and the Organization of Economic Cooperation and Development.

The model has over 290 demand and 180 supply regions. Regional detail varies based on data availability and a country's size and likely influence on the global natural gas market. For example, large consuming and producing countries, such as China, the U.S., India, Russia, and Japan have extensive subregional detail.[6]

Model output includes regional natural gas prices, pipeline and LNG capacity additions and flows, growth in natural gas reserves from existing fields and undiscovered deposits, and regional production and demand.

3. REFERENCE CASE

The Reference Case supply projections in Figure 1 indicate Russia will remain the largest single producer throughout the model time horizon.[7] It remains the largest single supplier of natural gas to the European market, primarily by pipeline, but it does see a slightly diminished market share as LNG and other pipeline supplies compete into Europe. European consumers have supported the proposed Nabucco pipeline, carrying natural gas from the Caspian states to Europe via Turkey, as a way of lessening dependence on Russia. The Reference Case implies, however, that Turkey only becomes a significant corridor for natural gas imports to Europe once Iraqi supplies are developed.[8] The "East of the Caspian" group of countries (Kazakhstan, Turkmenistan and Uzbekistan) export gas primarily through Russia. Moreover, exports to western China via Kazakhstan do not appear economic, although the option is allowed in the model.

Figure 2 focuses on the Russian exports by source and destination. The figure indicates that most growth in Russian exports originates from Eastern Russia and is destined for Northeast Asia. Eastern Siberian natural gas begins flowing into Northern China at the beginning of the next decade and eventually flows into the Korean peninsula as pipeline capacity is developed. Incremental production in the west comes primarily from supply developments in the Yamal Peninsula, Kara Sea, and Barents Sea, and serves to replace declining production in the mature fields in West Siberia, the Russian Caspian, Volga Urals and Black Sea.

6. More information is available upon request.
7. The figures generally present the data in regional aggregates in order to clearly discern trends.
8. The cases all assume that political turmoil in Iraq prevents development there until 2015.

Figure 1. Reference Case Supply

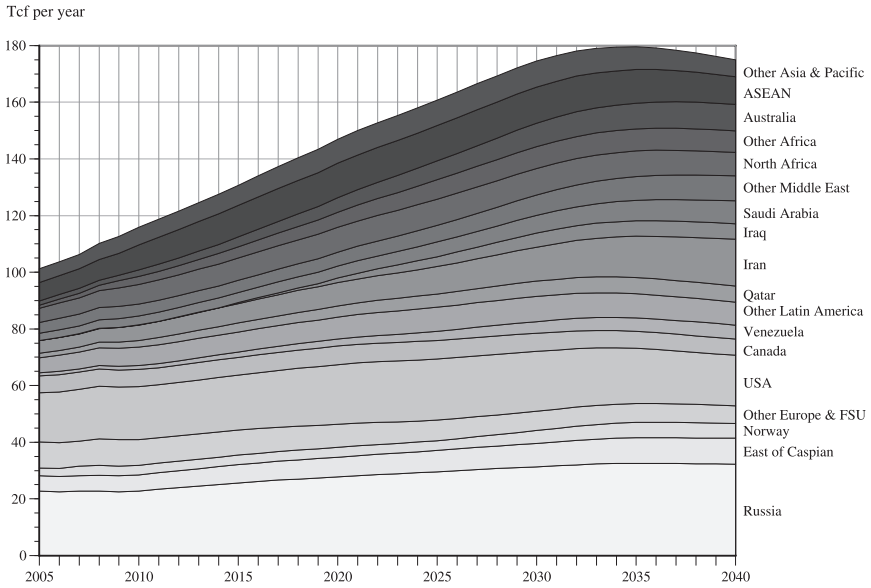
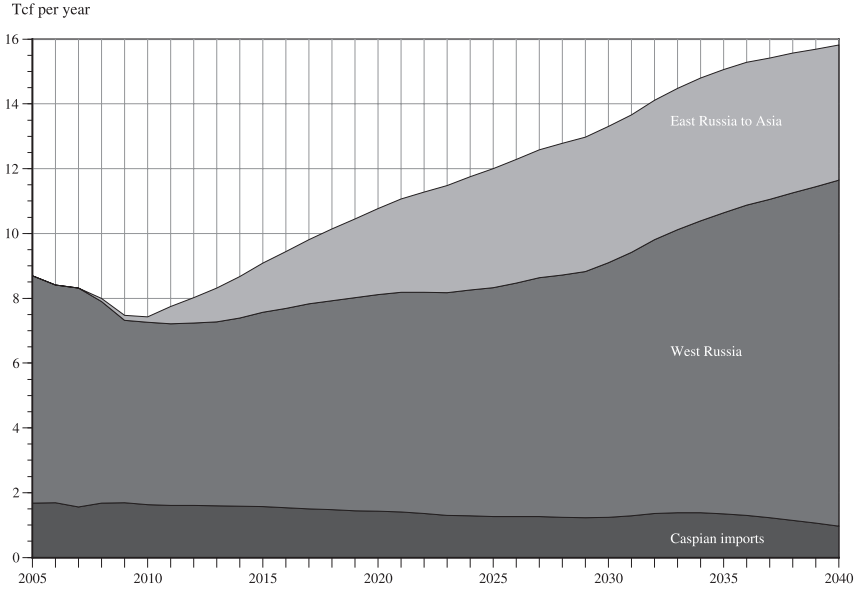


Figure 2. Russian Exports by Origin (Basin Aggregates)



Again referencing Figure 1, we see strong supply growth in the Middle East, with its share of world production projected to rise from about 12% to more than 18% by 2025 and more than 24% by 2035. The largest Middle East exporters are Qatar, the United Arab Emirates (UAE), Iran, and eventually Iraq. Although Figure 1 shows very strong supply growth in Iran, demand growth also is strong in part because Iran uses natural gas to assist with oil production thus mitigating Iran's ability to export natural gas. Nevertheless, Iranian natural gas is eventually exported as LNG from the mid 2020s, and longer term export growth comes largely via the development of a pipeline to Pakistan and India beginning in 2025. Flows from northern Iran to Azerbaijan, Armenia and Turkey are also expanded, but are highly dependent on developments in Turkmenistan. Iraq eventually becomes the dominant source of exports by pipeline from the Middle East, exporting natural gas produced in the northern and western provinces to Europe through Turkey.

Figure 3, summarizes LNG exports. Russian production in the Sakhalin region is exported as LNG, but also is eventually exported via pipeline to Japan, Northeast China and the Korean peninsula. In the Atlantic Basin, Barents Sea production eventually facilitates LNG exports beginning in the mid-2030s, but the majority of the gas produced in the region is exported via the Nordstream pipeline to Germany. Once Russia is supplying both the Atlantic and Pacific basins, it plays a key role in global price arbitrage since the netback price from sending supplies in any direction must be the same. Although the producing basins are not directly interconnected, they have common points of downstream reference, especially once a pipeline connecting east and west is constructed in the early 2030s.

Figure 3 also shows that overall growth in LNG supply is strongest from Australia and the Middle East, with the latter projected to supply from 25–30% of LNG shipments beyond 2035. Since the Middle East has better access to the sea than Russia, Turkmenistan or Kazakhstan, but is at a relative disadvantage for supplying exports via pipeline, until Iraqi production grows dramatically from 2025, most Middle East exports are in the form of LNG. Qatar is the largest exporter of LNG from the Middle East until the late 2030s. Qatar is the beneficiary of first-mover advantage, largely due to its vast reserves and openness to Western interest, and thus is an early leader in the export of LNG. Other resource-rich countries must delay entry until prices increase enough to justify the substantial fixed costs of incremental infrastructure. Early entry would drive down prices and lead to inadequate returns on investment. Roughly half of Middle East LNG production is projected to flow into the Atlantic Basin.

Figure 4 illustrates the Reference Case demand projections. The traditional markets of North America, Europe and the FSU are the largest consuming regions. The fastest growing region, however, is Asia, where demand growth exceeds 6% per year through 2020. Hence, global gas flows shift toward Asia over time. Figure 5, which summarizes global LNG imports, shows Chinese LNG imports growing substantially through 2030, commensurate with its rapid demand growth relative to its indigenous supply. In fact, LNG imports grow such that the market share plateaus at about 30% of the Chinese gas market around 2020, thus

Figure 3. Reference Case LNG Exports

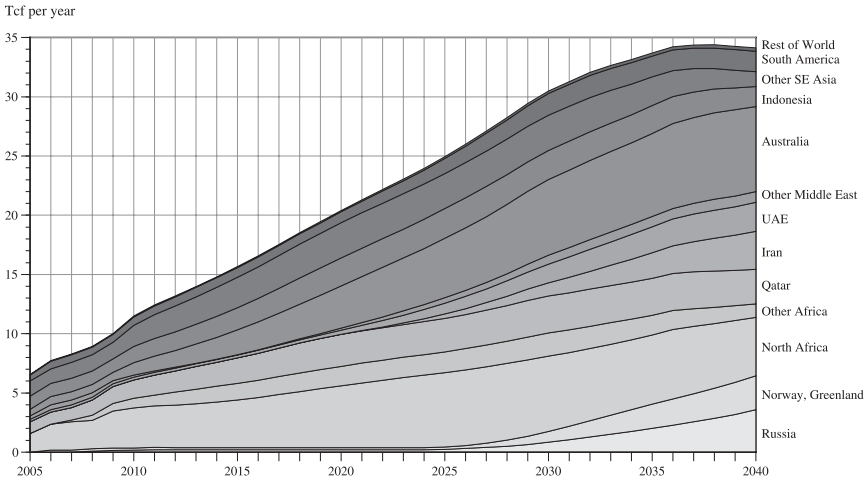
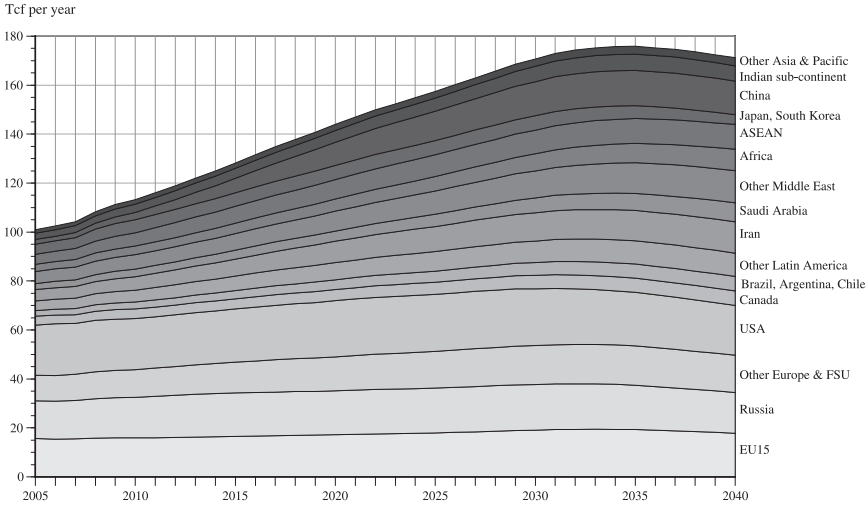


Figure 4. Reference Case Demand



indicating the importance of LNG for incremental demand growth over the next decade or so.

As demand growth in North America, Europe and Asia outstrips domestic supply, LNG imports into these regions generally see substantial growth. The availability of unconventional gas supplies, in particular shale gas, in the United States delays substantial growth in imports until after 2025.[9] Thus, the utilization rate of capacity that is either existing or under construction will remain low for a while. Beyond 2025, imports into the U.S. Lower 48 begin to grow. In addition, a substantial amount of LNG imported into Mexico and Canada is redirected to serve demand in the U.S.

In Europe, strong demand growth and dwindling domestic supply stimulates imports from many sources. Europe imports gas by pipeline from Africa, the Middle East, and Russia and also as LNG from North and West Africa, the Middle East, South America, and eventually, the Russian Arctic.

Figure 6 summarizes overall trade in natural gas, showing the rapid growth in exports by the Middle East and imports by Western Europe, Northeast Asia and, after 2025, North America. Russian exports are projected to decline from 2008, with a modest recovery beginning in the early 2010s and continuing until 2040 when exports are projected to be just less than twice what they were in 2008 (see Figure 2). The majority of the growth comes from gas directed to Asia.

Figure 7 presents a few selected price paths from the model. Prices at Henry Hub and the National Balancing Point (NBP) are of interest because these are liquid points commonly used for contract and derivatives trading. Prices at the German-Austrian border are of interest because they are the highest prices in Europe, and are often used to evaluate pipeline projects from Russia and the Caspian. This particular location represents the balance point in Europe between flows from the North Sea, LNG imports, flows from North Africa and flows from Russia and other former Soviet Republics. The two prices in Northeast Asia (Tokyo and Beijing) represent the other major markets served by Russia. The Sydney price has been included to indicate how low prices can be in an exporting country with high transport costs.

Figure 7 indicates that prices in different locations tend to move closely together beyond 2012 as LNG trade eliminates arbitrage opportunities. Prices in Japan and China move closely together until the late 2020s while they both rely on LNG from similar sources. Beyond that date, Chinese prices rise toward prices in Eastern Europe as China becomes more dependent on imports from Russia via pipeline. It is important to note here that prices in Southeast China (not pictured) do not experience this phenomenon as the region remains more heavily linked to LNG. Long run prices at Henry Hub and NBP are closely related after 2010 as LNG of similar cost provides marginal supply to each.

9. Shale assessments were developed from literature from the Association of American Petroleum Geologists, the Potential Gas Committee, and the USGS. The assessment of shale that is *technically recoverable* in the U.S. and Canada totals to 324 trillion cubic feet. Development costs are constructed using industry data on break-even economics in each of the 27 plays represented. More information is available from the authors upon request.

Figure 5. Reference Case LNG Imports

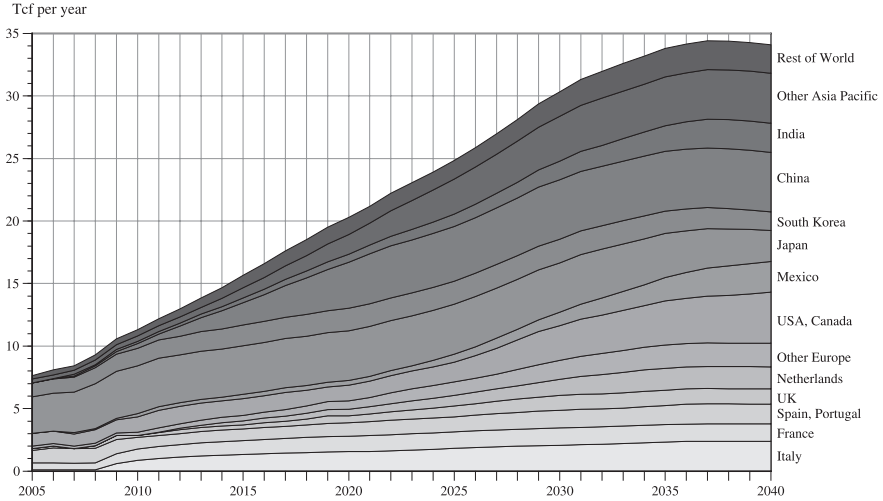


Figure 6. Reference Case Gas Trades

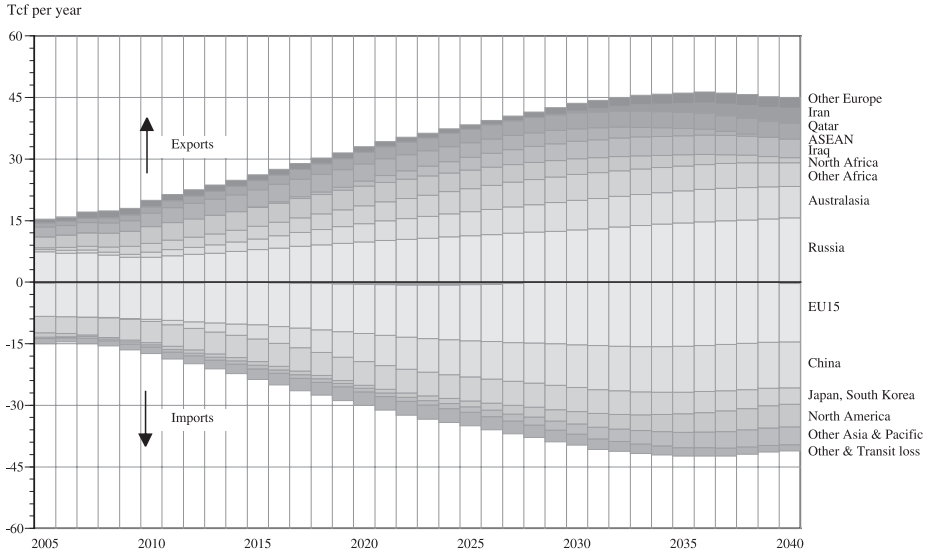
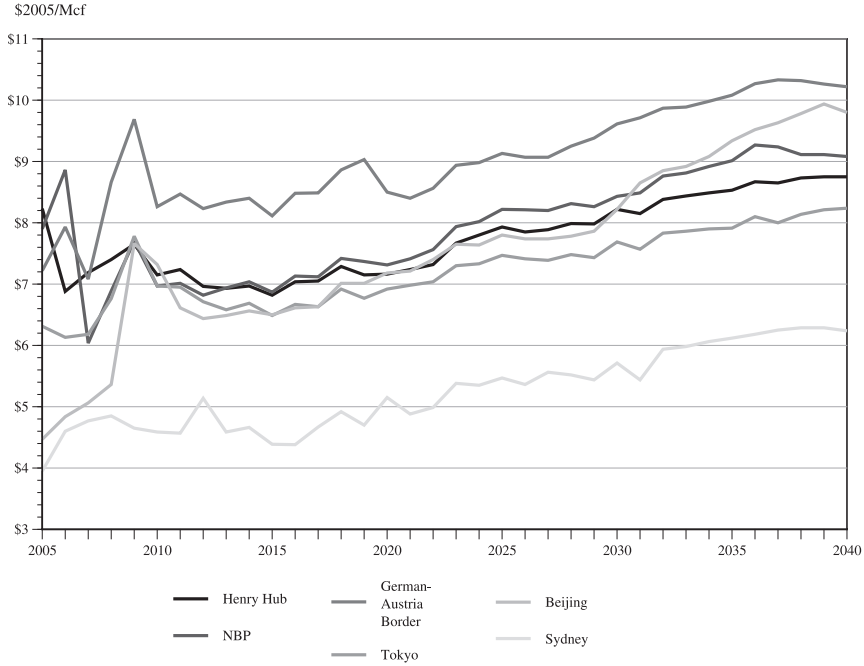


Figure 7. Reference Case Selected Prices



4. SCENARIO ANALYSIS

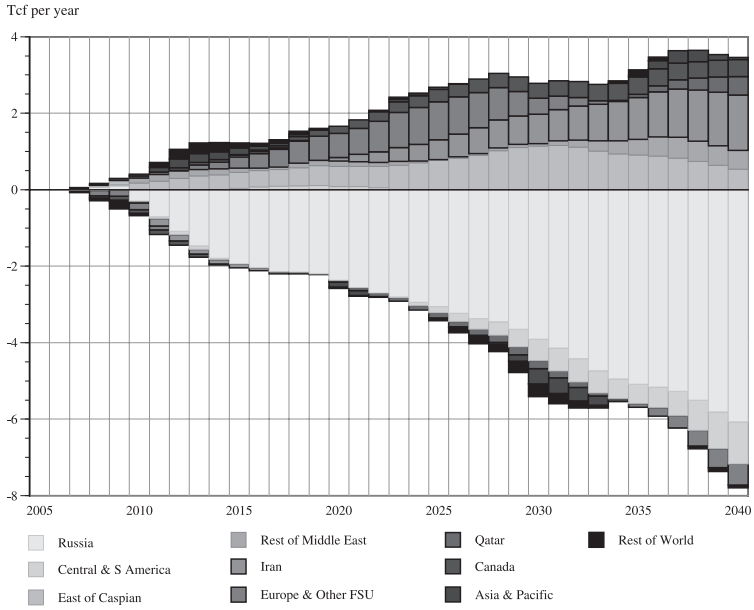
4.1. Scenario 1: Yamal Peninsula and Kara Sea Resources Remain Undeveloped

In this scenario, we prohibit the development of natural gas resources in the Yamal peninsula and Kara Sea, thus removing 440 tcf of the estimated 1,168 tcf of Russia's technically recoverable natural gas from potential development.

Figure 8 depicts the changes in supply relative to the Reference Case. The decline in overall Russian production becomes more pronounced over time and eventually reaches more than 6 tcf per year by 2040. Russian production in the Southwest and East rises slightly, but the increased production, especially in the Southwest, is not sustained. The East of Caspian countries exhibit a persistent positive supply response, but fall short of offsetting declines in Russia. Production in Europe and the remaining FSU countries increases in the near term but declines slightly beyond the early 2030s.

Figure 8 also shows that a range of other countries exhibit increases in supply. The most prominent among these are Iran, Qatar and the rest of the Middle East. In some of these cases, however, supply declines in some years, so some supply increases can also be regarded as intertemporal shifts in production (these

Figure 8. Supply Changes under Scenario 1



regions or countries have been represented on the figures using darker borders.

Figure 9 focuses on Russian exports. Imports from the East of Caspian countries increase relative to the Reference Case. Those supplies fill Russian pipeline infrastructure to Europe vacated by reduced Russian production. The slight increase in the East is driven by the fact that the lack of Russian supplies tends to lift prices in Europe and increase competition for LNG. Thus, as prices rise, incremental eastern Russian supplies become more attractive.

The demand changes relative to the Reference Case in Figure 10 are distributed fairly evenly across the globe as LNG and long distance pipelines transmit price changes to all regions. This has varying impacts across regions dictated by factors such as differences in marginal supply and demand elasticities and the ability of alternatives to take market share from gas. Nevertheless, the largest declines are in Russia and neighboring regions dependent on Russian exports, such as the rest of the FSU, China and Europe.

Figure 11 illustrates the change in prices relative to the Reference Case in select locations. The largest price changes are on the German-Austrian border, where the supply shortfall from Russia has greatest impact on the locations presented in the figure. Prices in Beijing also rise substantially beyond 2030 as higher priced imported LNG replaces East Siberian natural gas that is now diverted west. Similar movements in prices in the remaining locations reflect the fact that they are all linked to LNG prices at the margin.

Figure 9. Changes in Russian Exports by Origin under Scenario 1

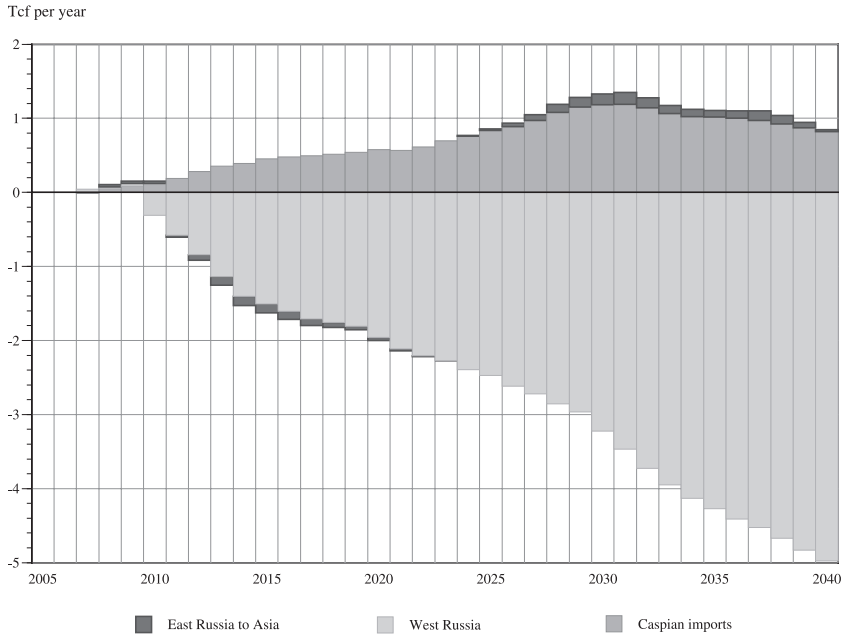


Figure 10. Demand Changes under Scenario 1

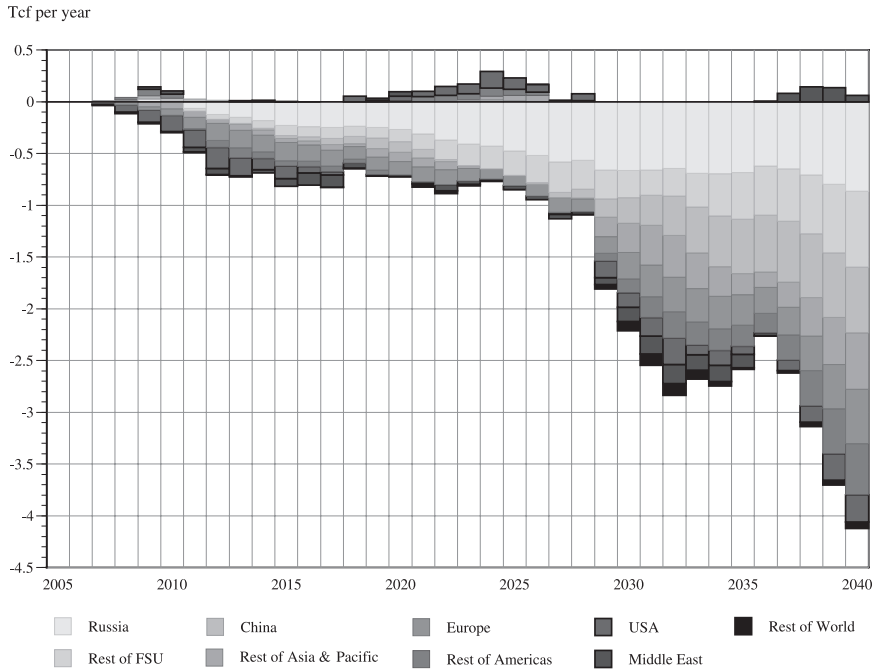


Figure 11. Selected Price Differences in Scenario 1

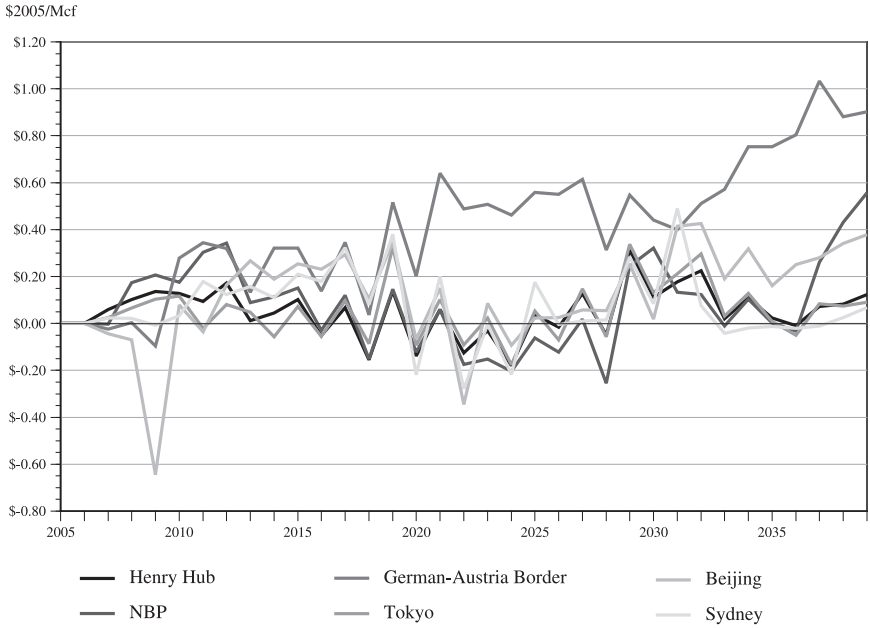


Figure 12. Changes in LNG Exports in Scenario 1

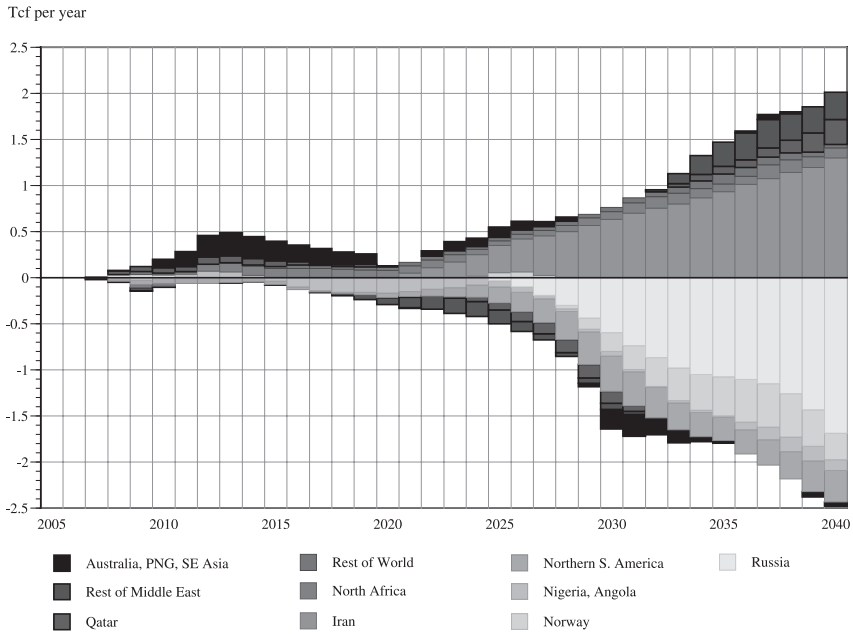


Figure 12 indicates the effects of reduced Russian supply on global LNG exports. Russian LNG exports are lower beyond 2025 as supplies from the Barents Sea are diverted to pipeline infrastructure. Iran sees the greatest expansion of LNG exports. The decline in LNG exports from Norway may appear anomalous, but it accommodates increased pipeline exports to Europe that replace lost Russian imports.

Reduced pipeline flows from Russia to Europe are offset, to some extent, by increased LNG imports to Europe. Figure 13 indicates that LNG imports into Western Europe rise collectively by as much as 0.256 tcf per year, or 700 million cubic feet per day, which is similar to the capacity of an average-size LNG import terminal.

The large decreases in LNG imports into the U.S. are noteworthy. The added competition for LNG supplies tends to raise price everywhere. This tends to raise domestic production in North America while lowering demand, thereby reducing North American LNG imports.

4.2. Scenario 2: Russian Exports are Severely Reduced in 2010

In this scenario, we consider an abrupt but temporary suspension in 2010 of roughly one third of the Reference Case Russian natural gas exports to Europe. The idea is to simulate a four-month cut-off of Russian supplies to Europe that could be prompted by political forces or result from severe physical outages.

The immediate impact is large increases in European prices (by over 90% at the German-Austrian border and almost 10% in the UK). Price increases in the Ukraine would be larger had we not assumed that the Ukrainian government would respond to the emergency by imposing non-price rationing equal to 20% of the Reference Case Ukrainian demand.

While the resulting price spike generates large rents for Russia in the short run, the scenario highlights the longer term risks for Russia. Europe responds to the short-term disruption by reducing demand and increasing supply and imports from elsewhere. While the ability to do so is limited by available infrastructure in the short term, the cut-off changes the growth and distribution of natural gas demand within Europe for many years to come, reflecting the autoregressive nature of demand in the RWGTM. This ultimately reduces Russian exports to Europe through 2020. Therefore, Russia sacrifices future revenue for short-term gain.

Figure 14 indicates the changes in supply relative to the Reference Case. While Russian supply is significantly lower in 2010, so is supply from the East of the Caspian countries whose production is captive to Gazprom's infrastructure. Alternative export routes across the Caspian and through Turkey, south through Iran, or east to China would allow these countries to escape the effects of Russia's curtailment of exports, but no such options exist in 2010.

Figure 14 also reveals that the sum of lost Russian production from 2010 through 2020 is almost as great as the cut-off itself. Beyond 2030 Russian sup-

Figure 13. Changes in LNG Imports in Scenario 1

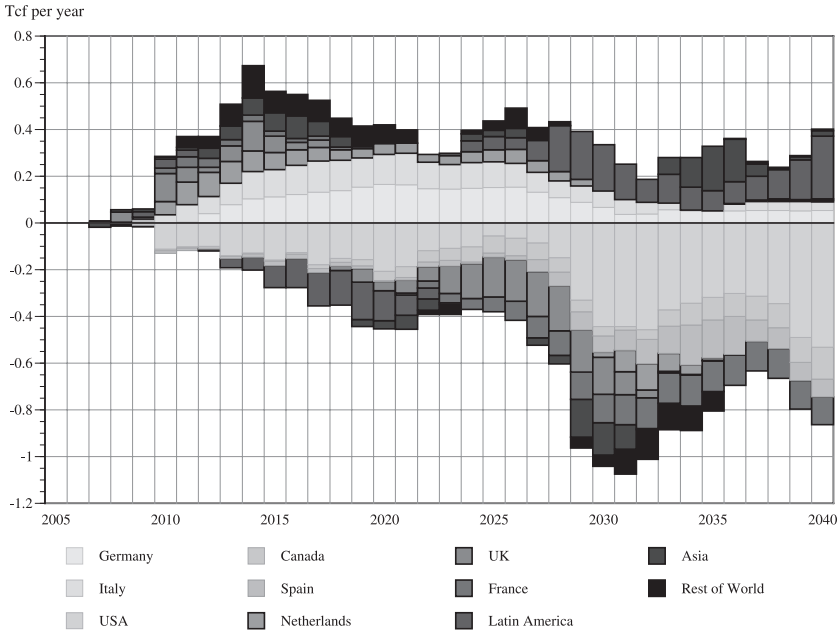
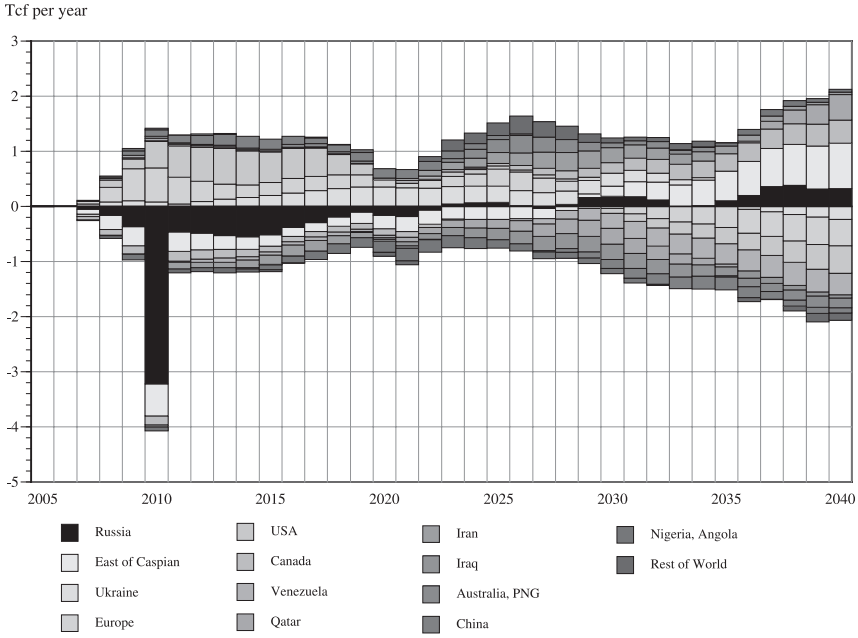


Figure 14. Supply Changes under Scenario 2



plies exceed the Reference Case as they replace declining production elsewhere. The East of Caspian countries increase supply beyond the late 2020s.

The cut-off of Russian supply in 2010 is also offset to some extent by increased supplies from Eastern Europe, Ukraine and the U.S., which then persist for the next decade. The U.S. is a major source of supply increases in the period up to 2020, but production then declines after the late 2020s. A number of countries, including Iran and Iraq, exhibit supply responses that are negative in some years and positive in others (all indicated by darker borders in the figure), reflecting intertemporal shifts in production and export patterns.

The change in supply in the years preceding the shock is the result of producers anticipating the shock and beginning to develop supplies accordingly. However, given the lead times for development, they do not have enough time to fully adjust supplies to counter the Russian disruption. This can be viewed as the anticipatory element of rising tensions between Russia and Ukraine or Russia and Europe more generally.

As referenced above, since demand responds dynamically to prices, the high prices caused by the supply disruption continue to reduce demand below the Reference Case for several years. Figure 15 indicates that the response is greatest in the Ukraine and other countries in Europe east of the German-Austrian border as these are the countries that are most directly affected by the disruption. Demand in most other locations increases in some years and declines in others, but the overall changes in any one country tend to be small.

Figures 16 and 17 illustrate the changes in LNG exports and imports. To begin, it is apparent that the increase in aggregate LNG imports in 2010 exceeds the increase in global LNG supply. The primary explanation is that Middle East LNG exports destined for the U.S. are diverted to Europe. Slight increases in LNG exports from ASEAN and Australia in 2010 also displace some Middle East exports to the Far East. The reduction in the average distance of LNG shipments reduces the losses from LNG transport.

Australia and Russia (especially after the late 2020s) are prominent among countries increasing their supply of LNG. The UAE produces less LNG relative to Reference Case beginning in the late 2010s, as do Qatar, Norway and South America from the mid 2020s. The reductions in the UAE and Qatar are partially compensated by increased production from Iran. The U.S. and Europe experience most of the net declines in LNG imports beyond the late 2020s. The large increase in Russian exports of LNG in the 2030's displaces some exports from Norway. Increased Russian exports into the Atlantic basin later in the time horizon also compensate for the reduced exports from South America.

Figure 15. Demand Changes under Scenario 2

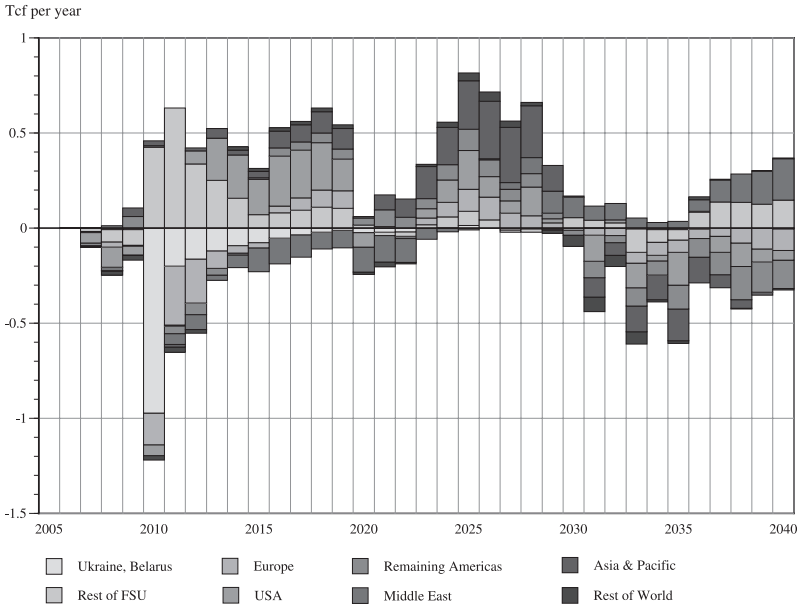


Figure 16. Changes in LNG Exports in Scenario 2

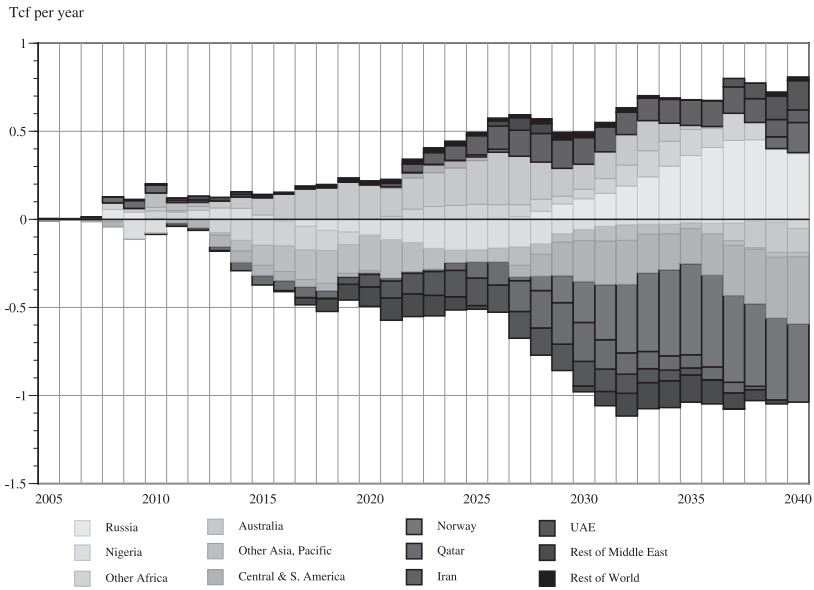
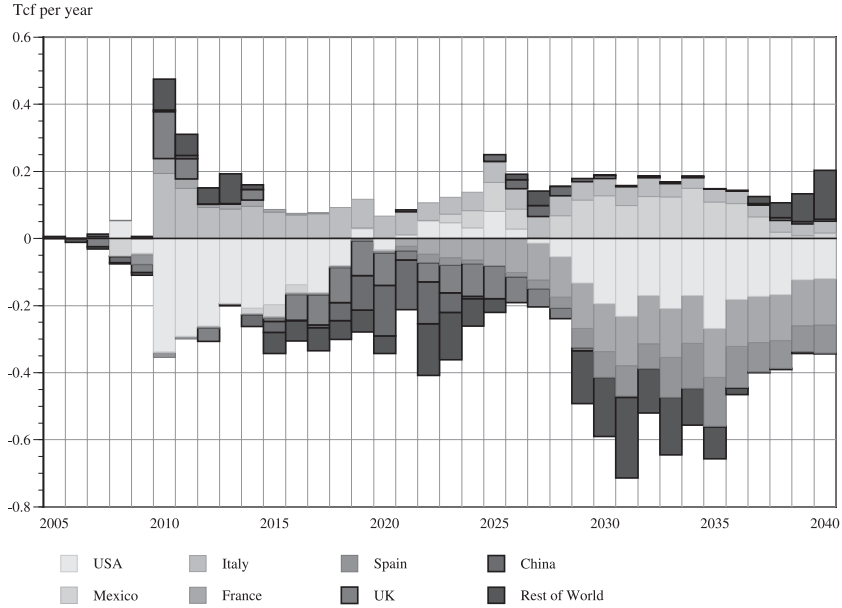


Figure 17. Changes in LNG Imports in Scenario 2



4.3 Scenario 3: Asian Pipeline Infrastructure from Russia Remains Undeveloped

In this scenario, we prohibit the development of pipelines from Russia to Northeast Asia (specifically China, Korea and Japan). Since no such infrastructure currently exists, by preventing these greenfield expansions we are able to discern the costs of political barriers to developments that the Reference Case results indicate are commercially viable.

Figure 18 presents the changes in supply relative to the Reference Case, and Figure 19 focuses on changes in Russian exports. We see that East Siberian resources that are shipped to Northeast Asia in the Reference Case are instead eventually redirected west, although higher transport costs to market result in lower East Siberian production. The increased flow of East Siberian supplies to the west slightly reduces production in West Russia and the East of Caspian countries. However, imports from the latter expand beyond 2030. Proposed pipelines from the Caspian region to China remain undeveloped even through they are allowed. In Figure 18 we also see a slight increase in Chinese domestic supply as a result of higher prices. The Middle East – Iran in particular – is once again a major source of marginal supply, especially beyond 2025. Qatari output expands in all years, but the increases are larger after 2030.

Figure 18. Changes in Supply under Scenario 3

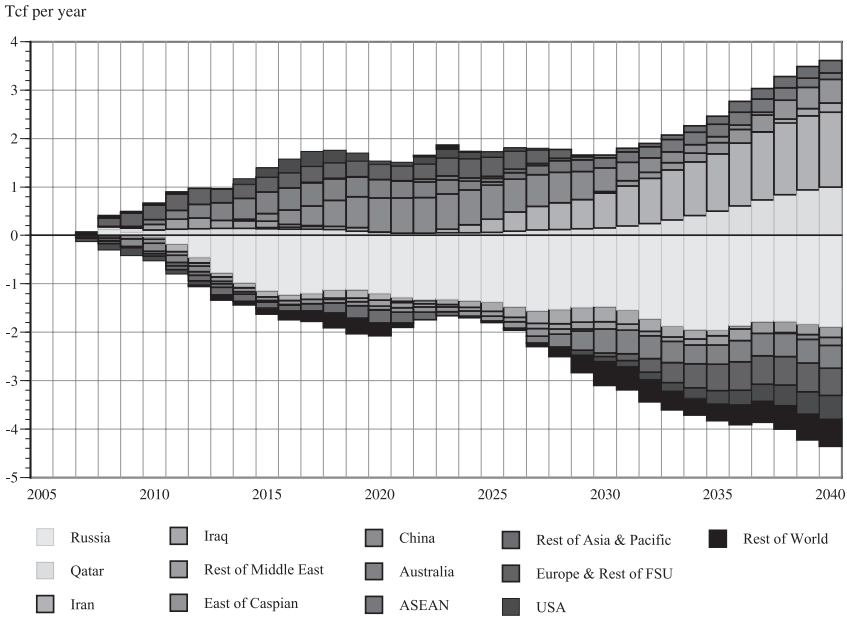


Figure 19. Changes in Russian trade under Scenario 3

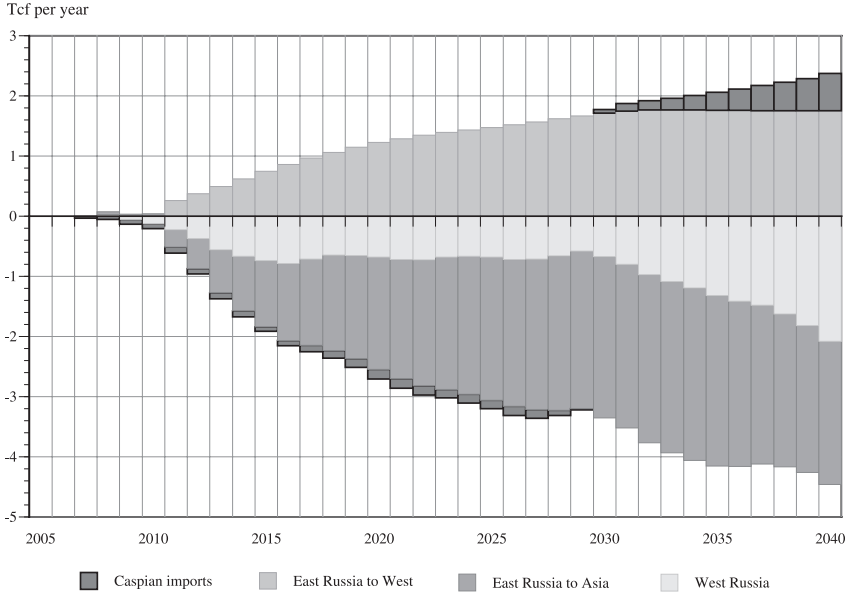


Figure 20. Changes in LNG Exports in Scenario 3

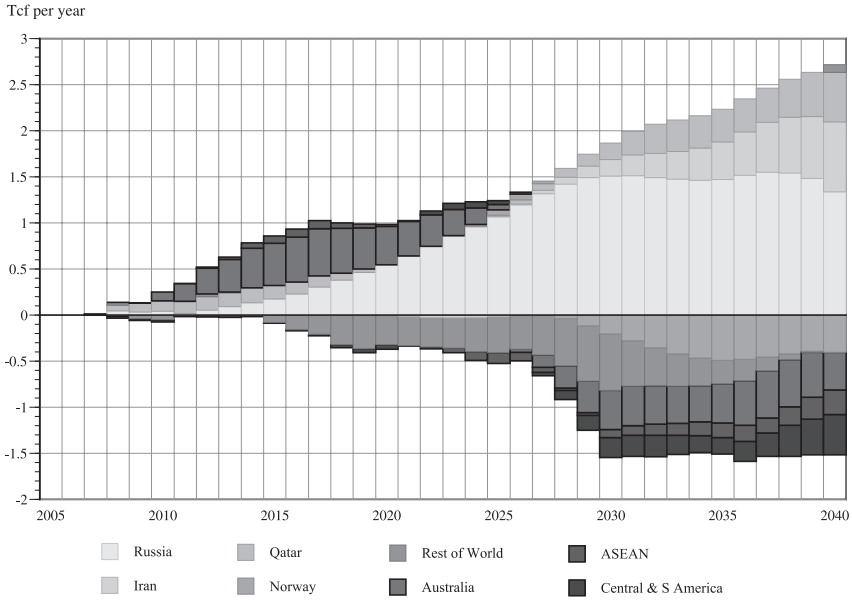


Figure 20 indicates that the supply shortfall from decreased Eastern Russian production is met largely by Russia itself as Sakhalin supplies that were exported as pipeline gas in the Reference Case are instead exported as LNG. Higher Asian reliance on LNG also stimulates greater LNG production in Australia up to 2025, and in Iran and Qatar in all years, with the greatest increases beyond 2025.

Figure 21, which depicts changes in LNG imports relative to the Reference Case, shows that world LNG imports expand in the aggregate, with China, South Korea and Japan taking the majority of the increase. Europe and Turkey experience most of the reductions in LNG imports. This shift is facilitated by increased pipeline flows from Russia to the West.

Figure 22 reveals that an absence of Northeast Asia pipeline infrastructure primarily reduces demand in China as it no longer benefits from lower-priced Russian pipeline gas. The main beneficiaries are consumers in Russia and its immediate neighbors, which all benefit from lower prices. The increased demand in North America is facilitated by lower demand for LNG in Europe as pipeline imports from Russia grow.

Figure 23 shows that the largest price increases occur in China. Prices actually decline slightly in Central and Eastern Europe and in the Former Soviet Union countries as supplies are bottlenecked in Russia forcing prices down and shifting supplies westward.

Figure 21. Changes in LNG Imports in Scenario 3

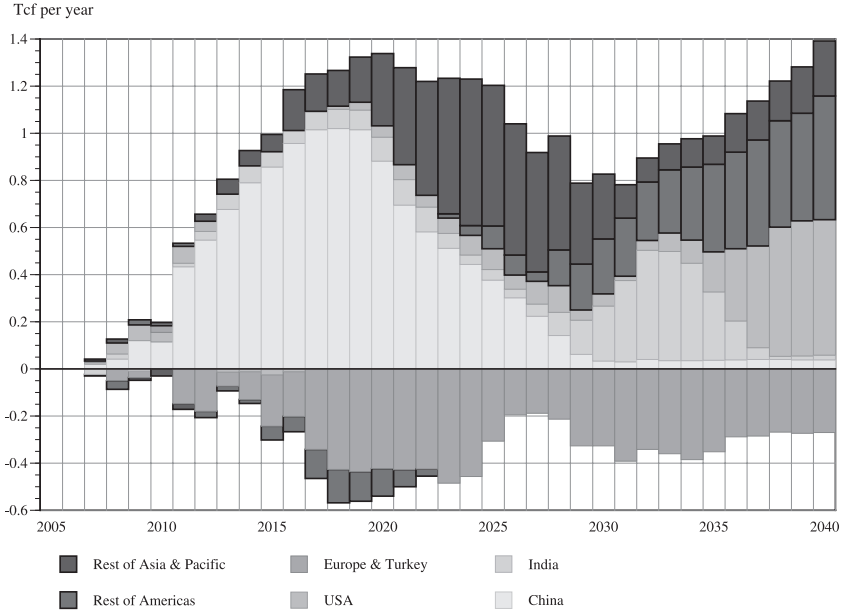


Figure 22. Changes in Demand under Scenario 3

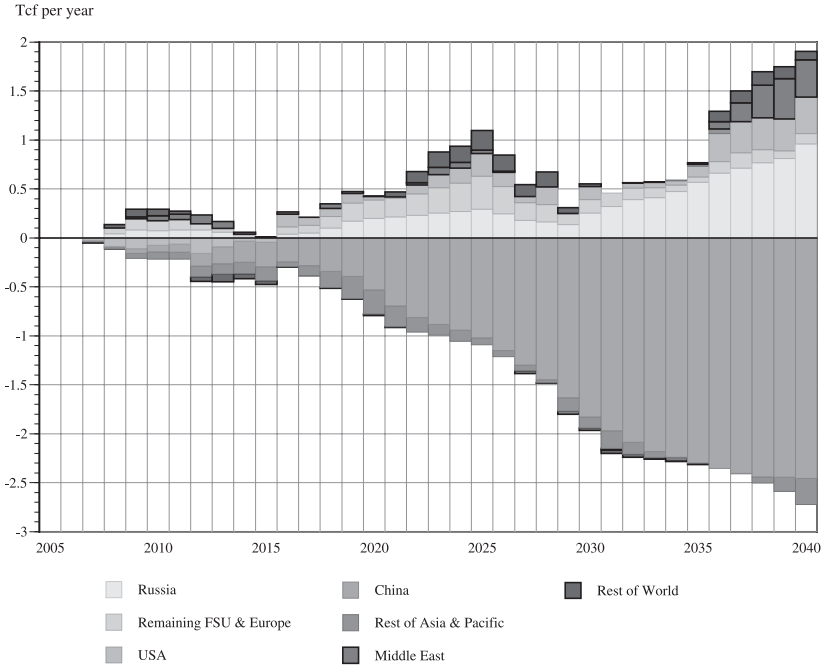
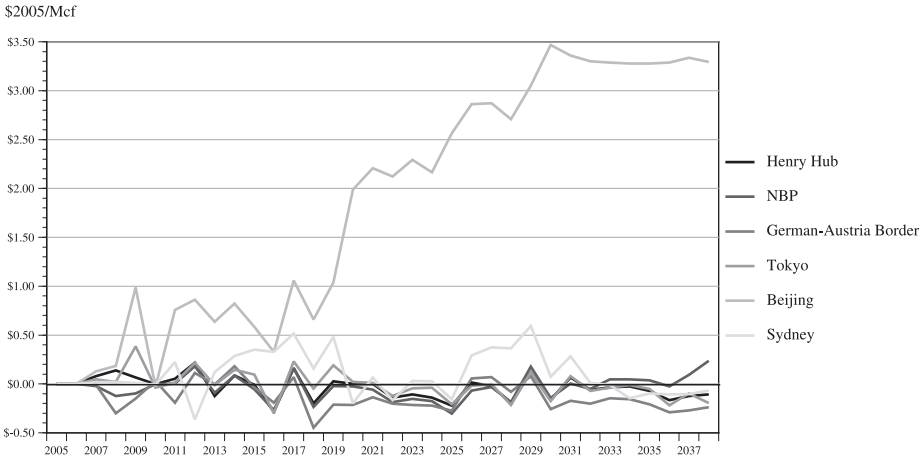


Figure 23. Selected Price Differences in Scenario 3



5. CONCLUDING REMARKS

We opened the paper by noting Russia's dominant status in the world natural gas market. It is currently the world's largest natural gas producer and has extraordinary potential for developing new resources. Russia also has a long history of exporting natural gas to Western Europe and is well-situated to satisfy rapidly expanding demand in Northeast Asia.

However, there is growing unease, especially in Western Europe, that Russia may be financially unable or unwilling to meet European demands. The recent cut-offs of Russian supply to Ukraine, and similar threats to Belarus in order to forcefully renegotiate prices and settle outstanding debt, have heightened West European concerns over Russia's future reliability as a major supplier. Russia's seemingly successful strategy in maintaining Central Asian dependence on Russian pipelines for transporting exports to European markets has only added to Western concerns.

The general implication of our analysis, however, is that Russia may have less ability to adversely affect West European gas markets than at first appears to be the case. In fact, any effort to gain excess rents in the near term will likely be offset by significant and sustained losses in the longer term. More generally, the developing global market for natural gas implies that disturbances in one location are spread across the globe. Intertemporal substitution by producers and demand response also reduces the effects of shocks in any one period.

Our results also highlight the importance of the Middle East as a possible counterweight to Russia. Coordinated action by Russia and the Middle East could therefore be a much more significant threat to the energy security of the rest of the

world. In addition, our analysis highlights the common interest that the countries of Western Europe, Northeast Asia and North America have in promoting the development of an efficient worldwide market for natural gas.

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Representing GASPEC with the World Gas Model

Ruud Egging, Franziska Holz†, Christian von Hirschhausen†** and Steven A. Gabriel***,**

This paper presents results of simulating a more collusive behavior of a group of natural gas producing and exporting countries, sometimes called GASPEC. We use the World Gas Model, a dynamic, strategic representation of world gas production, trade, and consumption between 2005 and 2030. In particular, we simulate a closer cooperation of the GASPEC countries when exporting pipeline gas and liquefied natural gas; we also run a more drastic scenario where GASPEC countries deliberately hold back production. The results show that compared to our Base Case, a gas cartel would reduce total supplied quantities and induce price increases in gas importing countries up to 22%. There is evidence that the natural gas markets in Europe and North America would be affected more than other parts of the world. Lastly, the vulnerability of gas importers worldwide is further illustrated by the results of a sensitivity case in which price levels are up to 87% higher in Europe and North America.

1. INTRODUCTION

The scenario of a cartel of natural gas producers, sometimes called a "GASPEC", is an important issue in international natural gas trade and has occupied a central role in the Energy Modeling Forum 23 study (EMF 2007). The three countries with the biggest natural gas reserves account for more than 50%: Russia: 25%, Iran: 16%, and Qatar: 14% (BP, 2008). Dwindling gas reserves in worldwide consuming countries contribute to worries over future gas supplies.

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* Corresponding author: regging@umd.edu, 1143 Glenn L. Martin Hall, Dept of Civil & Environmental Engineering, University of Maryland, College Park, MD 20742-3021 USA.

† DIW Berlin, Mohrenstr. 58, 10117 Berlin, Germany.

** Chair of Energy Economics and Public Sector Management, TU Dresden, 01062 Dresden, Germany.

*** Applied Mathematics and Scientific Computation Program, University of Maryland, College Park, Maryland 20742, USA.

Although the world's reserves-to-production ratio is about 60 years, it is much lower for North America (10 years) and Europe (24 years). Over the years, many countries have become largely dependent on importing gas and due to depletion of reserves more countries will rely on imports to cover significant parts of their gas consumption. Security of supply has become a concern of import-dependent countries, encompassing both infrastructural risks as well as political and economic uncertainties (Stern, 2007).

Proving the existence of cartel behavior in real markets is difficult. Salant (1976) and Pindyck (1978) were among the first to address the market power of OPEC in the oil market. Al-Qahtani et al. (2008) provide an extensive literature overview of the research related to the role of OPEC in the global oil market. To the best of our knowledge there is no model available to-date to adequately characterize the effects of cartel behavior in the world gas market. So far, the treatment of a potential gas cartel has been mainly qualitative, with some quantitative support from models that were not originally designed for such an analysis. For example, Perner and Seliger (2003) introduce cartel behavior "by hand" in an otherwise competitive model of international gas trade. They show lower pipeline expansion by the cartel members and higher investments by the fringe; LNG expansion proceeds slower in the Cartel Case, too. Since Perner and Seeliger (2003) assume Russia not to be part of the cartel, comparisons should be drawn with care. The difficulty of implementing cartel behavior in models of international gas trade was also the reason why, despite some discussion, no "Cartel Case" was explicitly included in the EMF 23 scenario design (EMF, 2007).

Another important issue for future natural gas trading is the development of capacities, both upstream (i.e., in natural gas production, pipelines, and LNG liquefaction capacities), and downstream (i.e., regasification terminals, storage, and distribution pipeline systems). Major investments in infrastructure will be necessary in the coming decades to transport additional volumes of natural gas over increasingly longer distances, requiring several trillions of dollars of investment (Cayrade, 2004, Finon and Locatelli, 2008 and IEA, 2003). However, so far research has not explicitly considered the impact that different market structures could have on infrastructure expansions.

In this paper, two important topics in the longer-term future of the natural gas industry are explored: the potential collusion between some exporting countries, and investments in infrastructure. The World Gas Model (WGM), a dynamic strategic representation of world gas production, trade, and consumption between 2005 and 2030 is used for the analysis. WGM is an extension of the European Gas Model described in Egging et al. (2008). The main contribution of this paper is: i) to illustrate how and where market driven infrastructure expansions will occur over the next decades; and ii) how more collusion in the global natural gas market could affect capacity expansions, trade-flows, consumption, production and price levels in the period up to 2030.

The organization of this paper is as follows: in Section 2 there is a brief discussion of the likelihood of the formation of a cartel by a group of exporting

countries. Section 3 illustrates some technical modeling aspects and the main features and extensions of the World Gas Model, including mixed complementarity problem (MCP) and cartel modeling, as well as an introduction to the endogenized investment decisions. Section 4 describes the data and the cases analyzed our Base Case and a Cartel Case, for the period 2005-2030. In addition, a scenario is run where the production capacities of certain exporting countries are constrained exogenously. Section 5 provides a discussion of results and their interpretation. Lastly, Section 6 provides conclusions and possible future research directions.

2. FROM GECF TO GASPEC?

The development of the "Gas Exporting Countries Forum" (GECF) has spurred concerns about the potential formation of a cartel on the world natural gas market. The GECF was formally set up in 2001. Since then, it has developed into a formal organization with broadening membership.[1] Several GECF countries are also OPEC members.

Is there a real danger of the GECF becoming a cartel, with a prominent role such as OPEC in the petroleum industry? The literature is divided on this issue, and so are industry experts and politicians. On the one hand, it is argued that the danger of a cartel is high. Observers point to the fact that OPEC, created in September 1960, also was slow in becoming a serious organization, but became so in the wake of the world oil market turmoil in 1973. Recent moves of individual countries show a tendency towards collusion in gas as well. Thus, Darbouche (2007) indicates closer Russian-Algerian gas cooperation, based on an extensive Memorandum of Understanding. According to Darbouche (2007), the GECF suffers from a weak institutional and organizational structure, but these conditions could change with Russia's recent involvement. Ehrman (2006) shares this view, when describing various possible structures that a gas cartel could evolve to. She addresses how ties among the GECF countries have gradually strengthened and become more formal over the past few years, as well as some actions taken by the member countries to enhance information exchange and natural gas market analysis.

On the other hand, one might argue that parallels between GECF and OPEC are artificial, and that the gas markets are less subject to market power than the world oil markets. It is argued that the long-term contracts in the gas business would make short-term oligopolistic behavior unrealistic. Also, the interests of the GEFC members, ranging from Iran to Norway (as observer) might be too diverse to pursue joint action (Hallouche, 2006). Finon and Locatelli (2008) analyze several possible forms of collusion, focusing on Russia. They conclude that in the short-term the chance of a successful cartel with just a few members is low since

1. In 2008, the GECF comprised Algeria, Bolivia, Brunei, Egypt, Equatorial Guinea (observer), Indonesia, Islamic Republic of Iran, Libya, Malaysia, Nigeria, Norway (observer), Qatar, Russian Federation, Trinidad & Tobago, United Arab Emirates and Venezuela. At the end of 2008, the members of the GECF established and formalized a collaborating structure to cooordinate their investments and supply strategies.

the barriers to entry in the European market are rather low for Gazprom's main competitors. In particular, the North Sea production is a competitive force that may counter-balance the Russian position in the next 20 years. Last but not least, it can be argued that the oil price indexation of many traditional gas contracts already emulates cartel (OPEC) behavior. See also Wagbara (2007) on different interpretations of the GECF.

3. MODELING ASPECTS

3.1 An Equilibrium Model of Natural Gas Markets: the World Gas Model

The World Gas Model (WGM) is a multi-period mixed complementarity model for the global natural gas market, allowing for capacity investments in the liquefied natural gas (LNG), pipeline and storage sectors. The model contains more than 80 countries and regions and covers about 98% of world wide gas production and consumption. It is an equilibrium model that includes game-theoretic elements by allowing for Nash-Cournot market power of individual producers (via their dedicated trading arms) as well as for collusion among groups of natural gas suppliers.

For each market covered, three seasons are modeled (low, peak, high demand) with the market participants including producers and their marketing and trading arms (traders), pipeline operators[2] and storage operators, LNG liquefiers, regasifiers, tankers (implicitly), marketers (implicitly), and consumers in three sectors (residential/commercial, industrial, and power generation) via their aggregate inverse demand functions. These players, except for LNG tankers, marketers and consumers, are modeled via convex optimization problems whose necessary and sufficient Karush-Kuhn-Tucker (KKT) optimality conditions when combined with market-clearing conditions comprise a market equilibrium formulation (Gabriel et al., 2005ab; Egging and Gabriel, 2006; Egging et al., 2008). The optimization problems of the players are typically profit maximization objectives subject to operational/engineering constraints, with all players except for the traders and the regasifiers being price-takers in the production, transportation, and storage markets. By contrast, the traders and regasifiers are allowed to behave strategically in multiple countries and can withhold gas to downstream customers to maximize their profits.

The producer sells gas directly to its dedicated pipeline trading arm (trader) as well as to the LNG liquefier. The trader then sells to the storage operator and the marketer, the latter being the interface with the three consumption sectors (residential/commercial, industrial, power generation). Each trader can be active in different countries, namely all those countries that he can reached by pipeline. The liquefier sells to a regasifier at an LNG import terminal. The regasifier in turn

2. For technical reasons, the functions have been split into two transportation players: one for operations and one for investment decisions.

sells to the storage operator and the marketer. The storage operator, finally, sells to the marketer taking advantage of seasonal arbitrage by buying gas in the low demand season and selling it to the marketer in the high and peak seasons.

Modeling traders as separate participants increases model transparency by clearly splitting production and export activities. Examples of traders in this sense in today's natural gas marketplace include Gazexport for Gazprom (Russia) and GasTerra for NAM (Nederlandse Aardolie Maatschappij, Netherlands).

3.2 Mixed Complementarity Problems and Investments

To compute market equilibria often the mixed complementarity problem (MCP) formulation is used (Facchinei and Pang, 2003). Each of the players (e.g., producers) is represented by a profit maximization problem subject to engineering or operational constraints. If players act non-cooperatively à la Nash-Cournot, then they need to take into account the actions of their competitors in this profit maximization. Taking together all the Karush-Kuhn-Tucker (KKT) optimality conditions for the players, combined with appropriate market-clearing conditions, then gives rise to a MCP.

Typically, MCPs for computing market equilibria do not include investments as decision variables. There are at least two reasons for this. First, investments are usually discrete choices corresponding for example to build/not build decisions or integer levels of the investment. If the integrality restrictions are taken into account at the same time as the MCP, the resulting problem is difficult to solve and in some cases there may not be a solution. Several examples that do combine these two aspects of market equilibria include the work of García-Bertrand et al. (2005, 2006) and Gabriel et al. (2006) in which electric power markets are modeled with the ability to keep/reject certain generators based on market conditions.

A second reason that investments are not always combined with MCPs is that there is a sequential aspect that must be considered. Typically, the investment decisions are made first, for example corresponding to long-term planning. Then, the market is considered with a fixed set of investments or network. This usually leads to a two-level problem which can be computationally more challenging than a MCP. In practice, researchers often either fixed the level of investments exogenously or take a continuous relaxation of the integer restrictions but mostly in the context of solving an optimization problem and not a MCP. In this paper we have adopted the latter relaxation approach since combining investments with MCPs is already a challenging strategy. Lise et al. (2008) adopt a similar approach but with less detail for the market players.

The following illustrates how the investment decisions have been implemented in the MCP framework. Consider an economic agent in a simplified multi-period setting. The agent has perfect foresight and must decide on his sales $SALES_y$ and capacity expansions Δ_y in each year y. The selling price π_y is exogenous to the agent, and his costs are given by a convex function: $c_y(SALES)$. The initial capac-

ity is $\overline{CAP}$; the costs for capacity expansion are b_y per unit; and there is an upper bound on the maximum expansion in each year, $\overline{\Delta}_y$. Finally, γ_y is the discount factor for future cash flows. The mathematical formulation for this simplified problem is as follows (symbols in parentheses are dual prices):

$$\max_{SALES_y,\, \Delta^L_{lm}} \sum_{y \in Y} \gamma_y \{\pi_y SALES_y - c_y(SALES_y) - b_y \Delta_y\} \tag{1}$$

$$\text{s.t. } SALES \leq \overline{CAP} + \sum_{y' < Y} \Delta_y, \quad \forall_y \ (\alpha_y) \tag{2}$$

$$\Delta_y \leq \overline{\Delta}_y \quad \forall_y \ (\rho_y) \tag{3}$$

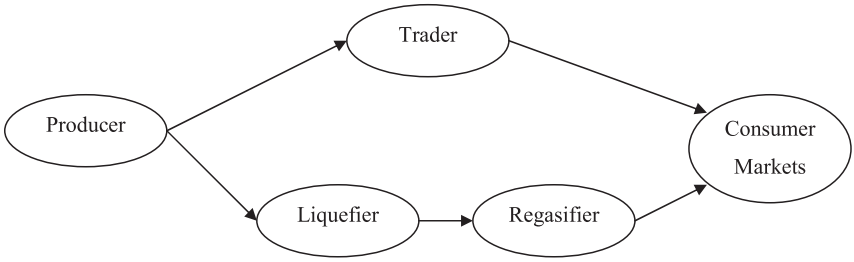
3.3 Representation of Market Power in WGM

In the present configuration of the World Gas Model, the market power lies with the pipeline trading arm of the producer (trader) and with the last element of the LNG value chain, the regasifier. This differs from the version of the World/European Gas Model in Egging et al. (2008) where only the traders exerted market power due to the focus on the European pipeline market. Both types of players, traders and regasifiers, are chosen for modeling reasons because they are the agents that face the final demand function emanating from the market (marketers). Facing the final demand allows them to manipulate it (that is, to take it into account in their profit optimization program) in case they exert market power. In modeling terms, there is a one-stage market game which can be expressed as a mixed complementarity problem (MCP). Figure 1 shows the possible routing of natural gas flows in the market game, via the pipeline trader or the LNG chain.

The standard definition of a cartel is that several producers jointly maximize their profits, that is, they maximize a single profit function given their individual cost functions. Given the current structure of our model, and the fact that a full-fledged cartel is unlikely to emerge soon, we model a close cooperation (or: collusion) between the members of the GECF, deploying the following approach:

- the pipeline exports are jointly optimized by all cartel members by exporting via one single cartel trader for all cartel member producers (as opposed to one dedicated trader for each producer);
- the LNG exports to each importing country, too, are jointly optimized by all cartel members by selling LNG via one single cartel regasifier in each importing country;
- all other LNG exporters will export to a different regasifier, that is assumed to exert no market power.

Figure 1. Natural Gas Export Chains



It should be noted that this is only an approximation of a standard cartel with one single monopolistic supplier as cartel supplies are split into pipeline and LNG supplies.[3]

4. DATA AND CASE DESCRIPTION

4.1 Base Case – Data and Calibration

The period considered for the case runs is 2005 to 2030, in five-year steps. 2035 and 2040 have also been included in the model data to allow for a sufficient payback of the investments in the last years, but no results are reported after 2030. The model has been calibrated to projections of the future energy markets, namely PRIMES forecasts for Europe (European Commission, 2008) and POLES forecasts for the rest of the world (European Commission, 2006).[4] These sources are used to determine the (exogenous) production capacities and the reference consumption quantities and prices of the demand function. POLES projections include a worldwide increase in natural gas production and consumption of 70% in 2030 relative to 2005.

Since the POLES projections are on a regional level rather than on country level, an assessment has been made to determine benchmark production and consumption levels for countries and regions included in the model. The model has been carefully calibrated to match observed production and consumption volumes in 2005 (BP 2007, IEA 2006) and to reflect a world wide average wholesale market price close to \$180 per 1000 cm^3, allowing for regional differences

3. The stability of the cartel is not modeled here.

4. While the PRIMES and POLES forecasts have the advantage of being officially approved forecasts, we have not been able to verify some of the underlying assumptions. In particular, it seems that their forecasts of natural gas production are optimistic, and not necessarily constrained by reserve availability. All scenarios require large capacity expansions in liquefaction, re-gasification and pipelines.

(BP, 2007).[5] For future years an effort has been made to reflect the PRIMES and POLES projections within about 5% deviation on a regional basis as well as for the major consumption and production countries. The calibrated worldwide Base Case consumption (production) in 2005 is 2368 (2435), and 3757 (3905) bcm in 2030, and a wholesale price of $375.[6] An average yearly reference price increase of 3%, in accordance with POLES projections is used.

For infrastructure capacities (pipelines, LNG liquefaction and regasification terminals, storage), project and company information from various sources (e.g., Oil and Gas Journal, GSE database at www.gte.be, EIA)[7] has been employed. This information was used to include existing additional capacities since 2005 and also considered when assessing the maximum allowable capacity expansions per period for the Base Case.

4.2 Cartel Case – Main Assumptions

In the following, we refer to the cartel as "GEC" (Gas Exporting Countries). The countries included in the cartel are the current full members, plus the observer Equatorial Guinea, and the Central Asian countries with large export potential. To implement the cartel every regasifier in the model data set had to be split up into two parts. One part, with full market power, to import from GEC countries; and a second perfectly competitive part, to receive LNG shipments from countries not included in GEC. Therefore an assessment had to be made to divide the base year regasification capacities and the allowed capacity expansions in future years. For the first and second model year (2005 and 2010) contractual obligations were explicitly considered when dividing up existing re-gasification capacities. For future years the allowed capacity expansions were set equal to 80% of the base values for the total regional regasification to represent 'GEC'-regasifiers, and 30% of the total regional regasification to represent the other regasifiers. A rationale for these values is that the GEC members currently have a market share of about 80% of LNG exports; but 30% (instead of 20%) allows non-GEC members to invest more and supply more LNG to countries from which GEC would withhold LNG supplies.

5. All reported prices are in $2005/1000 m^3.

6. WGM model accounts for losses in liquefaction, regasification, storage and pipelines. Consumption in WGM is corrected for 'own consumption' in the energy sector as reported by the IEA (www.iea.org/Textbase/stats/prodresult.asp?PRODUCT=Natural%20Gas).

7. We thank the Energy Information Agency for sharing data regarding seasonality of consumption and probable pipeline capacity expansions.

5. RESULTS AND DISCUSSION

5.1 Results Overview

A first look at some variables at a global level shows the significant impact of the cartel on the world natural gas market. As can be expected, the cartel reduces the total world production of natural gas (Figure 2) and increases the average price level (Figure 3) compared to the Base Case until 2030. All figures show the results for both cases (Base Case BC, and Cartel Case CC) for each five-year-period; the cartel members are designated by "GEC". The average price difference between the Cartel and Base Case is rather modest, which is a consequence of the specification of the Cartel Case with a Cournot fringe of non-cartel suppliers in addition to the cartel members. Hence, the average price in the Cartel Case is not as high as it would be in a "pure" cartel market with a competitive fringe.

Figure 2 shows the relative importance of the cartel members in the world natural gas market: they have a share in total production of about 50% in the starting year 2005, and this share increases to about 60% in 2030. Depending on the case, the GEC share in total production is somewhat lower in the Cartel Case due to the withholding strategy of the cartel members. As economic theory predicts, the cartel members can increase the prices and hence their profits by withholding quantities from the market.

As can be expected, given the importance of LNG exporters among the cartel members, the cartel impact is particularly manifest in the LNG market. Section 5.2.1 shows that the impact on the pipeline market is mostly felt in Europe. Figure 4 shows the liquefaction quantities for the cartel and the non-cartel liquefiers. The cartel members produce considerably lower quantities in the Cartel Case than in the Base Case. Because the withholding strategy is also adopted in the investment behavior (see Section 5.3) the non-GEC liquefiers can increase their market share over time and more than in the Base Case.

Figure 2. Yearly Production by GEC and Non-GEC (bcm)

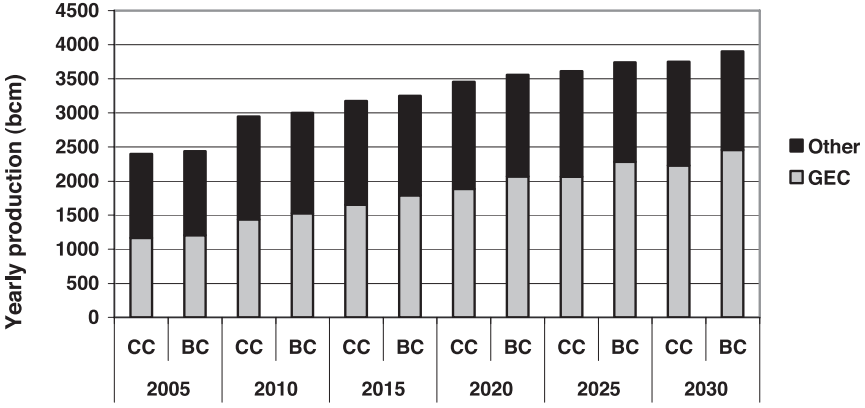


Figure 3. Volume-weighted World Average Gas Price

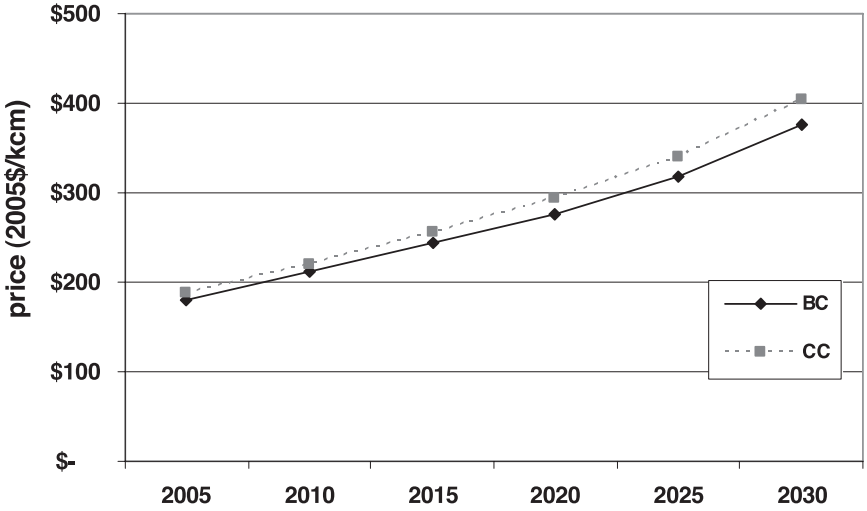
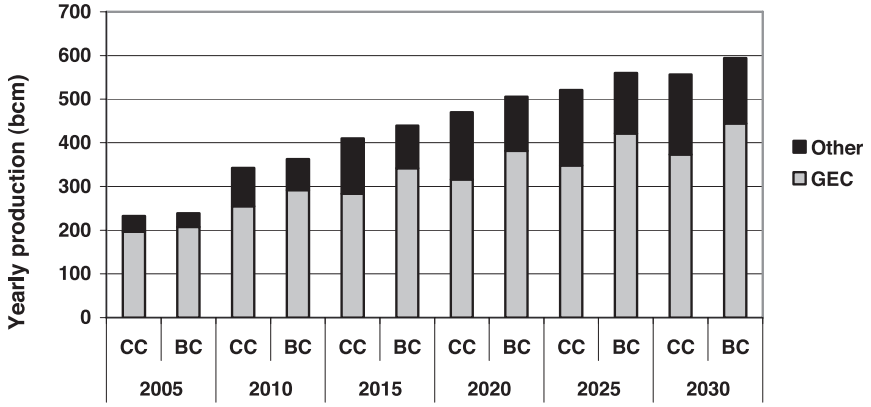
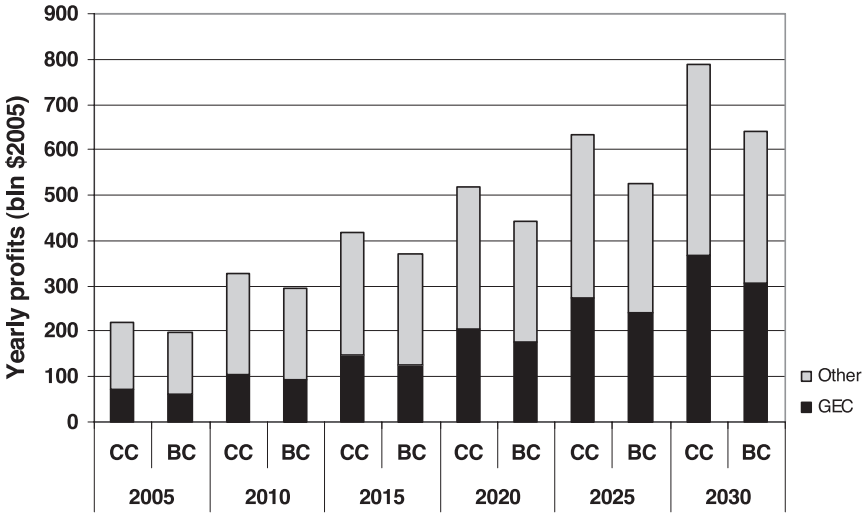


Figure 4. Yearly Liquefaction by GEC and Non-GEC Liquefiers (bcm)



The cartel members have an incentive to collude because their joint profit optimization yields higher joint profit levels than the sum of individual oligopolistic profits. Figure 5 shows that the model results reflect this behavior. The cartel members (GEC) obtain higher profits in the Cartel Case than in the Base Case in all model periods. The difference between the Cartel and Base Case is increasing over time because the withholding strategy in investments is felt more and more strongly with tighter and tighter capacities.

Figure 5. Indicative Yearly Profits Upstream (billion 2005 US-$)



Interestingly, also non-cartel members obtain higher yearly profits in the Cartel Case than in the Base Case. This is due to a positive price and a positive quantity effect. First, the overall higher price level induced by the cartel withholding strategy also applies to the sales of the non-cartel suppliers. Second, the non-cartel members can partly fill in the gap with natural gas supplies where the cartel members supply less than in the Base Case. This allows the non-cartel members to increase their quantities compared to the Base Case. Price and quantity effects combined lead to higher profits of the non-cartel members in the Cartel Case.

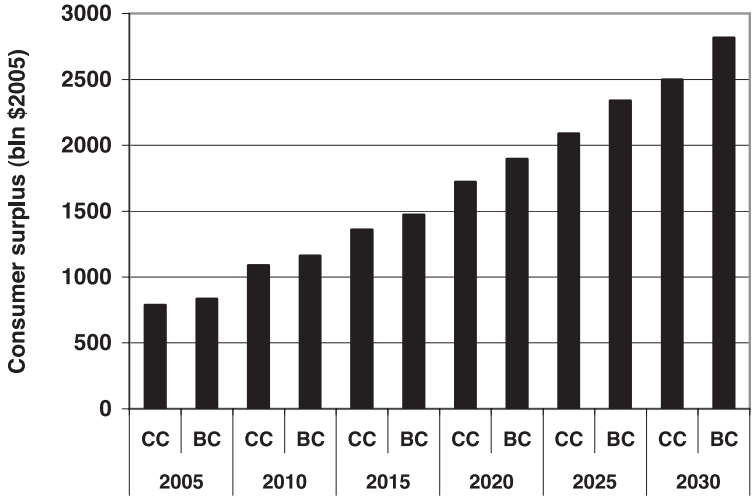
Figure 6 shows the consumer surplus in the world natural gas market. An increasing demand for natural gas is assumed (increase of reference quantities and prices in the demand functions for each period) which triggers an increasing consumer surplus over time. As can be expected, the higher price regime in the Cartel Case leads to a lower consumer surplus than in the Base Case. Again, the difference between the Base and Cartel Cases is the strongest at the end of the time horizon when the investment withholding is felt more keenly.

5.2 Regional Developments: Demand Side

In the following, the demand side of markets in Europe, Japan and North America, three regions with very different characteristics, are analyzed.[8]

8. See the appendix for an overview of which countries are included in these regions.

Figure 6. Indicative Global Yearly Consumer Surplus in Both Cases (billion 2005 US-$)



5.2.1 Europe

The European natural gas market can be characterized as a mature pipeline market with increasing reliance on LNG. Some countries are significant producers (Norway, United Kingdom, and the Netherlands), but most countries greatly rely on gas imports to cover domestic gas demand. Natural gas demand is projected to continue to grow on the European continent until 2030, but decline afterwards. In some countries demand reductions are anticipated earlier, which could affect the willingness of market players to invest in capacity. Table 1 shows for the years 2010, 2020 and 2030, for both cases, the total yearly consumption level of Europe (as well as Japan and North America), and the origins of the gas supplies to cover the demand: domestic production, LNG imports (and the share of GEC therein), and pipeline imports (and the amount bought from GEC members).

Table 2 shows the wholesale prices in the three regions for the three reported periods. The relative price increase in Europe is the most severe of the regions analyzed, although the Base Case prices (due to accessibility and proximity of the pipeline suppliers) are much lower, and the Cartel Case prices are still lower than in Japan and North America.

The numbers for supplies and price changes show that the impact of a cartel could be severe; in later years even more. The decreasing own production in combination with the increasing demand makes the import dependency higher,and the supply position of GEC stronger. LNG imports from other suppliers can only partially compensate for the volumes withheld by GEC.

5.2.2 Japan

Japan is the largest LNG importer in the world and will probably remain so for a number of years. Among the three regions analyzed, it is affected the least by a cartel. The high prices in the Japanese market make it very attractive for exporters. In later years LNG imports decline, however only after a pipeline from Sakhalin has been put in place.

5.2.3 North America

Production rates in North America are expected to start declining after 2010. Canada will for awhile continue to export to the U.S., and a pipeline from Alaska could lessen the immediate pressure on the market. To meet the projected consumption levels, a large number of LNG import terminals would have to be put in place in rather short term.

In 2010 North America as a whole is still close to self-sufficient. The almost one-fourth lower LNG imports from GEC members in the Cartel Case versus the Base Case are partially compensated by non-GEC suppliers, and the price impact of the cartel is negligible. However, in later years, the impact becomes more severe, with price increases of 7% to 14%.

Table 1. Consumption and Breakdown of Gas Supplies (bcm /year)

	Europe			Japan			North America		
	CC	**BC**	**Δ**	**CC**	**BC**	**Δ**	**CC**	**BC**	**Δ**
				2010					
Consumption	518	554	-6%	97	100	-4%	759	770	-1%
Production	286	275	4%	3	3	0%	715	713	0%
LNG Imports	71	71	0%	91	95	-4%	53	65	-19%
GEC	63	64	-3%	61	68	-10%	50	65	-23%
Pipeline Imports	166	212	-22%						
GEC	160	208	-23%						
				2020					
Consumption	582	635	-8%	103	106	-3%	772	809	-5%
Production	257	226	14%	3	3	0%	612	604	1%
LNG Imports	67	47	44%	81	84	-4%	165	210	-21%
GEC	55	41	33%	44	54	-18%	135	175	-23%
NetPipeInflows	262	367	-29%	16	16	0%			
GEC	235	346	-32%	16	16	0%			
				2030					
Consumption	616	667	-8%	104	113	-8%	741	801	-7%
Production	225	203	11%	3	3	1%	512	496	3%
Regasification	71	27	160%	64	73	-12%	231	304	-24%
GEC	55	22	148%	48	63	-23%	164	239	-31%
NetPipeInflows	320	437	-27%	35	35	0%			
GEC	272	393	-31%	35	35	0%			

Table 2. Wholesale Prices in Three Regions ($2005/1000 m^3)

year	Europe			Japan			North America		
	CC	BC	Δ	CC	BC	Δ	CC	BC	Δ
2010	280	243	15%	339	334	1%	331	324	2%
2020	379	312	22%	428	422	1%	465	433	7%
2030	521	437	19%	551	524	5%	606	533	14%

5.3 Regional Developments: Supply Side

The collusion in the Cartel Case leads to a notable reduction in total output compared to the Base Case. In this section, the focus is on selected suppliers both from the GEC (Algeria, Qatar, Russia) and others (Norway, Netherlands, Australia). This section also gives some insight into whether there is a shift in trade flows due to collusive behavior. In addition to a general reduction of trade flows from GEC countries, a shift of flows from cartel to non-cartel members can be expected as the latter may replace quantities withheld by the GEC. This is particularly true in Europe, which is affected by the cartel in both the pipeline and the LNG markets. Europe has the advantage, however, of having some important domestic producers (e.g., Norway, Netherlands) that can fill in considerable supplies, albeit within their reserve and production capacity limits.

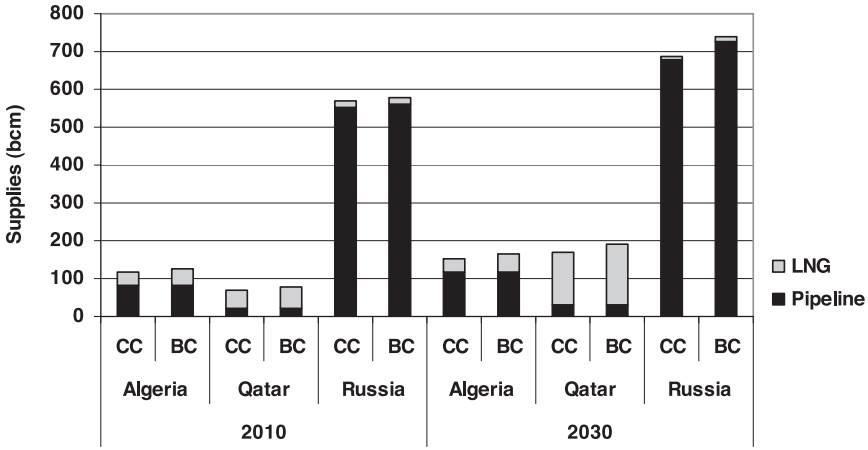
5.3.1 Gas Exporting Countries Forum: Qatar, Algeria, Russia

Figure 7 shows the total sales of three selected GECF producers (Qatar, Algeria, and Russia) in the Base and Cartel Case, split into pipeline and LNG sales. For all three producers, and similar to the global picture, the difference in output between CC and BC becomes larger over time, due to the withheld investment in previous periods.

For Algeria, the share of LNG sales in the Cartel Case decreases over time (from 37% in 2005 to 22% in 2030) and relative to the Base Case (29% in 2030). This can be explained by the following two points: first, Algerian LNG supply is relatively more expensive than its pipeline: second, there are lower cost LNG suppliers in the cartel that will preferably export more in order to minimize the total cartel supply costs.

Qatar, which is one of the most important cartel members with a very large liquefaction capacity in all model periods increases its LNG exports by a factor of approximately five in both cases between 2005 and 2030. Hence, the impacts of the Cartel Case on the Qatari output are especially strong. In 2030, when the difference to the Base Case is the largest, Qatar's output is 24 bcm (12.5%) lower. Although Qatar is a large LNG supplier, it also delivers some volumes to the domestic market and via pipeline to Oman and the United Arab Emirates, but the share of these pipeline sales decreases over time.

Figure 7. Algerian, Qatari and Russian Supplies Through Pipeline and LNG (bcm/year)



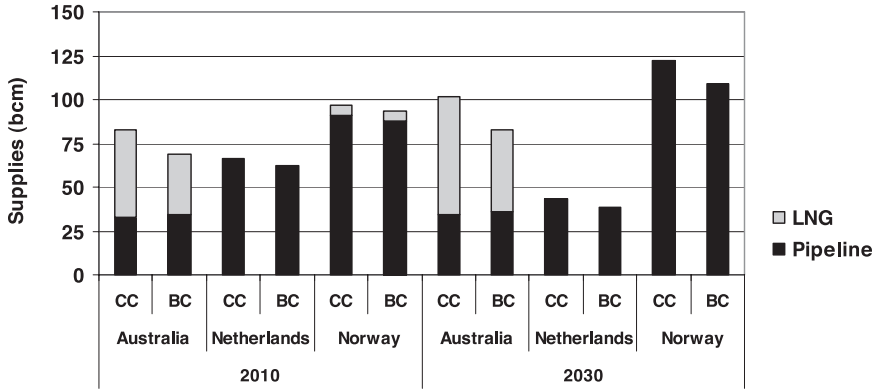
Russia is the largest of all suppliers to Europe and its participation in the GECF has evoked concern in Europe relative to supply security. Our model results show a limited effect of the Cartel Case, however, with Russia reducing its total exports by only 53 bcm (7%) relative to the Base Case. Interestingly, Russia does not fully use its liquefaction potential in the East (Sakhalin) and West (Baltic Sea, later Shtokman) and exports only 29 bcm at its peak (2020 and 2025, Base Case) via LNG. This is due to the relatively high costs of liquefaction operation and investment in Russia. Russian pipeline supplies, however, remain to a large extent available for the European market.

5.3.2 Compensation from Non-GECF Producers? Norway, Netherlands, and Australia

Europe is among the most affected consumption regions by the cartel because it imports both pipeline and LNG from GECF members. However, Europe can potentially compensate parts of the failing supplies by own production. Norway (not included in the definition of the European consuming region) and the Netherlands are particularly large producers in Europe with reserves of about 3 trillion cubic meters (tcm) and 1.25 tcm, respectively (BP, 2008).

As expected, Norwegian and Dutch output is notably larger in the Cartel Case than in the Base Case. Figure 8 shows that, in 2030, Norwegian supplies would be 13 bcm or 12% higher, and 5 bcm (14%) for the Netherlands. Their exports, mainly by pipeline, replace failing cartel imports, especially from Russia and the Caspian region.

Figure 8. Norwegian, Dutch and Australian Supplies Through Pipeline and LNG (bcm/year)



The exports from Australia are important because it is the largest non-GECF LNG supplier, but its ability to replace failing cartel supplies may be hampered by the long distances to the consuming markets since distance-based transport costs for LNG are part of the modeling assumptions. However, for consumers in the Pacific basin, such as Japan and South Korea, Australia can be an important supplier. Figure 8 reports that Australia indeed fills in the missing supply gap in the Cartel Case with very significant volumes. It increases its LNG exports by 50% between 2005 and 2030 in the Cartel Case, to 68 bcm per year.

5.4 Investments

WGM allows investigating the impact of cartel behavior not only in the short run, but also in the long run on investment decisions. The model includes endogenous investment decisions in transport infrastructure (pipeline, LNG liquefaction and regasification) and in storage. The global trade flow results indicate that there is a withholding strategy by the cartel members with respect to investments.

Figure 9 shows the yearly (lines) and the cumulative (bars) investments in pipeline capacity from cartel countries to all other countries. The pipelines investment between GECF countries and their non-cartel importers is the most affected by the cartel withholding, compared to pipelines between non-GEFC countries.

Figure 10 on liquefaction capacity expansion shows similar trends as for pipelines. While in 2010 and 2015 the investment levels in the Base Case and the Cartel Case are very similar (due to the proximity of the time period, for which many projects are already known, if not confirmed), there is a large investment gap between both cases starting in 2015. Together with the cumulative investments,

Figure 9. Pipeline Capacity Expansions from GEC to non-GEC Countries (bcm/year)

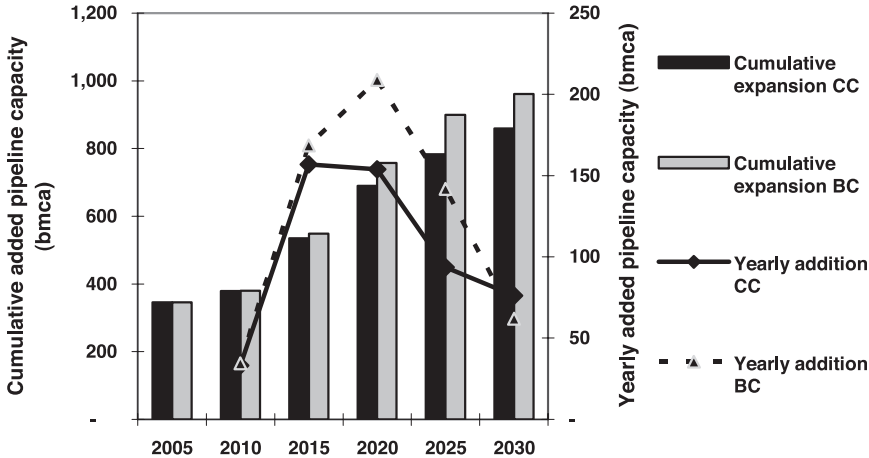
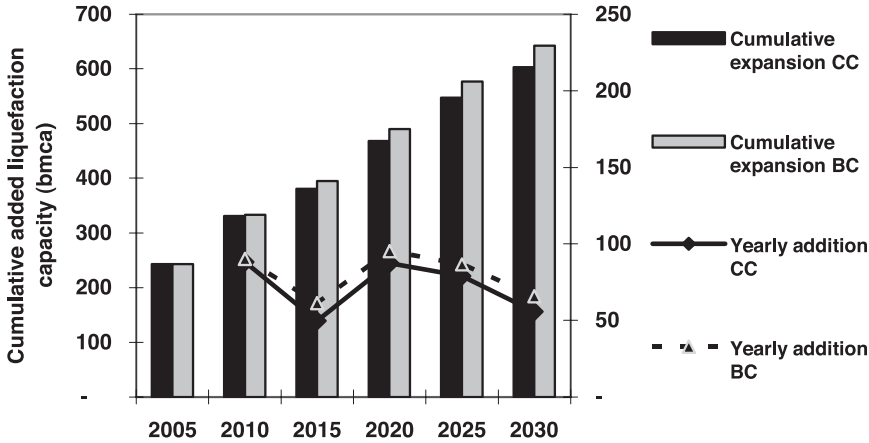


Figure 10. Liquefaction Expansions (bcm/year)



this clearly shows the withholding strategy of transport capacity of the colluding cartel countries. In 2030 the investments in pipelines (Figure 9) in the Cartel Case are higher than in the Base Case, which may seem somewhat puzzling. However, when looking at the cumulative capacity expansion it is explained by the large under-investment by the cartel members in the previous periods.

The model does not cover all aspects of the natural gas supply chain, for example domestic high pressure and distribution networks are not considered,

LNG ships are represented by distance-dependent cost term and losses, and projected production increases are exogenously determined. Therefore the following values should be considered with care: total investments in liquefaction, re-gasification, pipelines and storage amount to 742 $billion in the years 2005-2030 in the Base Case, and in the Cartel Case the total amount is 634 $billion, 17% lower.

5.5 Results of an Alternative Cartel Case

Since our model specification is only an approximation of a standard cartel, we present some results of a sensitivity simulation run (CC+) in this section to give an indication of what the effects of stronger collusion could be. In this specification, we have fixed the production capacity levels of the GECF countries to their 2005 levels, implying a reduction in production capacity of 50% in 2030 relative to the Base Case. This represents a situation where the cartel players withhold any additional capacities from the market in the long run. There is some spare capacity in the first model years, so that the effects are felt only in later periods.

Naturally the impact of the stronger collusion is more severe. Figure 11 shows the price increases in all three cases. Relative to the Base Case, in the sensitivity case the prices are 11, 29 and 44% higher in 2010, 2020 and 2030, respectively. Detailed results (not indicated graphically here) show European average prices of $816, North American prices of $975 and Japanese prices of $690 per 1000 m^3 in 2030: 87%,86% and 29% higher, respectively, than the Base Case results in Table 2.

Relative to the Base Case, in the sensitivity case the GEC production levels are 16, 33 and 42% lower in 2010, 2020 and 2030, respectively. Production levels of non-GEC countries are only 3, 9 and 11% higher in those respective years, by no means enough to compensate for the withheld supplies.

Also in the sensitivity case there are regional differences in the impact on prices and consumption. The case results suggest that Europe and North America are in a more vulnerable position than Japan.

6. CONCLUSIONS AND FUTURE DIRECTIONS

In this paper, we have applied the dynamic version of the World Gas Model (WGM) to analyze an important issue in international natural gas trade: the potential impact of a closer cooperation by the Gas Exporting Countries Forum (GECF). The model allows for modeling capacity investments endogenously, which is a particularly interesting feature when combined with strategic behavior of some of the market participants.

Intensified collusion within a group of gas exporting countries would reduce production, thus raising prices. North American and European price levels are shown to be 15-20% higher, creating a $180 billion yearly loss in consumer surplus and bringing upstream gas suppliers an extra $150 billion in yearly profits. Interestingly, more than half of the $150 billion additional yearly profits goes

Figure 11. Volume-weighted World Average Gas Prices for Three Cases

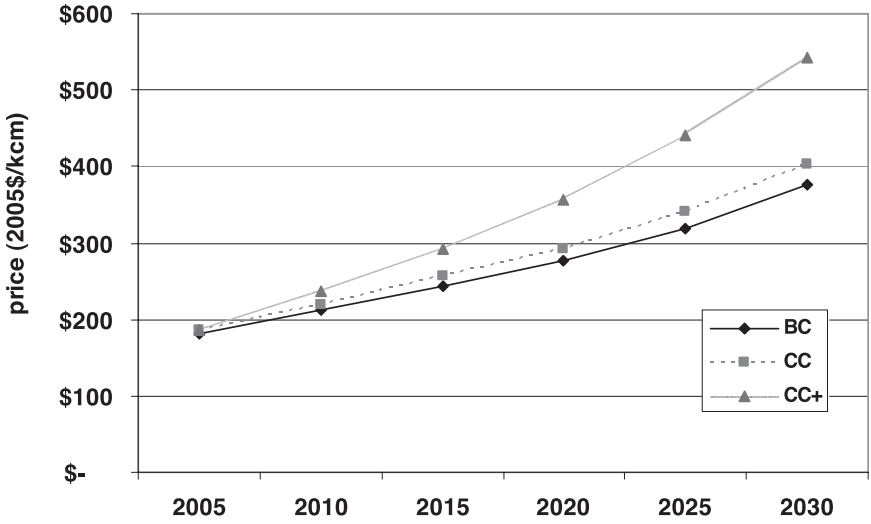
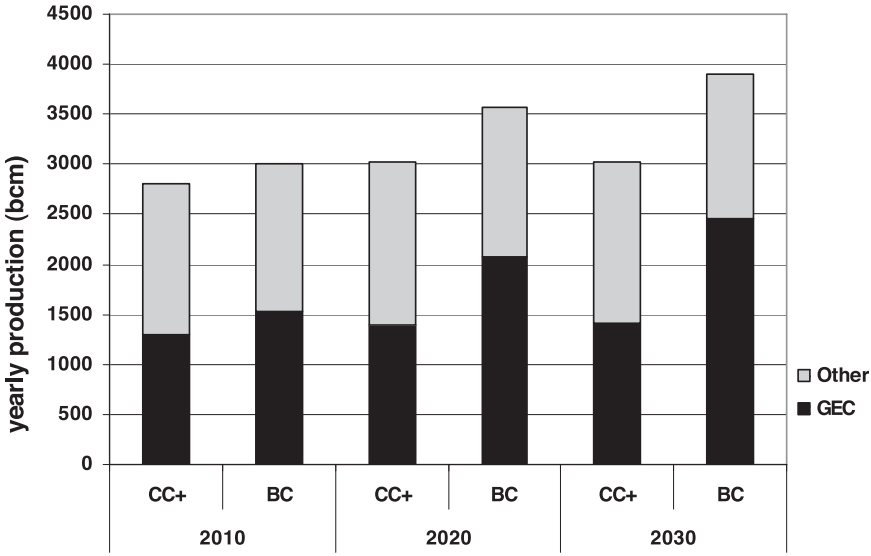


Figure 12. Yearly Production by GEC and Non-GEC in Sensitivity Case vs. Base Case (bcm)



to non-GEC members that would supply more natural gas at higher prices in a cartel situation. Since most non-GEC members have relatively low reserve-to-production ratios, they would probably not be able to sustain the higher production levels for decades to come. The low reserve bases of non-GEC countries are illustrated further by the results of a sensitivity case with production capacities of GEC countries fixed to the 2005 levels. Even much higher price levels in end user markets (+44% in 2030) only induce an eleven percent higher production in non-GEC countries.

Future possible research directions include further analysis of the production and demand projections that were used to calibrate the dynamic model. In particular, there may be a secular shift away from natural gas as the "bridging fuel" on the way to a low-carbon energy system. Natural gas has been identified as a "dirty" source of energy in the post-Kyoto world. Long-term demand projections are currently revised downwards by all major national and international forecasts. When taking into account the reserve constraints, potential limits to expanded natural gas production and consumption become even more restrictive. Upcoming research should take this new, sustainability-oriented perspective into account.

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A Dynamic Simulation of Market Power in the Liberalised European Natural Gas Market

Wietze Lise and Benjamin F. Hobbs***

Recent increases in the world price of oil have led to higher gas prices in Europe, possibly leading to greater opportunities for exercising market power. The effect of different gas producer strategies upon price levels in the liberalised European gas market over the period 2005-2030 is analysed using a dynamic gas market model that accounts for demand, supply, and investments in pipeline transport, LNG, and storage. The multi-period model formulation allows exploration of the dynamics of market power as transportation and storage capacities are augmented and interact with demand growth. The combined effects of spatial configuration of the supply network and supplier location upon intensity of competition in ten different regions in Europe are considered. Differences in prices are due to the interaction of (1) inherent ability of producers to exercise market power (determined by production capacity and costs) with the (2) accessibility of the market (determined by gas transport infrastructure).

1. INTRODUCTION

In 2005, natural gas consumption in the European Union (EU) states was approximately 530 billion cubic meters per year (bcm/y) (EU, 2004). Presently, this demand is fairly evenly divided between industry, power generation, and residential consumers. Figure 1 indicates that there are a dozen producing regions that potentially can sell gas to this market. However, recent events, for

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* Project Manager, IBS Research & Consultancy, Aga Han, Agahamami Cadessi 1/6, Cihangir, 34433 Beyoglu, Istanbul, Turkey.

** Theodore and Kay Schad Professor of Environmental Management, Department of Geography & Environmental Engineering, The Johns Hopkins University, 3400 North Charles Street, Baltimore, Maryland 21218, USA; Scientific Advisor, Policy Studies Unit, Energy research Centre of the Netherlands (ECN), Petten, The Netherlands.

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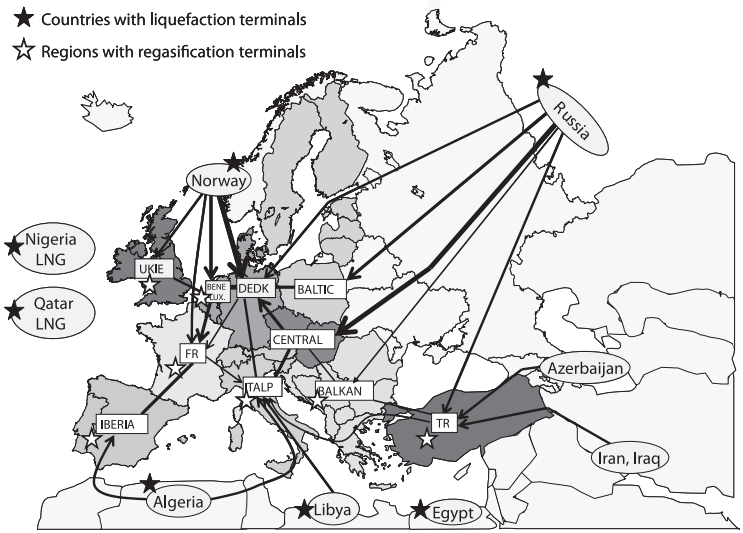
Figure 1. Geographical Coverage of the European Gas Market in the GASTALE Model



instance, where Russia disrupted European supply due to a conflict with Ukraine in January 2006, have highlighted the vulnerability of the EU market to the exercise of market power. Production in the EU countries can only meet about half of their own demand; meanwhile, the EU's production capacity is less than what just three major suppliers to the region (Norway, Russia, and Algeria) can devote to exports to the EU. Demand growth, in part spurred by the EU CO_2 Emissions Trading System, would increase this vulnerability. Consumption could potentially increase by more than 60% (or 2%/yr) by 2030, with power taking an increasing share. The growth rate in the eastern EU countries that were formerly in the Warsaw Pact is anticipated to be almost twice as high. Meanwhile, EU production capability is likely to fall from the present level of about 260 bcm/yr to two-thirds of that level by 2030 (EU, 2004). Although imports of LNG from elsewhere in the world could meet much of the growing gap between production and consumption in the EU, Norway, Russia, and Algeria will continue to play dominant roles in the EU natural gas market.

The purpose of this paper is to use the multiperiod version of GASTALE, an equilibrium model of the EU gas market, to explore the potential for exercise of market power by gas producers in the region between 2005 and 2030 and to illustrate the use of equilibrium models for that purpose. Figure 1 shows the study region, and Table 1 lists the producing and consuming regions considered. After providing a brief overview of methods for projecting market power in

natural gas markets (Section 2), we summarize the structure and assumptions of GASTALE (Section 3). Three cases of market power are presented in Section 4: perfect competition, pure Cournot competition among gas producers, and an intermediate base case in which the strategic behavior of producing region's actions is partially constrained by pre-existing contracts. A set of conclusions (Section 5) closes the paper.

Table 1. Producers and Consumers in GASTALE

Country/region	Included countries
Algeria	Algeria
Azerbaijan	Azerbaijan
BALKAN	Romania, Bulgaria, Greece, Croatia, Bosnia-Herzegovina, Serbia, Macedonia, Albania
BALTIC	Poland, Estonia, Latvia, Lithuania, Finland, Sweden
BENELUX	the Netherlands, Belgium, Luxemburg
CENTRAL	Hungary, Czech Republic, Slovakia
DEDK	Germany, Denmark
Egypt	Egypt
FR	France
IBERIA	Spain, Portugal
Iran, Iraq	Iran, Iraq
ITALP	Italy, Austria, Switzerland, Slovenia
Libya	Libya
Nigeria	Nigeria, Angola, Trinidad-Tobago
Norway	Norway
Qatar	Qatar, Oman, Yemen
Russia	Russia, Turkmenistan, Kazakhstan, Uzbekistan
TR	Turkey
UKIE	UK, Ireland

Note: Country/regions in CAPITALS are consumers, while country/regions in bold font are producers.

2. METHODS FOR PROJECTING MARKET POWER IN GAS MARKETS

There are several methods for characterizing and projecting market power in energy markets such as the EU gas market. We categorize them into statistical empirical models, competitiveness indices, experimental economics, and simulation models. Models can be further divided into agent-based and equilibri-

um models, the latter being the approach we adopt here. No method is completely satisfactory by itself; each has advantages that complement the others.

The statistical approach uses market outcomes to estimate the extent to which market power has been exercised in the past. For instance, Murry and Zhen (2008) identified dynamic price behavior at US gas hubs that was consistent with the exercise of market power. However, such estimates lose relevance to the extent that the market structure changes due to, for example, demand growth, reorganization of the industry, shifts in world markets, or alterations to gas transport and storage infrastructure. The many recent changes in EU gas markets mean that there is relatively little data that could be used to build statistical models for projecting market power in that region. However, statistical analysis can still help validate simulation models.

Competitiveness indices are simple summaries, such as the Hirschman-Herfindahl Index or whether the largest supplier is pivotal in a market. Such indices are commonly used in regulatory proceedings. For instance, the US Federal Energy Regulatory Commission evaluates applications by pipelines for market-based rates by assessing whether potential substitute pipelines have spare capacity that equals or exceeds the applicant's capacity (McAfee and Reny, 2007). However, indices may fail to capture aspects of markets, such as transmission limits, that have important impacts on the ability to exercise market power; for that reason, Borenstein et al. (1999) recommend use of simulation models.

The experimental economic approach, which uses live subjects, has the potential to identify likely modes of behavior among large market players because it allows for learning and suboptimal decision making. Further, it can capture features of market rules that are difficult to represent mathematically. An early evaluation of the efficiency of gas auctions on a network is by McCabe et al. (1990), but we have found no other experiments in a natural gas context. Agent-based mathematical models have a similar objective: to simulate imperfect and dynamic decision making by market players in the face of complex market environments, but using computerized instead of live agents. Without considering network constraints, Barrot and Tchung-Ming (2008) simulated the interaction of flexible contracts and spot markets in natural gas, considering how the former may amplify market power. Several agent-based efforts are reported to be underway to model market power in gas networks, but no actual applications have been reported (e.g., Tatara et al., 2007). Unfortunately, live experiments are expensive and both live and agent-based experiments tend to be difficult to replicate, so results are difficult to generalize.

The last approach we consider for projecting market power in gas markets is equilibrium modelling, the basis of our model GASTALE. Equilibrium models formulate the optimisation problems facing producers, transporters, traders, storage, and consumers of gas and then solve them simultaneously while imposing market clearing conditions. The results will depend both on market structure and on behavioural assumptions, for instance concerning conjectural variations or the degree of forward contracting (Gabriel and Smeers, 2006). The ability to accommodate different structural and behavioural assumptions is both an advantage

and disadvantage. The advantage is that the effect of structural changes can be explored in a way not possible with statistical models – for instance, the effect of a significant increase in transport capacity from Russia via the proposed Baltic pipeline. On the other hand, numerous possible structural scenarios together with fundamental uncertainties about the nature of competition among large producers mean that equilibrium models should be used to show a range of possible outcomes and not to make precise predictions. Thus, the emphasis should be on exploration of scenarios and the implications of different assumptions for market outcomes, rather than precise prediction.

Smeers (1997) and Gabriel and Smeers (2006) survey the use of equilibrium models for analysing gas markets issues, including market power. They observe that such models can provide useful insights, but have not been used as extensively as in the power sector. The first work in natural gas focused on market power among gas producers (e.g., Haurie et al., 1987; Mathieson et al., 1987; Breton and Zaccour, 2001; Golombek et al., 1995) using Cournot, Stackelberg, and monopoly solution concepts. (See EMF, 2007 for recent applications.) Most of these models calculate equilibria in a static (single-year) setting. An exception is Flam and Zaccour (1989) who compared open-loop and feedback solutions for a Cournot game among European gas producers who decide how to allocate production over a multiyear time horizon. Later, Zwart and Mulder (2006) incorporated network and more sophisticated production and storage investment and operation models in an open-loop Cournot model of the European market. The intertemporal aspect of gas production is important because production today has an opportunity cost in terms of reduced production later. Although GASTALE is also a multiperiod model, we simplify production by considering only scenarios of production capacity expansion, rather than endogenizing investment in that sector. But GASTALE represents expansion decisions in transport and storage endogenously in the same model.

Market power in the gas trading sector has also been modelled. Gabriel et al. (2005) and Gabriel and Smeers (2006) focus on market power on the part of either Cournot or Stackelberg traders who buy gas from producers who are assumed to be price-takers. The issue of double marginalization, which arises if both producers and downstream traders have market power, was a focus of studies by Boots et al. (2004) and Holz et al. (2008), with extensions proposed by Gabriel and Smeers (2006). The models assumed that traders are Cournot players who are price-takers with respect to the border price of gas, while producers are Cournot players who correctly anticipated the reactions of traders to changes in border gas prices. The resulting successive oligopoly yields higher prices for consumers than vertical integration between producers and traders. In the analysis of this paper, however, we assume that gas producers exercise the most market power in the EU market (which is not true in the US market, for instance). Consistent with the argument of Zwart and Mulder (2006) that the Cournot conjectural variation is most appropriate for gas producers, we adopt that framework (with some modification) in our GASTALE simulations.

Market power resulting from pipeline expansion decisions (especially involving Russian gas) has been a focus of other work using a variety of cooperative and noncooperative game theoretic models. Von Hirschhausen et al. (2005) compare the results of different frameworks considering Belarus, Ukraine, and Russia as players. Morbee and Proost (2008) extend the framework of static network-constrained models to include risk aversion on the part of players and the possibility of "hold up", tying into the literature on contracts and enforcement (see also Hubert and Ikonnikova, 2004). In our analysis below, we also model pipeline expansion endogenously; however, because we focus on the issue of producer market power, we assume that pipeline capacity is augmented when additional revenues can cover annualised costs (i.e., price-taking expansion).

Equilibrium models addressing market power have considered a variety of other types of natural gas market problems. These include games between distributors of gas and the agencies that regulate access and prices (Austvik, 2003; Gabriel and Smeers, 2006); the impact of lowering transmission fees upon competition among gas providers in the Netherlands (Lise et al., 2005; Van Witteloostuijn et al., 2007); interactions of electricity and gas markets in Spain using a successive oligopoly framework to analyze vertical integration issues (Vázquez et al., 2006); and optimal unilateral decisions by Russia in the CO_2 emissions and gas markets using a computable general equilibrium model that represents Russia as a monopoly with a competitive fringe (Hagem et al., 2006).

A variety of analytical methods have been used to solve market equilibrium models, including closed form solution (for simple models), iteration among components (Gauss-Seidel iteration), solution as a single equivalent optimisation problem, and complementarity methods (Labys and Yang, 1991). In complementarity problems, the first order (Karush-Kuhn-Tucker) conditions for each player's optimisation problem are combined with market clearing conditions to form a mathematical problem with the following form:

$$\text{Find } X,Y \text{ satisfying:} \qquad \begin{array}{l} X \geq 0;\ F(X,Y) \leq 0;\ X'\ F(X,Y) = 0 \\ G(X,Y) = 0;\ Y \text{ unrestricted} \end{array}$$

where X and Y are vectors of variables of lengths m and n, respectively, and $F(\ )$ and $G(\ )$ are vector-valued functions (not necessarily linear) of the variables, also of lengths m and n. The complementarity terms are the first row, and arise from the complementarity slackness conditions in the constrained optimisation problems of the market players. Regulatory inequality constraints can also yield such conditions (e.g., the price of emissions allowances can be positive only if emissions bump against the regulatory cap). If there are equality constraints, as in the second row, this is termed a mixed complementarity problem. A correctly specified model will have as many conditions as variables. Complementarity models found early application to simulation of gas markets (Matheison, 1985; Yang and Labys, 1985). Their use has grown recently because of the availability of powerful solvers (PATH) and their ability to represent equilibrium problems for which no

single equivalent optimisation problem might exist, especially where the exercise of market power is possible.

3. MODEL

The first version of GASTALE was a static model that was used to explore the vertical interaction between producers and within-country traders of gas, both of whom exercise market power (Boots et al., 2004). The model was formulated as a complementarity problem, and was later expanded to include interseasonal storage (Egging and Gabriel, 2006) and multiple years with endogenous expansion of storage, pipeline, LNG liquefaction, and LNG regasification (Lise and Hobbs, 2008). The latter version is used in this paper, which considers six scenario years (2005, 2010, …, 2030) and three seasons per year (low, medium, and high demand seasons, with low demand occurring in April-September and high occurring in December-January).

The basic market structure assumed by GASTALE includes producers, transporters, storage, and consumers of gas. Producers are the only strategic players, and pay regulated or subsidiary pipelines and LNG shippers to move gas to the market. Storage owners buy gas in the low demand period for sale in the other periods. As in other models (Gabriel et al. 2005), a type of congestion pricing is assumed in transport and storage. In particular, transporters and storage operators are assumed to charge long-run variable cost (including capital costs) unless capacity constraints bind; if the latter occurs, then the price charged for transport increases until the demand for transport services equals the supply. In order to formulate the model as a complementarity problem rather than as a much more difficult to solve EPEC (equilibrium problem with equilibrium constraints; see Daxhelet and Smeers, 2001), strategic producers correctly anticipate how consumption will react to price changes (using linear demand functions), but naively assume that they cannot affect the price of transport. The same assumptions are made about costs of storage (intertemporal transport). Under these assumptions, one transmission system operator (TSO) and one storage system operator (SSO) can be used to model those respective parts of the market. Prices are assumed to be wholesale prices within a region, so local gas distribution costs are not modeled. Wholesale prices are assumed to be fully arbitraged between industrial, power, and residential sectors, so that we can consider just one wholesale price per region.

The dynamic GASTALE used here represents the investment process for storage and transport facilities. One possible formulation would solve all years at the same time, with the TSO and SSO maximizing their profits subject to price-taking assumptions; however, that would unrealistically imply perfect foresight. GASTALE instead simulates a more short-sighted process by a recursive model. Additions to capacity are made every five years, based on a comparison of anticipated revenues in line with expansion costs in this period. Consistent with the short-sighted process, revenue projections are based upon assuming naively that the congestion prices that would be received in the year of expansion would con-

tinue to accrue in later periods. As a result, the TSO and SSO problems in each year include capacity expansion variables with an annualised cost that is inserted in their objective functions; this capacity is assumed to be available right away for use. Given the five-year time step of GASTALE, this is equivalent to five year's perfect foresight and lead time for investment. Then the amount of capacity that is added in that year, together with already existing infrastructure, is defined as the existing capacity in the subsequent period 5 years later (adjusted downwards for depreciation). Details on the formulation are presented in Lise and Hobbs (2008).

GASTALE is solved as follows: starting in year 2010, a single year equilibrium is obtained using the PATH solver among Cournot producers, the TSO, the SSO, and consumers, which includes values for all production, flows, prices, and expansion of transport and storage facilities. (The 2005 equilibrium is solved separately without any new facility investment.) Then the updated transport and storage infrastructure is inserted in the next year's model (2015), and the model is solved again. The process is repeated through 2030. The model's demand functions are calibrated to the EU Directorate General of Transport and Energy demand forecasts for the EU (2004) for the whole time horizon by ensuring that, under the base case assumptions, the demand functions pass through the quantity-price points that are consistent with the quantity forecasts and the prices yielded by this dynamic process. In the below analysis, the same model parameters are adopted here as used in the policy analysis by Lise et al. (2008) and Van Oostvoorn and Lise (2007), except for a recalibration of the production cost functions to simulate a situation with an oil price of 60 $/barrel in constant 2005 prices. Details on demand growth, demand functions, and costs and capacities of production, transport, and storage, as well as model validation, are provided therein.

4. ANALYSES

Three competition cases are simulated here to represent different degrees of market power. Compared to our earlier analyses using the dynamic version of GASTALE (Lise and Hobbs, 2008), these cases reflect updated gas production costs, and so show higher prices. We also provide additional details on the effect of market power on prices, quantities, investments, and operations.

The first case is a *perfect competition* benchmark, in which all producing regions (Table 1) are assumed to be price-takers. That is, each producer's optimisation problem maximizes revenue (given the market prices) minus costs.

The second is a Nash-Cournot equilibrium, in short *Cournot competition*, among producers, in which each producing region maximizes profits, assuming that other regions do not alter their sales in each consuming region. Companies within a producing region are assumed to form a fully cooperative cartel. Cournot competition is simulated by explicitly stating the consuming region's price in each producer's revenue function as a function of the sum of the sales variables (one for each producer) for that region. As a result, if a producer reduces its sales to a consuming region, it anticipates that the local price will increase at a rate determined

Figure 2. Quantity-Weighted EU Prices over Time in Three Competition Cases (Index, Average Price in 2005 is 100)

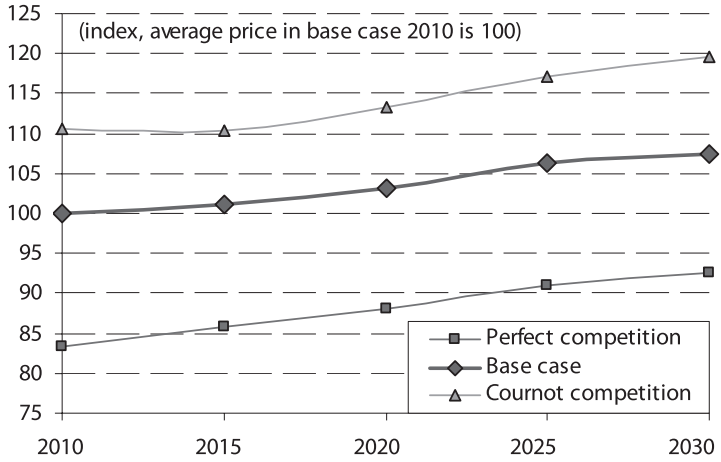
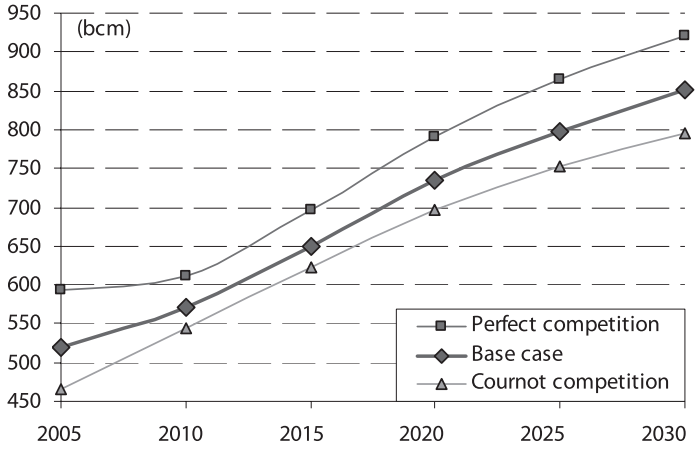


Figure 3. Production over Time for Three Competition Cases (bcm/yr)



by the slope of the demand curve, naively assuming no reaction on the part of rival producers. Although Mulder and Zwart (2006) argue that the Cournot conjectural variation is most realistic, the result of unrestrained Cournot competition is much higher prices than actually realized in European markets. Under our assumed demand elasticities (-0.75 power generation, -0.4 industry, -0.25 households), such Cournot competition would raise prices several fold compared to perfect compe-

tition, and quantities demanded would be 20% less. Political considerations and long-term contracts act as a restraint against such extreme market power.

Hence, we consider a third case, termed the *base case*, which is designed to match existing prices and to be consistent with official demand forecasts (EU, 2004). This was obtained by assuming that Russia exercises market power on 25% of export flows to the EU, while other countries instead exercise market power on 75% of their export flows. The remainder is assumed, in effect, to be provided under fixed long term contracts. Alternatively, this case can be viewed as one in which Russia prices so as to sustain a market share in the EU of about one-quarter, consistent with recent history.

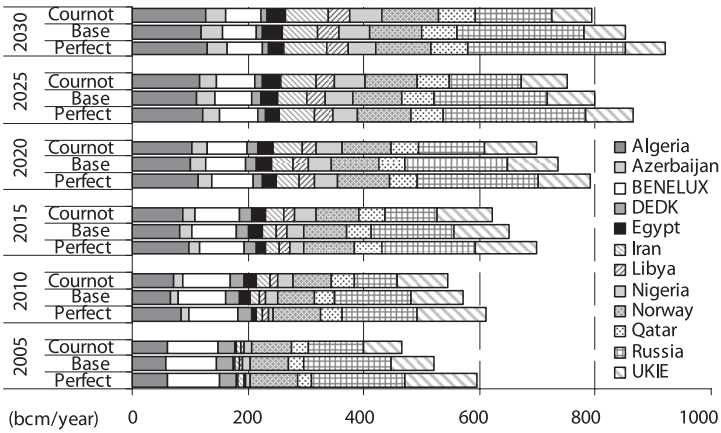
Thus, the perfect competition and Cournot cases bracket the base market power case. Because it is possible that future contracting practices, exercise of oligopsonistic market power, or government action will result in price mark-ups that differ from our base case, the competition and Cournot cases can be viewed as bounds upon future prices. Figures 2 and 3 illustrate this relationship among the cases, showing prices (weighted by quantity demanded in each demand period and each EU country) and total quantity demanded in each year. Prices in all three cases increase with time by similar amounts, and demand growth is strong. The base case results, as predicted, lie between the two extremes of pure price-taking and pure Cournot oligopoly. The changes in quantities imply arc elasticities on the order of –0.4 to –0.7, depending on the year and cases compared.

Figure 4 shows disaggregated results, breaking down EU sales among the twelve producing regions. The base case shows Russia maintaining a one-quarter market share, approximately. A comparison of the competitive and base cases shows that the following producers significantly restrict output to raise prices in the base case: Russia (despite the 75% forward contracting assumption); Algeria; Iran (just in later years, when pipeline infrastructure has expanded to accommodate potential Iranian sales); and the large EU producers (Norway and UKIE), especially in the early years. Note that the largest producers are not the ones who necessarily restrict output; market power outcomes are a complex interplay of production costs, network and storage constraints, and contracting assumptions. For instance, the BENELUX countries maintain their output in all cases, even though their production is similar in magnitude to Norway and UKIE, who do exercise market power. On the other hand, some exporting regions with relatively small market shares take advantage of the higher base case prices to increase output and, of course, profits, notably Egypt and Nigeria.

Turning to a comparison of competition with unrestrained Cournot competition, a Russia that is free of long-term contracts reduces its output by as much as 40% in order to increase prices by over 30%. UKIE also significantly reduces production, particularly in the early years. All other producing regions together produce about the same amount in the perfect competition and base cases, confirming that Russia is the most important strategic player. In contrast, Iran, Nigeria, and Egypt take advantage of the higher Cournot prices to expand sales to the EU.

We now consider the distribution of price increases due to market power

Figure 4. Production over Time in Twelve Regions for Three Competition Cases (bcm/yr)



which, due to network constraints and relative proximity of different producers, is by no means uniform. Table 2 shows prices in the low demand seasons for each region in 2010 and 2030 for the competitive case along with the percent price increases for the other two scenarios. Interestingly, prices under low demand are most affected by market power in percent terms, but have the lowest prices. Comparing first the base and competitive cases, we see that mainly eastern European countries suffer from the exercise of market power by Russia, with the Balkans, Central, and Turkish regions (Table 1) suffering price increases between 27% to 36% in 2010, while western and southern European countries experience price increases between 15% to 19% in 2030. UKIE is an exception because of the market power that its producers exercise – its price increases are similar to eastern Europe's. If we now consider the relaxation of contract constraints that limit market power (especially of Russia) in the base case, Cournot competition causes prices to go up by an additional 15% or more in Eastern Europe, but only about 10% elsewhere. The net result is that, compared to perfect competition, unrestrained Cournot oligopoly increases prices by over 50% in eastern Europe, but by only about 20% to 30% elsewhere because of the access other countries have to alternative suppliers. This shows that market accessibility is an important determinant of prices.

Table 3 shows the storage and transport investments made by GASTALE in each year within each of the three competition cases, while Table 4 shows aggregate capacities and utilization. In general, total investment in storage and LNG facilities over the time horizon does not change between the competitive and base cases, although there are shifts in geographical distribution and specific timing of investments. For instance, under the base case, there is more storage in the Balkan-Turkey and Baltic-Central regions. This storage serves to arbitrage peak-

Table 2. Prices under Low Demand in 10 Regions for 2010 and 2030 Under Perfect Competition and Percent Price Increases

	Perfect competition prices (€/1000 m³)		Base case price increase over perfect competition		Cournot price increase over base case		Cournot price increase over perfect competition	
Region	**2010**	**2030**	**2010**	**2030**	**2010**	**2030**	**2010**	**2030**
BALKAN	136.2	144.0	27%	18%	16%	13%	47%	34%
BALTIC	140.7	152.2	22%	22%	16%	16%	41%	41%
BENELUX	136.2	152.0	17%	15%	8%	11%	26%	28%
CENTRAL	136.5	147.4	36%	24%	23%	19%	68%	48%
DEDK	140.7	154.0	24%	19%	16%	16%	44%	38%
FR	144.1	154.7	22%	19%	11%	12%	34%	34%
IBERIA	141.8	148.2	15%	17%	7%	10%	23%	28%
ITALP	140.9	147.4	16%	17%	11%	13%	29%	32%
TR	119.9	133.4	31%	25%	11%	10%	46%	37%
UKIE	123.7	151.3	29%	15%	8%	10%	39%	27%

offpeak price differences in eastern Europe that might otherwise be exacerbated by Russian market power. Meanwhile, the base case shifts LNG investment to UKIE in order to moderate the price increases that would otherwise occur due to the restriction of supply from UKIE producers. UKIE is particular sensitive to seasonal swings, mainly due to the recent drop in production from their gas fields in the North Sea. UKIE has too few existing pipeline connections to compensate for the seasonal swing in demand, and the quickest and economically most attractive way to fill this gap is to invest in storage.

On the other hand, the base case sees approximately 50% more pipeline investment on average than competition, because the exercise of market power in eastern Europe (and to a lesser extent in the UK) results in sharpened price differences between western/southern Europe and the rest of Europe. Pipelines are then built in an attempt to arbitrage those price differences, with pipeline investment within the EU increasing by over 250% over the time horizon. Meanwhile, investments in pipelines that import gas from Norway, Russia, Asia, and Africa decrease somewhat compared to the competitive case, corresponding to lower imports. Aggregate pipeline use (measured as the sum of the bcm/yr flows across all pipelines in the model) is roughly 50% higher in both market power cases than under competition, because of heightened geographical price differences (Table 4).

Contrasting the extreme (Cournot) market power case with the competitive case shows similar patterns for pipeline and LNG investment as in the base case-competition comparison. However, storage investment increases by about 30% under Cournot competition, with additional investments occurring in all

Table 3. Investments (bcm/5 yrs of Capacity)

	Perfect competition		Base case		Cournot competition	
	2010	**2030**	**2010**	**2030**	**2010**	**2030**
Storage:						
BALKAN-TR	0.0	3.5	0.0	2.1	0.2	3.9
BALTIC-CENTRAL-ITALP	1.2	0.9	0.4	2.4	1.3	6.2
BENELUX-DEDK-FR	0.0	8.4	0.0	5.5	1.8	7.0
UKIE	12.8	0.0	6.9	2.3	11.9	3.6
Total new storage:	**14.0**	**12.8**	**7.3**	**12.3**	**15.2**	**20.7**
Pipelines:						
South-North	62.5	17.9	31.0	17.9	36.1	20.9
North-South	15.7	18.8	8.4	19.1	5.7	18.8
East-West	0.5	79.5	18.4	70.2	24.8	35.2
Within EU	14.9	37.9	226.8	103.5	218.0	135.7
Total new pipelines	**93.7**	**154.2**	**284.7**	**210.6**	**284.7**	**210.6**
Liquefaction:						
Algeria-Libya	0.0	21.9	1.1	22.6	0.4	18.8
Egypt	11.6	7.6	21.5	7.6	21.5	7.6
Nigeria-Qatar	30.0	29.4	32.6	29.4	38.6	29.4
Russia	0.0	3.2	8.5	1.7	8.5	1.7
Total new liquefaction	**41.5**	**62.0**	**63.7**	**61.2**	**68.9**	**57.4**
Regasification:						
BALKAN-ITALP	15.1	18.4	12.3	15.1	17.9	14.9
BENELUX-FR	21.4	12.8	14.0	11.9	15.5	11.6
IBERIA-TR	0.0	11.6	0.0	18.3	2.6	17.6
UKIE	0.0	12.1	38.0	15.8	35.5	16.6
Total new regasification	**36.6**	**54.9**	**64.2**	**61.2**	**71.4**	**60.6**

four aggregate regions shown in Table 3. Intuitively, one might have expected less investment, as overall gas volumes are smaller in the Cournot case. But because oligopolistic competition can yield greater price mark-ups under supply constrained (peak) conditions, as fewer suppliers have excess capacity, the attractiveness of storage is increased. This is reflected in the higher amount of storage in the Cournot case in Table 4. As a result, prices increase less than they otherwise would during the high demand season, and prices during the low demand season are higher.

The final set of results (last rows of Table 4) concern 'flexibility' or what might be called 'swing supply' – the differences between the amount of gas provided to consumers in the medium/high and low demand seasons. Either increased production and imports or increased use of storage can provide that flexibility. The table shows that the swing supply of storage is much higher in 2030 than in 2010, while pipeline swing supplies from other sources actually fall, indicating that the pipelines are being used closer to capacity in all seasons by 2030. Comparing the competitive, base, and Cournot cases shows that the main effect of large producer

Table 4. Use and Operational Capacity for Storage, Pipelines, Liquefaction and Regasification, and Swing Supply (bcm/yr)

	Perfect competition		Base case		Cournot competition	
	2010	**2030**	**2010**	**2030**	**2010**	**2030**
Storage:						
Total stored	63.6	97.3	54.1	101.3	69.5	115.2
Storage capacity	79.1	97.3	72.5	101.3	80.3	115.2
Pipelines:						
Total transported	412.8	714.3	709.3	1054.3	675.1	1020.0
Pipeline capacity	709.5	867.8	900.5	1112.1	939.6	1057.1
Liquefaction:						
Total liquefied	56.0	198.8	102.9	211.2	117.2	223.1
Liquefaction capacity	103.5	225.7	125.7	225.0	130.8	225.7
Regasification:						
Total regasified	56.0	198.8	102.9	211.2	117.2	223.1
Regasification capacity	111.0	228.1	138.7	225.0	145.9	228.9
Flexibility / Swing Supply:						
RU-pipeline	38.2	23.0	38.3	13.7	20.4	7.4
RU-LNG	0.8	5.0	0.0	0.0	0.0	0.0
NO-pipeline	12.9	3.2	11.0	9.4	9.7	4.1
pipeline-other	1.3	0.0	23.5	8.7	20.0	4.0
LNG-other	24.1	21.2	22.8	13.8	13.6	2.6
Storage	63.6	97.3	54.1	101.3	69.5	115.2

market power is to decrease swing supply from Russia, which is consistent with the greater use of storage in eastern Europe that we just noted above. Under market power, LNG swing supplies also fall in importance relative to the competitive case; this is due to increased use of storage (in the Cournot case) and more intensive use of LNG import facilities throughout the year. The effect on imports via the Norwegian and other pipelines is ambiguous, with a large increase in the base case but lesser under Cournot Competition.

5. CONCLUSIONS

Equilibrium models can show what degree of market power might possibly be exercised under alternative assumptions concerning market player behavior and market structure. We have provided illustrative scenarios for the EU market which indicate that Russia has the highest incentives to exercise market power, and that such exercise will tend to increase price differences over space within the EU, which will encourage within-EU pipeline construction, and over time, will encourage storage construction. Differences in prices are due to the interaction of the (1) inherent ability of producers to exercise market power (determined by production capacity and costs) with the (2) accessibility of the market (determined by gas transport infrastructure).

Although the dynamic GASTALE model is an improvement over the previous static version because of its endogenous increase in transport and storage capacity, a number of modelling improvements are desirable in it and other gas market models. These include endogenous investment in production and representation of intertemporal production tradeoffs (Zwart and Mulder, 2006); more realistic representation of transport and storage technology (Midthun, 2007); stochastic models that represent how uncertainty and risk aversion affects market equilibria (Gurkan et al., 1999; Zhuang and Gabriel, 2008); and market power on the part of other players, including storage, traders, and pipelines. Careful validation against historical data is also desirable. However, because of structural and parameter uncertainty that are inherent to equilibrium models, their use must necessarily be for exploration of scenarios and implications of assumptions rather than point projections.

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Perspectives of the European Natural Gas Markets Until 2025

Franziska Holz†, Christian von Hirschhausen* and Claudia Kemfert**

We apply the EMF 23 study design to simulate the effects of the reference case and the scenarios to European natural gas supplies to 2025. We use GASMOD, a strategic several-layer model of European natural gas supply, consisting of upstream natural gas producers, traders in each consuming European country (or region), and final demand. Our model results suggest rather modest changes in the overall supply situation of natural gas to Europe, indicating that current worries about energy supply security issues may be overrated. LNG will likely increase its share of European natural gas imports in the future, Russia will not dominate the European imports (share of ~1/3), the Middle East will continue to be a rather modest supplier, the UK is successfully converting from being a natural gas exporter to become a transit node for LNG towards continental Europe, and congested pipeline infrastructure, and in some cases LNG terminals, will remain a feature of the European natural gas markets, but less than in the current situation.

1. INTRODUCTION: THE EUROPEAN NATURAL GAS MARKET

The European natural gas market lends itself particularly to the EMF 23 study design. It is in the middle of a deep structural change that comprises both, restructuring and vertical unbundling, as well as changing supply relations. Contrary to the reform process in the U.S., restructuring in continental Europe has only started seriously with the second European Gas Directive (2003/55/EC, so-called "Acceleration Directive") whereas the UK had started the reform of its natural gas sector in the early 1990s already. In continental Europe, a small number of players still dominate the national wholesale markets; vertical unbundling is pursued by most member states, though with varying degrees of success. The individual countries are poorly interconnected, and the limited access to pipeline capacity prevents liquid hubs from emerging.

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* DIW Berlin, Mohrenstr. 58, 10117 Berlin, Germany.

† Corresponding author: fholz@diw.de, phone +49-30-89789-337, fax +49-30-89789-113.

The second aspect, supply structures, also plays an important role in the energy policy debate, and it is the focus of this paper. Europe is a relatively mature pipeline market, with a significant increase in LNG regasification capacity and imports over the last years (IEA, 2004, 2007). In the next decades, the demand for natural gas is generally expected to rise, albeit with some uncertainty on the extent given new developments that may reduce the relative benefit of natural gas in environmental or cost terms (e.g. competition with coal with CCS for power production). In institutional terms, European natural gas supplies are also undergoing the global trend from long-term contracts towards shorter-term trading and a more important role for spot markets. "Energy supply security" is a particularly sensitive issue in European natural gas, especially with a view to the dominant supplier, Russia.

These issues have been studied in the previous literature. Several models have indicated that market power is indeed an issue in the European natural gas market, amongst them Boots et al. (2004), Egging and Gabriel (2006), and Egging et al. (2008). Smeers (2008) summarized and discussed the papers that develop strategic models of European natural gas supply. Hubert and Ikonnikova (2003) and Hubert and Suleymanova (2006) have focused on the specific role of Russia as a supplier to Europe, and the strategic role of transit countries such as Ukraine or Poland. OME (2001, 2005) have provided in-depth numbers of potential prices and quantities of gas supply options for the EU. Stern (2007) provides a balanced discussion of the true "supply security" issues.

In this paper, we report simulation results for European natural gas supplies to 2025, following the EMF 23 study design (EMF, 2007). We apply a strategic model of European gas supply, called GASMOD, that was developed in the early phase of the EMF 23 study, and then slightly adopted to suit the requirements of the EMF 23 study design. The GASMOD model is described in detail in Holz et al. (2008), and therefore will not be presented in detail in this paper. Instead, we focus on the results of GASMOD with regard to the EMF 23 Reference case, and most of the EMF 23 scenarios (see EMF, 2007, p. 30). The next section provides a non-technical model description and discusses data sources and assumptions. Section 3 then summarizes the model results for the EMF Reference case, and five scenarios: higher demand growth, Russian exports constrained, Middle East exports constrained, Middle East & Russian exports constrained, and liquefaction constrained. We put particular emphasis on the future role of Russia, potential alternative supply sources, and model results for the UK market in transition.

In general, our results suggest rather modest changes in the overall supply situation of natural gas to Europe. This also indicates that current worries about energy supply security issues may be overrated:

- LNG will likely increase its share of European natural gas imports in the future, but stay relatively stable beyond 2015;
- Russia will continue to play an important role as a supplier to Europe (~ 1/3 of imports), but it will not play the dominant role that many studies (and politicians) suggest it might play;

- In the time frame of our analysis (2025), the Middle East will continue to be a rather modest supplier, and its exports are more likely to be directed to the Asian and the North American markets;
- the UK is in the process of successfully converting from being a natural gas exporter to become an importer and a transit node for LNG towards continental Europe;
- congested pipeline infrastructure, and in some cases LNG terminals, will remain a feature of the European gas markets, but less than in the current situation;
- the diversification of natural gas supplies, already observed in this decade, should continue and contribute to supply security.

2. THE GASMOD MODEL: MODEL DESCRIPTION AND DATA SPECIFICATION

The model used is a modified version of the static GASMOD model. It corresponds to the description by Holz et al. (2008), except for the regional and technology aggregation (pipeline vs. LNG), the demand function, the time frame and the market power assumptions for certain countries.

GASMOD is a model of the European natural gas trade on a yearly basis.[1] It is programmed in GAMS in the mixed complementarity format and solved using the PATH solver (Ferris and Munson, 2000). We include data for all relevant exporters to Europe, which can supply pipeline gas and/or LNG (Table 1). An exporter can use both technologies simultaneously, but each technology is modeled as a separate player, contrary to Holz et al. (2008) where both technologies were aggregated to one player per country. The importing market in Europe is represented by a disaggregated representation of continental Europe, assuming one wholesale company (marketer) per country that can import from both technologies. Figure 1 shows the structure of the model, exemplified by two exporters (Russia by pipeline and Algeria by LNG) and two European markets (Germany and France), with imports and wholesale trade between each other. European importers are detailed in Table 1 with their import technologies in 2025. In addition, we include the possibility for endogenous domestic production in all European countries. Final consumption is aggregated to total demand of all sectors in each importing country. We model the trade relations in bilateral pairs of exporters-importers, or marketers-final markets,[2] and use aggregated and calibrated capacity bounds for each pair and technology.

1. Given the focus on yearly trade volumes, we do not include storage which would provide seasonal swing supplies, neither do we include reserve optimization.

2. Note that the pairs are not limited to adjacent countries.

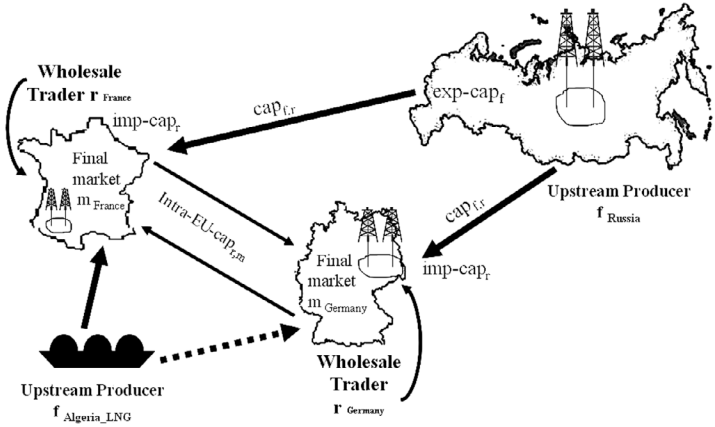
Table 1. Countries Included in the GASMOD Model, with Possible Export/Import Technologies by 2025

Region	Country	Export/Import Technology in 2025
Exporters		
Europe	United Kingdom	pipeline
	Netherlands	pipeline
	Norway	pipeline and LNG
	Russia	pipeline and LNG[a]
North Africa	Algeria	pipeline and LNG
	Libya	pipeline and LNG
	Egypt	pipeline and LNG
Middle East	Iran	pipeline and LNG
	Iraq	pipeline
	"Middle East" (Qatar, UAE, Oman, Yemen)	LNG
Overseas	Nigeria/West Africa	LNG
	Trinidad	LNG
	Venezuela	LNG
Importers		
West Europe	United Kingdom	pipeline and LNG
	Netherlands	pipeline and LNG
	Spain and Portugal	pipeline and LNG
	France	pipeline and LNG
	Italy and Switzerland	pipeline and LNG
	Belgium and Luxemburg	pipeline and LNG
	Germany	pipeline and LNG
	Denmark	pipeline
	Sweden and Finland	pipeline
	Austria	pipeline
	Greece	pipeline and LNG
Eastern Europe	Poland	pipeline and LNG
	Hungary, Czech and Slovak Rep.	pipeline
	"Balkan" (former Yugoslavia and Albania)	pipeline and LNG
	Romania and Bulgaria	pipeline
	"Baltic region" (Estonia, Latvia, Lithuania)	pipeline
	Turkey	pipeline and LNG

a. This refers to the Shtokman LNG project and does not include the Sakhalin LNG project in the Pacific because it can be considered as relatively too expensive to supply to the European market.

GASMOD is a game-theoretic partial equilibrium model of the European natural gas market. Exports to Europe and wholesale trade within Europe are represented as successive markets in a two-stage structure. Market power can be assumed in both market stages, thereby leading to double marginalization of the final customers. We assume market power to be exerted in a Cournot framework. A Cournot market model typically yields higher prices than the perfect competi-

Figure 1. Stylized Representation of the GASMOD Model Setup



tion model (or Bertrand models), thereby giving an incentive to more (higher cost) players to participate in the market. The results of this equilibrium model correspond to the Nash equilibrium of the Cournot game in each market stage. The model results must therefore be interpreted as long-term market equilibrium that does not reflect the short-term adaptation path to the equilibria. Hence, this model type is also not appropriate to simulate short-term market shocks.

In Holz et al. (2008) we consider three stylized cases of market power in each market stage in order to assess the most realistic scenario for the current European natural gas market: Cournot competition in both market stages, perfect competition in both market stages, and EU liberalization (Cournot competition in export market, and perfect competition in the wholesale market). In line with the market observation we identify the successive Cournot market model as the most realistic representation, but with exceptions for certain countries where the double marginalization structure leads to very high prices and low imports or consumption. Hence, in the GASMOD version used for the EMF simulations, we use a successive Cournot model with a competitive fringe in the export market, and the assumption of perfect competition for certain final markets. On the production market, next to the Cournot players, we assume the small players to be the competitive fringe (Libya, Egypt, Iran, Iraq, Nigeria, Trinidad, and Venezuela, and all domestic European producers except the UK and the Netherlands). On the wholesale market level in Europe, we assume the following markets to be competitive: in the UK, Denmark, Sweden/Finland, Romania/Bulgaria, the Baltic countries, and Turkey.[3]

3. In reality, these countries, except for the UK, do not have competitive but monopolistic market structures with generally only one player supplying the final market due to missing interconnection infrastructure with other countries. However, the downstream monopoly leads to very high prices in the model results that are not reflected in the real-world data. We therefore decided to assume perfect competition for these countries that have little impact on the overall European market.

In this paper, we apply the method of comparative static simulations for the time period 2003 – 2025. We simulate the years 2003, 2010 and continue in five-year steps up to 2025. For each year, we adapt the data input, namely the reference demand and import volumes and prices, the production and transport capacities and costs. In the absence of founded knowledge about the future market structure, we assume the same market structure prevailing in all model periods.

In particular, as agreed within the EMF group and based on EIA (2005) projections, we assume the reference demand volumes (needed to specify the demand function) to increase by 1.8% p.a. in Western Europe and by 2.2 % p.a. in Eastern Europe. The increase of the reference prices (that are also included in the demand function) is based on projections by the European Commission (European Commission, 2003) with an annual growth rate of 0.8% until 2010, of 2.06% between 2010 and 2020, and 1.25% between 2020 and 2025.[4] The production and transport cost data are based on OME (2001) for 2003 and OME (2005) for all other periods. They mainly include a cost reduction over time of LNG supplies relative to pipeline supplies to Europe.

Export and transport capacities are included based on available project data up to 2006, and are reported in Table 2. We adopt a rather conservative approach for those projects that are suggested but not yet constructed and do not include any projects beyond those known by 2006. Hence, we assume little increase in export capacities to Europe after 2020. This is consistent with the assumption that the mature European market will experience a slower demand growth after 2020 because demand substitutions in favor of natural gas will have taken place by then (e.g., in power generation).

3. RESULTS FOR THE EMF SCENARIOS TO 2025

3.1 Scenario Overview

We simulated the following scenarios with the GASMOD model: EMF reference scenario (with data as described above), a slightly higher demand growth scenario, constraint on Russian exports to Europe, constraint on Middle East exports to Europe, and constraint on liquefaction capacity. Those cases were agreed upon in the EMF group and are described in EMF (2007).

Figure 2 shows the GASMOD results of all scenarios for the last model year (2025). As underlined in EMF (2007), the European natural gas market demonstrates a lot of resilience and the overall export picture seems to be similar between the scenarios. In particular, Europe will rely to a larger extent on imports than today with only about a sixth from the large domestic producers Netherlands and the UK. Russia will continue to have an important albeit not dominant role as

4. Note that as we go to print, current natural gas prices have increased significantly and price forecasts are heterogeneous as rarely before. Also, higher prices are likely to reduce demand in the long run. Nonetheless, to ensure consistency we stick to the scenarios as defined by the EMF 23 group.

Table 2. Assumed Export Capacities for 2003 to 2025, in bcm per year

	2003	2010	2015	2020	2025
UK	120	78	51	24	20
Netherlands	80	80	80	80	80
Norway Pipe	86	119	119	119	119
Norway LNG	0	6	11	11	11
Russia Pipe	172	186	186	196	196
Russia LNG	0	0	0	6	11
Algeria Pipe	35	53	53	61	61
Algeria LNG	28	38	38	38	43
Libya Pipe	8	8	8	16	24
Libya LNG	1	4	4	9	14
Egypt	12	23	28	28	28
Iran Pipe	10	10	14	20	20
Iran LNG	0	0	24	36	36
Iraq	0	0	0	10	20
Middle East	36	103	111	120	120
Nigeria	13	34	67	98	98
Trinidad	19	23	37	47	47
Venezuela	0	0	0	0	11
Total Pipe	511	534	511	526	540
Total LNG	108	232	321	393	419

supplier to Europe with less than a third of European imports in all scenarios.[5] On the other hand, the Middle East with its LNG exporters Qatar, UAE, Oman and Yemen will play only a limited role because other LNG producers (Norway, Nigeria and West Africa, Caribbean with Trinidad and Venezuela) can supply Europe at lower costs. In total, LNG will have a share of about 25 % of all imports. This share will be more than double the current share of LNG in European imports (10% in 2003) and it implies more than a tripling of the LNG volumes. The relatively large number of potential LNG suppliers to Europe will allow for a more diversified picture than was prevailing in Europe in the last decades, and thereby improving the European supply security.

Figure 3 shows the evolution of natural gas exports to Europe over time. Consistent with the assumption of a growing reference demand, we find growing exports to Europe. Some exporters can increase their share in the European import

5. While one third of European imports from Russia may seem high, this is considerably lower than earlier forecasts. For example, EC (2001) expected over 60% of the European imports coming from Russia.

Figure 2. Model Results of Exports to Europe by Exporting Country in 2025 for all EMF Scenarios (in bcm per year)

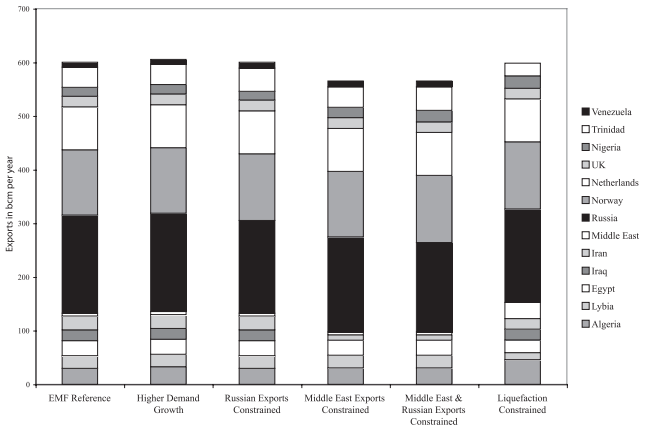
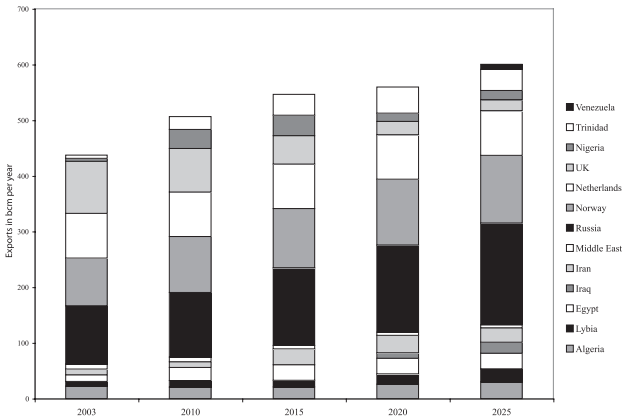


Figure 3. Model Results Exports in Each Model Year, EMF Reference Scenario (in bcm per year)

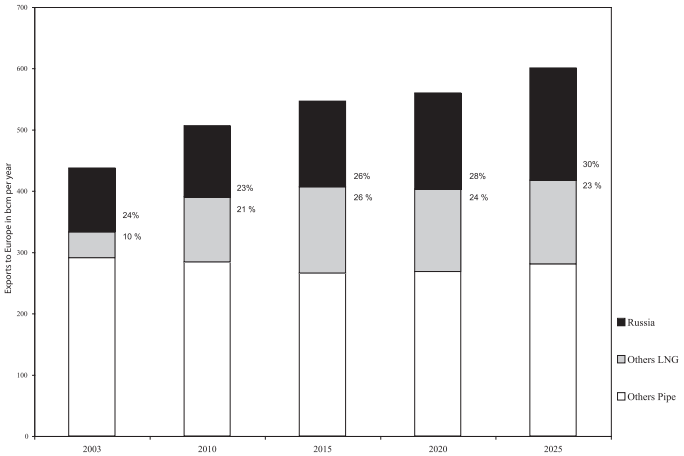


portfolio due to new build and expanded export capacity, especially LNG producers such as Venezuela (assumed to be starting in the early 2020s), Iran (starting in 2015; OME, 2005), as well as Nigeria and Trinidad & Tobago (strong expansions planned in the next years). Figure 4 illustrates that the increased share of LNG mainly substitutes pipeline supplies from other suppliers than Russia, especially the falling UK production.

3.2 The Role of Russia

Russia will continue to supply about one third of the European natural gas imports, without, however, hitting any export capacity constraint to Europe (Holz,

Figure 4. Shares of European Imports from Russia, Other Pipeline and LNG in Reference Scenario Results (in bcm per year)



2007).[6] Hence, the EMF scenario of "Constrained Russian Exports" that consists of limiting the Russian export infrastructure for all future periods to the existing capacity in 2005 (180 bcm of pipeline capacity) has almost no effect in the model results. The only impact can be found in later periods, when the planned LNG terminal of the Shtokman field, is excluded in this scenario and its small LNG volumes are supplied by other LNG exporters than in the reference scenario.

Russia's important position is mainly due to the large volumes exported to some West European countries (Germany, Italy) and especially the strong dependence of Central and Eastern Europe on Russian natural gas supplies. All Eastern European countries have dependency rates on Russia of above 50 % (e.g., Czech Republic and Hungary for 75 %, Poland for 67 % of their imports); several rely on Russia for all of their natural gas imports today (Bulgaria, Baltic countries, Slovakia) (BP, 2008). The relative proximity to Russia and the existing pipeline infrastructure create a lock-in position for Eastern Europe and only few infrastructure projects are in the discussion to reduce the dependency on Russia. In addition to some projects (with relatively small volumes) of reverse flows from Western Europe (Germany, Austria), much hope lies on the *Nabucco* project with supplies from Iran and possibly some Caspian countries. Given the current financial and political obstacles to this project, we have not included it in our data set.

6. This suggests, among other things, that the much debated *Nordstream* pipeline from St. Petersburg through the Baltic Sea into Germany lacks an economic justification. Note that we calculated a long-term equilibrium, but not short-term interruption scenarios. Hubert and Ikonnikova (2003) and Hubert and Suleymanova (2006) provide a game-theoretic analysis of the *Nordstream* project that is based on its strategic value.

3.3 The LNG Market (Liquefaction Constraint Scenario)

The West European countries are (geographically) in a more comfortable position than Eastern Europe because they can rely on a larger number of pipeline exporters (e.g. Norway, Algeria) and many have a seashore line that allows for access to the international LNG market. In addition to the "traditional" LNG importers of the 1990s and before (France, Italy, Spain, Belgium, Turkey), the 2000s have seen Portugal, Greece and the UK entering the LNG market with new build regasification terminals. Plans for more LNG terminals have been advanced for all of the existing importers and for potential new importers such as the Netherlands and Germany (likely in the 2010-2015 period), Poland, Croatia and Ireland (less likely to be realized soon). Many of the LNG expansion/construction plans are for the period until 2015. In Figure 4 we saw that the LNG share in European imports increases until 2015 when it reaches a plateau of approximately 25% where it remains stable for the next periods.

Only in the scenario of "constrained liquefaction", the Middle East LNG exporters (Qatar, United Arab Emirates, Oman) can supply a significant share of European LNG imports. The scenario is defined as limitation of liquefaction capacity to those projects that were already in operation or under construction at the end of 2005 (EMF, 2007). Hence, new entrants on the (Atlantic) LNG supply market, such as Russia, Venezuela and Iran do not start supplying LNG in all periods. Instead, existing LNG exporters, especially those with large capacities, will replace the lacking LNG volumes albeit at higher costs and hence with somewhat lower volumes (negative price effect on the import demand function).

The Middle East with liquefaction capacities of 36 bcm in 2003 and about 20 bcm more under construction in 2005 obtains an increased market share in Europe in this scenario. Other LNG exporters that benefit from the restricted liquefaction capacity increase are Algeria and Norway and Nigeria in later periods (highlighted in Table 3). In the reference scenario, a large part of their LNG exports does not go to the European market but is available for the North American and Pacific (East Asian) market (not included in the GASMOD model). The scenario of constrained liquefaction capacity also highlights which LNG exporters are the preferred suppliers to the European markets in the reference case, namely those where the expected capacity expansion over the periods results in large export volumes and hence in large losses in the "Liquefaction Constraint Scenario" compared to the "EMF Reference Scenario". Table 3 reports that these are mainly Trinidad & Tobago, Egypt and Libya. The cost decrease of LNG compared to pipeline exports plays a major role in explaining the high future export potential.

3.4 Results for the United Kingdom

The United Kingdom is the natural gas market in Europe where several developments that are characteristic for the entire European market take place "in a nutshell". First, the UK market has already undergone a liberalization process to

Table 3. Difference of LNG Exports in "Liquefaction Constraint Scenario" Compared to EMF Reference Scenario, in bcm per year (percentage)

	2010	2015	2020	2025
Norway	0.1 (+1 %)	*-1.9* *(-24 %)*	*-1.4* *(-19 %)*	2.9 (+96 %)
Russia	0	0	*-6.0* *(-100 %)*	*-10.3* *(-100 %)*
Algeria	4.1 (+57 %)	10.7 (+166 %)	13.6 (+227 %)	14.2 (+222 %)
Libya	0	0	*-5.0* (-56 %)	*-10.0* (-71 %)
Egypt	0	*-4.6* *(-16 %)*	*-4.6* *(-16 %)*	*-4.6* *(-16 %)*
Iran	0	*-14.5* *(-100 %)*	*-11.0* *(-100 %)*	*-5.9* *(-100 %)*
Middle East	5.7 (+68 %)	19.5 (+327 %)	21.6 (+375 %)	24.4 (+445 %)
Nigeria	*-11.0* *(-32 %)*	*-13.5* *(-37 %)*	8.5 (+58 %)	6.9 (+42 %)
Trinidad	0	*-14.1* *(-38 %)*	*-23.7* *(-50 %)*	*-14.6* *(-39 %)*
Venezuela	0	0	0	*-9.2* *(-100 %)*

a competitive wholesale market that the European Commission still struggles to achieve on the European Continent. Moreover, the UK market does not only experience a strong decline in domestic production over the course of the analyzed period (assumed to fall to about 1/6th of its 2003 level in 2025) but also has the strategy to meet (parts of) the increasing need for imports with LNG. Similarly, decreasing domestic production and increasing (LNG) imports can be observed in Europe as a whole.

The UK started to develop LNG regasification projects in the early 2000s and has three operating terminals in 2008 (Milford Haven, Isle of Grain, and an Excelerate vessel in Teesside). There are expansion plans for these terminals and construction plans for three or so more regasification ports in the next decade. In total, the UK will have more than 40 bcm per year of LNG import capacity by 2015. Together with an increased pipeline import volume from Norway and the Continent (Belgium and the Netherlands), this will compensate for the decline in domestic production. Figure 5 shows that the UK can potentially keep its natural gas consumption level stable, thanks to the increased import capacities. The competitive wholesale market with lower prices than on the monopolistic market further enables the UK consumers to maintain their consumption levels.

Figure 5. Model Results for the UK Market (Consumption, Imports, Production for Domestic Consumption Exclusive Exports)

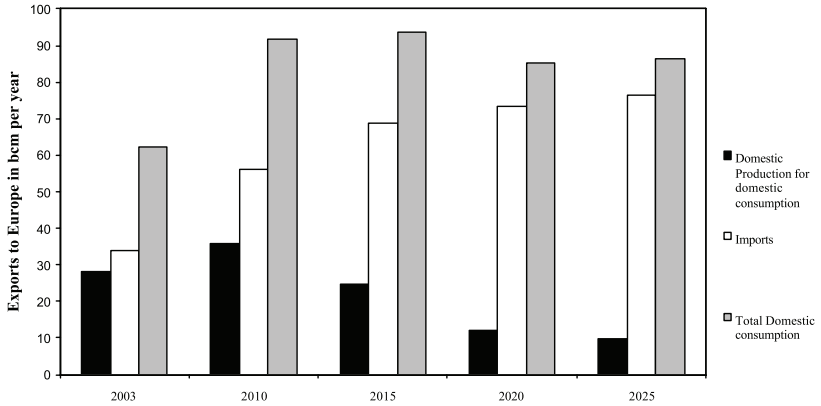
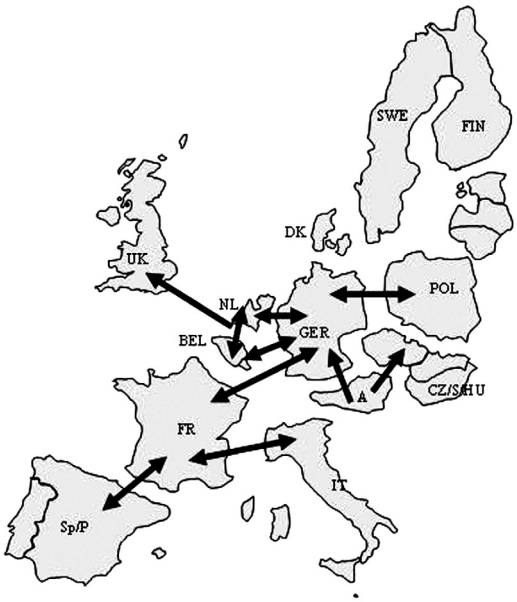


Figure 6. Pipeline Bottlenecks in West and Central Europe in 2015



3.5 Infrastructure Bottlenecks in Europe

Several of the trade flows that result from our modeling exercise are constrained by the assumed infrastructure capacities. This is particularly important for all intra-European pipeline flows. Figure 6 shows a stylized map with the congested border capacities between the countries in West and Central Europe. Our model data set is based on the assumption that the current European market structure will persist until 2025, with predominantly monopolistic, generally vertically integrated (between wholesale trade and shipping, incl. pipeline ownership) natural gas companies. This market structure has shaped the existing infrastructure situation in Europe with insufficient liquid interconnection between European countries. The monopolistic wholesale companies that are also the owners of the network have no incentive to invest in cross-border capacities because that would give market access to competitors from abroad.

4. CONCLUSIONS

In this paper, we have presented the reference case simulation and scenario calculations of the EMF 23 study design, focusing on the supply and demand situation in Europe. We applied GASMOD, a strategic model of European gas supply. In general, we find that Europe is likely to increase its supply security through diversification: the number of suppliers increases over time, and the role of Russia stays within a reasonable range, with about 1/3 of total imports. We also find that infrastructure availability remains a critical issue, mainly for pipelines. This supports policies in favor of higher incentives for infrastructure investments.

The success story of the UK can be seen as a "role model" for the future of European gas supplies. From being a net exporter, the UK has transformed into a gas importing country, without putting supply security at risk. A competitive industry structure and appropriate network regulation and investment incentives have favored this transition. Our model results suggest that Europe need not to be overly worried about increased import dependence, provided that the institutional framework is adopted accordingly.

Last but not least, let us point out some critical points in the analysis: Demand forecasts are uncertain because of gas price changes, but also because of climate protection policy and the need for low-carbon technology at scale. Also, our results depend upon the choice of model parameters (e.g. elasticities) and assumptions about new infrastructure to be built. Upcoming research should move from a comparative static analysis to a dynamic model with endogenous investment decisions, similarly to Egging et al. (2009), Zwart (2009), and Lise et al. (2009) in this volume.

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European Natural Gas Markets: Resource Constraints and Market Power

*Gijsbert T.J. Zwart**

The European natural gas market is characterized by declining indigenous resources, particularly in the UK and the Netherlands, and a growing dependence on a small number of large exporters who, as a consequence, see their market power increasing.

In this paper we analyze long-run scenarios for the European natural gas markets in a model, NATGAS, that explicitly includes both factors, resource constraints and producers' market power. Finite resources lead to interdependencies of current production decisions and future opportunities. These decisions in turn depend on the potential for large producers to set market prices above marginal costs.

We analyze the impact of conditions on the global LNG market on market shares of pipeline gas suppliers, as well as on the speed of depletion of indigenous European resources. We focus on how shadow prices of resource constraints affect substitution patterns in the various scenarios.

1. INTRODUCTION

Two main factors governing the policy debate on the European natural gas market are the decline of indigenous resources, combined with the growing dependence for a large share of gas supplies on a few foreign gas exporters, and the market power this may confer. In one to several decades, gas resources of major EU producers UK and the Netherlands are forecast to dry up. To meet growing

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* TILEC, Tilburg University, and Netherlands Bureau for Economic Policy Analysis, CPB, PO Box 80510, 2508 GM The Hague, The Netherlands, e-mail: g.t.j.zwart@cpb.nl.

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demand, three large exporters to Europe – Russia, Norway and Algeria – will see their roles, and perhaps the associated pricing power, enhanced.

An important potential competing source of supplies will be imports of liquefied natural gas, LNG. LNG suppliers increasingly compete on a global market, shipping their production to the highest price bidders. Conditions in other consumer markets will therefore set prices for LNG imports, and such prices will largely be exogenous to regional European developments.

We analyze the relations between market power, resource depletion and LNG imports in Europe in a simulation model, NATGAS, that includes both the effects of resource constraints and of market power at the production level. Finite resources lead to interdependencies of current production decisions and future opportunities. Depletion decisions in turn interact with the potential for large producers to set market prices above marginal costs, where these costs themselves should be interpreted to include opportunity costs associated with conserving resources for future production.

Within this framework we study the impact of different assumptions on the availability of LNG. In the face of varying LNG imports, what substitution patterns do we observe from indigenous production, external pipeline supplies and demand? One key observation is that although total available indigenous resources are fixed and finite, the changing long-run price perspectives will lead resource constrained European producers to shift their production profiles over time. At any given moment, these intertemporal constraints may cause a player's production to function either as a complement or as a substitute to contemporaneous LNG imports.

The NATGAS model is a mixed complementarity model of Cournot producers in a network setting. It builds on a sequence of earlier simulation models of the EU energy markets. Golombek et al. (1995, 1998) used a Cournot model of the European gas market to assess the impact of liberalization on prices in Europe, while Mathiesen et al. (1987) compared Cournot, competitive and collusive equilibria in the European market. Haurie et al. (1987) studied an application to a market with stochastic demand.[1] In Boots et al. (2004), the impact of traders in a conjectural variations production market is investigated. More recent contributions focussing on producer market power in the European gas market include Egging and Gabriel (2006), Holz et al. (2008), Egging et al. (2008), Lise et al. (2008), and Zwart and Mulder (2006). Related recent Nash-Cournot models of the US market are studied, for example, in Gabriel et al. (2005a,b).

Modelling of (endogenous) longer-term dynamics in network models of natural gas markets is still underexplored. An early discussion on how Cournot network models could be applied to the European natural gas market was provided in Flåm and Zaccour (1989), though here the idea was not yet implemented in practice. Dynamic investment in electricity market models was addressed by Denis et al. (2002), Pineau and Murto (2003) and Murphy and Smeers (2005).

1. See also Gabriel and Smeers (2006) for an overview of the earlier literature.

These authors all focus on investment in production capacity. In NATGAS, we combine this approach to investment with the finiteness of resources (see e.g. Withagen, 1999, for an overview of literature on oligopoly power with exhaustible resources). An application of intertemporal optimization under Cournot competition in energy markets is given in Bushnell (2003), in a complementarity model of electricity markets including hydropower generation.

The structure of this paper is as follows. We first sketch the structure of the EU natural gas market and its suppliers. We then briefly describe the key characteristics of the NATGAS model. In section 4 we analyze the patterns of production and imports in various scenarios on LNG costs and market power. We close with some concluding remarks.

2. GAS SUPPLIES TO EUROPE

Currently, the major EU producers are the UK and the Netherlands. Denmark, Germany, Italy, Poland and Romania play smaller roles, both in terms of production and reserves. By the end of 2006, total indigenous remaining reserves were approximately equal to 2800 bcm (billion cubic meters, BP, 2008), or less than six times annual EU consumption. Total annual EU production was slightly over 200 bcm in 2006 (IEA, 2007), and EU consumers depend to a large extent on pipeline imports of natural gas from, in particular, Russia, Norway and Algeria.

Even though the corresponding reserves to production ratio suggests that in about 14 years the EU will entirely depend on imports, the situation is slightly less gloomy if one takes into account the additions to reserves from gas exploration activity. Indeed, as Stern (2002) points out, proven reserves in the EU stayed more or less constant over the years 1981-2001, in spite of continuous production: new reserves were added at a similar pace. More important is the quantity of total resources, including those too expensive to exploit at current prices and technology, and those currently yet undiscovered. Though by their nature such resource estimates are substantially more uncertain than figures for proven reserves, both known but undeveloped finds and surveys of suitable geological structures do allow for some indications of their magnitudes. For example, the Department of Business, Enterprise and Regulatory Reform (BERR, 2007) provides a central estimate of total remaining UK resources of 1313 bcm of natural gas, compared to a proven reserves figure of 684 bcm and past cumulative production of just over 2000 bcm of natural gas. And similarly, the midpoint estimate for resources in the Dutch Continental Shelf small fields equals about twice their proven reserves (EZ, 2008). Seeliger (2004) lists values for other European producers.

Even with these figures of remaining resources, EU production is widely expected to decline substantially in the coming decades, in particular for the two major producers, the UK and the Netherlands. Because of still growing demand for natural gas, the need for increased imports from outside the EU is apparent. Fortunately, reserves and estimates for remaining resources in the EU's suppliers are huge: for instance, remaining Norwegian resources are estimated at almost

5000 bcm (NPD, 2008), and Russian proven reserves alone equal about ten times this figure (IEA, 2007). For the EU, a more pressing question is at what price these resources will be made available. Since the 2007 Norwegian Statoil - Norsk Hydro merger, state controlled monopolists have dominated production in all three major gas exporters to the EU: Norwegian StatoilHydro, Sonatrach for Algeria and Gazprom for Russia. It is natural to assume that these firms will, to some extent, use the market power they are endowed with. Also within Europe, entry into the producing sector is typically restricted, and producers are not necessarily price takers, though levels of competition in the various countries will differ. In this paper we will indeed assume that production can be described by an oligopoly model.

As indigenous resources dwindle, will the European gas market essentially become a triopoly, perhaps complemented by smaller pipeline supplies from other North-African or former Soviet Union states? Not necessarily: supplies from elsewhere in the form of liquefied natural gas, LNG, may contest this market, depending on prices in Europe and other consumer regions. The global market for LNG has experienced substantial growth over the past decade, with annual growth rates of over 7% (Elkins, 2008). Currently, LNG only caters for a small share of total gas demand in the European market, around 50 bcm out of total gas demand of over 500 bcm. Although this share is expected to increase, LNG consultant Jensen Associates (2007a) indicates that projections of LNG growth are very uncertain, and estimates a range for the global LNG market in 2020 of 400 bcm to 600 bcm (compared to some 190 bcm in 2005). His estimate for the share going to Europe displays even greater uncertainty, ranging from hardly any growth (if pipeline imports continue to be relatively cheap) to 170 bcm in the most positive scenario.

LNG is more flexible in destination than pipeline gas. Liquefaction facilities in source countries make up the larger part of costs in the LNG chain, while on the other hand, regasification terminals in destination countries account for a much smaller share of the costs in the chain. Indeed, in this latter segment there is overcapacity. Global regasification capacity is roughly twice as large as global liquefaction capacity.

Differences in shipping costs of LNG to various demand centers (Europe, the US, and the Far East) are, at one to a few cents per cubic meter, relatively minor compared to gas prices. Therefore, a producer such as Qatar or Nigeria may choose a destination for its gas based on the highest net-back price. As a result, provided LNG prices are competitive with costs of piped gas, LNG could give rise to arbitrage between these various global regions. Although currently, the LNG market is still dominated by relatively inflexible long-term contracts allowing little scope for interim renegotiation of the cargo's destination, the market for flexible LNG is growing. As Jensen Associates (2007a) documents, flexibility of destination might grow as spot markets for LNG grow in importance, but also as more and more LNG contractors become themselves active in multiple downstream markets, and can arbitrage within their own portfolios. Jensen Associates (2007b) estimates current flexible volumes in the Atlantic Basin LNG market at some 30% of total volumes.

3. THE NATGAS MODEL

In view of the importance of producer market power and finiteness of resources in describing the European gas market, we set out to create a model capturing both characteristics, NATGAS, and see how they interact. In this section we give a brief overview of the structure of the model. For details we refer to Zwart and Mulder (2006).

3.1 Geographical and Temporal Dimensions

We model gas production and consumption in Europe, aggregating data into a limited set of markets. We distinguish production centers inside the EU (the most important ones being the UK and the Netherlands), as well as Europe's pipeline suppliers Norway, Russia and North Africa. We treat exports to Europe in the form of LNG as one single source. Available LNG supplies vary with market prices. We aggregate European demand into nodal demand centers, tied together through a simplified transmission network of links between these nodes. Table 1 lists the various supply and demand nodes included.

Table 1. Groups of Countries Represented as Supply or Demand Nodes

Suppliers	
Russia	including transits from other former Soviet Union
Netherlands	separately considers Groningen field and small fields
Norway	including Denmark
UK	
North-Africa	including pipeline gas from Algeria and Libya
Eastern Europe	mainly Romania and Poland
Germany	including Switzerland and Austria
Italy	
LNG market	
Demand	
The Netherlands	distinguishing low- and high-calorific markets
Belgium	as above
Germany	including Switzerland and Austria, as above
UK	including Ireland
France	
Italy	
Iberian Peninsula	
Eastern Europe	

In the time dimension the model is discretized into ten sets of five years each, starting from the first period 2007-2011 to, finally, 2052-2056. The period studied consists of the first thirty years.

3.2 Producer Market Power

Producers are located in each of the supply regions, and compete in selling output to the various consumer regions. Decision variables for each producer are quantities of natural gas sold to each consumer region (in each five-year period), and investment in new production capacity (for each five year period). Clearly, the aggregate quantities produced in any period cannot exceed available production capacity built up in previous periods.

Oligopoly behavior is described as the equilibrium of a non-cooperative game in which all producers simultaneously choose capacities and output. In solving for this equilibrium, we make the Cournot assumption on producers: each producer maximizes the present value of his profits taking the decisions of his competitors as given. The intensity of competition in this Cournot game is determined by the number of producers in each region: as the number of Cournot players in each supply region grows, the Cournot solution will converge to the perfect competition outcome. In the model analysis we will compare low competition scenarios, where every supply node is populated with a single monopolist, to situations in which the production market in some nodes will be shared by symmetric competitors.

The oligopoly game describes producers' investment and production decisions over time, and therefore producers' strategies are functions of time. In the NATGAS model we consider the so-called open-loop solution concept for dynamic games, where strategies are functions of time only.[2] Essentially, producers simultaneously and non-cooperatively choose an entire investment and depletion path for the resources they are endowed with.

3.3 Incorporating the Resource Constraint

Gas producers dispose of a finite marketable quantity of natural gas and face the choice at what point in time to produce this quantity. As is well known (Hotelling, 1931; Stiglitz, 1976), in equilibrium production will be such that each producer will be indifferent between producing now and postponing production until tomorrow: marginal profits rise at the rate of discounting.

In the NATGAS model, this relation between production quantities at various points in time is realized by explicitly adding the constraint that total production over time be constrained by an exogenous total resource quantity (the sum of reserves, estimated potential and undiscovered resources). The shadow price of this constraint is known as the resource rent. This rent is an opportunity cost of producing in any period, and links behavior across periods. Consequently, current production decisions will be affected by expectations of future prices. The

2. The alternative would be a closed-loop solution, where players' strategies are allowed to depend on decisions of their competitors in previous periods. Sometimes the two coincide, see e.g. Flåm and Zaccour (1989).

expected structure of the market, and its competitiveness, ten years from now will have an effect on the resource rent, and hence the choice of depletion paths now.

3.4 The LNG Market

We model the global LNG market as a competitive fringe: LNG is available to Europe at costs determined by an exogenous supply function. The threshold price at which LNG-imports become available to Europe should be set by the opportunity costs for LNG suppliers of supplying to alternative destinations (corrected for differences in shipping costs). If European gas prices determined by pipeline competition remain below gas prices in the US or the Far East, LNG would be diverted to those regions, while as European prices exceed those prices, more LNG will be made available to Europe. In the model simulations we will analyze the effects of different assumptions on these opportunity costs.

Clearly, even if market prices exceed prices at which LNG will be available, LNG terminal capacity is required in Europe to accommodate any imports. In NATGAS, investment in LNG import capacity is treated as endogenous. Independent, price taking players are assumed to choose capacities and to purchase LNG deliveries constrained by those capacities. In the investment equilibrium, such price takers will make zero net profits in the long run.[3]

3.5 Other Players Included in the Model

Besides the Cournot producers and price taking LNG importers, several other players are included in NATGAS, all of which we model as profit maximizing price takers:

- regulated investors in transport capacity between the various demand and supply nodes
- traders arbitraging between different demand nodes, making sure that prices equalize as long as spare transport capacity is available
- storage owners arbitraging price differences between high demand winter and low demand summer seasons

Finally, in each region, consumers are represented by an exogenously specified time dependent aggregate demand function.

4. PATTERNS OF SUBSTITUTION

LNG supplies are likely to play an increasingly large role in global natural gas markets. However, the pace of growth of LNG supplies to European natural gas markets remains highly uncertain. Firstly, global growth of LNG produc-

3. The assumption of perfect competition for these players seems consistent with the currently observed wave of new entrants investing in such terminals in various European countries.

tion remains unpredictable. Despite abundant resources worldwide, development of new liquefaction capacity on the longer run may be affected by, for instance, sharp cost inflation (with liquefaction costs doubled over the last few years, see Jensen Associates, 2007c), by political tensions (with large available resources in e.g. Iran, Venezuela, Nigeria), or by steps by producers to coordinate production decisions in an OPEC-like cartel.

Secondly, different consuming regions compete for supplies. Increasing price responsiveness of LNG shipments causes cargoes to be delivered where prices are highest. As a result, a surge in Far Eastern gas demands (e.g. because of Japanese nuclear power station outages) draws LNG to the Far East even from the Atlantic basin. As long as LNG is scarce compared to demand, prices remain set by the highest priced region. If Europe's alternative of pipeline gas remains cheaper, LNG will, at least initially, not play a big role, as emphasized by Jensen Associates (2007a). We investigate the effects of differing assumptions on LNG costs in the NATGAS model. In a scenario where LNG availability is lower (or LNG is only available at higher costs), we expect lower imports of LNG. How will the market cope with this shortage? What sources will substitute for the gap in imports? In response to higher prices, we may anticipate both demand response and larger incentives for production, and we explore the relative importance of these various sources of gas.

We will be particularly interested in the extent of shifting production patterns in time. Resource constrained producers cannot just increase production: higher production now means lower production in the future. How do changing expectations in LNG costs alter the balance of depletion schedules, in particular for tightly constrained producers such as the UK? Here we note two opposing effects: higher LNG costs may raise current revenues and make production more attractive, but higher future expected costs cast their shadows into the present as well: they raise the resource rents and make production more costly. As we will see, in some cases the second effect dominates and lower LNG imports in those cases go together with lower current production from indigenous producers.

Apart from LNG availability, also producer market power will influence production decisions, although again here any effects of increased competition may be muted by the resource constraints. In our baseline simulations we make the 'worst' assumption on market power and assume that in each country, one Cournot producer is active. We then evaluate the effects of increased competition among producers.

4.1 The Baseline

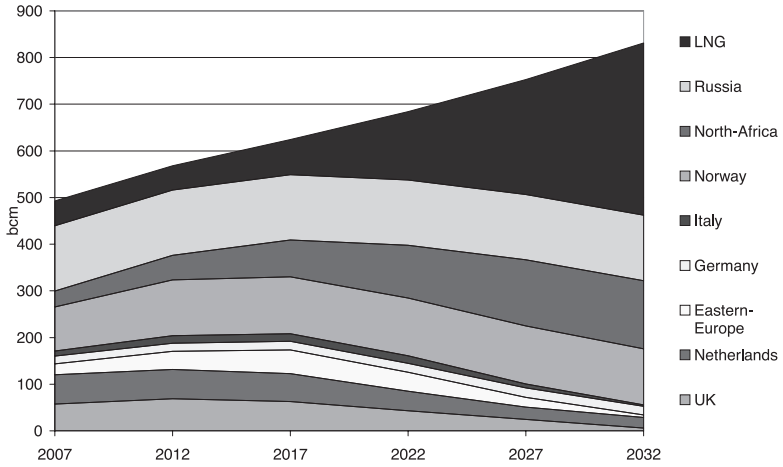
In the baseline scenario we assume LNG costs of 29 cents per cubic meter (ct/m³) in winter, and 25 ct/m³ in summer, and keep these constant for the entire simulation period. These prices correspond roughly to prices currently observed in the market and equal around $ 11 to 13 per MMBTU, for comparison with US units. The seasonal spread in costs of 4 ct/m³ is of the same order of

magnitude as long run average costs of seasonal storage. As to market power, in the baseline we make the relatively bleak assumption that a single producer, exploiting its full Cournot market power, dominates each producer region. We will explore the impact of changing the level of LNG costs and degree of market power in various scenario analyses.

Data on production and infrastructure costs and current capacities are based on Zwart and Mulder (2006) and sources cited there, but where possible updated with more recent data from IEA (2007), and with information on cost inflation in the sector as documented by IEA. We keep these data the same for all scenarios. Russian production costs are highest (but still lower than our baseline LNG costs), production from the Dutch giant onshore Groningen field is cheapest. Initial production costs for other European and Norwegian gas are all similar in magnitudes. For all regions, costs are assumed to increase as resources are depleted. We include some additional exogenous bounds on production. Firstly, we exogenously limit future capacity from the Groningen field (in line with expectations on the field's physical possibilities); secondly, we do not allow any region's production capacity to increase by more than 50% in any five-year period; and finally, we assume Russian exports to Europe will not drop below current values, reflecting the sunk character of large part of the infrastructure, a constraint which at least initially binds.

We plot the baseline estimates in figure 1. Within the thirty years horizon under study, a large part of indigenous resources are depleted: the Dutch small fields and the UK, eastern Europe and Italy. Only some German production and a modest rate of production from the Groningen field remain. Initial significant growth of output comes mainly from Norway, North-Africa and Eastern Europe. For Russian supplies, the lower bound on exports to Europe is equal to current

Figure 1: Baseline EU Supplies



exports. This constraint binds throughout the study period in this scenario. We note that in this baseline scenario, LNG imports first increase at a relatively modest pace, growing to around 75 bcm (billion cubic meters) per year around 2020, with initial large imports mainly in Spain. Only when EU resources are in rapid decline do LNG imports pick up, with import terminal capacity growing fastest in the UK.

Our main interest does not lie in the absolute values of imports from various sources, but rather in the sensitivity of the depletion and import patterns to assumptions on LNG costs and market power. We explore these issues next.

4.2 Changes in LNG availability

We consider three alternative scenarios for LNG costs, to obtain some insights into the mechanisms governing the relations between current prices, price expectations and depletion decisions in the EU gas market. We will look at one lower costs scenario, with winter and summer LNG costs 5 cents lower (24 and 20 ct/m³, or average 22 ct/m³), LNG22 for short, and two higher ones, with costs 34 (30) ct/m³ in winter (summer) and 39 (35) ct/m³, LNG32 and LNG37 respectively.

The main effect of these changing assumptions on levels of LNG imports is to shift their growth pattern in time: at higher LNG costs, growth of LNG imports does not start until in a later period. In the LNG37 scenario, LNG will not appear on the market at all for the first 15 years. Eventually though, LNG imports do increase. In LNG22, LNG is relatively cheap compared to pipeline gas and growth is much faster, already reaching 150 bcm per year in 2020. Given that the market clears in all scenarios, how are these large differences compensated for by changes in other sources of supply and demand? We first analyze the substitution patterns at a single point in time, the third period in the model simulation. Then we focus on intertemporal shifts in production: how do producers shift their depletion schedules in response to the various LNG scenarios?

Table 2 plots the changes in third-period supply and demand for each LNG scenario, relative to the baseline scenario. The first thing we note is that the large differences in LNG imports across the various scenarios are predominantly matched by large changes in demand. As a result of changing LNG import costs, market prices are affected and these expand or restrict demand. Clearly, price effects are largest in those regions where LNG imports set the margin, in particular Spain and the UK. Average prices in other regions are affected, too. This happens through spillover effects such as arbitrage over available pipeline connections, or rerouting of supplies from the continent to the UK by Norway. The bulk of the remaining compensation is from Norwegian production, with also some contribution from the UK, the Netherlands and North Africa.

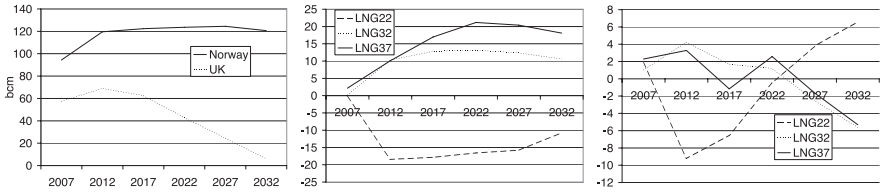
As pointed out, changes in a country's production in one period must be accompanied by compensating changes in another, if the resource constraint is binding. Rather than looking at effects of the LNG scenarios in a single period, we now turn to the effects on depletion schedules over time. In doing so we focus

Table 2: Changes from Baseline Scenario Results, in Third Period (2017-2022) Supply and Demand, by LNG Scenario (in bcm)

	LNG	demand	Norway	UK	Netherlands	North-Africa	other
LNG22	82	43	-18	-7	-4	-4	-6
LNG32	-53	-35	13	2	2	0	1
LNG37	-75	-54	17	-1	2	0	4

on two countries, the UK and Norway. The former faces tighter constraints, and consequently a higher resource rent, than the latter. For the UK, in the baseline the shadow price of the resource constraint equals over 7 ct/m³, a value comparable in magnitude to physical production costs. For Norway, the resource rent is over three times smaller. Figure 2 shows the UK's and Norway's production schedules in the baseline scenario (left-hand panel) as well as deviations from these schedules (Norway centre panel, UK right-hand panel) under the alternative LNG prices.

Figure 2. Baseline Norwegian and UK Production (left panel) and Differences in Per Period Production Levels (in bcm) in the Scenarios (Norway centre, UK right)



Norwegian imports are projected to grow in the first ten years and to remain stable afterwards during the thirty-year study period[4]. The level of this plateau varies with the scenario in an intuitive way: higher LNG costs (and lower LNG imports) straightforwardly lead to substitution by Norwegian production.

The situation is different for the UK. Here we observe the trade-off between taking immediate advantage of higher current prices, and saving gas in response to higher future expected prices. In comparing the baseline with slightly higher prices in the LNG32 scenario, it is the immediate effect that dominates: the UK's production schedule is shifted to the present as a whole, leading to lower remaining production in the tail end, the last two periods. However, when comparing LNG32 with even higher LNG costs, LNG37, we see a reversal: in response to a further decline in LNG imports, UK production in the second and third periods

4. Norwegian production starts to go down at the end of this period. Simulations were done for a significantly longer period of fifty years, to avoid introducing artifacts related to the choice of finite study period duration.

drops as well, in favour of higher volumes compared to LNG32 in the latter 15 years of the study period. The resource rent leads to conservation of gas in anticipation of higher future prices. In case of cheaper and more plentiful LNG imports, the LNG22 scenario, we see the resource effect mainly in the first period. In conjunction with higher first period LNG imports compared to the baseline, also UK production is increased: production and LNG imports act as complements rather than substitutes for this shift. As a consequence of the lower LNG costs in the future, the UK resource rent goes down and saving gas is less attractive.

4.3 Changes in Market Power

In the baseline scenario, we assume that each country fully exploits its full Cournot market power. We now evaluate the effect of more aggressive competition. Within the EU, currently the production market is often shared by a larger number of competing firms, particularly in the UK. EU pressure on liberalizing the gas sector and promoting intra-EU competition is primarily directed at the wholesale (or midstream) market[5], rather than at upstream production. Still, it is conceivable that a more liquid and transparent internal wholesale market will reduce entry barriers for EU producers and cause the EU upstream market to be more competitive in the study period. The case is different for outside producers, but here, too, competition might be more aggressive than pure monopoly under the threat of new pipeline imports from e.g. Libya, Iran or Turkmenistan.

We study the effects of such increased competition on the role of LNG in Europe and on production schedules across the study period of resource-constrained producers. For this we introduce two competition scenarios: EUduopoly, where we assume each producer region within the EU to be operated by two (independent) firms, and Duopoly, where also the Norwegian, North-African and Former Soviet Union supplies are Cournot duopolies. We keep LNG costs at the baseline levels, 29 ct/m³ for winters and 25 ct/m³ in summers.

As Stiglitz (1976) observes, in the presence of resource constraints the relation between competition and output is less clear-cut than in unconstrained industries. A monopolist with zero production costs, facing constant elasticity residual demand, will not behave differently from a price taker. When these assumptions are relaxed, however, increased competition will usually lead to a shift of production to the present[6]. This is indeed what we observe in the simulation results, figure 3: in both cases, LNG, with its fixed supply function, is initially kept at lower levels by the increased production from pipeline producers. In the EUduopoly scenario, this is reversed later, when indigenous resources are depleted. The effect of higher competition is mainly to reduce prices slightly initially, with exporter market power taking over at a later stage (but still kept in check by

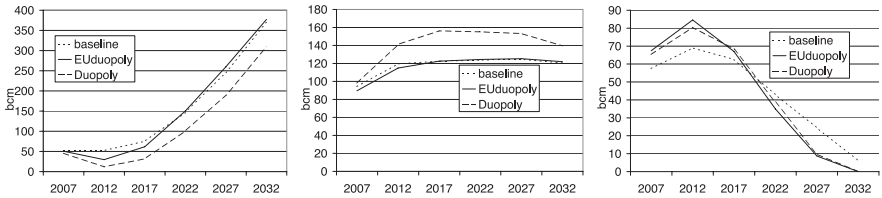
5. We do not explicitly model this segment of the market here. Models analyzing market power of European wholesalers include those of Egging et al. (2008) and Lise et al. (2008)

6. Captured by Solow (1974)'s "A monopolist is the conservationist's friend."

the LNG fringe supply curve). When also the major exporters to Europe behave more competitively, in the Duopoly scenario, we see a larger increase in demand, and lower LNG imports all over the study period.

This is reflected in the production profiles of the UK and Norway: in the EUduopoly scenario, there is a sharp increase in UK production, partially balanced by lower Norwegian exports to the EU (and lower LNG imports). In the Duopoly scenario, also Norway shifts its production forward in time, and achieves a higher plateau rate; the UK's gain from earlier production is slightly reduced and the production peak is somewhat lowered.

Figure 3: LNG Imports (left), Norwegian Production (centre), and UK Production (right) (in bcm) Under the Market Power Scenarios



5. CONCLUDING REMARKS

We have used the NATGAS model to study how equilibrium supplies to the European natural gas market respond to changing conditions in the world LNG market, as well as to changes in assumptions on producer market power. The main feature that distinguishes the NATGAS model from various other approaches is the focus on long-term dynamics, incorporating both the resource constraints and the market power that play an important role in the real world. We highlighted the interaction between short and long-term production decisions relevant in particular for the more tightly resource constrained producers, such as the UK. We observed how, because of these intertemporal links, constraints on LNG availability may lead to short-term reductions in output by competing suppliers, who conserve gas in response to a more favorable outlook on long-term prices. The analysis of market power and depletion patterns demonstrates that increased competition leads to slightly faster depletion of indigenous resources; the main welfare benefit is therefore to reduce current prices, at the expense of higher future prices.

The scenarios illustrate how shadow costs, in particular the resource rent, affect production decisions under changing circumstances: these costs may be comparable in size to real production costs. One direction for further research is to analyze more extensively the impact of competition on the shadow costs of production, including other ones beside the resource rent. Another aspect that could deserve future attention is the relation between European markets and the global

LNG market. In the current study, we treated the LNG market as exogenous. Clearly, providing a global modelling framework that allows linking the LNG market endogenously to conditions in both European and other regional markets would be desirable. Steps in this direction are reported in Egging et al. (2009), Aune et al. (2009) and Hartley and Medlock (2009), all included in this issue.

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Market Arbitrage: European and North American Natural Gas Prices

Stephen P. A. Brown and Mine K. Yücel**

The development of an international market for liquefied natural gas (LNG) and the resulting opportunities for intercontinental arbitrage are seen as creating a world in which movements in natural gas prices are linked between continents. Increased flows of LNG into the United States and the potential sensitivity of these shipments to price differentials between Europe and North America suggests the possibility of a strengthening relationship between natural gas prices on these two continents. At the same time, there is considerable evidence linking natural gas price movements in Europe and North America to those for crude oil. Accordingly, we use a series of econometric tests to determine whether the co-movement between natural gas prices in Europe and North America is mediated through crude oil prices or is being shaped directly by gas-to-gas arbitrage.

1. INTRODUCTION

For many years, pipelines were the primary means for moving natural gas, and natural gas prices were, by and large, determined in the prevailing continental markets. The development of an international market for liquefied natural gas (LNG) and the resulting opportunities for intercontinental arbitrage are seen as creating a world in which movements in natural gas prices are linked between continents. Neumann (2009) finds that shipments of LNG across the Atlantic have enabled some co-movement in natural gas prices between European and North American markets. Increased flows of LNG into the United States and the potential sensitivity of these shipments to price differentials between Europe and North America suggests the possibility of a strengthening relationship between natural gas prices on these two continents.

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* Research Department, Federal Reserve Bank of Dallas, P.O. Box 655906, Dallas, TX 75265, spa.brown@yahoo.com, mine.k.yucel@dal.frb.org.

At the same time, there is considerable evidence linking natural gas price movements in Europe and North America to those for crude oil. Asche et al (2006) and Josse-Vásquez and Neumann (2006) find cointegration between natural gas and crude oil prices in the U.K. market, with Asche et al showing changes in crude oil prices lead those for natural gas. Similarly, Bachmeir and Griffin (2006), Villars and Joutz (2006), Brown and Yücel (2008b) and Hartley, Medlock and Rosthal (2008) find cointegration between natural gas prices in the U.S. market with Brown and Yücel showing that changes in crude oil prices lead those for natural gas.

With different crude oil prices moving closely together on international markets, the link between crude oil and natural gas prices raises the possibility that the co-movement of natural gas prices in European and North American markets is mediated through crude oil prices rather than by gas-to-gas arbitrage facilitated by shipments of liquefied natural gas (LNG). Accordingly, we use a series of econometric tests to determine whether the co-movement between natural gas prices in Europe and North America is mediated through international crude oil prices. These tests reveal that the co-movements of oil and natural gas prices in European and North American markets likely play an important role in the co-movement of natural gas prices between the two continents. LNG may reinforce the link between natural gas and oil prices because most contracts for LNG delivery in Europe are priced against crude oil.

2. PRICE SHOCKS IN OIL AND NATURAL GAS MARKETS

To examine how natural gas price shocks are transmitted across the Atlantic and how oil prices might affect this transmission, we undertake a series of causality tests involving weekly data for natural gas and crude oil prices at major trading nodes over an uninterrupted span of 570 weeks from June 13, 1997 through May 9, 2008. The natural gas prices include Henry Hub in the United States and the National Balancing Point (NBP) in the United Kingdom. The crude oil prices include West Texas Intermediate (WTI) and Brent.

Henry Hub is the principal trading hub for natural gas in the United States. Near New Orleans, Henry Hub comprises a series of 16 pipeline interconnects at a single facility that draw their supplies from the largest concentration of natural gas producing regions in the country and nearby terminals for importing LNG. These pipelines directly serve markets throughout the U.S. East Coast, the Gulf Coast, the Midwest, and up to the Canadian border. Interconnections with pipelines across Texas link the Henry Hub market to those in the U.S. West. Serletis and Herbert (1999) find that the Henry Hub spot price is strongly correlated with the NYMEX futures price, which is the most widely traded natural gas contract in the world. As such, the Henry Hub price represents a national market price for natural gas that is determined relatively close to the wellhead.

The NBP is a pricing and delivery point for natural gas in the United Kingdom. It is similar in concept to Henry Hub, but its location is more diffusely

specified as within the United Kingdom's national transmission system without any precise location. The NBP is the pricing and delivery point for the Intercontinental Exchange natural gas futures contract. It is the most liquid gas trading point in Europe and is a major influence on the price that European consumers pay for their gas at home. The NBP is some distance from Spain, where most LNG cargos are imported into Europe, but it is interconnected to continental supplies of natural gas and adjacent to LNG import facilities in the United Kingdom. As such, the NBP price best represents a European market price for natural gas that is determined close to end users.

West Texas Intermediate crude oil (WTI) and Brent are standard marker crude oils on international markets. WTI is a crude oil of a specific gravity and sulfur content delivered at Cushing, Oklahoma. It is used as a benchmark in oil pricing in North America and is the underlying commodity for the New York Mercantile Exchange's oil futures contracts. Bachmeir and Griffin (2006), Villars and Joutz (2006), Hartley, Medlock and Rosthal (2008) and Brown and Yücel (2008b) use WTI to examine the relationship between crude oil and natural gas prices in the United States.

Brent Crude is a blend of 15 oils from the North Sea. Its price is a benchmark for oil produced in Europe, Africa and the Middle East. Asche et al (2006), Josse-Vásquez and Neumann (2006), and Neumann (2009) use Brent to examine the relationship between crude oil and natural gas prices in the United Kingdom.

We conduct a variety of causality tests with these four variables. We test for causality between the Henry Hub and NBP prices of natural gas. We also test for causality between each of the natural gas prices and the prices of WTI and Brent. Most importantly, we test for causality between Henry Hub and NBP while accounting for the potential influence of crude oil prices on those for natural gas. Taking a cue from Brown and Yücel (2008a), we also conduct the latter test while allowing for local exogenous influences that might shape the supply and demand for natural gas at Henry Hub.

2.1 The Data

Our data set allows us to examine the relationship between weekly crude oil and natural gas prices over an uninterrupted span of 570 weeks from June 13, 1997 through May 9, 2008. Although the Henry Hub, WTI and Brent prices are available for earlier dates, the uninterrupted series for the NBP price that can be considered market determined begins on June 13, 1997. We use the Henry Hub, WTI and Brent prices as reported by the *Wall Street Journal* and obtained as a weekly series from the Haver Analytics data base. The NBP price series is obtained from Heren and converted from pence per therm to dollars per million Btu using exchange rates reported by the Federal Reserve System.

As an initial step in our work, we check whether the data series are integrated or stationary. A time series that is integrated is said to have a stochastic trend (or unit root). Identifying a series as an integrated, non-stationary series

means that any shock to the series will have permanent effects on it. Unlike a stationary series, which reverts to its mean after a shock, an integrated time series does not revert to its pre-shock level. Applying conventional econometric techniques to an integrated time series can give rise to misleading results. As shown in Table 1, augmented Dickey-Fuller tests revealed that all natural gas and oil price series are difference stationary.[1] The augmented Dickey-Fuller tests fail to reject the hypothesis that logged data have unit roots (as shown by the column labeled "Levels") and reject the hypothesis that the differenced data have unit roots (as shown by the column labeled "First Differences").

Table 1. Unit Root Tests

(Logs of Weekly Data, June 13, 1997 through May 9, 2008)

	Augmented Dickey-Fuller Tests	
variables	**Levels**	**First Differences**
Henry Hub	-1.2997	-13.7055**
NBP	-1.5076	-13.6502**
WTI	0.5694	-7.6406**
Brent	-0.1036	-23.9725**

+, * and ** denote significance at better than 10, 5 and 1 percent, respectively.

2.2 Cointegration Tests

After determining that all of the natural gas and oil price series are integrated of order 1, we test for cointegration between the two natural gas prices and between each natural gas price and each crude oil price. Two integrated series are cointegrated if they move together in the long run.

Cointegration implies a stationary, long-run relationship between the two difference-stationary series. As such, the cointegrating term provides information about the long-run relationship. If cointegration is not taken into account in estimating the relationship between the cointegrated variables, the relationship could be misspecified, and/or parameters could be inefficiently estimated.[2]

The Johansen procedure reveals that all pairs of natural gas and oil prices are cointegrated as shown in Table 2. The estimated β between Henry Hub and NBP is 1.13, so that a one-percent change in NBP prices means about a one-percent change in the Henry Hub price. The estimated values of β between Henry Hub and WTI and Brent are 0.44 and 0.80, respectively, which means that for a

1. Because prices increase sharply over the analysis period, all price variables are expressed in natural logs throughout the empirical analysis.

2. See Engle and Yoo (1987).

Table 2. Bivariate Johansen Cointegration Tests

Henry Hub and NBP

Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
p=0	0.0297	17.3779**	17.0249**
p≤1	0.0006	0.3530	0.3530

Standardized Eigenvalues or βs with Standard Errors

Henry Hub	NBP
1	-1.1322
0	(0.0674)

Standardized α Coefficients with Standard Errors

Henry Hub	NBP
-0.0096	0.07249
(0.0093)	(0.0182)

Henry Hub and WTI

Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
p=0	0.0172	12.3209*	9.7984+
p≤1	0.0055	3.1330+	3.1330+

Standardized Eigenvalues or βs with Standard Errors

Henry Hub	WTI
1	-0.4376
0	(0.0297)

Standardized α Coefficients with Standard Errors

Henry Hub	WTI
-0.0327	0.0008
(0.0107)	(0.0054)

Henry Hub and Brent

Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
p=0	0.0270	14.7727*	14.7216*
p≤1	0.0001	0.0510	0.0510

Standardized Eigenvalues or βs with Standard Errors

Henry Hub	Brent
1	-0.8004
0	(0.1096)

Standardized α Coefficients with Standard Errors

Henry Hub	Brent
-0.0514	0.0092
(0.0144)	(0.0093)

continued on next page

Table 2. Bivariate Johansen Cointegration Tests (continued)

NBP and WTI

Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
p=0	0.0163	12.3847*	9.3746+
p≤1	0.0053	3.0101+	3.0101+

Standardized Eigenvalues or βs with Standard Errors

NBP	WTI
1	-0.3953
0	(0.0426)

Standardized α Coefficients with Standard Errors

NBP	WTI
-0.0452	0.0009
(0.0148)	(0.0038)

NBP and Brent

Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
p=0	0.0202	12.6498*	10.8538+
p≤1	0.0034	1.7960	1.7960+

Standardized Eigenvalues or βs with Standard Errors

NBP	Brent
1	-0.3790
0	(0.0382)

Standardized α Coefficients with Standard Errors

NBP	Brent
-0.05147	0.0019
(0.0382)	(0.0053)

+, * and ** denote significance at better than 10, 5 and 1 percent, respectively.

one-percent change in the price of oil, the price of natural gas changes less than one percent. For NBP, the cointegrating relationship between NBP and WTI and Brent prices are similar. For a one-percent change in either oil price, NBP changes about 0.4 percent. A trend term is not significant in any of the cointegrating relationships and is not reported.

2.3 Bivariate Estimation

Because the crude oil and natural gas price series are cointegrated, we account for cointegration in their relationship by specifying an error-correction model in which changes in the dependent variable are expressed as changes in the independent and the dependent variables, plus an error-correction term, as recommended by Engle and Granger (1987). For cointegrated variables, the error-correction term reflects the deviations from the long-run cointegrating relation-

ship between the variables. The coefficient on the equilibrium error reflects the extent to which the dependent variable adjusts during a given period to deviations from the cointegrating relationship that occurred in the previous period.

We utilize an error-correction model to specify the relationships between each pair of prices:

$$P_{h,t} = \gamma_{hj} + \beta_{hj} P_{j,t} + u_{hj,t} \tag{1}$$

$$\Delta P_{h,t} = a_{hj} + \alpha_{hj}(CI_{hj,t-1}) + \sum_{i=1}^{n} b_{hj,i}\Delta P_{j,t-i} + \sum_{i=1}^{n} c_{hj,i}\Delta P_{h,t-i} + \varepsilon_{hj,t} \tag{2}$$

$$\Delta P_{j,t} = a_{jh} + \alpha_{jh}(CI_{hj,t-1}) + \sum_{i=1}^{n} b_{jh,i}\Delta P_{h,t-i} + \sum_{i=1}^{n} c_{jh,i}\Delta P_{j,t-i} + \varepsilon_{jh,t} \tag{3}$$

where $P_{h,t}$ is a logged natural gas price; $P_{j,t}$ is another logged natural gas or oil price; the $CI_{hj,t}$ are equilibrium errors in the estimated cointegrating relationship between the two prices ($CI_{hj,t} \equiv u_{hj,t}$); a_{hj}, b_{hj}, c_{hj}, α_{hj}, a_{jh}, b_{jh}, c_{jh}, α_{jh}, γ_{hj}, and β_{hj}, are parameters to be estimated; and $\varepsilon_{hj,t}$ and $\varepsilon_{jh,t}$ are standard normal error terms. We estimate the model for the two natural gas prices together and for the natural gas prices with the price of crude oil.

For an error-correction model, movements in the explanatory variable, ΔP_j, lead those of the dependent variable, ΔP_h, if the coefficients on the cointegrating term and the lagged values of the explanatory variable are jointly significant in Equation 2. In such an error-correction process, a shock drives the dependent variable out of alignment with its long-term relationship with the explanatory variable, and the dependent variable adjusts at the weekly rate α_{hj} to realign with its long-term relationship with the explanatory variable. At the same time, the recent history of both prices, as expressed by their lagged values, also shapes the short-term pricing dynamics.

Similarly, movements in the explanatory variable, ΔP_h, lead those of the dependent variable, ΔP_j, if the coefficients on the cointegrating term and the lagged values of the explanatory variable are jointly significant in Equation 3. A shock drives the dependent variable out of alignment with its long-term relationship with the explanatory variable, and the dependent variable adjusts at the weekly rate α_{jh} to realign with its long-term relationship with the explanatory variable. The recent history of both variables also shapes the short-term pricing dynamics.

If estimation reveals that only one of the explanatory variables is significant in explaining the movements of the other, the significant explanatory variable is regarded as weakly exogenous. Movements in a weakly exogenous variable can be regarded as determined independently of the system specified in Equations 1-3, and the estimating equation in which it appears as a dependent variable can be dropped when examining the system's dynamics.

As shown in Table 3A, we find bi-directional causality between the Henry Hub and NBP prices of natural gas.[3] The equation explaining the NBP natural gas price finds that Henry Hub is significant at better than one percent. The lagged values of NBP are also significant at better than one percent. The equation explaining the Henry Hub natural gas price finds that the NBP price is significant at better than five percent. The lagged values of Henry Hub are also significant at better than five percent. These findings of bidirectional causality are indicative of coordinated natural gas prices across the Atlantic, with both prices adjusting to each other. The bi-directional causality may be interpreted to mean that LNG shipments play a role in arbitraging natural gas prices across the Atlantic.

We also find that oil prices are weakly exogenous in determining both the Henry Hub and NBP prices of natural gas.[4] As shown in Table 3B, the model for Henry Hub and WTI finds that Henry Hub is not significant in the WTI equation, but WTI is significant in the Henry Hub equation at better than one percent. As shown in Table 3C, the model for Henry Hub and Brent finds no significant causality in either direction.[5] Table 3D shows that NBP is not significant in the WTI equation, but WTI is significant in the NBP equation at better than one percent. And finally, Table 3E shows that NBP is not significant in the Brent equation, but Brent is significant in the NBP equation.

The model for Henry Hub and Brent shows no causality. For the other three models relating natural gas prices to those for crude oil, however, causality runs strictly from the crude oil prices to the natural gas prices. In these three models, the price of natural gas adjusts to movements in deviations from the long-term relationship between crude oil and natural gas prices in an error-correction process. Short-term dynamics are shaped by the lagged values of the crude oil price and the dependent variable. Such findings raise the possibility that crude oil prices are a vehicle through which natural gas prices are coordinated across the Atlantic.

As reflected by the relatively low R^2 values, the overall explanatory power of the bivariate models is relatively low. For the models finding significant causality, however, the R^2 values are similar to those reported for similar bivariate error-correction models using weekly data, such as Brown and Yücel (2008b). The overall F-statistics do show that the bivariate models have significant explanatory power in those cases where causality is found.

3. For each of the models, the Akaike information criteria recommend the appropriate lag structure for the causality tests. We report the optimal lags with the causality tests in Table 3.

4. These findings are consistent with Asche et al (2006) for the U.K. and Brown and Yücel (2008b) for Henry Hub.

5. The cointegration tests reported above show that a given percentage change in Brent is related to a quantitatively larger change in Henry Hub than the same percentage change in WTI. The non-significance of causality tests between Henry Hub and Brent could be indicative of contemporaneous movement, which we confirmed with additional econometric testing. In such a case, causality cannot be inferred.

Table 3A. Bivariate Error-Correction Model of Henry Hub and NBP Prices

	HH causes NBP		NBP causes HH	
explanatory variables	**coefficients**	**Significance of joint F-tests‡**	**coefficients**	**Significance of joint F-tests‡**
constant	0.0052 (0.7552)		0.0031 (0.8930)	
ΔP_{NBP} (t-1)	-0.1412** (3.2079)		0.0475* (2.1194)	
ΔP_{NBP} (t-2)	-0.1690** (-3.8166)	0.0004	0.0182 (0.8104)	
ΔP_{NBP} (t-3)	-0.0333 (-0.7649)		0.0077 (0.3496)	0.0317
ΔP_{NBP} (t-4)	-0.0592 (-1.1393)		0.0313 (1.4498)	
cointegrating term (t-1)	-0.0873** (-4.0641)		0.0160 (1.4263)	
ΔP_{HH} (t-1)	0.0688 (-0.8291)		0.0705+ (1.6627)	
ΔP_{HH} (t-2)	-0.0501 (-1.3926)	0.0038	-0.0015 (-0.0344)	0.0193
ΔP_{HH} (t-3)	-0.0228 (-0.2742)		-0.0671 (-1.5865)	
ΔP_{HH} (t-4)	-0.1273 (-1.5409)		-0.0951* (-2.2522)	
	$R^2 = 0.05$ adj $R^2 = 0.04$ Significance of Overall F-Statistic: 0.0000‡		$R^2 = 0.18$ adj $R^2 = 0.15$ Significance of Overall F-Statistic: 0.0031‡	

Lags determined by Akaike information criteria. Values shown in parentheses are t-statistics.
+, * and ** denote significance at better than 10, 5 and 1 percent, respectively.
‡Probability that coefficients are jointly equal to zero.

Table 3B. Bivariate Error-Correction Model of Henry Hub and WTI Prices

	HH causes WTI		WTI causes HH	
explanatory variables	**coefficients**	**Significance of joint F-tests‡**	**coefficients**	**Significance of joint F-tests‡**
constant	0.0033 (1.8662)		0.0032 (0.9206)	
ΔP_{WTI} (t-1)	-0.1454** (3.3814)		0.0949 (1.1189)	
ΔP_{WTI} (t-2)	-0.1577** (-3.6419)	0.0001	-0.0894 (-1.0438)	
ΔP_{WTI} (t-3)	-0.0906 (1.0908)		0.0251 (0.2904)	0.0085
ΔP_{WTI} (t-4)	-0.0715+ (-1.6485)		-0.0826 (-0.9640)	
cointegrating term (t-1)	0.0008 (0.1022)		-0.0532** (-3.6025)	
ΔP_{HH} (t-1)	0.0239 (1.10440)		0.0815 (1.9039)	
ΔP_{HH} (t-2)	-0.0323 (-1.4912)	0.1102	0.0154 (0.3607)	0.0531
ΔP_{HH} (t-3)	-0.0303 (-1.3967)		-0.0503 (-1.1755)	
ΔP_{HH} (t-4)	0.0431* (1.9859)		-0.0749+ (-1.7452)	
	R^2 = 0.05 adj R^2 = 0.04 Significance of Overall F-Statistic: 0.0003‡		R^2 = 0.18 adj R^2 = 0.03 Significance of Overall F-Statistic: 0.0009‡	

Lags determined by Akaike information criteria. Values shown in parentheses are t-statistics.
+, * and ** denote significance at better than 10, 5 and 1 percent, respectively.
‡Probability that coefficients are jointly equal to zero.

Table 3C. Bivariate Error-Correction Model of Henry Hub and Brent Prices

	HH causes Brent		Brent causes HH	
explanatory variables	**coefficients**	**Significance of joint F-tests‡**	**coefficients**	**Significance of joint F-tests‡**
constant	0.0031 (1.2653)		0.0039 (1.0655)	
ΔP_{BRENT} (t-1)	-0.0539 (-1.1771)		-0.0016 (-0.0230)	
ΔP_{BRENT} (t-2)	0.0281 (0.2567)	0.3712	0.0236 (0.3351)	
ΔP_{BRENT} (t-3)	0.0176 (0.3789)		-0.0593 (-0.8417)	0.1088
ΔP_{BRENT} (t-4)	-0.0713 (-1.5718)		-0.0663 (-0.9484)	
cointegrating term (t-1)	0.0042 (0.3982)		-0.0438** (-2.750)	
ΔP_{HH} (t-1)	0.0876** (2.96360)		0.0753+ (1.1656)	
ΔP_{HH} (t-2)	0.0077 (0.2567)	0.5931	0.0066 (-0.1428)	0.3456
ΔP_{HH} (t-3)	-0.0108 (-0.3592)		-0.0446 (-0.9776)	
ΔP_{HH} (t-4)	0.0238 (0.7847)		-0.0811+ (-1.7474)	
	$R^2 = 0.03$ adj $R^2 = 0.01$ Significance of Overall F-Statistic: 0.0956‡		$R^2 = 0.04$ adj $R^2 = 0.02$ Significance of Overall F-Statistic: 0.0256‡	

Lags determined by Akaike information criteria. Values shown in parentheses are t-statistics.
+, * and ** denote significance at better than 10, 5 and 1 percent, respectively.
‡Probability that coefficients are jointly equal to zero.

Table 3D. Bivariate Error-Correction Model of NBP and WTI Prices

	NBP causes WTI		WTI causes NBP	
explanatory variables	**coefficients**	**Significance of joint F-tests‡**	**coefficients**	**Significance of joint F-tests‡**
constant	0.0031+ (0.7253)		0.0063 (0.9258)	
ΔP_{WTI} (t-1)	0.1502** (3.5452)		-0.3372* (2.0734)	
ΔP_{WTI} (t-2)	-0.1299* (-3.0289)	0.0004	0.0486 (0.2949)	
ΔP_{WTI} (t-3)	0.0856* (2.0021)		-0.2711 (-1.6518)	0.0010
ΔP_{WTI} (t-4)	-0.0449 (-1.0556)		-0.0559 (-0.3426)	
cointegrating term (t-1)	0.0059 (1.0035)		-0.1048** (-4.6111)	
ΔP_{NBP} (t-1)	0.0119 (1.04752)		-0.1322* (-3.0224)	
ΔP_{NBP} (t-2)	0.0107 (0.9321)	0.5200	-0.1583** (-3.6068)	0.0011
ΔP_{NBP} (t-3)	0.0002 (0.0157)		-0.0251 (-0.5811)	
ΔP_{NBP} (t-4)	-0.0011 (-0.0971)		0.0515 (1.2253)	
	$R^2 = 0.04$ adj $R^2 = 0.10$ Significance of Overall F-Statistic: 0.0024‡		$R^2 = 0.11$ adj $R^2 = 0.03$ Significance of Overall F-Statistic: 0.0000‡	

Lags determined by Akaike information criteria. Values shown in parentheses are t-statistics.
+, * and ** denote significance at better than 10, 5 and 1 percent, respectively.
‡Probability that coefficients are jointly equal to zero.

Table 3E. Bivariate Error-Correction Model of NBP and Brent Prices

	NBP causes Brent		Brent causes NBP	
explanatory variables	**coefficients**	**Significance of joint F-tests‡**	**coefficients**	**Significance of joint F-tests‡**
constant	0.0031 (1.3196)		0.0043 (0.6174)	
ΔP_{WTI} (t-1)	-0.0430 (-0.7519)		-0.2024 (-1.5819)	
ΔP_{WTI} (t-2)	0.0412 (0.9033)	0.3712	-0.1088 (-0.8415)	
ΔP_{WTI} (t-3)	0.0351 (0.7632)		-0.1166 (-0.9035)	0.0021
ΔP_{WTI} (t-4)	-0.0677 (-1.4919)		-0.0011 (-0.0083)	
cointegrating term (t-1)	0.0057 (0.6777)		-0.0988** (-4.2001)	
ΔP_{NBP} (t-1)	0.0044 (0.27081)		-0.1581** (-3.4735)	
ΔP_{NBP} (t-2)	0.0216 (1.3408)	0.5931	-0.1122 (-2.4456)	0.0032
ΔP_{NBP} (t-3)	0.0021 (0.1299)		-0.0140 (-0.3115)	
ΔP_{NBP} (t-4)	-0.0101 (-0.6556)		0.0594 (-1.3627)	
	$R^2 = 0.02$ adj $R^2 = 0.00$ Significance of Overall F-Statistic: 0.5540‡		$R^2 = 0.10$ adj $R^2 = 0.08$ Significance of Overall F-Statistic: 0.0000‡	

Lags determined by Akaike information criteria. Values shown in parentheses are t-statistics.
+, * and ** denote significance at better than 10, 5 and 1 percent, respectively.
‡Probability that coefficients are jointly equal to zero.

2.4 Multivariate Estimation

To examine whether natural gas prices on either side of the Atlantic play an independent and direct role in determining natural gas prices on the other side of the Atlantic, and whether oil prices have a role in the coordination natural gas prices, we consider a multivariate model of natural gas price determination with both natural gas and crude oil prices as explanatory variables as follows:

$$\Delta P_{h,t} = a_{hjk} + \alpha_{hj}(CI_{hj,t-1}) + \sum_{i=1}^{n} b_{hj,i}\Delta P_{j,t-i} + \alpha_{hk}(CI_{hk,t-1}) + \sum_{i=1}^{n} b_{hk,i}\Delta P_{k,t-i} + \sum_{i=1}^{n} c_{h,i}\Delta P_{h,t-i} + \varepsilon_t \tag{4}$$

where $P_{h,t}$ is a logged natural gas price; $P_{j,t}$ is the other logged natural gas price; $P_{k,t}$ is a logged oil price; the $CI_{hj,t}$ are equilibrium errors in the estimated cointegrating relationship between the two natural gas prices; the $CI_{hk,t}$ are equilibrium errors in the estimated cointegrating relationship between the natural gas price and an oil price; a_{hjk}, b_{hj}, b_{hk}, c_h, d_x, α_{hj}, and α_{hk} are parameters to be estimated; and ε_t is a standard normal error term.

The bivariate model for Henry Hub and NBP (reported in Table 3A above) shows NBP has a significant role in explaining movements in the Henry Hub price of natural gas. As shown in the top panel of Table 4, the addition of WTI to the model reduces the NBP price to marginal significance, but WTI is significant at better than five percent. The lags of Henry Hub are also marginally significant.

The addition of Brent to the bivariate model for Henry Hub and NBP yields no significant variables. Even though Brent is not significant in explaining the Henry Hub price of natural gas in either the bivariate or multivariate models, its inclusion in the multivariate model yields insignificant coefficients on the NBP price of natural gas.

Similarly, the bivariate model for Henry Hub and NBP (reported in Table 3A above) shows Henry Hub has a significant role in explaining movements in the NBP price of natural gas. As shown in the bottom panel of Table 4, the addition of WTI to the model yields an insignificant Henry Hub price, but WTI is marginally significant. The lags of NBP are significant at better than one percent. The addition of Brent to what had been a bivariate model results in insignificant coefficients for both Henry Hub and Brent. The lags of NBP are significant at better than one percent.

In short, natural gas prices on both sides of the Atlantic adjust to deviations from the long-run relationship between natural gas and WTI prices in an error-correction process. Short-term dynamics are shaped by the lagged values of the WTI price and the dependent variable. For either Henry Hub or NBP natural gas prices, the natural gas price on the other side of the Atlantic continent appears

Table 4. Multivariate Causality Tests for Natural Gas Prices

	Dependent Variable Henry Hub	
explanatory variables	**Significance of Joint F-tests‡**	**Significance of Joint F-tests‡**
HH lags	0.0533	0.1284
NBP lags & $CI_{HH,NBP}$	0.0723	0.1284
WTI lags & $CI_{HH, WTI}$	0.0207	
Brent lags & $CI_{HH,Brent}$		0.2151
Optimal Lags	4	4
	R^2=.07 Adj R^2=.04 Significance of Overall F-Statistic: 0.0005‡	R^2=.05 Adj R2=.03 Significance of Overall -Statistic: 0.0166‡

	Dependent Variable National Balancing Point	
xplanatory variables	**Significance of Joint F-tests‡**	**Significance of Joint F-tests‡**
NBP lags	0.0029	0.0083
HH lags & $CI_{HH, NBP}$	0.7015	0.7009
WTI lags & $CI_{NBP,WTI}$	0.0708	
Brent lags & $CI_{NBP,Brent}$		0.2430
Optimal Lags	4	4
	R^2=.11 Adj R^2=.09 Significance of Overall F-Statistic: 0.0000‡	R^2=.10 Adj R^2=.08 Significance of Overall F-Statistic: 0.0000‡

Optimal lag length is determined by the Akaike information criterion. Causality test includes term to account for errors in cointegration between NBP and Henry Hub, WTI and Brent.
‡Probability that coefficients are jointly equal to zero.

to have little or no independent influence once the price of crude oil is included in the model.

These findings suggest that crude oil prices play an important role in coordinating natural gas prices across the Atlantic, and that direct arbitrage through LNG might have a lesser role. The marginal contribution of NBP in the model for the Henry Hub price suggests the possibility of some direct coordination between natural gas prices across the Atlantic, which could be facilitated by shipments of LNG. The evidence for such a relationship is weak, however. European pricing of LNG against oil could be reinforcing the relationship between crude oil and natural gas prices on both sides of the Atlantic.

2.5 Estimation with Additional Variables

Brown and Yücel (2008b) find a number of additional variables affect the supply and demand for natural gas in the United States and the price at Henry Hub. The inclusion of these variables in the multivariate equation for the Henry Hub price of natural gas allows us to control for the influence of these additional variables on the Henry Hub price. Their inclusion in the multivariate equation for NBP allows us to see if the influence of these variables is arbitraged back to the NBP price.

The additional variables suggested by Brown and Yücel (2008b) include heating degree days, deviations from normal heating degree days, cooling degree days, and deviations from normal cooling degree days for the United States, U.S. natural gas storage and shut-in production in the Gulf of Mexico.[6] Augmented Dickey-Fuller tests revealed all these additional variables are stationary in their levels representation.

There is little reason to expect these variables to be driven by natural gas or crude oil prices. Therefore, the additional variables are added to the multivariate model as exogenous, which yields the following:

$$\begin{aligned}\Delta P_{h,t} = a_{hjk} + \alpha_{hj}(CI_{hj,t-1}) + \sum_{i=1}^{n} b_{hj,i}\Delta P_{j,t-i} + \alpha_{hk}(CI_{hk,t-1}) \\ + \sum_{i=1}^{n} b_{hk,i}\Delta P_{k,t-i} + \sum_{i=1}^{n} c_{h,i}\Delta P_{h,t-i} + \sum_{y=1}^{z} d_y X_{y,t} + \varepsilon_t\end{aligned} \tag{5}$$

where $P_{h,t}$ is a logged natural gas price; $P_{j,t}$ is the other logged natural gas price; $P_{k,t}$ is a logged oil price; the $CI_{hj,t}$ are equilibrium errors in the estimated cointegrating relationship between the two natural gas prices; the $CI_{hk,t}$ are equilibrium errors in

6. The heating and cooling degree data are collected by the National Oceanic and Atmospheric Administration and are obtained from the Haver Analytics data base. Data on U.S. natural gas storage are collected by the U.S. Energy Information Administration (EIA). Following Brown and Yücel (2008b), we calculate a storage differential as the difference between the storage in a given week and the average for that week over the past five years (the latter series also reported by the EIA). Shut-in production in the Gulf of Mexico is a series that Brown and Yücel (2008b) assembled from individual reports made by the Minerals Management Service of the U.S. Department of Interior.

The use of four weather series—heating degree days, deviations from normal heating degree days, cooling degree days and deviations from normal cooling degree days—allows for both the influence of weather and seasonality. The normal seasonal influence of weather is reflected in the difference between heating degree day deviations and heating degree days, and in the difference between cooling degree deviations and cooling degree days.

Heating degree days are available as a population or gas-weighted series. Cooling degree days are only available as a population-weighted series. For heating, natural gas is used directly. Gas-weighted heating degree days have more intuitive appeal and had a slightly better fit in the estimated equations. Consequently, we use gas-weighted heating degree days and population weighted cooling degree days. We find substantially similar results to those reported above when using the population-weighted data in place of the gas-weighted data.

the estimated cointegrating relationship between the natural gas price and an oil price; X_y is a vector of z stationary exogenous variables representing local supply and demand conditions at Henry Hub; a_{hjk}, b_{hj}, b_{hk}, c_h, d_x, α_{hj}, α_{hk} and d_y, are parameters to be estimated; and ε_t is a standard normal error term.

Because the price of Brent proved insignificant in the multivariate models above, we limit the analysis with exogenous variables to the two models with WTI as an explanatory variable. As shown in Table 5, inclusion of the exogenous variables does not change the basic results shown above.

For the Henry Hub price of natural gas, the relationship with WTI remains an error-correction process. As found by Brown and Yücel (2008b), the exogenous variables affecting U.S. natural gas supply and demand are jointly significant in explaining the Henry Hub price. The NBP price is insignificant, as are lagged values of the Henry Hub price.

For the NBP price of natural gas, the relationship with WTI also remains an error-correction process. The exogenous variables affecting U.S. natural gas supply and demand are marginally significant, but a joint test with the exogenous variables and the Henry Hub price finds insignificance. The Henry Hub price is insignificant, and lagged values of NBP are marginally significant.

Table 5. Multivariate Causality Tests with Exogenous Variables

	Dependent Variable	
explanatory variables	**HH Significance of Joint F-tests‡**	**NBP Significance of Joint F-tests‡**
NBP lags		0.0653
HH lags	0.1597	
HH lags & $CI_{HH,NBP}$		0.3158
NBP lags & $CI_{HH,\ NBP}$	0.1597	
WTI lags & $CI_{HH,WTI}$	0.0000	
WTI lags & $CI_{NBP,\ WTI}$		0.0376
Exogenous Variables	0.0000	0.0564
Exogenous Variables, HH lags & $CI_{HH,NBP}$		0.1450
Optimal Lags	4	4
	R^2=.18 Adj R^2=.15 Significance of Overall F-Statistic: 0.0000‡	R^2=.13 Adj R^2=.10 Significance of Overall F-Statistic: 0.0000‡

Optimal lag length is determined by the Akaike information criterion. Causality test includes term to account for errors in cointegration between NBP and Henry Hub, WTI and Brent.
‡Probability that coefficients are jointly equal to zero.

The addition of exogenous variables to the model reinforces our earlier results. The inclusion of WTI in models explaining either Henry Hub or NBP natural gas prices renders the other natural gas price either marginally significant or insignificant, while WTI itself is very significant. These findings suggest that the coordination of natural gas prices across the Atlantic occurs through co-movements with WTI rather than gas-to-gas arbitrage.

3. CONCLUSIONS

Bivariate causality tests between the Henry Hub and NBP prices of natural gas show bidirectional causality, indicating coordinated movement in natural gas prices across the Atlantic. These findings suggest the possibility of arbitrage, which could be accomplished through shipments of LNG. Although both the European market and North American markets are recipients of LNG cargos, neither currently has LNG export facilities. Consequently, arbitrage is limited to the diversion of cargos.

At the same time, bivariate tests between natural gas prices and crude oil prices on both sides of the Atlantic reveal an error-correction process in which natural gas prices adjust to deviations from the long-term relationship between natural gas and crude oil prices. Short-term dynamics are shaped by the recent history of the respective natural gas and crude oil prices. The existence of such a process suggests the possibility that the coordination of natural gas prices across the Atlantic could be facilitated through co-movements with crude oil prices.

Testing in several different multivariate models reveals that crude oil prices could play an important role in coordinating natural gas prices across the Atlantic. These multivariate models suggest that direct gas-to-gas arbitrage may not be as important, but the extensive pricing of LNG against oil in Europe could mask such arbitrage by statistically reinforcing the relationship between crude oil and natural gas prices.

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Linking Natural Gas Markets – Is LNG Doing its Job?

*Anne Neumann**

The increase in liquefied natural gas trade has accelerated the integration of previously segmented markets in North America, Europe, and Asia. This paper provides evidence on the integration of the transatlantic natural gas market; it thus complements other papers in the EMF 23 study that focus on prices and international natural gas trade. We test the theoretical proposition that in integrating markets commodity prices should move closer than before. Using 2,059 pairs of daily spot prices for natural gas in North America and Europe we investigate price dynamics covering the period from 1999 until 2008. We apply the Kalman Filter technique which measures convergence by allowing for dynamic structural change to gain detailed information on trends inherent in prices over time. Results suggest an increasing convergence of spot prices on either side of the Atlantic Basin.

1. INTRODUCTION

Markets for natural gas have witnessed profound changes in the past decade. Liberalization in most parts of the world, restructuring of former vertically integrated supply chains, and falling transportation costs especially for liquefied natural gas (LNG) have pushed the emergence of a new "international natural gas market", replacing the former regionally segmented markets in North America, Europe, and Asia. In addition, traditional pricing schemes are being reviewed moving from long-term, often oil-price indexed natural gas prices towards prices based on market mechanisms.

The literature on market integration in commodity and natural gas market has studied a variety of regional integration processes, but global natural gas markets per se have not yet been analyzed. The integration of the North American

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* DIW Berlin, Mohrenstr. 58, D-10117 Berlin, Germany. Email: aneumann@diw.de, phone: +49-(0)30-89789-304.

market following FERC Order 436 (1985) has been studied extensively, e.g. by Serletis (1997), Walls (1994), and De Vany and Walls (1995), who use correlation and cointegration analysis. Results of an integrated market were confirmed by studies using other econometric tools such as time-varying coefficients, Johansen test procedure, and impulse response functions, e.g. King and Cuc (1996), Cuddington and Wang (2006), and Serletis and Rangle-Ruiz (2004). Work on the cointegration of European natural gas import prices was first carried out by Asche, Osmundsen and Tveteras (2001, 2002). For the UK market, that has been liberalized 15 years earlier than Continental Europe, Panagiotidis and Rutledge (2007) show that the linkage between the natural gas price and the price of oil has become more volatile over time which can be interpreted as a sign of decoupling of the natural gas price from the oil price. Neumann et al. (2006) have shown that integration between the UK market and the largest Continental European wholesale market (Zeebrugge) works well, but that price convergence between different Continental European markets is still to come about. Last but not least, Siliverstovs et al. (2005) were the first to address the issue of international market integration for natural gas; they concluded that for the period preceding liberalization of natural gas markets in Europe, i.e. the 1990s, the hypothesis of integrated transatlantic natural gas prices should be rejected.

The EMF 23 study has a focus on prices and trade patterns in international natural gas markets presenting regional prices for natural gas. These are mainly calibrated by linking natural gas to petroleum prices (EMF, 2007, p. 18). However, price dynamics in natural gas markets may differ from those of crude oil, e.g. due to a different industrial organization of the sector. Existing literature analyzes the relation of different commodities (Hartley et al., 2008, Brown and Yücel, 2008, Villar and Joutz, 2006) and argues in favor of a long-run stable relationship of crude oil and natural gas prices. This paper provides evidence on the integration of international natural gas markets, hence spot prices for a single commodity. We test the theoretical proposition that in integrating markets of homogenous products, prices should move in the same direction; when achieving full integration, price differentials should only represent differences in transportation costs and/or quality. Construction of LNG import and export facilities worldwide facilitates flexibility in global trade of natural gas. Our hypothesis, spurred by evidence and market participants, is that as markets, in particular transatlantic natural gas markets, are getting closer intertwined, price integration is the natural consequence.

The remainder of the paper is structured in the following way: the next section describes the recent developments on the international natural gas markets upon which our hypothesis of increasing integration is based. Section 3 provides the model specification and explains the data on natural gas and oil prices. Section 4 presents the estimation results: we find a trend towards a higher level of integration between North American and European natural gas prices. Section 5 concludes.

2. RECENT TRENDS IN INTERNATIONAL NATURAL GAS MARKETS

International natural gas markets have gone through substantial institutional and economic changes during the past decade. This section describes the major changes on the North American and the European wholesale markets, and points out the critical role of liquefied natural gas (LNG) for the process of integration.

2.1 Development of trading hubs in North America and in Europe

North America pioneered the restructuring of natural gas markets as early as the 1970s, with deregulation of wellhead prices (Natural Gas Policy Act, 1978) followed by opening up of access to the trunk line natural gas infrastructure (FERC Order 436, 1985). Subsequently, the trading place "Henry Hub" in Louisiana emerged as the market centre. It is closely connected to not less than 16 pipelines, LNG infrastructure and three salt caverns for storage. Since 1988 Henry Hub serves as delivery and reference point for the New York Mercantile Exchange (NYMEX) gas futures contract and is the reference point for all natural gas export contracts to Mexico. Natural gas futures at the NYMEX have a depth of 5 to 6 years and are complemented by options since 1992. It is a liquid market serving as reference for almost all natural gas trade in North America.

The UK followed the US path with a time lag of about a decade. Breaking up the monopoly of British Gas in the UK in 1986 marked the landfall of the first truly competitive gas market in Europe. Already in 1994 the National Balancing Point (NBP), a notional trading point on the National Transport System (NTS), was used as an informal market and developed towards the main place for spot natural gas trading activities from 1996 onwards. There has been a steady increase in volume traded both physically and financially. A further expansion is expected once the LNG import quantities rise to substantial levels after the opening of import terminals (Isle of Grain, Milford Heaven). Recently, the NBP has served as a reference point for prices in long-term contracts, which has furthermore strengthened its role.

Continental Europe trailed far behind the US and the UK for a long time, until the EU Acceleration Directive (2003/55/EC) paved the way to a more stringent market opening. With regard to wholesale markets, the only significant development to date was the opening of the Zeebrugge hub (Belgium), after the connection with the UK through the Interconnector pipeline. Since its start in 1999, traded volumes have increased steadily. A second hub on the Dutch transmission grid (TTF) was set up in 2003 and has gained more importance since 2005. We seem to observe a certain "déjà vu" effect of repeated history of natural gas trading in Continental Europe, now in its early stages as was Henry Hub 20 years ago.

The restructured industry in Europe and North America features a high proportion of spot trading. Recent natural gas sales contracts are of a relative short duration comparatively to the traditional long-term contract. Contract prices are being keyed to a natural gas market indicator, since oil-linked pricing is a poor indicator of a gas-to-gas competitive market. Trade press reporting for a reference point such as the Henry Hub in America, the NBP in the UK, or Zeebrugge in Continental Europe provides transparent information about the market. This favors competition, an aspect to which we now turn.

2.2 Increasing role of LNG and emerging transatlantic competition

Given its ease of use and environmental friendliness, natural gas has become a key fossil fuel for the power sector and other industrial and residential demand. Demand for natural gas is increasing in all regions of the world, thus leading to upward pressure on prices and potential competition between the formerly segmented regions. In this context, the increase in LNG-trade provides the missing link for market integration across regions, in particular across the Atlantic Ocean. Although LNG has been around for about four decades now, it is only during the last decade that it has come to play a role as a serious means of interconnecting markets. In fact, one already observes an active arbitrage in the Atlantic Basin, where LNG shipments from Trinidad and Nigeria have been diverted either to the US or Europe depending on spot prices. The impact of these swaps and diverting activities has so far only been modest on the spot price in countries where cargoes have been sent to.

The three major natural gas consuming regions of the world (North America, Europe, and Asia) differ in their import structure. Whereas LNG so far has only played a minor role in North America representing 3.6 % of US natural gas consumption in 2007, countries like Japan and South Korea are fully dependent on LNG imports. In Europe both pipeline and LNG imports coexist and quantities differ on national levels. However, construction of a number of LNG importing facilities in the US and Europe should lead to significant interaction of these two regions.

According to theory, arbitraging possibilities occur in cases when the price differential of a homogeneous commodity exceeds transportation costs. Thus, convergence of North American and European prices should take place until the difference reflects only transportation costs. The technical prerequisites for LNG to play that role are fulfilled: there is an increasing amount of liquefaction and regasification capacities on either side of the Atlantic. Ship capacities are not critical, first, because there is a large amount of non-dedicated capacities under construction (IEA, 2007, p. 52), and second, there are no observable barriers to entry into that market. A favorable regulatory regime is established following the Hackberry Decision in the US and Article 22 of the European Gas Directive 2003/55/EC.

Recent evidence confirms the growing role of LNG: its share in global natural gas trade has risen to about 20% and is expected to reach 30% in the coming years (Cornot-Gandolphe, 2005). A growing share of this LNG-trade is short-term trading, about 11% (~20 bcm) in 2004, and rising (IEA, 2006). Spot trading of LNG has so far mainly occurred during cold winter month, providing an opportunity to meet peak demand, and during times of substantial price differences between North America and Europe.[1] This is possible in times of increased flexibility inherent in long-term contracts. Natural gas storage deposits could be filled whilst sustainable low prices prevail, thus incurring strategic redirections of tankers to alternative market places performing at higher prices.

3. DATA AND MODEL SPECIFICATION

3.1 Data

We are interested in the relation between natural gas spot prices on either side of the Atlantic Basin. Using daily data covering the time period January 1999 until May 2008 provides a sample with 2,059 pairs of observations when prices are reported for the same day in the transatlantic basin.

The National Balancing Point (NBP) and Zeebrugge refer to the European and Henry Hub (HH) to the North American price included in this analysis.[2] Quotations for the NBP and Zeebrugge are provided by Heren and converted from pence per therm into $/MBtu using daily exchange rates taken from the Federal Reserve Bank. Data on Henry Hub are as reported by the Energy Information Administration. Table 1 provides summary statistics of prices in levels and log-levels. Annual volatility, calculated as the standard deviation of the logged prices, was highest in 2005 when it reached 4.12 at NBP and 2.66 at the Henry Hub.

Table 1. Summary Statistics

	NBP	(log)	Zeebrugge	(log)	Henry Hub	(log)
Mean	4.57	1.32	4.84	1.41	5.44	1.59
Maximum	33.75	3.52	33.59	3.51	18.85	2.94
Minimum	1.03	0.03	1.92	0.25	1.59	0.46
Std. Dev.	3.23	0.61	3.16	0.57	2.46	0.48
Skewness	2.27	0.32	2.29	0.34	0.79	-0.35
Kurtosis	11.65	2.62	11.88	2.91	4.20	2.37
Observations	2,389		2,223		2,309	

1. LNG imports to the US have decreased continuously since 2004 as flows were shifted from the US to markets in Asia and Europe (EIA, 2008).

2. We include Zeebrugge prices since it is a trading place where LNG import facilities, long distance pipelines, and storage facilities intersect. Hence, a trading party would at this date refer to Zeebrugge rather than NBP for possible LNG trade. However, spot cargoes have been mainly sent to facilities in Spain, but there are no price quotes publicly available for the time period under consideration.

3.2 Model Specification

Recent developments in LNG trade and expectations of developments are going to change the pattern of integration between natural gas prices in North America and Europe. These trends are unlikely to be caught in a framework of cointegration based on long-run relationships: Before markets or prices can be considered integrated they have to undergo a gradual change from separation towards integration. Cointegration analysis is based on the assumption of a fixed structural relationship between variables over time. Splitting the sample into subsamples and applying cointegration analysis should lead to the same result: if prices converge towards the end of the sample they should be cointegrated in the last subsample under consideration (King and Cuc, 1996). To avoid the reduction of degrees of freedom, we introduce a time-variant coefficient into the linear relationship of prices which measures convergence by allowing for dynamic structural change. Considering prices for Henry Hub and NBP (Henry Hub and Zeebrugge, respectively) we constitute a linear relationship between these two:

$$P_{i,t} = c_{ij} + \beta_t P_{j,t} + \varepsilon_t \tag{1}$$

$$\beta_t = \beta_{t-1} + \mu_t \tag{2}$$

where P is the price in regions i and j, t denotes time and c_{ij} allows for transportation costs which are assumed to remain constant over time. Equation (2) determines values of β_t based on data of previous observations. If no profitable arbitraging opportunities arise prices are expected to equalize up to the difference in transportation costs, hence are considered to follow the law of one price. It holds for values of β_t equal to one, therefore prices are said to be more integrated the closer β_t is to one. This is valid since the price differential should converge towards transportation costs implying β_t to converge to the value of one. Formally, this can be expressed as $E\{\lim_{t\to\infty}(P_j - P_i)\} = c_{ij}$ with the final state of convergence represented by $E\{\lim_{t\to\infty} \beta_{ij}\} = 1$.[3]

We use the Kalman Filter technique to the whole sample of daily prices in order to gain detailed information on trends inherent over time. The Kalman filter processes the spot prices and provides information on the value of the parameters c_{ij} and β_t for each point in time over which both price series are available by proceeding in two successive steps. First, it estimates β_t by using information up to *t-1*. Following, information at time t is realized and the estimates of β_t are updated by incorporating prediction errors from the first step.

Hence, the filter produces linear minimum mean square error estimates of β_t using observed data up through time t. These estimates are optimally updated as data beyond t becomes available. The filter also ensures that the revisions made

3. Hall, Robertson, and Wickens (1992) provide a refined interpretation of strong and weak convergence based on these expected values.

in β_t at time $t+k$ follow a (time-varying) moving average process of order $k-1$. If the error terms are assumed to be normally distributed, the parameters can be estimated by using the maximum likelihood method.[4] The Kalman filter exploits the dynamics of prices over time and removes the noise from the system by recursively conditioning current estimates on all past measurements.

An often voiced argument in context of this type of analysis of natural gas prices is the influence of oil prices. Even if it is argued that oil remains the driving force for natural gas prices we believe that prices for natural gas will behave increasingly independently of oil prices. Following the findings in Hartley et al. (2008) we use prices at Rotterdam (ARA) for Europe and in Los Angeles, CA for US, (FOB quotes) to analyze this relation. Therefore we extend the analysis by applying the same technique to natural gas price data adjusted for the price of residual fuel oil. Hence, we generate two time series which are by definition uncorrelated to the price of oil but highly correlated with the price of natural gas.

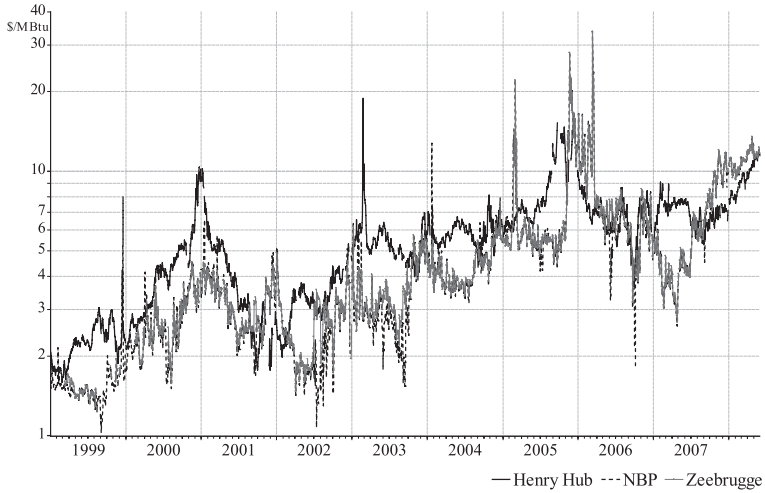
$$\begin{aligned} P_{i,t}^{NG} &= c + P_{i,t}^{Oil} + \varepsilon_{i,t} \qquad i = \{Europe, USA\} \\ \widetilde{P}_{i,t}^{NG} &= \frac{\varepsilon_{i,t}\,\sigma^2{}_{P_i^{NG}}}{\sigma^2{}_{\varepsilon i}} + \overline{P}_i^{NG} \end{aligned} \tag{3}$$

Following equations (3) and (4) results in new series for the Europe and the US which are the residuals of an OLS of the residual fuel oil price on the original natural gas price. Data is taken from EIA and converted from cent per gallon using a calorific value of 38,157 kwh. Equation (4) generates the final decorrelated time series ($\widetilde{P}_{i,t}^{NG}$) by normalizing the variance of the residual series to the original series variance and adding the mean of the original price ($\overline{P}_{i,t}^{NG}$) to the generated data.

Figure 1 shows the original time series in levels using logarithmic scaling on the y-axis. The upward trend in prices for natural gas since the end of the 1990's is clearly depicted. Prices in North America and Europe are an image of one another until the end of 2002 with Henry Hub consistently prevailing at a higher level. Price spikes reflect exogenous influences such as the events around 09/11, hurricanes Rita and Katrina. Note that prices in the UK jumped to exorbitant levels in the cold winter 2005/2006 but have decreased to a conventional level since; the cold snap in January 2001 is clearly reproduced in Henry Hub prices. Zeebrugge prices mirror NBP prices, confirming the cointegration relationship shown in Neumann et al. (2006).

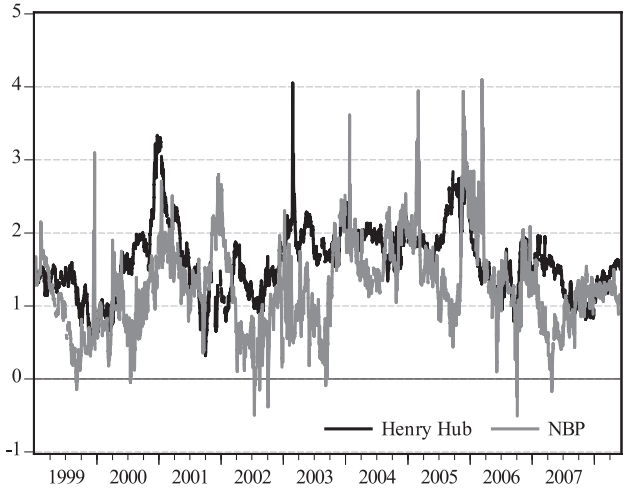
4. See Harvey (1987) and Meinhold and Singpurwalla (1993) for a more detailed and technical description of the Kalman filter.

Figure 1. Natural Gas Prices



The generated decorrelated time series for natural gas in Figure 2 indicate seasonality of prices for natural gas in particular in the winters of 2000/01 and 2005/06. Natural gas consumption at least in the US is characterized by strong seasonal peaks during the winter heating season (space heating) and lesser peaks in the summer cooling season (electricity generation).[5]

Figure 2. Generated Decorrelated Natural Gas Prices



5. For an in-depth analysis of the relation between natural gas and oil prices as well as seasonality and weather see Brown and Yücel (2008) and Hartley, Medlock and Rosthal (2008).

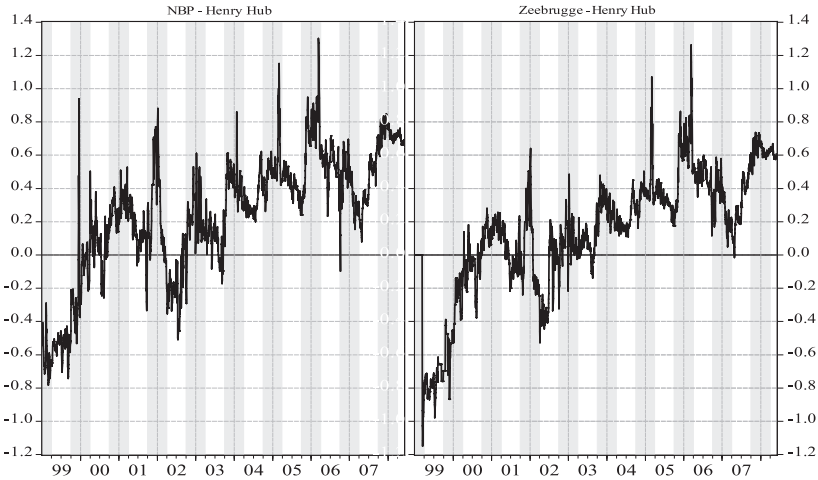
4. RESULTS

4.1 Natural Gas Spot Prices

The analysis investigates the relation between the natural gas prices on either side of the Atlantic, i.e. the Henry Hub and NBP / Zeebrugge spot prices over time from 1999 to 2008. Applying a time-variant coefficient methodology allows us to determine whether recent trends in international LNG trade have led to a convergence of spot prices in the US and Europe towards the law of one price. An application of the Kalman filter to daily pairs of logged spot data results in the estimation of the β_t-coefficient for the time period under consideration. Theory predicts that in a perfectly integrated market beta should be equal to one and c_{ij} would be interpreted to implicit transportation or transaction costs. Due to the non-normalized distribution of the estimated β_t, it is ambitious to test the statistical significance of this β_t -coefficient. Plotting the values of the coefficient over time provides an opportunity to evaluate whether or not convergence occurred. Figure 3 depicts in the left panel the result for the original natural gas spot prices assuming NBP to depend on prices quoted at the Henry Hub; the right panel shows the beta-coefficient for Zeebrugge and Henry Hub.

There is evidence of prices converging towards the law of one price for both estimated relations, hence the β-coefficient moving towards the value of one.[6]

Figure 3. Beta Coefficients



6. For values of β_t not equal to one the interpretation of the variable accounting for transportation costs is rather ambiguous since there is no strict interpretation of this value in money terms. The filter does require a value of the mean and variance of β_0 to begin the recursions. These values are estimated prior to the adjustment process by using the maximum likelihood method (Harvey, 1987). Hence, the estimated β-coefficients at sample start are somewhat "distorted".

Interestingly, one could argue that there is some seasonality in the convergence more intensively occurring during winters (shaded areas) when markets are tight. It is during these times, i.e. when spot prices for natural gas are high and more volatile, that LNG cargoes are potentially redirected from the original unloading terminal to a more profitable market.

4.2 Decorrelated Prices

Accounting for the strong relationship of prices for residual fuel oil, mainly in power generation, we generated two time series highly correlated to the values of the respective spot price for natural gas in the US and Europe, but independent of oil prices. Applying the methodology of the Kalman filter as described above results in the beta coefficient as depicted in Figure 4.

Whereas there is no clear evidence of convergence towards the law of one price when adjusting for the influence of residual fuel oil, the graph of the estimated coefficients exhibits interesting features. First, for the period until approximately 2003, prices seemingly do not interact. However, some indications of beginning intertwining of transatlantic developments are suggested for the second half of the sample. In particular, we observe a stronger tendency of natural gas prices to converge during the winter season of demand (shaded areas). Also, it coincides with first spot cargoes delivered to Spain in Europe and signed swap deals.[7] Deliveries to the UK's terminal at Isle of Grain have followed the price difference of North American and UK spot prices since late 2005 (IEA, 2006). Rather surprising is the enormous impact of high prices in the UK during winter 2005/06 on the price relationship.[8]

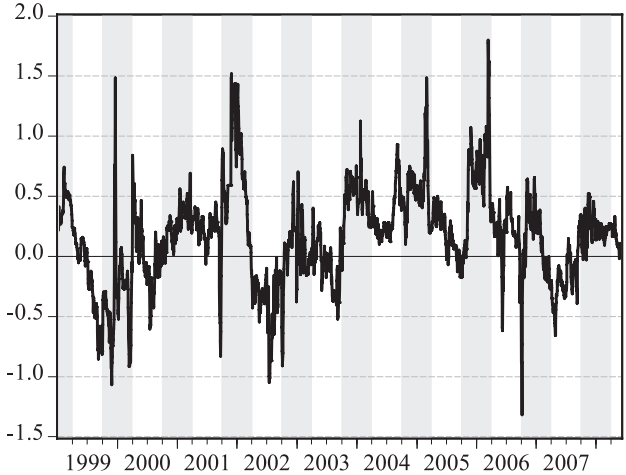
5. CONCLUSION

This paper provides evidence on the integration of international natural gas markets. We have outlined the importance of LNG in the Atlantic Basin and reflected recent progress in the evolution of shorter-term trading for natural gas. LNG has been identified as the key driver for the transmission of regional impacts on prices. Hence, the market for natural gas is currently undergoing substantial change where regionally isolated markets are becoming more integrated. Under such circumstances, economic theory predicts that prices in two regions will converge towards the law of one price until the difference represents transportation or transaction costs only. Using daily data for the Henry Hub in the U.S., NBP in the UK, and Zeebrugge in Continental Europe, we apply a time-variant coefficient estimation methodology to test the hypothesis of price convergence covering the period from January 1999 until May 2008.

7. Nigeria signed a deal with GdF and Enel in November 2005, GdF and Gazprom signed an arrangement allowing Gazprom to deliver a LNG cargo to Cove Point in the US.

8. The Kalman filter has been applied to the two subsamples as described before with results almost identical to the one presented in Figure 3.

Figure 4. Beta Coefficients for NBP - Henry Hub (decorrelated series)



In a first step we apply the Kalman filter technique to the logged values of spot prices for Henry Hub and NBP. The results show evidence of prices converging towards the law of one price. Following, we adjust the original price series for the influence of residual fuel oil prices and natural gas generating two time series which are highly correlated to the price of natural gas but independent of oil. Results obtained from the Kalman filter methodology for the generated series are less evident of a convergence process, but provide some support for recent trends in transatlantic LNG trade. In general, we observe closer linkage between prices in the winter months, which seems a reasonable result. At present, only importing facilities are located in the US and Europe. Therefore, arbitrage is essentially limited to the diversion of cargoes from their original destination to either side of the Atlantic wherever prices are higher. The construction of a liquefaction plant in either Europe or the US has the potential to enhance further arbitraging opportunities in the Atlantic basin.

Further research might extend this analysis to Asian markets. Another open question is what effect the recent price increase in oil and natural gas prices has on the market, and how LNG trading will develop under these circumstances. Last but not least, further restructuring of the natural gas sector in Europe and Asia should tend towards more liquid natural gas markets in these regions and, thus, favor the convergence of prices over time.

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Modeling the Growth in Gas Reserves From Known Fields

Kevin F. Forbes and Ernest M. Zampelli***

The extent to which future United States demand for natural gas is satisfied by imports of LNG is contingent on the adequacy and cost competitiveness of North American supplies. One of the cheaper and more important sources of natural gas supply is accounted for by reserve appreciation, i.e., reserve growth, in known fields. Based on an extensively applied methodology developed by Arrington (1960), the increase in proved ultimate recovery is presumed to increase at a diminishing rate with the age of the field. In this paper, a single equation model of natural gas reserve growth in the Gulf of Mexico is developed and estimated. The results strongly suggest that the annual growth rate in the reserves of a field is significantly affected by initial discovery size, price, water depth, and unobserved field-specific effects. Hence, estimating oil and gas reserve growth using an Arrington based approach may underestimate the response of reserve growth to changes in economic fundamentals.

1. INTRODUCTION

The extent to which future domestic demand for natural gas is satisfied by imports of LNG is contingent on the adequacy and cost competitiveness of North American supplies. One of the most important sources of supply is accounted for by reserve appreciation, i.e., reserve growth, in known fields. Indicative of the importance this supply source, in 2006, the latest year for which published reserve data are available, approximately 98 percent of the dry natural gas reserve additions in the United States were accounted for by reserve changes in known fields.[1]

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* Center for the Study of Energy and Environmental Stewardship, Department of Business and Economics, The Catholic University of America, Washington, DC 20064. Email: Forbes@CUA.edu.

** Department of Business and Economics, The Catholic University of America, Washington, D.C.

1. In 2006, net reserve changes in known fields equaled 24,836 Bcf. while new field discoveries were 409 Bcf (EIA, 2007, Table 8)

Based on an extensively applied methodology developed by Arrington (1960), the increase in proved ultimate recovery is presumed to increase at a diminishing rate with the age of the field. An excellent overview of the methodology is presented in Morehouse (1997). While the contribution of the economic environment to the growth process has been acknowledged by geologists, the application of the Arrington method presumes that growth is independent of the economic environment. Given the implicit assumption that growth is systematically affected only by age, the contribution of reserve growth to supply will invariably diminish as fields become more mature.

This paper challenges this view. Specifically, we estimate the growth in reserves from over 500 known gas fields in the federal offshore waters of the U.S. Gulf of Mexico (GOM). A single equation model of natural gas reserve growth in the Gulf of Mexico is developed and estimated. Specifically, the annual growth rate in a gas field's reserves is hypothesized to be a function of the age of the field as measured by the number of years since first production, the field's reserve size in the year of first production, the real price of natural gas, water depth, and a set of unobserved field-specific factors. Unlike a traditional fixed effects model that cannot account for time-invariant variables, the empirical analysis makes use of a three-stage estimation process that estimates fixed effects in the presence of time-invariant variables. The results strongly suggest that age is not the sole factor in explaining a field's annual reserve growth. In particular, we find that the annual growth rate in the reserves of a field is significantly affected by initial discovery size, prices, water depth, and unobserved field-specific effects. Hence, estimating oil and gas reserve growth using an Arrington based approach may yield a distorted assessment of future energy supplies.

2. MEASURING RESERVES GROWTH: THE CURRENT STATE OF THE LITERATURE

Ideally, one would measure reserve growth by comparing the current known oil and/or gas volumes (equal to cumulative production plus remaining reserves) of fields discovered in say, 1950, with their initial discovery sizes. Unfortunately, this is often not possible because the initial discovery sizes of fields discovered before 1975 or so are many times unknown. The standard solution to this problem is based on the work of Arrington (1960). With his method one can estimate reserve growth even when the initial discovery sizes are unknown and the number of time series observations is small. The Arrington method makes use of a ratio which has come to be known as an annual growth factor. This factor is the ratio of known oil and/or gas volumes from fields of a given age relative to the known volumes of fields in the previous age category. Mathematically, under the Arrington method one computes annual growth factors (AGF) as follows:

$$AGF_k = \frac{\sum_{t=t_0}^{T-k} KPV_{t_0,t_0+k}}{\sum_{t=t_0}^{T-k} KPV_{t_0,t_0+k-1}} \tag{1}$$

where:

AGF_k is the annual growth factor for k years after discovery
KPV_{t_0,t_0+k} is Known Petroleum (and/or natural gas) Volumes k years after discovery for fields discovered in year t_0
T is the last year for which data are available

In equation (1), the numerator is summed over all discovery years for fields that are k years old; the denominator is the corresponding sum for fields that are k-1 years old. For example, when k = 5, the numerator would equal the sum over all discovery years of the known petroleum values for fields that are five years old; the denominator would equal the corresponding sum for fields that are four years old. Accordingly, the equation in this case would yield a weighted average of the AGF for five year old fields. In the absence of growth, the AGF would equal unity. Values of the AGF less than unity imply negative reserve revisions.

In his original paper, Arrington fitted a smooth curve between the three year weighted averages of the AGFs for a sample of reservoirs and the number of years since discovery. This curve was used to arrive at a predicted AGF for each year following discovery, $PAGF_k$. The predicted cumulative growth factor for k years after discovery ($PCGF_k$) is the product of the predicted annual growth factors, i.e.

$$PCGF_k = PAGF_1 \times PAGF_2 \times PAGF_3 ..... \times PAGF_k . \tag{2}$$

Note that this methodology implicitly assumes that the age of the field or reservoir is the only systematic determinant of reserve growth. If this is not the case, then the method will likely yield a biased measure of growth. For example, if, as we suspect, the economic environment affects reserve growth, then an Arrington-based supply analysis will underestimate the response of supplies to higher prices.

Numerous studies including Marsh (1971), Dolton *et. al*. (1981), Root (1981), Megill (1989a, 1989b, 1989c, 1989d), Attanasi and Root (1994), Attanasi, Mast, and Root (1999) and Root et, al. (1995) have applied variations of the basic Arrington method to project growth for fields in the U.S. onshore. Application of the method by Klett (2004) to Energy Information Administration oil and gas reserves data over the period 1977-1996 yielded AGFs that declined rapidly over the first three years following discovery and then stabilized at a value slightly more

than unity until about 90 years following discovery.

Several studies have applied Arrington's methodology in examining reserves appreciation in the GOM Outer Continental Shelf (OCS). These studies make use of annual field level data from either the Energy Information Administration (EIA) Oil and Gas Integrated Field File (OGIFF) or the Field Reserve History file from the United States Minerals Management Service (MMS). These data are available from 1977 and 1975 onwards, respectively.

Using the MMS GOM OCS data, Drew and Lore (1992) find that the annual growth rate for all oil and gas fields ranges from 10% per year in their first decade of productive life to 5% per year in the second decade, and to 3% in the third decade. Lore, *et.al*. (1996, 1999) calculate AGF's and PCGFs using (1) and (2) respectively for 876 fields from the MMS database. Their results indicate that fields on average more than double in size within 6 years of discovery and triple within 16 years. They calculate that fields quadruple in size in about 40 years.

Attanasi (2000) examines reserve appreciation in the GOM OCS using the EIA OGIFF data. Based on the restricted least squares estimate in which AGFs are assumed to decline monotonically with the age of the field, Attanasi concludes that reserve appreciation in the GOM OCS is more robust than that reported by Lore *et al*. (1996, 1999). Specifically, he concludes that oil fields grow by a factor of eight within 50 years while gas fields grow by a factor of almost six.

There are two notable studies of reserve growth in the North Sea which do not rely on the Arrington method. Watkins (2002) examined reserve appreciation for 126 oil fields in the North Sea. In contrast to the GOM research noted above, Watkins analyzes reserve appreciation from the year of first production instead of the year of discovery. This is justified by noting that the time interval between discovery and first production in the offshore can be long and that the number of years since the year of first production is a better measure of field maturity than the number of years since discovery. In contrast to the Arrington based findings for the GOM, he reports substantially lower reserve appreciation factors. In an earlier working paper, Sem and Ellerman (1999) also examined oil field reserve appreciation in the North Sea. Like Watkins, appreciation is measured as of the year of first production. Using both random and fixed effects specifications, the CGFs are regressed on the age of the field, age interacted with binary variables representing field size, a binary variable representing the sector in which the field is located, and a binary variable representing the post-1985 time period. Their results indicate that with the exception of medium sized fields, oil reserves appreciate 2-3% per year regardless of sector, year, or age. For the medium sized fields, i.e. those fields with reserves between 100 and 400 million barrels in the first year of production, no significant reserve appreciation could be statistically discerned. The authors regard this outcome as a puzzle and conclude the paper by suggesting that the inclusion of "time varying factors such as the amount of development drilling, injection, **prices** (emphasis added) or perhaps changing tax treatment may contribute to a greater understanding of reserve appreciation in the North Sea." (Sem and Ellerman, 1999, p. 35)

3. DATA AND MEASUREMENT ISSUES

In this paper, we employ a database from the United States Minerals Management Service (MMS) to evaluate the reasonableness of the Arrington method in estimating the reserve growth of known gas fields in the federal offshore waters of the U.S. Gulf of Mexico (GOM). We focus on natural gas because of the gas prone nature of the Gulf. The database was downloaded from the MMS website (http://www.gomr.mms.gov/homepg/offshore/fldresv/resvmenu.html). This database provides a year by year reserve history for every oil and gas field in the federal offshore waters of the Gulf of Mexico over the period 1975 through 2003. In contrast to the United States Energy Information Administration's reserve estimates, this database is not based on a survey of the operators. Instead, the estimates are produced by MMS, who as leaseholder, has access to the proprietary data that are needed to estimate reserves. In theory, this provides the data series with a consistency that a survey based database cannot hope to match. This may not be a trivial consideration given that the reserve estimates can change with changes in reserve ownership when the database is based on survey. For example, the 2000 EIA survey of domestic oil and gas reserves deducted 533 Bcf. of natural gas reserves from the reserves of operators in the Texas portion of the Federal offshore Gulf of Mexico who transferred the operations of existing fields to another operator; the acquiring operators reported that the transfer increased their reserves by 767 Bcf (EIA, 2001, Table 8). Finally, given the intense interest of the investment community in the reserve replacement ratio, firms have a financial interest in the estimates that they report. One example of where financial incentives are believed to have contributed to a reserve overstatement is Royal Dutch/Shell Group's admission in 2005 that its oil and gas reserves as of 2002 had been overstated by 41 percent (New York Times, 2005).

Proved reserves are defined by the MMS as the "quantities of hydrocarbons which can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under current economic conditions, operating methods, and government regulations" (MMS, 2005, p 2). This definition of reserves is essentially equivalent to EIA's definition of proved reserves as " volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions." (EIA, 2007, p. 1). Consistent with these nearly identical definitions, the correlation between the EIA and MMS measures of aggregate remaining proved gas reserves in the Gulf of Mexico OCS over the period 1990 through 2003 equals 0.86.[2]

The MMS has been estimating proved reserves for the Gulf of Mexico since its inception in 1982. Prior to 1982, reserves were published by the United States Geological Survey.

2. EIA does not report Gulf of Mexico OCS proved reserves prior to 1990.

One key issue in the literature is how best to measure the age of the fields. Drew and Lore (1992), Lore, *et.al*. (1996, 1999), and Attanasi (2000) base the age of the fields on the year of discovery. Klett (2004), Sem and Ellerman (1999), and Watkins (2002) have pointed out, using the discovery year as the starting point for reserve growth ignores the impact of delayed field development. Our view is that calculating age based on the year of discovery can result in severe biases when "old" but undeveloped fields are brought on stream. One dramatic example of this is a field that was discovered in 1955 that did not commence production until 1977. To assess the magnitude of this possible bias, CGFs were calculated through 2000 for all oil and gas fields discovered between 1975 and 1998. For these same fields, the AGF's and associated CGF's were also calculated using the Arrington method with age being calculated based on the number of years since discovery. Fields that were discovered in 1975 were 25 years old in the year 2000. Using the Arrington method, one would expect 25-year-old fields to have a CGF of 3.62. The actual CGF for fields discovered in 1975 is a modest 2.01. This does not appear to be an outlier. Except for three years (1980, 1981, and 1985) the actual CGF's calculated by discovery year are substantially lower than the CGF's calculated using the Arrington method with age being calculated based on the number of years since discovery. Clearly, based on these data the Arrington method with age based on the number of years since discovery produces a misleading estimate of cumulative reserve growth. For this reason, we will measure age based on the year of first production.

Consistent with our expectations, a preliminary analysis of the data indicated that the vast proportion of the gas fields in the GOM have a water depth less than 200 meters. In keeping with the exploratory nature of this research, we will therefore restrict the analysis to natural gas fields with a water depth less than 200 meters.

4. AN ECONOMETRIC MODEL OF RESERVE GROWTH

A model of reserve growth was estimated using field specific panel data for 526 gas fields. Because of our interest in the relationship between the economic environment and reserve growth, our analysis focuses on the determinants of the AGF. In our opinion, specifying the model in terms of the CGF would require the inclusion of variables that reflect the economic environment in each year of field operation. This would present a nontrivial estimation problem given the unbalanced nature of our data set.

The model hypothesizes that the AGF for a given field in year t is a function of the year of first production, the age of the field in year t, the water depth of the field, the initial discovery size, and the price of natural gas in year t. The model also includes unobserved field specific factors as an explanatory variable. Algebraically, the model is:

$$ln(AGF_{k,t}) = \alpha_0 + \sum \alpha_k ProdYearDum_k + \beta_1 / AGE_{k,t} + \beta_2 LnPGAS_t + \beta_3 WaterDepth_k + \beta_4 InitialSize_k + \beta_5 OtherFactors + \varepsilon_{k,t} \quad (3)$$

where:

$ln(AGF_{k,t})$ is the natural logarithm of the annual growth factor for field k in year t.

$ProdYearDum_{k,}$ is a binary variable representing the year of first production

$AGE_{k,t}$ is the age of field k in year t based on the year in which field k was brought onstream.

$LnPGAS_t$ is the natural log of the natural gas price in constant 2000 dollars in year t. The prices are based on MMS reported natural gas sales and production volumes for the Gulf of Mexico.

$WaterDepth_k$ is the average water depth of field k in feet.

$IntialSize_k$ is the known natural gas volume (Bcf) for field k in the year of first production.

OtherFactors is a variable that measures unobserved time invariant field specific characteristics. This variable was estimated using a three stage procedure that is described below.

Equation (3) was estimated over the period 1976 through 2003 for fields that commenced production over the period 1976 through 2001. The fields were discovered over the period 1955 through 2001.

Standard panel estimation does not allow for the estimation of both the effects of time invariant variables (e.g. *WaterDepth*) and unobserved field specific effects. Very simply, perfect collinearity between the fixed effects and the time invariant variables precludes the implementation of the standard procedure. In an innovative paper, Plümper and Troeger (2007) develop a three-stage estimation method, the fixed effects vector decomposition, to circumvent this problem. Its logic is rather straightforward. Since the fixed effects measure the influence of all time-invariant variables, they first run a standard fixed effects model with all time-varying variables but *excluding all the observed time-invariant variables* (in our case, the time invariant variables are $IntialSize_k$ $WaterDepth_k$ and $ProdYearDum_k$). The resulting estimated fixed effects, therefore, measure the influence of both the observed and the unobserved time-invariant unit-specific factors. In the second stage, the estimated fixed effects from the first stage are regressed on all the observed time-invariant variables only. This effectively decomposes the fixed effects into two parts: that which can be explained by the observed time-invariant variables and that which can be explained by other unobserved time-invariant factors. The latter, of course, is represented by the estimated second-stage residuals. The third and final stage consists of a pooled estimation of the dependent variable on the time-varying variables, on all the observed time-invariant variables, and on the second stage residuals (which in this paper are referred to as *OtherFac-*

tors). Because of the orthogonality between the observed time-invariant variables and the *OtherFactors*, the perfect collinearity problem is avoided. The interested reader should consult the appendix for a more technical outline of the procedure.

Preliminary estimation of equation (3) indicated the possible presence of AR(1) disturbances at the third stage. The equation was subsequently re-estimated using the Prais-Winston transformation to correct for the first order autocorrelation. The stage three estimates of equation (3) are presented in Table 1. The reported standard errors are robust to heteroscedastic disturbances.[3] Consistent with the literature, the coefficient on 1/*AGE* is positive and statistically significant indicating that reserve growth diminishes with the age of a field, *ceteris paribus*. While the literature has focused almost exclusively on this variable, the results reported in Table 1 also indicate that the economic environment can affect the level of growth. Specifically, the coefficient on *LnPGAS* is positive and highly statistically significant. The coefficient on *WaterDepth* is negative and statistically significant. Since operating costs are a function of water depth, this finding is consistent with the view that reserve growth and operating costs are inversely related. The coefficient on *IntialSize* is negative and is also highly statistically significant. One possible explanation for this finding is that reserve appraisals of new fields are costly and that the benefits from a more complete appraisal vary directly with the size of the discovery. This of course leaves the larger fields less potential for growth, on a percentage basis, relative to their smaller cousins. Finally, the low R^2 and adjusted R^2 values are typical of many panel models where there exists much diversity across cross sectional units. The high F-statistic, despite the low R^2 and adjusted R^2 values, testifies to the overall significance of the model while the small p-values associated with the estimated coefficients attest to the significance of the explanatory variables at well below standard levels.

The estimated *ceteris paribus* effect of the start-up of production in 1976 is reflected in the constant term. The differential impacts for other years are reflected in the production year binary variables (*ProdYearDumxx).* The coefficients on these variables appear to suggest two reserve growth regimes. Prior to 1987, the majority of the coefficients are positive and statistically significant implying that the reserve growth process for fields that commenced production in the years 1977-1986 was at least as long as for those fields that went on stream in 1976, the year corresponding to the overall constant. After 1986, the majority of the coefficients are negative and statistically significant implying that the reserve growth process for these fields was shorter than in 1976. One possible reason for this is the diffusion of 3-D seismic technology over the latter time period that yielded more accurate and comprehensive initial reserves assessments.

3. The null hypothesis of normality of the third stage errors was rejected by a Jacque-Bera test. This is not a major concern since the estimation procedure adopts the robustness of the fixed effects estimator which is fully robust to a non-normal error structure. The authors thank Jeffrey Wooldridge for pointing this out.

Table 1. Panel Fixed Effects Vector Decomposition Estimates

Variable	Coef.	Std. Err.	t	P-Value
1/AGE	0.042	0.005	8.88	0.000
LnPGAS	0.056	0.002	28.01	0.000
WaterDepth	-1.44E-04	3.59E-06	-40.13	0.000
InitialSize	-6.26E-11	1.77E-12	-35.32	0.000
ProdYear_dum2	0.020	0.001	16.90	0.000
ProdYear_dum3	0.003	0.001	3.07	0.002
ProdYear_dum4	0.003	0.001	3.61	0.000
ProdYear_dum5	0.007	0.001	7.02	0.000
ProdYear_dum6	0.014	0.001	14.63	0.000
ProdYear_dum7	-0.006	0.001	-6.56	0.000
ProdYear_dum8	-0.013	0.001	-12.31	0.000
ProdYear_dum9	-3.71E-04	0.001	-0.35	0.724
ProdYear_dum10	0.007	0.001	5.52	0.000
ProdYear_dum11	-3.90E-04	0.001	-0.31	0.760
ProdYear_dum12	-0.020	0.001	-16.14	0.000
ProdYear_dum13	-0.017	0.001	-16.37	0.000
ProdYear_dum14	-0.028	0.001	-28.43	0.000
ProdYear_dum15	0.001	0.001	1.23	0.219
ProdYear_dum16	-0.023	0.001	-21.58	0.000
ProdYear_dum17	-0.002	0.001	-1.46	0.143
ProdYear_dum18	-0.027	0.002	-12.76	0.000
ProdYear_dum19	-0.107	0.002	-57.08	0.000
ProdYear_dum20	-0.066	0.002	-27.80	0.000
ProdYear_dum21	-0.066	0.003	-23.98	0.000
ProdYear_dum22	-0.124	0.002	-70.38	0.000
ProdYear_dum23	0.024	0.002	11.93	0.000
ProdYear_dum24	-0.139	0.002	-66.36	0.000
ProdYear_dum25	-0.116	0.002	-68.49	0.000
ProdYear_dum26	0.024	0.001	23.69	0.000
OtherFactors	0.959	0.005	195.48	0.000
constant	-0.028	0.001	-29.94	0.000
Number of obs.	6300			
F(31, 6271)	21451.89			
P-Value	0.000			
R^2	0.081			
adjusted R^2	0.077			

Standard errors are robust to heteroscedasticity and autocorrelation.

5. CONCLUSION

The traditional approach to measuring reserve growth relies on the method first proposed by Arrington (1960). Under its basic form, a weighted average annual growth factor is calculated for all fields of a given age. The product of the annual growth factors over all ages represents the cumulative growth factor. While the Arrington method is currently viewed as one of the more useful approaches to measuring reserve growth, it ignores the effect that the economic environment as well as other factors such as the initial discovery size have on reserve growth. This paper has provided evidence that these factors do indeed play a critical role in the reserve growth process.

The importance of these findings should not be underestimated. The increases in U.S. natural gas prices since 2000 have convinced many analysts and observers that LNG imports will very soon be required if future U.S. natural gas demand is to be satisfied. Otherwise, the increase in natural gas prices is expected to continue virtually unabated due to the perceived inadequacies of U.S. natural gas supplies. Interestingly, however, a recent analysis of global LNG by Paul Sankey and Ryan Todd of Deutsche Bank, Sankey and Todd (2008), presents a somewhat different scenario. In their words, "…US gas supply growth is strong enough that we see the US market remaining relatively insular for the next 4-5 years, with price set by domestic F&D costs." (p. 1). The authors further contend that "If the USA can sustain the kind of gas supply growth seen recently, then more natgas exports are a real economically reasonable response." (p. 27). And finally, they observe that "Expectations for 2008 US natural gas production have been revised upwards to 6% YOY, with 2% expectations for 2009 likely under upwards pressure given current gas price and drilling activity." (p. 27). The findings of this paper are entirely consistent with Sankey and Todd. Higher prices suggest greater reserve appreciation which in turn suggests greater supplies. The U.S. need for LNG is dampened with the possibility, in fact, that U.S. natural gas exports actually increase. This is not a scenario that is likely under an Arrington-based view of reserve growth.

APPENDIX

Fixed Effects Vector Decomposition

This appendix provides a more technical description of the three-stage fixed effects estimation procedure, formally known as fixed effects vector decomposition, developed by Plümper and Troeger (2007) and is drawn largely from their paper. Consider the model:

$$y_{it} = \alpha + X_{it}\beta + Z_i\gamma + u_i + \varepsilon_{it} \tag{A-1}$$

where X_{it} represents a vector of time-variant variables, Z_i represents a vector of time-invariant variables, u_i is the unit-specific fixed effect, and ε_{it} is the normally

distributed random error component. The unit-specific effect u_i is assumed to be correlated with at least one of the time-variant variables and with at least one of the time-invariant variables. The fundamental problem with using the standard fixed effects procedure to estimate (A-1) is the perfect collinearity that would exist between the unit-specific dummy variables and the time-invariant variables. Recalling, however, that unit fixed effects, in general, represent the mean impact of all omitted unit-specific time-invariant variables provides the basis for an alternative procedure. First, estimate (A-1) *without* the time-invariant variables using the standard fixed effects method. This effectively demeans the data and removes the individual effects u_i giving:

$$y_{it} - \bar{y}_i = (X_{it} - \bar{X}_i)\beta + \varepsilon_{it} - \bar{\varepsilon}_i \equiv \ddot{y}_{it} = \ddot{X}_{it}\beta_{FE} + \ddot{\varepsilon}_{it} \qquad \text{(A-2)}$$

where $\ddot{y}_{it}$, $\ddot{X}_{it}$, and $\ddot{\varepsilon}_{it}$ are the time-demeaned data on y, X, and ε, respectively, and where equation (A-2) is known as the within or fixed effects transformation. Estimating (A-2) yields the fixed effects estimator $\hat{\beta}_{FE}$ and estimates of the u_i given by:

$$\hat{u}_i = \bar{y}_i - \bar{X}_i\hat{\beta}_{FE}$$

In the second stage, the $\hat{u}_i$ are regressed on a constant and the vector of observed time-invariant variables Z_i. Specifically, we estimate the equation:

$$\hat{u}_i = \varpi + Z_i\gamma + \eta_i \qquad \text{(A-3)}$$

where ω is the constant term and η_i is the error. Note that η_i is the part u_i that is *not* explained by the time-invariant Z variables. The residuals from the second stage estimation, $\hat{\eta}_i$, are estimates of this portion of u_i. In the third stage, the complete model is re-run without the unit effects but with their decomposed fixed effects vectors using pooled OLS:[4]

$$y_{it} = \alpha + X_{it}\beta + Z_i\gamma + \ddot{\eta}_i + \varepsilon_{it} \qquad \text{(A-4)}$$

Since $\hat{\eta}_i$ is no longer correlated with the Z_i one can account for the impacts of the unit-specific fixed effects that are unobserved. Note that the coefficient on $\hat{\eta}_i$ should be equal to or very close to one in the stage 3 estimation.

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4. If heteroscedasticity and/or serial correlation are present, appropriate alternatives to pooled OLS should be employed.

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