IA INTERNATIONAL ASSOCIATION FOR ENERGY ECONOMICS
EE

Newsletter

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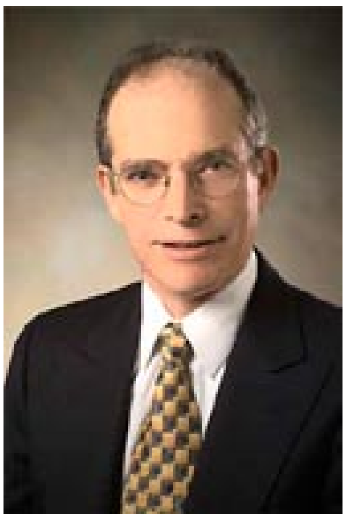
Second Quarter 2005

President's Message



I was in Vienna a couple of weeks ago participating in an International Atomic Energy Agency workshop on peaceful uses of nuclear technologies. We discussed things like the high concentrations of proven conventional oil and natural gas reserves in the Persian Gulf and Russia, the huge magnitude of annual carbon emissions reductions required to stabilize human influence on climate, and the potential role nuclear power could play in easing both burdens (though with its own political, economic and technological complexities). These discussions eventually turned to how important it is to educate folks inside and outside our respective policy-making communities about our energy, economic, environmental and technology options and trade-offs.

Such "education" is non-trivial. Our countries have different needs, different priorities and different energy supply options, and thus are likely to be affected differently by energy supply interruptions. We also have somewhat different value sets and approaches to problem solving. And in each country, there are many vested interests, with advocates and detractors for each energy technology and policy option.

Perhaps some of this mattered less when our economies and markets were less interconnected. But today, when Russia sneezes, the US and EU catch cold. When China grows hungry for oil or steel or cement, the rest of the world pays higher prices to help feed it. And at least for the foreseeable future, the role of China, India and other developing countries in economic and energy markets is expected to grow substantially, so this global influence seems unlikely to wane, and global oil and natural gas dependence on key Persian Gulf countries and Russia is expected to grow.

I'm not sure what this means, but it does suggest that while each of our countries is free to develop and implement its own internal energy policies, the rest of the world, through global energy markets, may be affected by those policies, further suggesting that we may not be as free in developing and implementing our own energy policies as we think.

At the same time, any country that has energy as a major economic component and a major component of its exports cannot afford to let its domestic energy prices get too far out of line with those of its international competitors.

Climate change policy discussions have long recognized there is "one world" for carbon emissions. So policies like emissions trading, the Clean Development Mechanism, etc. have been developed to help encourage the least cost carbon emissions reductions first. How well such policies will work out if/when carbon emission reduction requirements really begin to bite, how this will affect less carbon intensive oil and natural gas relative to coal, and how this might or might not affect international economic competitiveness are important questions.

In global oil and in increasingly global natural gas markets, I don't know whether similar "one world" policy discussions have occurred recently. There many of these discussions in the 1970s, including a consumer-producer dialogue. Here the thought simply is that a barrel of oil or

(continued on page 2)

Editor's Notes

Maureen Crandall focusses on the Caspian energy situation and concludes that its energy promise has been overstated and that production from the area will not make a major or lasting contribution to the world's energy supplies and its energy security. To say that these states are strategic is to acknowledge post 9-11 foreign policy concerns, largely

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President's Message *(continued from page 1)*

MCF of natural gas saved in China, India, Germany, the US, etc., is a barrel of oil saved in the rest of the world. As with carbon, if such saving is lower cost in some countries than others, wouldn't harvesting this low hanging fruit provide a global benefit?

The same thought might apply to the supply side, though it is a bit more complicated because some OPEC member countries admittedly artificially restrict the supply of their low cost crude oil.

"One-world" approaches might take the form of seeking renewed consistency and economic rationality in public policies and implementing supporting agreements to foster desired behavior. Given the differences and needs among individual countries, these efforts might require more focused development and implementation of clean energy supply enhancing and demand reducing technologies that would be cost-competitive and the marketplace would want to adopt. Such technologies need not be gold plated to make a difference. Simple situational technologies and/or simple emergent "disruptive" technologies, ala Clayton Christensen, could make a huge difference. Perhaps even some significant bilateral/multilateral public private technology partnerships might emerge.

Most folks want cheap supplies of energy at relatively stable prices to support their economic well being. They get upset and "engaged" when prices rise sharply and/or supplies are not regularly available. This is an even more serious problem for much of the developing world where billions of people routinely go without. According to the IEA, some 1.6 billion people currently do not have access to electricity, and unless something drastically changes, by 2030, 1.4 billion people still won't have access.

This brings me back to education and our Association. We have a vital role to play in helping to provide good theory and analysis that can help improve communication and break down the barriers of understanding across universities, the private sector and the public sector, and across our developed and developing countries. We also can help educate the general public in each of our countries, and help support both policy makers and investors in making better informed decisions.

Saying this, of course, is much easier than making it happen, and I'd like to see IAEE Headquarters, National Affiliates and/or local Chapters help accomplish this better. Sometimes one idea can make all the difference. So please send me your suggestions on this and/or other IAEE issues of concern electronically in care of Dave Williams (iaee@iaee.org). I look forward to hearing from you.

I also hope to see you at our IAEE International Conference in Taipei, Taiwan (June 3-6), our IAEE European Affiliate Conference in Bergen, Norway (August 28-30), and/or our Annual USAEE/IAEE North American Conference in Denver, Colorado (September 18-20).

Very best wishes,

Arnie Baker

CALL FOR PAPERS

8th USAEE/IAEE/Allied Social Science Associations Meeting
Boston, MA – January 6 - 8, 2006

The IAEE annually puts together an academic session at the ASSA meetings in early January. This year's program chair will be Carol Dahl of the Colorado School of Mines and the session chair will be Fred Joutz of George Washington University.

The theme for the session will be *Current Issues in Energy Economics and Modeling.*

If you are interested in presenting please send an abstract of 200-400 words to Carol Dahl at (cdahl@mines.edu) by May 15, 2005. At least one member of each paper must be a member of the IAEE for the paper to be included in our session. The session along with discussion remarks will be published in the Papers and Proceedings of the next North American Meeting of the USAEE/IAEE. Preliminary decisions on papers presented and discussants will be made by July 1. The program including abstracts will be posted at iaee@iaee.org by September 1, 2005. Please send abstracts in electronic format that is easily converted into program information. (e.g. word, wp, text). Suggestions or volunteers for paper discussants are most welcome.

For complete ASSA meeting highlights and pre-registration information please visit:

http://www.vanderbilt.edu/AEA/index.htm

Editor's Notes *(continued from page 1)*

defined by terrorist events, that the area could be a staging area for repeat terrorist attacks.

Seth Blumsack and Lester Lave posit that conventional measures of market structure give a misleading picture of the competitiveness of electric power markets. They advance the notion of the "pivotal supplier" as better suited to the electric power industry. Using this they find that the Californian, PJM and New York markets are far less competitive than thought. They further examine five market-power mitigation systems and the cost and effectiveness of them.

William Edwards discusses the impact of OPEC's recently stated intention to use U.S. inventory levels as a guide in making its production/price decisions; the idea being that the way to keep prices high is to restrain production so that inventories never rise to comfortable levels. This method of price control is unsound, he argues, because it can only lead to price uncertainty and volatility.

Gbadebo Oladosu and Adam Rose analyze the cost-side income distribution impacts of a carbon tax in the Susquehanna River Basin Region of the U.S. They conclude that the impacts are modestly negative, resulting in about a one-third of one percent reduction in the region's gross product in the short run and approximately double that in the long run.

Frits van Oostvoorn examines European gas supply security over the medium and longer term. He looks out to 2030 and notes that the EU consumer will be increasingly depending on natural gas imported from a relative small number of remote exporters. The parts Russia and Ukraine will play is particularly noted.

DLW

28TH ANNUAL IAEE INTERNATIONAL CONFERENCE

Hosted by: International Association for Energy Economics (IAEE) & Chinese Association for Energy Economics (CAEE)

Globalization of Energy: Markets, Technology, and Sustainability

3-6 June 2005

The Grand Hotel, 1 Chung-Shan N. Road, Section 4, Taipei, Taiwan 104, ROC

Conference Themes & Topics

Keynote Plenary Session Themes: ***The Future of Energy: Solar Energy and Photovoltaics***

Plenary Session Themes: ***Energy Security, Cooperation, and Policy in the Pan-Pacific Rim***
Energy Business
Energy and Poverty in Asian Countries

Dual Plenary Session Themes:
- The Middle East Situation and Energy Security
- Regulation and Deregulation of the Energy Market
- Global Policy Options Dealing with GHGs Emission Control
- Rethinking of the Nuclear Energy
- Prospect for New Energy Technology
- Emerging Issues

Other Session Themes & Topics:

Prospects for Global Energy Development
- Global and Regional Energy Demand and Supply
- New Paradigm under the World Trade Organization
- Restructuring and Deregulation
- Inter-Regional Energy Security and Reliability
- Liberalization and Market Power
- Role of International Energy Suppliers

Prospects for Energy Technology Development
- Green and Renewable Energy Technology
- Conservation Know-how and R&D
- Fuel Cell and Hydrogen Technology
- Distributive Energy Systems
- Diffusion and Collaboration in Energy Technology

Sustainability
- Sustainable Energy Development
- Global Warming and Energy
- Energy and Pollution Control
- Nuclear Safety and Waste Disposal
- Rationality and Energy Selections
- Policy Options and Strategies

Individual Energy Sectors
- Coal
- Oil
- Natural Gas (including LNG)
- Electricity
- Renewable Energy and New Energy

Energy Efficiency and Energy Modeling
- Energy Statistics and Energy Efficiency Indicators
- Energy Modeling, Simulation, and Forecasting
- Energy Conservation Program and Demand-Side Management
- Integrated Resource Planning and Demand Response
- ESCO and New Business Model

***** REGISTER NOW *****

Early Registration in Special Rates Deadline: 30 April 2005

The Grand Hotel Reservation in Special Rates Deadline: 6 May 2005

We are pleased to invite all of you to join the 28th Annual IAEE International Conference. There will be 10 plenary sessions and 42 concurrent sessions. For *online registration*, please visit the conference official website at: http://www.iaee2005.org.tw For *requesting registration form electronic file or paper copy*, please download from our website or email/write to the CAEE conference secretariat: **Yunchang Jeffrey Bor**, Ph.D., Conference Executive Director, Chung-Hua Institution for Economic Research (CIER), 75 Chang-Hsing Street, Taipei, Taiwan 106, ROC, Tel: 886-2-2735-6006 ext 631; 886-2-8176-8504, Fax: 886-2-2739-0615, E-mail: iaee2005@mail.cier.edu.tw

Please register early to grasp our special rates offering and mark your calendar for this important conference. You are kindly urged to register early, and book the airline flight and hotel as soon as possible because most of the hotels in Taipei will soon be fully booked due to the Dragon Boat Festival and the world's second largest Computex Exhibition held at the beginning of June 2005.

IAEE BEST STUDENT AWARD: US$1,000 cash prize plus waiver of conference registration fees. If interested, please contact IAEE headquarters for detailed applications/guidelines. **STUDENT PARTICIPANTS:** Please inquire about scholarships for conference attendance to iaee@iaee.org

TRAVEL DOCUMENTS: International delegates are urged to contact their consulate, embassy, or travel agent regarding the necessity of a obtaining a Taiwan Visa. Use CAEE contact information above to obtain a letter of invitation for the conference. We strongly suggest you allow plenty of time for document processing.

General Organizing Committee

Vincent C. Siew: General Conference Chairman; Chairman of the Board, Chung-Hua Institution for Economic Research (CIER), Taiwan, ROC. **Huey-Ching Yeh:** Program Committee Chairman; Director General, Bureau of Energy, Ministry of Economic Affairs, Taiwan, ROC. **Ching-Chi Lin:** Organizing Committee Chairman; Chairman of the Board, Taiwan Power Company; Taiwan, ROC. **Ching-Tsai Kuo:** Sponsorship Committee Chairman; Chairman of the Board, Chinese Petroleum Corporation, Taiwan, ROC.

BIEE Academic Conference in Association with UK Energy Research Centre
22-23 September 2005, St. John's College Oxford
Conference Programme

Thursday 22nd September

10.00 a.m. Accommodation Registration (Residential Main Porter's Lodge)

From 10.45 a.m. Conference Registration

11.30 a.m. Opening and First Plenary Session

Security of Supply and transition to a Low Carbon Economy, Sir Crispin Tickell, Green College Centre for Environmental Policy and Understanding, Oxford

Efficiency, Technology and Emissions Trading, Michael Grubb, Carbon Trust/Imperial College

13.00 p.m.Lunch

14.00 p.m. First Parallel Session

Topic 1: Demand Policies: *Session Leader, Brenda Boardman, Environmental Change Institute, University of Oxford*

Topic 2: Emissions Trading: *Session Leader, Steve Sorrell, SPRU - Science and Technology Policy Research, University of Sussex*

Topic 3: Technology and Innovation: *Session Leader, Chris Hendry, Cass Business School*

Topic 4: Security of Supply: *Session Leader, Goran Strbac, University of Manchester*

16.00 p.m.Tea

16.30 p.m. **Student Market Place**

A highly interactive event in which students will set-up shop around posters, presenting their academic work in a 5-7 minute presentation followed by discussions with their audience. Students should submit title and short (one para) abstract.

18.30 p.m. Drinks

19.00 p.m. Conference dinner

Friday 23rd September

9.00am. Second Plenary Session

Global Energy Scenarios, Wim Thomas, Shell

10.00 a.m. Coffee

10.30am Third Plenary Session

EU, EU Neighbours and US: energy and climate policies: Frank Umbach, German Council on Foreign Relations (DGAP) Shirley Neff, Americans for Solar Power/President-elect, USAEE

12.30 p.m.Lunch

13.30 p.m. Second Parallel Session

Topic 1: Energy and Environmental Regulation*, Peter Pearson, Imperial College, London*

Topic 2: Social Cohesion and Energy Interdependence*, Session Leader, Patrick Devine-Wright, De-Montfort University*

Topic 3: EU Enlargement and Neighbours*, Session Leader, Jonathan Stern, OIES Oxford Institute for Energy Studies/ University of Dundee*

Topic 4: Fossil Fuel Futures – the transition*, Session Leader, Jim Watson, SPRU – Science and Technology Policy Research, University of Sussex*

Topic 5: Nuclear and Renewable Energies*, Session Leader, Robin Wallace, Institute for Energy Systems, University of Edinburgh*

Topic 6: Energy Modelling*, Session Leader, Paul Ekins, Policy Studies Institute*

15.30 p.m. Conference closes

Conference fee (including accommodation/dinner/lunch): £250
BIEE members: £220
Students: £50

To register, please contact
Administration Office:
37 Woodville Gardens
W5 2LL London
Or vist our website

Tel: 020 8997 3707
Fax: 020 8566 7674
E-Mail: ADMIN@BIEE.ORG
Website: WWW.BIEE.ORG

British Institute of Energy Economics

Realism on Caspian Energy: Over-Hyped and Under-Risked

*By Maureen S. Crandall**

Introduction

The Caspian region's oil and gas potential has attracted a lot of interest since the breakup of the Soviet Union. The U.S. and other major oil consuming countries focused on the idea that the Caspian would become a major alternative to oil supplies from the volatile Middle East, postponing the days of higher prices or demand restraints. The region is often termed strategic, without specifying the strategic nature of the links to either U.S. foreign policy or to energy policy. The area was hailed as having as much as 200 billion barrels in oil reserves. Before these overstatements were challenged, the Caspian's oil potential was likened to a new Middle East. While the region is rich in gas, there are as yet only limited markets for natural gas.

The themes of this paper are two. The first is that the Caspian's energy promise has been overstated, and that production from the area will not make a major or lasting contribution to the world's energy supplies and its energy security. Moreover, development will proceed more slowly than anticipated. The second is that the political fragility and instability of this region are great. Poor governance and political risk are already diminishing foreign investor interest, and are ultimately likely to slow oil and gas development rather than advance either. In addition, production forecasts of both oil and gas are inseparably linked to and dependent upon transport options and challenges across these landlocked countries. Several states could implode into civil wars that spread across borders, increasing the risk foreign investors face. In these "one-bullet" regimes, one needs a large dose of caution in evaluating the Caspian's hydrocarbon potential.

We consider energy and related developments in Azerbaijan, Georgia, Kazakhstan, Turkmenistan, and Uzbekistan, with an eye also on the interests of China, Iran and Russia. After 13 years of independence, the Caspian states are for the most part highly authoritarian, poor, and thoroughly corrupt, still run by Soviet-era leaders, who pay little notice to democratic norms. Their goal is to preserve and consolidate their power. In our view, democracy and accountability are unlikely to take root. Azerbaijan has the Aliyev dynasty, with rising oil revenues providing the means to buy support. Georgia is important for oil and gas transport, but is nearly a failed state. Kazakhstan probably has the best energy prospects for improving its citizens' living , but it is hardly a model of participatory democracy, freedom of expression or responsible governance. Turkmenistan is a failed state. Uzbekistan is the linchpin of Central Asia, containing key pipelines and the largest population. It dreams of becoming the political and military power in Central Asia, and like the others has no qualms in suppressing internal opposition. China closely watches both political and energy developments, given its rapidly rising energy consumption. Iran and Russia see themselves as long-term players in the Caspian, and each wants a role in energy developments and/or transport flows.

The regional leadership has not successfully implemented rules of law or independent judiciaries, has not moved to defuse ethnic and regional tensions or conflicts, has become increasingly intolerant of dissent, and widely abuses human rights. The risks of dissidents' turning to extremism are high and can feed potential terrorism. Moreover, oil and gas monies rolling in to public purses now and in the future are at risk of being siphoned off or otherwise misused.

The Caspian in Context: Reserves and Production

Oil reserves estimates have varied from 25 billion barrels to nearly 10 times that much. Much of the range is due to equating estimates of oil in place with proved, probable, or possible reserves, with no regard to the degree of certainty or the impacts of oil prices. According to the Department of Energy's Energy Information Agency (EIA), proved oil reserves range from 17 to 33 billion barrels. Most of these are in two countries: Kazakhstan and Azerbaijan.[1] For natural gas, there is agreement that proved reserves are about 6.5 trillion cubic meters (tcm), with Turkmenistan holding the largest deposits (outside of Russia). Proved gas reserves in the near term are of lesser interest than oil, since they matter only if there are established markets and transport capacity, or are likely to be.

Table 1
Projections of Future Caspian Oil Production ('000 b/d)

	2010	2015	2020
Azerbaijan (AZ)			
Azeri-Chirag-Guneshli	1,000	700	380
Kazakhstan (KZ)			
Tengiz	700	750	750
Karachaganak	400	300	225
Kashagan	450	1,050	1,200
Other KZ*	300	400	400
Total KZ	1,850	2,500	2,575
Total KZ & AZ, - key fields	2,850	3,200	2,955
Uzbekistan (UZ)	200	200	200
Turkmenistan (TU)	200	200	200
Russia and Iran (Caspian area)	Negligible	Negligible	Negligible
Total	**3,250**	**3,600**	**3,355**

* Estimate includes other existing Kazakh fields/areas and possibly new offshore areas.

There are a variety of projections as to how much oil will be produced and when. By 2003, Kazakhstan alone accounted for just over 60 percent of the total of 1.8 million barrels per day (mmb/d) for the region as a whole. This level of production, however, accounted for only 2.3 percent of world oil production, based on BP figures. Five major projects cur-

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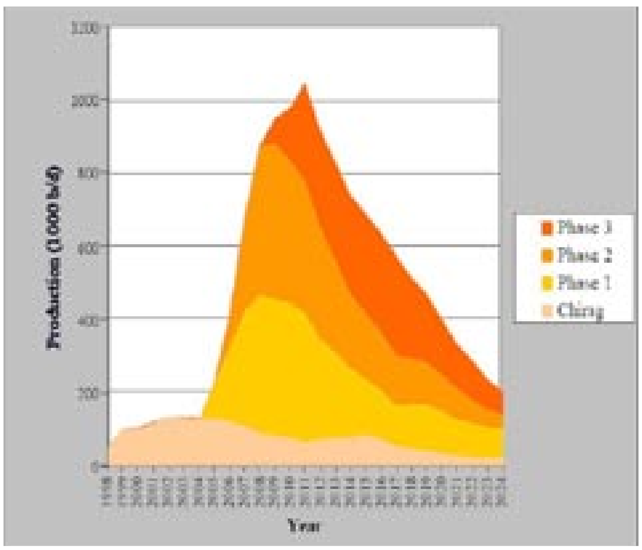
*Maureen Crandall is Professor of Economics at the National Defense University. She may be reached at crandallm@ndu.edu This is an edited version her paper presented at the 24th Annual North American Conference of the IAEE/USAEE in Washington, DC, July 8-10, 2004. The views expressed in this article are those of the author and do not reflect the official policy or position of the National Defense University, the Department of Defense, or the U.S. Government.

[1] See footnotes at end of text.

rently underway will drive future oil and gas output. These are the offshore Azeri-Chirag-Guneshli (ACG) oil fields and the Shah Deniz gas field in Azerbaijan, the Tengiz and Karachaganak onshore oil fields in Kazakhstan, and Kazakhstan's offshore Kashagan oil field. While other prospects exist they are not likely to make a major impact on regional production in the next 10 to 15 years. Moreover, old onshore production in Azerbaijan is declining, and no new large fields have been found there. Table 1 shows our best estimate of future Caspian oil output.

These estimates are lower than some provided by other observers. We believe EIA is overly optimistic, projecting regional oil production as 3.1, 4.4, and 5.2 mmb/d, in 2010, 2015, and 2020, respectively.[2] These forecasts assume that everything moves ahead with no delays, but development plans are likely to slip in the future as they have in the past. The Kazakh government announced that its oil production alone will amount to 2.3 mmb/d in 2010 and 3.5 mmb/d in 2015, but these are levels which international oil companies have publicly doubted. The drop in ACG production in Azerbaijan after 2010 (Figure 1) is unlikely to be offset by substantial new finds there, and Kazakh future production profiles remain uncertain.

Figure 1
Azerbaijan's Projected ACG Production Profile



Source: BP, "Azeri, Chirag & Gunashli Full Field Development Phase I."

Our estimates reflect the recurring tendency for oil and gas development projects in this region to slip behind schedule. There were delays in the realization of the Tengiz oil export pipeline from Kazakhstan through Russia, in the refurbishment of the line from Azerbaijan to Georgia, in the rerouting of the line from Azerbaijan through Russia to avoid Chechnya, and in the Baku-Tbilisi-Ceyhan (BTC) oil pipeline project, which was originally proposed in 1997 and should have been operational by now. Tengiz's and Kashagan's development schedules slipped in the face of environmental and fiscal issues between the government and the consortia, as did Karachaganak's production schedule due to technical issues. Shah Deniz gas development was also delayed. Russian-Kazakh partners in other offshore and shared fields are in no hurry to start committing capital in the face of higher taxes and unsatisfactory production-sharing agreements. Moreover, the geology of these deep and high-pressure fields is complex and challenging, requiring sulfur and mercaptans removal and using the associated sour gas. Finally, a number of oil and gas pipelines run through regions of civil unrest, and are at risk of sabotage and disruption, potentially affecting both output levels and their timing.

The Caspian in Context: Forecasts of World Oil Consumption and Production

Whatever ones' projections of Caspian reserves and production, one can estimate what fraction of world oil demand and capacity they might account for in future years. We use the estimates of EIA and the OECD's International Energy Agency. Table 2 below provides estimates of each. Production in 2003 from the four Caspian countries amounted to 1.8 mmb/d, according to BP, or 2.3 percent of the world's actual production. Using the previously projected levels of Caspian oil production, we show the Caspian contributing about 3-3.5 percent of the world's total oil supply and demand in the years ahead.

Table 2
World Oil Consumption and Production, 2010-2020, and Caspian Oil as Percent World Consumption and Production ('000 b/d)

Year	2010	2015	2020
World Consumption - EIA	91.4	100.5	110.3
- IEA	88.8	n/a	104.0
World Production Capacity - EIA	95.1	104.7	114.9
Caspian Oil Production	3.2	3.6	3.4
Casp. as % World Consumption	3.5-3.6%	3.6%	3.1-3.3%
Casp. as % World Production Capacity	3.4%	3.4%	3.0%

Thus, from an energy security perspective, the Caspian region is a source for diversification of world oil supplies, but it remains only a small player on the world scene. As one international oil executive remarked privately, it is nice to know the Caspian is there, since the region offers an alternative should there be production problems in Venezuela, Nigeria, Angola, parts of the Middle East, or elsewhere.

Pipelines and Other Transportation: Critical Keys to Future Production

Forecasts of production often invite differences of opinion, but there is no controversy on the landlocked nature of the Caspian producing states and the challenges of getting oil to markets. Companies and governments alike must solve simultaneous equations incorporating projected outputs and appropriate transport options timed to be ready when production builds. There have been a plethora of pipeline and other transport proposals. Caspian oil today moves by pipeline, rail, tanker, and barge, and is likely to continue to do so for some time to come. Barge transport and swaps are on the rise, and environmental concerns, taking on a greater role, may both advance some new pipeline construction projects and retard others.

We divide pipeline proposals into four categories: those that have been built or are under construction, those that might be constructed or rehabilitated over the next 10 years or so, those that are unlikely to be built in that period, and those unlikely to be built at all. Key interest today focuses on the second category. Built or under construction pipelines include:

- The BTC pipeline, scheduled for completion in 2005. It is the favorite of the United States since it avoids both Russia and Iran and helps an ally, Turkey. Its capacity will be 1-1.2 mmb/d for production from the ACG fields. Capacity could expand in the future to 1.6-1.7 mmb/d, if warranted. Its predecessor western pipeline route from Baku, Azerbaijan to Supsa, Georgia, will continue in use while the northern pipeline route from Baku to Novorossiysk, Russia, will serve as a BTC backup, or could be reversed to carry Russian oil to BTC.[3] The literature is unanimous in concluding that BTC was not the least-cost alternative. The debate continues as to whether there is sufficient Azeri oil to justify the project. Kazakhstan has expressed interest in barging production to BTC in the years after 2010, but has made no commitment. This pipeline and its companion South Caucasus Project (SCP) gas pipeline may be at future risk of sabotage or interruption.
- Also under construction, the SCP will deliver 6.6 bcm annually of Azeri Shah Deniz gas to Turkey, beginning in 2006 or later. Project design permits expansion to at least 16 bcm per year.
- The Caspian Pipeline Consortium (CPC) pipeline from the Tengiz field in Kazakhstan to Novorossiysk, Russia. Opened in 2001, its initial capacity is 565,000 b/d, with eventual expansion to 1.3 mmb/d. It could further expand to about 2.0 mmb/d should demand conditions merit. This line also carries liquids from the Karachaganak field, and from other fields east of Tengiz.[4]
- The Odessa-Brody pipeline, completed in 2001. Originally proposed as a Bosporus bypass to carry Caspian oil north, it lay vacant for several years. It now carries Russian oil south for shipment through the Bosporus. This arrangement could be only a temporary one for a period of three years.
- The expansion of the Atyrau, Kazakhstan to Samara, Russia pipeline to 300,000 b/d, completed in 2001. Its capacity could rise to 500,000 b/d by 2006. Historically used in a northerly direction, it could carry Caspian volumes in the future, or it could be reversed if the shortage of outlets for Russian exports continues.

The second category of pipelines includes those that have a chance of being built between now and 2015. It is comprised of a new export pipeline for Kashagan production if needed, of competing proposals for a Bosporus bypass, one of which is likely to be built in this time period, and of oil and gas export pipelines to China, which may require rehabilitation of existing Central Asian gas pipelines.

- Much has been written about the expected size of Kashagan, and its peak production level of 1.2 mmb/d in 2016 if it stays on schedule. Will there be a new export pipeline for this field? Some would argue there is sufficient expandability in existing lines, be they BTC, CPC, Odessa-Brody, Samara, and the northern and western routes from Baku, to accommodate Kashagan, provided there is a quality bank at Russian termini. Others suggest that additional fields will be found nearby, that a new line will be needed, and that a likely route will be to China or through Iran, regardless of the U.S. political posture toward Iran. We have serious doubts that such a new crude oil export line will be needed, let alone built, before 2015.
- Bosporus bypass pipeline ideas abound but none have been built The Turks are ever more concerned about the risks of tanker accidents and pollution in the Bosporus. In 2003 about 3 mmb/d of crude and products passed through the Bosporus, and some observers project a level of 4.0 mmb/d by 2010. There is no fixed capacity limit to the Straits; it is what the Turks say it is, and that will depend on regulations governing length, size and spacing of ships, tug escorts, required Turkish pilots, refusal to permit nighttime passage, and other stipulations the Turks succeed in imposing under the Treaty of Montreux. The 2004 winter weather delays and demurrage charges generated rethinking on whether and when a bypass pipeline makes economic sense. There is, however, a free-rider problem: why should a shipper incur an additional bypass tariff of about $1 per barrel so as to permit competitors to use the now less-congested Straits for free?

  When the opportunity costs resulting from delays become too great for Bosporus tanker passage, a bypass is likely. Of the various proposals, we judge that the line across Turkish Thrace from Kiyikoy to Ibrikbana/Saros will be built within the next five years, for it is the shortest in distance and offers the greatest capacity at 1.0-1.2 mmb/d. Russia's Transneft supports this proposal and may ultimately finance and build it. TNK-BP has allegedly guaranteed oil for the $900-million line. Despite Turkey's interest in reducing congestion in Straits, Ankara has yet to commit funds.
- An oil pipeline across the Caspian Sea to link Kazakh oil production, and perhaps Russian as well, to BTC. Insufficient volumes, together with the absence of agreed seabed delimitation, estimated costs, and environmental challenges from earthquakes and mud volcanoes have put this proposal on the back burner for now. When barged volumes begin to approach or exceed 400,000 b/d, however, industry experts agree that a trans-Caspian oil pipeline becomes preferable to ship transport. This project is likely to go forward but closer to 2015 rather than sooner.
- China already buys Central Asian oil, and its rapid energy demand growth has led to a revival of interest in projects to deliver both oil and gas. In 2004 construction began on an oil pipeline linking Kazakhstan and China; capacity estimates range from 200,000 to 400,000 b/d. A previous proposal in the 1990s for a 400,000 b/d oil

pipeline from Kazakhstan to China was abandoned due to insufficient reserves and high costs. The new oil pipeline would have appeared in the third category in this author's view, had not China's energy demand become so strong and had not the idea of a Russian oil pipeline from Angarsk to Daqing seemingly fallen victim to the proposal for a larger oil pipeline from Russia to Japan. In addition, the Central Asian countries hope to export gas to neighbors and to China, but pipelines from Turkmenistan, Kazakhstan, and Uzbekistan to and through Russia need substantial repair. Turkmenistan, however, agreed to sell gas to Russia and Ukraine in volumes that lead one to question not only how it will be transported, but also whether the reserves are sufficient, regardless of Chinese interest. China's agreement to buy gas from Russia's Kovytka gas field may once again squeeze Turkmenistan's hopes of selling gas to China. Nonetheless, China's West-to-East gas pipeline could in the future link in the west to a gas pipeline from Kazakhstan.

In the third category are pipelines that are not likely to move forward in the next 10 years or so, but could occur beyond 2015, if production profiles and demand conditions warrant:

- A new main export line for peak Kashagan output and for other north Caspian oil, of approximately 1-1.5 mmb/d capacity, running south to an Iranian port and onward to Kharg Island. Kazakhstan's President Nazarbayev favors this line. It could also carry Turkmen oil, and displace swaps. This idea faces legal and environmental challenges similar to those of a trans-Caspian line from Kazakhstan to Baku. Moreover, as long as relations between the U.S. and Iran remain strained, American law will prohibit U.S. participation.
- A second Baku-Tbilisi-Ceyhan line, or an increase to 1.7 mmb/d of the present one. There is a certain first-mover advantage, in that once the current pipeline is operating successfully, it may be simpler to expand existing facilities than to plan and execute a *de novo* pipeline project.
- A trans-Caspian – Turkmenistan to Baku – gas, and perhaps oil pipeline. This project was proposed some years ago, but was abandoned in the face of Turkmen intransigence, the decision to build the SCP line, and the recognition that the Turkish gas market was oversupplied. When Turkish gas demand recovers and grows, and gas pipeline links to Greece and elsewhere in Western Europe are realized, this project could yet revive.

A final category is pipelines that are not likely to be constructed:

- Construction of a second pipeline parallel to the CPC line. We rule this out for reasons of overdependence on Russia as a transit country, and of vulnerability to Turkish limitations on tanker passage through the Bosporus.
- The proposal to Russia by Georgia's leader for an oil pipeline from Novorossiysk, Russia through Georgia to join the BTC pipeline. While this was an attempt to appeal to Russian interests to find additional oil export options, it is a Georgian ploy to increase its role and importance as an oil transit country.
- A gas pipeline from Turkmenistan through Afghanistan to Pakistan and possibly to India. The Asian Development Bank is considering whether to support this project. Regardless of Pakistani-Indian political differences or recent warming in relations, neither country faces any acute future shortage of gas, and has other options from Iran and Qatar.

While actual and proposed pipelines attract the lion's share of attention and financing, Caspian oil moves as well by rail and barge. Kazakhstan ships by rail to China, and also by rail from Baku to the Black Sea. In the absence of an oil export pipeline through Iran, swaps of both Caspian and Russian oil to the Iranian port of Neka are rising. So far this has not drawn noticeable ire from the U.S. government. Iranian refineries in Tehran and Tabriz are being reconfigured to utilize Caspian oil, and swaps make economic sense. Further expansion of Neka's capacity may not occur, however, should BTC offer a more convenient method to market.

Costs and Prices

Cost information on development efforts in Azerbaijan and Kazakhstan is for the most part proprietary. Some estimates drawn from company data have been published, nonetheless, indicating that fully built up costs for the newer offshore areas fall in the $15-20 per barrel range, well above those in the Middle East. Built-up costs include all the costs of development, transportation, and operation. Costs should decline once capital expenditures are recovered, and interest charges no longer included.

In a period of robust oil prices of $30-40 per barrel, these costs look extremely attractive, although the opposite was true in 1999 when prices fell as low as $10 per barrel. If the government's typical profit share is 80 percent, with a 20 percent share for the investors, then at a price of $30 and a cost of $15, the latter are left with $3 per barrel as their return. Alternatively, at a price of $20, and the same profit-share split, company profits are $1 per barrel, which is probably not enough to justify the investment. Most estimators conclude that a price of above $20 per barrel is needed to justify overall Caspian investment. Should prices fall below this level, new development and production activity is likely to halt, and production could not compete with output from the Middle East.

Flow rates and well productivity, however, may be as important as world prices in estimating costs and returns. Flow rates have been as great as 5,000-10,000 barrels per well, with one well setting a record of 18,000 b/d in 2002; these rates are comparable to some from the most prolific wells in the Middle East.[6] This geologic advantage, together with technology likely to drive costs down even further, indicates that Caspian oil, at least from the more prolific deposits, can likely be profitable at from $15 to $20 per barrel.

Further evidence on costs, based on conversations with company representatives, indicates that:

- In Azerbaijan's offshore, production from the ACG fields remains profitable at a per-barrel wellhead price of $12, but generally not below that level.

- In Kazakhstan's onshore Tengiz field, the estimated price needed for profitability is about $15-20 per barrel. Lifting costs are low, however, at less than $3.25 per barrel. Capital investments in new developments in the northern Caspian region are unlikely at prices of $9-10.
- In Kazakhstan's offshore Kashagan field, costs are as yet speculative, since production has not begun. Development costs will be steep, however, and transportation costs an issue, depending on whether a new export pipeline is required. Characteristics making for high costs are the depth of the structure (4,000-5,000 meters), extreme reservoir pressures of 1,000 atmospheres, the high ratio of hydrogen sulfide gas, and the shallowness of the sea. The latter requires both artificial islands to serve as drilling platforms and specially designed icebreakers and tugs to avoid environmental damage.
- In a Kazakhstan onshore field operated by PetroKazakhstan and LUKoil, production costs are low, about $2 or less per barrel, but transportation costs – primarily by rail – east to China or west to join existing pipelines are estimated in the $12-14 per-barrel range. New pipeline connections, however, have brought down these costs.

Shaping the Course: Political Issues and World Markets

While the recoverable resources of the Caspian regime are not negligible, they are located in a politically unsettled and risky area. For the most part, we see political developments slowing and holding back energy development rather than advancing it. These include a number of considerations:

- Ongoing regional, ethnic, or religious tensions, if not outright conflict and civil war. These include the Nagorno-Karabakh dispute involving Azerbaijan and Armenia; Georgian difficulties with secessionists in Abkhazia and South Ossetia, and with Chechen dissidents finding refuge in the Pankisi Gorge; recurring Russia-Chechnya problems; disputed borders between Central Asian countries; and the strengths of the Islamic Movement of Uzbekistan (IMU), Hizb al-Tahrir, or other religious or extremist groups in the Fergana Valley and throughout the region. These all pose risks of varying degrees to present and future foreign energy investment. The BTC pipeline as well as other existing western oil facilities make attractive targets for dissidents.
- The need for well-defined production-sharing agreements, clear national regulations on environment and local content, and appropriate tax and fiscal regimes. This means that there must be a rule of law and an effective court system. The investment climate has markedly deteriorated, particularly in Kazakhstan, as the government imposed fines, sought to make changes in previous agreements, tightened fiscal terms and local content regulations, and prohibited gas flaring. While companies might be hard-pressed to consider walking away from billions of dollars in investments, their capital is scarce and has other competing uses, which may limit their commitment to these countries.
- Absence of political agreement on seabed and water column delimitation among all five Caspian littoral states. Three – Russia, Kazakhstan, and Azerbaijan -- have struck agreements, but until all five do, investment proposals for development of some borderline fields, future cross-Caspian pipelines, and cooperative environmental measures are likely to be postponed, awaiting an enforceable legal framework to govern future capital expenditure commitments. Disputes over sea demarcation, backed by force, may escalate, interfering with production and transportation operations.
- Succession issues, and those of continuing corruption and strongman dictatorial governance, once the current Central Asian leaders depart. A generation or more may be needed before any of these countries begins to function as a democracy. The change in Georgian leadership sent a chill through Central Asia's leaders, as they toughened restraints on the opposition and consolidated all their levers of power. Azeri-style dynasties are likely to occur in both Kazakhstan and Uzbekistan, while Turkmenistan is likely to slide into civil war. Political upheavals heighten the risk energy companies face, increase the potential for arbitrary changes in the regulations governing their investments, and generally raise the costs of doing business.
- Social and economic unrest arising from human rights abuses and continuing corruption and poverty. Impoverished peoples under repressive regimes often react by embracing militant Islam and rabid anti-Americanism. Foreign energy companies are also a target, should the population perceive little improvement in living standards from oil revenues as the corrupt and unaccountable governments line their pockets, fail to diversify the economies and engage in grandiose projects. The U.S. is increasingly identified with supporting corrupt and authoritarian governments in its war against terrorism. We cut aid to Uzbekistan due to human rights abuses, but aid the Uzbek military. What happens to western energy investments when the cauldron boils over?
- Lastly, what will oil prices be in 2010 and beyond? By the end of this decade a number of new projects are expected to be on stream worldwide. The estimates vary, with EIA projecting an increase of 11 mmb/d in production in 2010 over 2002 levels, and one private forecaster suggesting the 2010 increment relative to 2004 production is likely to be closer to 20 mmb/d. About 1.5 mmb/d of these amounts is Caspian production; depending on how demand increases and OPEC behaves, these capacity increments could put severe downward pressure on oil prices, perhaps pushing them down to non-economic levels for cost recovery.

U.S. Interests

Does the U.S. have strategic energy interests in this region? We would say no; the Caspian is an area that is not expected to make a major or sustained contribution to the world's exports, and in that sense is no more strategic than any other small exporting area around the world. This is not to deny that from the perspective of private investors, the region may be hugely strategic to their bottom lines.

It is important to distinguish between foreign policy objectives and energy policy objectives. In foreign policy, various U.S. administrations have stated that the U.S. goal is to prevent conflict and to strengthen pluralism, freedom, democracy, and prosperity in the former Soviet republics. In its July 2000 report, the Commission on America's National Interests set out a U.S. hierarchy of interests considered vital, extremely important, important, and secondarily important. Energy concerns appear only as to ensuring viability and stability in terms of production and trade, in the sense of avoiding disruptions. Nowhere on the list of vital interests (those for which the U.S. is prepared to fight), or of extremely important ones (those that if compromised would "prejudice but not strictly imperil" the U.S.'s ability to safeguard its citizens), or of important ones (those which if compromised would have "major negative consequences" for the U.S.'s ability to protect its citizens) do Caspian energy developments or U.S. interests therein appear.

The Commission's report was published before September 11, 2001. Since then, it is the global war on terrorism that colors U.S. foreign policy. While formerly the Caucasus and Central Asia were viewed through a Cold-War lens as to if and how Russia might try to reassert control, they became, post 9-11, key allies for U.S. actions in Afghanistan and Iraq. Post 9-11 and post-Afghanistan, Central Asia in particular was judged and/or feared as a place where the Taliban could be reconstituted. To say that these states are "strategic" is to acknowledge a collection of post 9-11 foreign policy concerns largely defined by terrorist events, together with the fear that Islamic radicals may repeat terrorist attacks to humble the U.S. and its western allies.

These states are not of strategic importance, however, to world energy markets. The U.S. supports world diversification of energy reserves and producing locations to reduce vulnerability to supply disruptions. Georgia is the one state in this region that can possibly be viewed with some concern for its "strategic" energy role, since as an energy transit state it links Azerbaijan and Central Asia to Turkey and the west. If Georgia implodes, or if war over Nagorno-Karabach between Armenia and Azerbaijan restarts and spills over into Georgia, energy investments in the BTC pipeline as well as Azeri production are likely to be at risk. But this producing region as a whole, while accounting for billions of dollars in investments, is unlikely to be a large and sustained future producer and contributor to the world's energy supplies, and cannot be considered of strategic energy importance to the U.S.

Footnotes

[1] One frequently hears the region's oil promise compared to that of the North Sea. But this is an inaccurate perception and raises false hopes of significant future production. The North Sea's proved oil reserves are placed at 60-70 billion barrels, of which about 17 billion barrels remain. The two basins should be compared at the same stages of their lives; certainly reserves numbers will change over time with new discoveries and new knowledge, but the fact remains oil reserves in the Caspian region are less than half those of the North Sea. See A.M. Samsam Bakhtiari, "North Sea oil reserves: half full or half empty?" *Oil & Gas Journal*, August 25, 2003, who gives 60-70- billion barrels of oil reserves for the North Sea basin. Private correspondence of the author with Bakhtiari confirms 60-70 billion barrels for the North Sea, compared with 20-30 billion barrels for the Caspian Sea region.

[2] DOE/EIA, *Annual Energy Outlook 2004*, January 2004, Table A21. See also Cambridge Energy Research Associates' January 2004 estimates for Caspian capacity of 4.5 mmb/d in 2010.

[3] The western route has a capacity of about 150,000 b/d, and the northern route, despite a nominal capacity of 180,000 b/d, currently carries only about 50,000 b/d.

[4] U.S. arguments against using Russia as a transit country, so prominent in the BTC debate, were not voiced in the process of concluding this pipeline project.

[5] See Jeanne M. Perdue, "Technology credited for new records," *Drilling and Production Yearbook*, March 2003, for noting that in March 2002 a Chirag well set a record for that year of 18,000 b/d. See http://www.eandpnet.com/pdf/Miscellaneous.pdf.

Mitigating Market Power in Deregulated Electricity Markets

By Seth Blumsack and Lester B. Lave*

Abstract

Conventional measures of market structure used by economists, such as the Herfindahl Hirschman Index (HHI), give a misleading picture of the competitiveness of electric power markets, since these metrics do not consider the special properties of electricity as a commodity. The notion of a "pivotal supplier" is better-suited to the electric power industry; one or more players are pivotal if they have the ability to blackout an area by withholding generating capacity. Our analysis of pivotal oligopolies in California, PJM, and New York finds that all three of these markets are far less competitive than their HHIs would suggest. Even without explicit collusion, groups of suppliers are able to influence prices through strategic bidding behavior. We also evaluate five candidate market-power mitigation systems within the context of these three power systems. The cost of capacity expansion, either through new generation or transmission, will increase costs past the point of efficiency savings from restructuring. Additional transmission will also be ineffective without competitively-priced imports. Price caps and forced divestiture will likely decrease system operating efficiency. Long-term contracts will not mitigate market power unless the contract terms are sufficiently long and can be structured to efficiently distribute risk. We also find that different mitigation schemes have very different cost and effectiveness implications for different power systems; no one solution should be applied to every operating area.

Introduction

All competitive markets are free markets, but not all free markets are competitive. Markets where one or more firms have the ability to raise price and profit are unlikely to yield benefits for consumers when regulation ends. The experience of California and Pennsylvania, the two U.S. pioneers in electric restructuring, could not have been more different. Most observers saw California's energy crisis as a "perfect storm" in which drought, high demand, and fuel supply issues converged to raise prices. A deeply flawed market design exacerbated these effects. An uncompetitive market structure certainly received some blame for California's power woes, but the conventional wisdom maintained that minor modifications to the market rules, together with a respite from the perfect storm, would produce a competitive electricity market that would serve consumers far better than the regulated system.

This paper summarizes results from Blumsack, Lave, and Perekhodtsev (2002) and Blumsack and Lave (2004). California, PJM, and New York are shown to have market structures far less competitive than conventional metrics would suggest. Mitigating the market power of the largest suppliers in each system will raise costs, thus eroding what little savings have been gained thus far from deregulation. Further, each mitigation option has very different cost, effectiveness, and efficiency implications for a given system; different mitigation schemes will work best in different systems.

Structure of the California, PJM, and New York Electricity Markets

Most analyses of California's power crisis are performance-based – the salient question is the amount of market power actually exercised.[1] Borenstein, Bushnell, and Wolak (2000) and Joskow and Kahn (2002) find that electricity prices exceeded competitive levels for a large number of hours during the summer of 2000, even after accounting for fundamentals such as the Northwest drought and natural gas supply disruptions.

In contrast to the analyses of market performance, our emphasis is on measuring the structure of bulk power markets. The conventional tool used by economists to measure market structure is the Herfindahl-Hirschman Index (HHI); the sum of the squared market shares of every firm in the market. The HHI ranges from zero (a perfectly competitive market) to 10,000 (monopoly). The HHI has few underpinnings in economic theory, but remains the generally accepted measure of the potential for market power. After deregulation and divestiture by the state's investor-owned utilities, California's HHI was 664. The HHI in PJM is 1,160 and 637 in the New York ISO. U.S. antitrust regulations define a concentrated market as one with an HHI exceeding 1,800 (DoJ/FTC 1997), so proponents of electricity deregulation could argue persuasively that these markets would be competitive.

In markets for electricity, however, the HHI is a poor measure of market structure and has been shown to be a poor predictor of market performance (Williams and Rosen 1999); an HHI less than 1,800 does not indicate that deregulation will lead to a competitive market. Since electricity demand and supply must balance at each second, the largest supplier can disrupt this balance by withholding generation capacity from the market during peak periods, resulting in price spikes or blackouts. FERC refers to such a firm as a pivotal supplier.[2] Previous work (Blumsack, Lave, and Perekhodtsev 2002), has argued that FERC's pivotal supplier designation does not go far enough, since two or more suppliers acting together could be pivotal. Coordinated withholding by multiple generators would violate the Sherman Antitrust Act, but withholding without communication is not illegal. The potential for implicit collusion is shown in Perekhodtsev, Lave,

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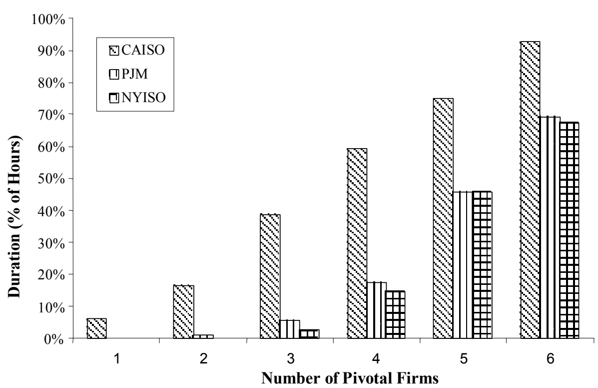
[1] See footnotes at end of text.

and Blumsack (2002), who model electricity auctions as Bertrand-Edgeworth competition with a capacity constraint. The Nash equilibrium is not a single-price bid for each firm, but rather a distribution in which the probability of bidding above marginal cost is greater than zero. They show that power prices in California decrease as the size of the pivotal group grows. Simulations by Talukdar (2002) provide further evidence that suppliers in hourly auctions can learn quickly to bid as oligopolists, even with no communication between bidders.

Since market power depends on both the demand and supply sides of the market, the load-duration curve can be used to indicate during which hours one, two, or more suppliers acting together would have market power. A group of *n* firms is said to form a pivotal oligopoly in a given hour if the surplus system capacity in that hour is less than the combined generation assets of the *n* firms. The surplus system capacity (as well as generation ownership) is based on demand and a residual measure of supply which excludes committed power and inflexible (must-run) generation resources such as nuclear and geothermal.[3]

Figure 1
Pivotal Firm Duration Curves for California, PJM and New York



The Pivotal Firm Duration Curve calculated for California over the period of high prices (a one-year period between June 2000 and June 2001) is shown in Figure 1. California's deregulation scheme was unique in that the state's utilities were not allowed to engage in long-term contracting, reducing the amount of data needed to calculate the number of pivotal firms in a given hour. Pivotal Firm Duration Curves are also calculated for PJM and the New York ISO over the same period. The curves for PJM and New York overstate market power since long-term contracts are not factored in to residual demand and supply.

The Pivotal Firm Duration Curves in Figure 1 imply that electric power markets in California, PJM and New York are far less competitive than conventional measures would suggest. For example, in California during the crisis period, an oligopoly consisting of three or fewer firms could have set the market price 40% of the time. PJM and New York appear more competitive than California, but far less competitive than their HHIs would suggest.

Mitigation Options

In most markets, holding inventories is sufficient to guard against the exercise of market power. In electricity markets, large-scale storage is too expensive; we examine some other options for mitigating market power.

FERC's Solution: SMD and SMA

In June 2001, FERC effectively halted electricity deregulation in the West by imposing cost-based price caps on the entire Western Interconnect. FERC's Standard Market Design Order demands that grid operators implement a "hard cap" at all times of the year, with additional cost-based bid caps during times of high prices.[4] Under cost-based bid caps, in which price is constrained to equal variable cost, the fixed costs of a new generating plant can be recovered only if its variable costs are lower than the market price. Determining the profitability of new plants would require knowledge of how often the market price would exceed the variable cost of the new plant. This in turn would require the generator to know the marginal cost curve of every plant in the system, and how the system-wide marginal cost curve would change with the addition of new capacity. FERC would need to know the same information in order to determine the "correct" cap on the market price. In other words, cost-based mitigation is a higher-cost version of regulation. FERC would replace the regulated system, with its high costs and certain profits, with a similar high-cost system with uncertain profits.

Another of FERC's proposals (the Supply Margin Assessment, or SMA) would apply price caps only to pivotal suppliers.[5] While SMA is certainly an improvement over widespread price caps, the screen currently proposed by FERC overestimates the ability of suppliers to be pivotal, since monthly or annual average loads would be used in place of the actual load duration curve.[6] The FERC proposal would treat a supplier as pivotal over an entire month or year, even if they were pivotal in only a few hours. Further, the SMA will only screen for pivotal monopolies; the Pivotal Supplier Duration Curves in Figure 1 suggest that regulators should also be concerned with pivotal oligopolies.

Capacity Expansion

Market power in electric power systems can be reduced by constructing excess generation or transmission capacity. The appeal of capacity expansion as a market-power mitigation strategy depends on how much is needed, since the investment will raise costs, as shown in Table 1.[7] For example, mitigating pivotal duopoly in California would require generation investments amounting to 3.5 GW, or between $2.4 billion and $4.8 billion. Electricity costs would rise by between 13 and 27 cents per kWh in order to mitigate pivotal duopoly.

Mitigating market power through capacity expansion is socially beneficial if the costs are offset by other benefits of deregulation, such as increased operating efficiency or new services which benefit consumers. California's failure to mitigate market power has cost the state dearly in terms of rolling blackouts and much higher prices. However, expanding generation capacity to prevent a pivotal duopoly would have cost between 13 and 27 cents per kilowatt hour and would not have completely mitigated a pivotal group of three firms or more. In Pennsylvania, prices have remained stable with deregulation (partially due to mandated rate freezes); PJM too would see costs rise if it were to mitigate market power through capacity expansion.

Figures from Hirst (2001) and Blumsack, Lave, and Perekhodtsev (2002) suggest that the cost of mitigating pivotal duopoly through transmission expansion would be about one cent per kWh; clearly a lower-cost solution than new generation. Further, siting generation in California has historically been difficult; expanding transmission capacity may be easier if additional lines can be added to existing towers. In general, however, the effectiveness of building transmission is limited by the extent of competitively-priced imports. If neighboring systems experience coincident peaks, import power will not be available at competitive prices, and investment in transmission would largely be wasted. Table 2 shows how monthly loads are correlated between selected Western states and Eastern NERC Regions. The negative correlations between California and the Northwest suggest noncoincident peaks; California could easily draw on surplus Northwest hydropower to combat the exercise of market power. Monthly loads in the East, however, are highly correlated; building transmission to solve the system-wide pivotal supplier problem would run into competition for neighboring imports during peaking periods (as well as native-load constraints on availability), and large line losses from more distant resources.

Increased Demand Response

Making demand responsive to price is a worthy goal, but by itself is unlikely to eliminate pivotal suppliers, since a monopolist can still exercise market power when the demand curve is downward-sloping. Sweeney (2002) asserts that small amounts of demand response could curb the exercise of market power. Table 3 shows the amount of demand response needed to mitigate all pivotal oligopolies of a given size in California and PJM between June 2000 and 2001. Smaller amounts of demand response will mitigate pivotal suppliers at some times but not others. The price elasticity of demand would have to range between -0.1 and -1.55 to mitigate pivotal suppliers in California (Blumsack and Lave 2004); the best estimates of short-run elasticity are around -0.3 (Houthakker 1951, Caves and Christensen 1980). If suppliers are pivotal in a small number of hours, demand response may be preferable to capacity expansion.

Table 2
Demand Correlation Matrices for Western States and the Eastern Interconnect

Western States					
	AZ	CA	NM	OR	WA
AZ	1				
CA	0.90	1			
NM	0.93	0.80	1		
OR	-0.10	-0.04	0.10	1	
WA	-0.48	-0.41	-0.33	0.77	1
Eastern Interconnect					
PJM	1				
NYISO	0.92	1			
ECAR	0.90	0.78	1		
SERC	0.87	0.83	0.88	1	
NEPOOL	0.91	0.86	0.84	0.74	1

Divestiture

Prior to the opening of California's deregulated electricity market, the state's investor-owned utilities were required to divest many of their generation assets. Regulators believed that without divestiture, incumbent utilities would have tried to influence the state's electricity auction. Given that regulators acknowledged the likely pivotal status of the utilities, their willingness to let individual suppliers control substantial shares of capacity is surprising. We infer that regulators focused on market share data and concluded that the resulting market would be competitive, as the HHI indicated. From the breakup of Standard Oil to the threatened breakup of Microsoft, divestiture has long been a favorite tool of an-

Table 1
The Cost of Mitigating Market Power Through New Generation

Pivotal Group Size		**California**		**PJM**		**NYISO**	
	System Capacity (GW)	**54**		**60**		**38**	
	Capital Cost ($/kW	**$600**	**$1200**	**$600**	**$1200**	**$600**	**$1200**
1	Additional Capacity Needed (GW)	10.5		0.0		0.0	
	Required Investment ($billion)	7.12	14.24	0.00	0.00	0.00	0.00
	Marginal Cost (cts/kWh)	35.25	70.51	0.00	0.00	0.00	0.00
2	Additional Capacity Needed (GW)	3.5		5.4		0.0	
	Required Investment ($billion)	2.40	4.81	3.67	7.34	0.00	0.00
	Marginal Cost (cts/kWh)	13.44	26.88	196.27	392.54	0.00	0.00
3	Additional Capacity Needed (GW	3.3		5.4		4.0	
	Required Investment ($billion)	2.24	4.49	3.66	7.32	2.73	5.46
	Marginal Cost (cts/kWh)	5.68	11.37	38.73	77.46	83.66	167.31
4	Additional Capacity Needed (GW	3.2		4.0		2.9	
	Required Investment ($billion)	2.15	4.31	2.74	5.48	1.95	3.90
	Marginal Cost (cts/kWh)	3.73	7.46	12.55	25.11	15.11	30.22
5	Additional Capacity Needed (GW	3.0		3.6		2.5	
	Requited Investment ($billion)	2.01	4.02	2.46	4.92	1.70	3.4
	Marginal Cost (cts/kWh)	2.95	5.90	4.82	9.64	4.81	9.63
6	Additional Capacity Needed (GW	2.9		3.6		2.3	
	Required Investment ($billion)	1.96	3.92	2.46	4.91	1.57	3.14
	Marginal Cost (cts/kWh)	2.39	4.78	3.20	6.40	3.28	6.57

titrust regulators. In the context of electricity markets, divestiture seems appealing; if firms are permitted to hold only small amounts of capacity, they may cease to become pivotal.

The appeal of divestiture increases as excess system supply decreases. Table 4 recalculates the Pivotal Firm Duration Curves for California and PJM under various divestiture scenarios, assuming that inflexible generation (nuclear and geothermal) is not divested. As the maximum generator size shrinks to 1 GW, the hours when firms were pivotal falls below 10% in PJM. The frequency of a six-member pivotal oligopoly falls from 93% of hours between June 2000 and June 2001 to 8% of hours. Divestiture is effective in limiting the incidence of pivotal firms in California, but since surplus capacity is higher in PJM, proportionally more divestiture would be required in California.

Table 3
Mititating Pivotal Suppliers Through Demand Response

Pivotal	CA Demand Response		PJM Demand Response	
Group Size	MW	%	MW	%
1	4840	12%	5395	15%
2	3534	10%	5395	15%
3	3296	10%	5381	18%
4	3165	12%	4030	16%
5	2951	12%	3617	16%
6	2877	13%	3611	19%

The effectiveness of divestiture as a market power mitigation strategy is limited by economies of scale in generation. Systems dominated by large plants are less amenable to market-power mitigation through divestiture. For example, the largest plant in Arkansas represents 20% of the state's capacity. Ownership of large plants can be broken up into smaller shares, but control must still remain in the hands of a single party. The incentives of a private ownership group and the ISO are likely to be incompatible, with owners desiring to maximize joint profits and the ISO seeking to maximize system reliability at low cost.

Table 4
Pivotal Firm Duration Curves in California and PJM Under Divestiture Scenarios

Divestiture in California

	PFDC Under Capacity Ownership Limit (%Hrs)				
Number of Pivotal Firms	No Limit	4GW	3GW	2GW	1GW
1	6%	5%	4%	3%	3%
2	16%	13%	8%	5%	3%
3	39%	32%	20%	8%	4%
4	59%	55%	41%	14%	5%
5	75%	70%	60%	26%	6%
6	93%	88%	75%	41%	8%

Divestiture in PJM

	PFDC Under Capacity Ownership Limit (%Hrs)				
Number of Pivotal Firms	No Limit	4GW	3GW	2GW	1GW
1	0%	0%	0%	0%	0%
2	1%	1%	0%	0%	0%
3	6%	6%	2%	0%	0%
4	18%	17%	6%	1%	0%
5	46%	45%	16%	4%	1%
6	69%	69%	42%	10%	2%

For California or PJM, total demand is many times larger than the efficient generation size, so technical economies of scale are not an issue (Christensen and Greene 1976, Johnson 1960). However, there may be important economies of scale in management. A single large combined cycle natural gas generator might use only a fraction of the time of a pollution control specialist, personnel manager, and gas purchaser.[8] While these services could be supplied by consultants, the costs might be higher or the quality of service lower.

Recent consolidation in the nuclear industry suggests that managerial economies may be important. In addition to operating at lower costs, skilled or better-trained operators appear to deliver higher availability times and higher capacity factors for their plants.[9] Table 5 shows the progress of capacity factors for nuclear power plants between 1993 and 2002. While the firm-wide capacity factor has increased since 1993 for all firm sizes, larger firms have seen greater gains. The average nuclear capacity factor for firms with only one nuclear plant grew by 15% between 1993 and 2002; during the same period the average nuclear capacity factor for the industry's largest firm grew by 27%.

Long-Term Contracts

California's deregulation scheme has been widely criticized for prohibiting long-term contracts. Sweeney (2002) suggests that encouraging forward contracts in the three-to-five year range would greatly reduce the ability of generators to exercise market power. Such contracts were signed *en masse* at the end of California's power crisis; the contract prices were lower than the prevailing spot prices at the time the contracts were signed, but far above the prices prevailing in the regulatory era or the post-crisis period.

Frequent auctions encourage implicit collusion (Talukdar 2002, Perekhodtsev, Lave, and Blumsack 2002). Reducing the frequency of trading through long-term contracts would discourage this sort of collusion. Contracts in and of themselves will not cure the pivotal supplier problem; the structure of the contracts must reduce the incentive of suppliers to charge high prices. The only way to achieve this is for the buyer of the contract to have some outside option as a bargaining chip (Laffont and Martimort 2002) in case the contract price offered by the supplier is too high. The bargaining power of a buyer such as an ISO comes from the ability to build new generation; such an outside option of building new capacity implies that the contracts market must support contracts longer than the three- to five-year deals signed by California, possibly as long as life-of-plant contract. A generator seeking capital for a new plant is unlikely to attract lenders without a guarantee that they will be repaid. Similarly, public utility commissions are unlikely to allow utilities to include the cost of new plants in the rate base unless the utility is actually earning money from the plant. Capacity built for the sole purpose of deterring market power (while the utility actually serves load through the spot or shorter-term contract markets) will erode efficiency gains from deregulation, as discussed in the section on Capacity Expansion.

Long-term contracting will successfully deter market

Table 5
Consolidation and Performance in the Nuclear Power Industry, 1993 - 2003

1993

# of Plants	Number Of Firms	Mean Capacity Factor	Median Capacity Factor	Standard Deviation
1	35	0.669	0.713	0.166
2	9	0.644	0.710	0.212
3	2	0.660	0.660	0.096
More than 3	1	0.635	0.635	0.000

1997

No of Firms	Number of Plants	Mean Capacity Factor	Median Capicty Factor	Standard Deviation
1	35	0.673	0.748	0.240
2	8	0.733	0.829	0.181
3	3	0.758	0.768	0.065
More than 3	1	0.540	0.540	0.000

2000

# of Plants	Number Of Firms	Mean Capacity Factor	Median Capacity Factor	Standard Deviation
1	33	0.742	0.824	0.221
2	9	0.802	0.841	0.131
3	3	0.814	0.861	0.096
More than 3	1	0.883	0.883	0.000

2002

No of Firms	Number of Plants	Mean Capacity Factor	Median Capicty Factor	Standard Deviation
1	29	0.823	0.863	0.166
2	8	0.842	0.852	0.085
3	3	0.875	0.884	0.017
More than 3	1	0.911	0.911	0.000

power only if the contract is structured such that the incentives of the buyer and seller coincide. Imperfect information and uncertainty lead to moral hazard, since the buyer cannot observe how the generator is running the contracted plant. If the contract specifies a fixed price per MWh, with a take-or-pay clause and a fuel pass-through, the generator has little incentive to bargain for the lowest fuel price. Further, moral hazard issues arise in the staffing and operations of the plant specified in the contract (and its construction costs, if the plant is new). The buyer wants the generator to exert a high level of effort in keeping costs down and reliability high. Meanwhile, the generator wants to do as little as possible while satisfying the terms of the contract.[10]

The multi-task nature of electricity contracts can also give rise to diseconomies of scope. Each task required of the generator (purchasing fuel, maintaining the plant, and so on) imposes an additional moral hazard problem (Laffont and Martimort 2002). The marginal cost of resolving an additional incentive incompatibility may be larger than the marginal expected benefit from having the generator perform an additional task.[11] The generator's decreasing marginal utility of consumption implies that additional effort must be compensated with a more-than-proportional increase in the contract price. If such diseconomies exist, it may be a lower-cost solution for the buyer to assume some of the responsibilities normally given to the generator.[12]

Conclusion

Restructured electricity markets in California, PJM, and New York may be free, but they are far less competitive than conventional market-power metrics would suggest. The fact that supply and demand must balance at all times gives monopoly power when demand is sufficiently high to allow pivotal oligopolies to threaten blackouts by withholding supply. Pivotal firms as large as six groups could have set the price in a majority of the hours of the year in all three systems. Large pivotal oligopolies can be easily formed without explicit communication.

California taught the U.S. that transforming regulated electricity markets into competitive markets is far more difficult than was assumed. FERC's counterparts in Europe and Asia would do well to heed this same lesson. Regulators need to more carefully assess whether a combination of actions exist that would control market power while still offering savings to consumers. FERC's attempt to control this power by controlling price would prevent new capacity, since fixed costs would not be reimbursed. FERC's solution would target only single pivotal suppliers, but we show that larger pivotal groups also had potential to exercise market power. Expanding generation capacity is promising but prohibitively expensive. Expanding transmission capacity is attractive only if capacity is available for export, which may be true in the West, but not in much of the Eastern Interconnect. Forcing suppliers to divest assets would reduce their market power, but would also raise costs due to economies of scale in management. Making demand more responsive to price holds promise for preventing the extreme high prices that prevailed in California. With sufficiently long time horizons, long-term contracts could prevent market power if the difficulties of moral hazard and risk distribution could be surmounted.

Footnotes

[1] The conventional measure of market performance in economics is the Lerner Index, defined as the percentage by which price exceeds marginal cost (also known as the price-cost markup). Using the Lerner Index to assess the performance of electricity markets has been widely criticized; see Borenstein, Bushnell, and Kittel (1998).

[2] See, for example, FERC Supplier Margin Assessment Order, 97 FERC ¶ 61,219 at 61,967.

[3] The calculation of the Pivotal Firm Demand Curve is discussed in more detail in Blumsack, Lave, and Perekhodtsev (2002). They calculate two sets of Pivotal Firm Duration Curves, with and without must-run energy. The sets of curves are similar for California and New York, but the inclusion of must-run energy (mostly nuclear power) in the duration curve for PJM results in two- or three-firm pivotal oligopolies during every hour of the year.

[4] FERC Notice of Proposed Rulemaking, Docket No. RM01-12-000, ¶317,318,398 – 410.

[5] FERC Supplier Margin Assessment Order, 97 FERC ¶ 61,219 at 61,967. Whether this Order would supplant market-power mitigation discussed in the Standard Market Design has not yet been resolved.

[6] FERC Supplier Margin Assessment Order, Staff Paper on Supply Margin Assessment and Alternatives, Docket PL-02-8-000.

[7] The figures in Table 1 assume capital costs of between $600/kW and $1,200/kW, with anly used to prevent the exercise of market power; its costs are therefore only charged to those hours with a pivotal group of a given size. A detailed example of the cost calculations can be found in Blumsack and Lave (2004).

(continued on page 23)

Low Inventories or Stable Price? - You Can't Have Both

*By William R. Edwards**

OPEC has recently stated its intention to use U.S. inventory levels as a guide in making its production/price decisions. The idea is that the way to keep prices high is to restrain production in such a way that inventories never rise to comfortable levels. If the consumer is always worrying about getting adequate and timely supply, then he will not worry about the price he pays for this supply.

On the surface this may look reasonable. But upon close examination it becomes apparent that this method of price control is patently unsound and does a huge disservice to both the consumer and the producer. The reason for this is that an environment of supply uncertainty is an environment of price uncertainty and volatility.

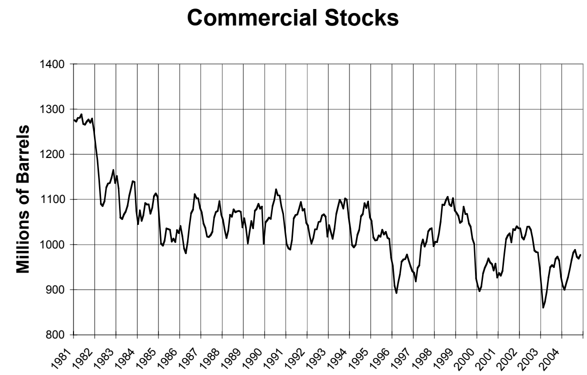
It is well known that oil futures prices as determined by the New York Mercantile Exchange (Nymex) is the major factor in current petroleum pricing. Correlations show that the Nymex now sets the price and the producing countries simply follow this price. History reveals that extreme volatility can occur on any commodity that is traded under a highly leveraged environment. When small moves in price create large demands on the financial assets of the participants, one can expect knee-jerk reactions on the price that these participants are willing to pay. Such is the case with oil futures prices on the Nymex.

The oil futures market has no restraints in pricing most of the time. When the supply situation is comfortable, futures prices can move up and down at will and are not influenced at all by real world fundamentals. Normally these fluctuations are modest in magnitude. However, when supply factors create a tight situation, the real oil world exerts a major influence on the futures market. It is a certainty that if inventories fall to minimum operating levels upward pressure on prices will be the result. Not only will prices rise, they will do so dramatically.

It is the nature of highly leveraged speculative markets to over-emphasize any movement, either up or down. A tight supply situation is just what the skilled trader wishes for. In this environment trading becomes impulsive and erratic. Prices move rapidly in both directions with large fluctuations. This is exactly the situation that is created when OPEC production cuts achieve low inventory levels.

For purposes of illustration, let us look at the inventory situation in the United States. Commercial inventories of crude and product normally range between 1000 and 1100 million barrels. The normal seasonal fluctuation is about 100 million barrels. This is shown in the following figure where commercial stocks are shown for the past twenty-three years.

The years 1996, 2000, 2003 and 2004 stand out in this chart because the inventory levels dropped in those years to



the 900 million barrel level. Each of those years experienced a significant increase in price in the subsequent months. The erratic price jumps that we are now experiencing are confirming again that the 900 million-barrel level for the United States represents "empty tanks". Thus it should come as no surprise that OPEC's production cut in the 2003 winter created a surprisingly sharp run-up in prices. This was followed in 2004 by a refining capacity tightness that compounded OPEC's production-cutting actions.

It is popular for oil producers to place the entire blame for the current extreme price volatility on psychological factors within the futures market. While it is true that the futures market contributes greatly to the magnitude of the price swings, it is inappropriate to place the entire blame for this situation on oil futures. Had not the inventory levels been reduced by the supply-restraint imposed by the producers, the role of the Nymex in this increase in volatility would never have been a factor. So ultimately the blame for price volatility lies at the feet of the OPEC producers.

If stability is to be returned to the oil markets, OPEC must return to a system that allows the free and adequate supply of petroleum markets without the imposition of supply restraints. In other words, **it is impossible to have both low inventories and price stability**. It is easily understood that if inventories are near tank bottoms, or at the operating minimum, any unexpected bobble will drastically affect prices. In order to avoid price instability, the customer must feel a sense of confidence that the oil will be there when he needs it. This confidence is impossible if inventories are skimpy.

OPEC should not be in the position of trying to manage customers' inventory levels. It is entirely reasonable and appropriate for an individual refiner or consumer to decide what inventory level is comfortable for his business. The function of price management by OPEC should be an activity completely separate from supply management and must be conducted within the framework of a smoothly functioning supply system. Discovering and adopting such a system is OPEC's challenge.

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The Income Distribution Impacts of Climate Change Mitigation Policy

*By Gbadebo Oladosu and Adam Rose**

Introduction

Mitigating the potentially dramatic impacts of climate change is one of the leading environmental policy concerns of the 21st Century. Since the combustion of fossil fuels is the largest single source of greenhouse gases in industrialized countries, carbon taxes and carbon emission permits are at the forefront of instrument design in this era of incentive-based policies (Weyant, 1999; Rose and Oladosu, 2002). While promising a cost-effective solution, the macroeconomic impact of implementing these instruments is, however, predicted on average to be negative for most policy designs.[1]

The distribution of the cost burden of climate change mitigation policies, like that of nearly all environmental and energy policies, will inevitably be uneven within and across the categories of households and businesses (Rose et al., 1988). The benefits of these policies (avoided damages of climate change) are distributed unevenly as well, and in a different manner than the cost (see, e.g., Oladosu, 2000). Although dozens of studies have investigated potential aggregate economic impacts of climate change policy (see, e.g., Weyant, 1999; IPCC, 2001), very few have examined their distributional impacts.

The purpose of this paper is to analyze the cost-side income distribution impacts of a carbon tax in the Susquehanna River Basin (SRB) Region of the United States. The analysis is undertaken with a computable general equilibrium (CGE) model specially constructed for this purpose in terms of conceptual design and detailed empirical specification of income and consumption relationships (see Oladosu, 2000). The analysis is undertaken at the regional level for two major reasons. First, climate change impacts, a major driver of the pace and shape of mitigation policy, are likely to vary by region in a large country such as the U.S. Moreover, climate impacts are not likely to conform to sub-national political boundaries but rather to major ecosystems, a notable example being a watershed. Second, implementation of climate change mitigation policy will take place at the regional and local levels. In any effort to match remedies to problems in general, and to match beneficiaries to cost-payers in particular, a regional approach will be necessary and will likely shift attention away from artificial boundaries like political jurisdictions (see, e.g., Easterling et al., 1997).[2]

Distributional impacts are important for two reasons. First, from a normative standpoint, previous studies have generally found carbon taxes to be regressive (i.e., to place a disproportionate burden on lower income groups). This is important from the standpoint of equity, or fairness, in its own right. Second, for more pragmatic reasons, the distribution of impacts is important for policy formation and viability, since groups negatively impacted can mobilize opposition (Rose et al., 1988). Bovenberg and Goulder (2002) have pointed out that businesses are likely to have more clout than consumers in this regard. However, accelerating concern about environmental justice (broadly defined) draws attention to lower income and minority households, and effectively mobilizes opposition on their behalf.

Background

A small number of studies have examined the income distribution impacts of carbon taxes or carbon emission permits (see, e.g., Harrison, 1995; Metcalf, 1998; as well as the reviews by Repetto and Austin, 1997; and Speck, 2001). We begin by summarizing the three special features most emphasized to distinguish the impacts of these policies in contrast to the incidence of taxes in general. First, although the initial focus is on a few but very prominent sectors that emit carbon (Coal/Oil/Gas extraction, transportation, and refining), the fundamental role of these products, however, means that carbon reduction policies will eventually ripple throughout the economy, with possibly surprising outcomes. This is one of the major reasons computable general equilibrium models are used.

Second, fossil energy products and most energy-intensive processed goods (food, housing, automobiles) are necessities, making it relatively more difficult to substitute away from them. Spending on necessities is inversely related to income and, hence, all other things being equal, carbon taxes would lean toward being regressive in partial equilibrium terms.

Third, unlike most existing taxes, carbon taxes are not aimed primarily at raising revenue. Moreover, they do not create a distortion in the price system but are intended to correct one. These factors have important implications for the disposition of carbon tax revenues (or revenues from the auction of carbon emission permits), including the possibility of using carbon tax revenues for tax relief that promises to reduce the distortionary nature of the pre-existing tax system. This revenue recycling can take a number of forms (reductions in personal income taxes, corporation income taxes, etc.), with different distributional impacts. Again, however, the final impacts of these alternatives are not a priori obvious when one allows for general equilibrium considerations.

Overall, a large number of other factors, both unique to carbon taxation and applicable to tax policy in general, can have a major bearing on the relative unevenness of impacts

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[1] See footnotes at end of text.

(OECD, 1995; Oladosu and Rose, 2003). It is also important to note several factors that affect the size of the aggregate impact, since it will also have a bearing on the degree to which the baseline income distribution changes. Of course, the size of the aggregate impact can affect the distribution of impacts in highly nonlinear models or where such factors as income elasticities of demand vary strongly across income groups. Major factors include:

1. energy-intensity of the economy
2. magnitude of the carbon tax or emission permit price
3. unit upon which the tax is based
4. narrowness or breadth of products or entities on which the tax is imposed
5. point of initial imposition of the tax (i.e., upstream suppliers of energy or downstream users)
6. ability to shift the tax forward onto customers or backward onto factors of production
7. extent of factor mobility
8. extent to which general equilibrium effects are taken into account
9. extent of production/income distribution/consumption interactions
10. extent to which dynamic effects are taken into account
11. use of annual income versus lifetime income as a reference base
12. extent to which demographic considerations are taken into account
13. type of revenue recycling
14. asset market considerations
15. degree to which the impacts result in unemployment
16. basic parameters and assumptions of the analytical model

In our analysis, we evaluate the influence of nearly all of these factors on income distribution impacts of a carbon tax on the SRB.

Model Formulation

Overview

Several factors need to be considered in designing a CGE model for policy analysis. The most important ones are the issues to be analyzed, size and nature of the economy, and data availability. These factors guide choices in the specification of various segments of the economy in terms of detail and functional forms (see Oladosu, 2000, for full details of the model). This section presents the specification of a static, regional computable general equilibrium (CGE) model of the Susquehanna River Basin (SRB). The model is structured to be consistent with the objectives of assessing the impacts of climate change policies on the regional economy.

The SRB CGE model includes four main types of activities: production, consumption, trade and investment performed by four institutions: enterprises, households, government, and external agents. The SRB economy is divided into 49 sectors and market goods in the model, delineated to highlight climate change and policy sensitivity in the economy. The Electricity sector is further divided into five sub-sectors to represent the various types of electricity generation sources in the SRB economy. Production activities are modeled using non-separable, nested constant elasticity functions (NNCES). Labor, capital, energy and materials are the four aggregate factors of production in the model, with energy and materials being further disaggregated into the 49 component market goods. Consumer behavior in the model utilizes a household production function formulation for both market and non-market goods. Households are represented by a 9-income bracket categorization. Government is disaggregated into Federal and State/Local levels. These governments receive their incomes mainly from five types of taxes: social security, indirect, income, trade, and profit taxes, which are expended on the purchase of market goods and transfers to other institutions. The remainder of aggregate demand is investment goods and net additions to stock. The regional nature of the model necessitates a nested trade structure with the Region and the Rest of the U.S. in the lower nest, and the Rest of the World in the upper nest. This trade structure is tied to the supply of market goods to regional and external markets.

Data requirements for the model include the social accounting matrix, factor demand and supply data, household expenditure and demographic data, capital composition matrix, capital and labor income mapping data, and environmental data among others. With these data and the model specification, necessary parameters for implementing each module are derived using a combination of several approaches. Econometric estimation is used in implementing the indirect utility function for households, while literature synthesis and expert judgments were used in deriving elasticities of substitution for producer and household cost functions. Parameters such as the industry-by-occupation matrix, capital composition matrix, capital income allocation matrix and various other labor supply parameters are based on similar data for the entire or other parts of the United States. Other model parameters were calibrated using economic data specific to the SRB economy. Still other model parameters are directly computable from the various data and calibration features.

The major data source for the model, the IMPLAN database (MIG, 1998), distinguishes 528 industries and market goods, which were aggregated to 49 industries and market goods. For households, expenditures on market goods are disaggregated from the three income brackets of the IMPLAN database to the nine income categories of the SRB CGE following Rose et al. (1994) and Oladosu (2000).

Elasticities of substitution and transformation are the main parameters that need to be specified for import and export functions in the SRB CGE model. Without the requisite time-series or cross-sectional data for estimating these parameters, we synthesized the literature to determine the appropriate range of values (see, e.g., Reinert and Roland-Holst, 1992; and Shiells and Reinert, 1993).

Carbon Tax Policy Modeling

At the 1997 Kyoto conference of parties, the United States committed to a reduction of its carbon equivalent emission of GHGs to 7.0 percent below 1990 levels between 2008-2012. Estimates of the marginal value of a ton of carbon or carbon tax/permit price to achieve comparable targets vary widely from a low of $5 to a high of $250 (Weyant, 1999; Rose and Oladosu, 2002). We have chosen to evaluate a carbon tax rate of $25 per ton of carbon, a level often cited as being an upper-bound for a U.S. commitment to a GHG reduction treaty, with the case of $100 per ton of carbon simulated as part of a sensitivity analysis. The determination of the tax rate is exogenous to the SRB economy, and we also assume the same tax rate applies elsewhere in the U.S. (and implicitly to major trading partners).

Given that fossil fuels consumption is the major source of carbon emissions in the U.S., upstream consumption taxes on crude oil, natural gas and coal are simulated using the SRB CGE model. Other carbon emitting activities such as agriculture and land-use activities have not featured prominently in the carbon tax/permit market discussion, so we have omitted these from consideration.

Implementation of a product tax requires that the carbon tax be converted to an ad valorem tax. Since emission factors and energy content of fossil fuels vary within a very narrow range, tax rates can be easily calculated once fossil fuel prices are known.

A multitude of possible carbon tax scenarios can be formulated depending on the treatment of trade effects, revenue recycling assumptions, tax rates and types, as well as time horizon considerations. Table 1 summarizes the carbon tax scenarios simulated using the SRB CGE model. The base scenario (Scenario 0) is a $25/ton ad valorem, upstream consumption tax on Coal, Crude Oil and Natural Gas, with the proceeds going into general government spending. Fuel prices and emission factors on which tax rates are based are presented in Table 2.

Table 1
Alternative Carbon Tax Scenarios

Case	Tax Rate ($/ton)	Type of Tax	Other Characteristics
0	25	Consumption	Revenue goes into general government spending
A	25	Production	Revenue goes into general government spending
B	25	Consumption	Lump sum transfer of tax revenue to households
C	25	Consumption	Tax revenue used to offset personal income tax
D	100	Consumption	Revenue goes into general government spending

Results

Aggregate and Sectoral Impacts

A $25/ton carbon consumption tax, with proceeds going into general government spending is our Reference Case—Case 0). Overall impacts on the economy are measured by Gross Regional Product (GRP), which is projected to decline by 0.30 percent in the short run. Long-run changes in this variable are a little over two times that for the short run. Real producer price index declines by 0.24 percent in the short run and by 0.33 percent in the long run. Average factor prices also change significantly, except for the short-run capital return rate. Average wage and capital return rates decline by 1.02 percent in the long run. The short-run wage rate declines by 0.44 percent, though labor supply response (employment) to wage rate changes was small in both cases, with the largest decline of 0.23 percent in the long-run. Total revenue resulting from the carbon tax is around $700 million in both instances.

Table 2
Principal Carbon Tax Scenarios

Consumption Tax Conditions:

Sector	Fuel Price	Emission Factor	Percent Tax
Coal	$26.8/short ton	0.027 ton/mmbtu	53
Crude Oil	$17.2/barrel	0.021 ton/mmbtu	18
Natural Gas	$2.8/mcf	0.015 ton/mmbtu	13

General Closure Conditions:
- Sectoral occupational wage rates are linear functions of a freely adjusting average wage rate
- Sectoral government expenditures are constant shares of total government spending, while government balance is fixed at the benchmark level
- Transfers are constant shares of transferors' income

External Closure:
- Import and export prices adjust to maintain 1995 relative domestic and external prices
- External agents savings adjust to maintain a zero overall balance of payments

Short-run Closure Rules:
- Capital stock is fixed by sector, and sectoral return rates adjusts freely

Long-run Closure Rules:
- Capital is mobile across sectors, and sectoral return rate is a linear function of average rate of return in the economy
- Total capital stock is flexible, and relative wage and capital return rate is constant

Note: *mcf* = thousand cubic feet; *mmbtu* = million British thermal units.

The primary effect of the consumption tax is to increase energy costs, and consequently shift sectoral marginal cost functions upward. Intuitively, the extent of this effect would vary with the share of energy in production, implying that large energy users would feel the effects of the tax most. Although this sectoral distinction is important, it is merely a starting point for examining the effect of the tax on producer behavior. A subtle but crucial factor is the extent of substitution possibilities among energy sources, as well as between energy and other inputs. This factor influences how much increased energy costs would increase production costs. Also, the demand-side effects of income and price changes throughout the economy could induce sectoral price changes in either direction.

The highest price increases in the short run are for the energy sectors. Supply prices increase by 52.50 percent for Coal, 9.36 percent for Crude Oil, 12.01 percent for Natural

Gas, 5.90 percent for Petroleum Products, 3.28 percent for Electric Services, and 3.22 percent for Gas Utilities. Output prices for these sectors, except those of Crude Oil and Coal, also increase, meaning that supply-side effects of the tax dominated the demand-side effects. For Coal and Crude Oil, the reverse is the case. Results for the remaining sectors of the economy suggest a dominance of demand-side effects of the energy price increases. Output changes are consistent with the observed price changes. The highest output reductions are for Coal, Crude Oil, Petroleum Products, and Electric Services: 22.90 percent, 5.03 percent, 3.44 percent, and 1.09 percent, respectively. All but two of the remaining sectors are projected to incur output declines of less than 1.00 percent.

Consumption and Income Distribution Impacts

Household (personal) income distribution effects of the carbon tax are driven by several factors. Income changes in the economy affect household disposable income. In turn, household income changes are determined by the allocation of labor and capital incomes as well as transfers. Labor income depends on household labor supply, which is influenced by the wage rate and labor supply elasticities. The average wage rate received by each household group also depends on the occupational composition of its working members. Since capital income allocation is based on fixed shares, changes in sectoral capital income are transmitted proportionally to households. Producer price changes affect household commodity costs, depending on substitution possibilities among inputs, as well as the market goods composition of commodities. Finally, the allocation of expenditures, and the resulting commodity demands are simultaneously determined. Given the linear expenditure system household utility functions, expenditures on subsistence commodity quantities adjust for cost changes before supernumerary expenditures are allocated to individual commodities according to marginal expenditure shares.

Distributional impacts are presented in Tables 3 and 4 for our Reference Case (Case 0). Table 3 shows that in the short run the first four income groups increase most of their commodity demands, while the last five groups decrease most of their demands. However, Fuel/Utilities decline in all households. These results suggest that income effects under the tax are more favorable to the lower income groups than to higher ones. As shown in Table 4, the former are projected to experience an income increase of just under 0.40 percent and the latter groups reductions of between 0.37 percent and 0.66 percent. Given the accompanying cost decreases that also favor the first four groups, lower income households are able to secure increased consumption of commodities of up to 0.80 percent in cases such as Housing by the $5K-$10K bracket. The opposite result for Fuel/Utilities implies that its price increase more than offsets all the positive income effects.

Long-run household results reflect the same factors as discussed above, but the patterns of results differ considerably for several reasons (see the bottom half of Table 3). First, income decreases now occur in all households, although not nearly as much for the lower income groups. Second, the cost-of-living index for most of the lower income groups increase, while those for some of the higher income groups de-

Table 3
Short- and Long-Run Consumption Effects of a $25/ton Consumption Carbon Tax: Government Expenditure of Tax Revenue (percent change)

	$0K-$5K	$5K-$10K	$10K-$15K	$15K-$20K	$20K-$30K	$30K-40K	$40K-$50K	$50K-$70K	>$70K	Overall
Short-Run										
Commodity Demands										
Food	0.30	0.38	0.45	0.41	-0.10	-0.05	-0.12	-0.31	-0.38	-0.07
Housing	0.79	0.80	0.64	0.61	-0.07	-0.14	-0.19	-0.31	-0.32	-0.09
Fuel/Utilities	-0.41	-0.64	-0.30	-0.40	-0.43	-0.34	-0.33	-0.56	-1.03	-0.52
Household Operation	0.67	0.69	0.67	0.59	-0.21	-0.19	-0.33	-0.53	-0.46	-0.22
Clothing/Jewelry	0.36	0.43	0.49	0.49	-0.13	-0.29	-0.13	-0.31	-0.37	-0.17
Transportation	0.04	-0.06	0.09	0.00	-0.47	-0.34	-0.23	-0.34	-0.52	-0.34
Health	0.76	0.75	0.70	0.68	-0.10	-0.25	-0.10	-0.28	-0.30	-0.04
Recreation	0.53	0.70	0.78	0.96	-0.10	-0.13	0.01	-0.11	-0.03	0.04
Others Commodities	0.69	0.73	0.71	0.75	-0.10	-0.16	-0.24	-0.44	-0.38	-0.15
Long-Run										
Commodity Demands										
Food	0.07	0.09	0.13	0.05	-0.39	-0.23	-0.45	-0.65	-0.77	-0.39
Housing	0.46	0.54	0.40	0.36	-0.37	-0.51	-0.51	-0.66	-0.66	-0.41
Fuel/Utilities	-1.16	-1.56	-0.92	-1.07	-0.87	-0.64	-0.63	-0.94	-1.67	-1.00
Household Operation	-0.14	-0.14	-0.06	-0.09	-0.90	-0.98	-1.16	-1.41	-1.36	-1.04
Clothing/Jewelry	0.04	0.06	0.02	-0.02	-0.52	-0.83	-0.49	-0.68	-0.80	-0.59
Transportation	-1.69	-2.01	-1.43	-1.33	-1.72	-1.34	-0.78	-1.01	-1.62	-1.31
Health	0.44	0.50	0.44	0.39	-0.45	-0.71	-0.40	-0.55	-0.53	-0.35
Recreation	-0.12	-0.12	-0.12	0.04	-0.79	-0.89	-0.62	-0.80	-0.88	-0.71
Others Commodities	0.31	0.39	0.27	0.34	-0.48	-0.60	-0.83	-0.99	-0.84	-0.63

crease. Thus, both Fuel/Utilities and Transportation demand decline more in all households than in the short-run. Demand increases by the first four income groups are now projected only for Food, Housing, Health, Clothing/Jewelry, and Other Commodities. Decreases in all other commodities are more severe for all groups than in the short run.

except in Cases B and C.

A production tax on carbon emitting products as simulated in this study is different from the consumption tax mainly in its trade effect. The consumption tax implicitly imposes the tax on both domestic demand/sales and imports, while the production tax imposes the same tax on domestic sales/demand and exports. Given that domestic and external prices adjust to maintain their base year relative levels, one would expect the results of both cases to be similar, with impacts being slightly less severe and generating less tax revenue in Case A.

Table 4
Short- and Long-Run Welfare Effects of a $25/ton Consumption Carbon Tax: Government Expenditure of Tax Revenue

		$0K-$5K	$5K-$10K	$10K-$15K	$15K-$20K	$20K-$30K	$30K-40K	$40K-$50K	$50K-$70K	>$70K	Overall
Short Run:	**Units**										
Per Capita Income	(%Δ)	0.36	0.37	0.37	0.36	-0.37	-0.42	-0.42	-0.64	-0.66	-0.44
Utility	(%Δ)	0.94	0.21	0.29	0.22	-0.28	-0.15	-0.18	-0.22	-0.12	-0.06
Eq. Variation/Capita	$	-5.50	-24.39	-46.01	-63.11	24.14	25.67	31.60	79.44	169.65	24.82
Gini Coefficient	(%Δ)	-	-	-	-	-	-	-	-	-	-0.15
Theil Index	(%Δ)	-	-	-	-	-	-	-	-	-	-0.14
Long Run:	**Units**										
Per Capita Income	(%Δ)	-0.27	-0.26	-0.25	-0.25	-0.96	-1.04	-1.04	-1.27	-1.30	-1.06
Utility	(%Δ)	-0.40	-0.11	-0.09	-0.06	-1.08	-0.67	-0.71	-0.56	-0.33	-0.51
Eq. Variation/Capita	$	2.48	13.47	14.85	19.32	94.90	115.81	128.85	207.32	456.75	121.49
Gini Coefficient	(%Δ)	-	-	-	-	-	-	-	-	-	-0.16
Theil Index	(%Δ)	-	-	-	-	-	-	-	-	-	-0.15

The welfare impacts of the tax on each income bracket are depicted by various measures in Table 4. The equivalent variation in per capita terms is slightly U-shaped in the short run but displays an obvious progressive pattern in the long run.[3] Overall, the welfare effects on the cost side of a carbon tax are negative and more pronounced in the long run than in the short run. The relatively better outlook of lower income households in terms of percent changes in the per capita welfare measure may be explained as follows (in addition to the consumption pattern effects noted above). Although, employment across all household groups declines, higher income households lose more, because they tend to belong to higher wage occupations and sectors that suffer higher declines in output. Second, dividend reductions resulting from economic contraction can be expected to hit higher income households harder than lower income ones.

The Gini coefficient and the Theil index results represent single parameter measures of the changes in income inequality among income groups due to the carbon tax. The calculations are based on expenditures rather than income (because the former is considered a more consistent metric), and are expressed as percentage changes over the benchmark. These indexes declined by around 0.15 percent in both the short and long run, meaning the tax is mildly progressive, which conforms to the relative per capita welfare effects.

Sensitivity Tests

We performed alternative carbon tax scenario simulations specified in Table 1. Discussion of these alternative scenario results focuses on their main areas of differences from the Reference Case Scenario. Except for Case D, aggregate effects (in terms of GRP and employment) are about the same as Case 0. Distributional impacts vary only slightly as well

Cases B and C examine alternative carbon tax revenue recycling approaches against the weak and strong form of the double-dividend hypothesis. In Case B, the carbon tax revenue was transferred to households in a lump sum as an equal percentage of benchmark household income shares. In Case C, carbon tax revenues were used to reduce household income tax rates by a little over 4 percent for each bracket.[4] Lump sum transfers enhance progressivity more than income tax reduction, because the former returns relatively more to lower income households.

In Case D, the tax rate was raised four-fold, and the lump-sum revenue return was again based on benchmark household income shares. However the macroeconomic decline is less than four-fold in relation to Case 0, indicating a nonlinear response, or a type of economic resiliency.[5]

Summary

We found that the aggregate impacts of a carbon tax on the Susquehanna River Basin were negative but modest: approximately a one-third of one percent reduction in GRP in the short run for all scenarios (including revenue recycling) and approximately double that much in the long run. The energy sectors, especially Coal and to some extent Oil Extraction, bear the brunt of the impacts. In terms of consumption patterns, though households are projected to spend less on nearly all goods and services, the largest shifts are away from Fuels/Utilities and Private Transportation in both the short and long run. Still, however, lower income groups spend relatively more of their income on Food, Housing, and Health Services than prior to the imposition of the tax. In terms of household distributional effects, the carbon tax is mildly progressive when measured in terms of income bracket changes, per capita equivalent variation, and Gini coefficient changes based on expenditure patterns. Moreover, various sensitivity test indicate our results are robust.

We do, however, refrain from suggesting the carbon tax progressivity we found in the SRB generalizes to all other regions. Given the number, complexity, and, in some cases, idiosyncrasy of factors affecting the outcome, analysis should be undertaken on a case by case basis. Some a priori hypotheses on the relative regressivity/progressivity should only be ventured if the vast majority of determining factors line up on one side of the issue or the other.

A major limitation of the analysis is that it pertains to only one side of the ledger. Also important is the distribution of benefits from the damages avoided by carbon emission reductions. Although this aspect is beyond the scope and space limitations of this paper, we can report on the overall conclusion reached in Oladosu (2000)—that the benefits of the SRB carbon tax are projected to be slightly progressive, i.e., potential damages would fall relatively harder on low income groups, and their avoidance would thus help these groups relatively more. Of course, timing considerations are important when combining the cost and benefit sides. The benefits of the carbon tax imposed in 2010 will be small in that year but will increase over time. Thus, cost considerations are likely to dominate the distributional impacts in the near term.

Endnotes

[1] The Kyoto Protocol allows for trading of individual country emission quotas to implement its overall target. From a business decision and tax revenue standpoint, a carbon tax and carbon emission permits are equivalent when the latter are auctioned. Note also that although President Bush has deemed Kyoto to be "dead," state and local governments throughout the U.S. are making commitments to reduce greenhouse gases (CCAP, 2002). This includes a recent agreement by the New England Governors, which provides for emissions trading between the states to meet their targets.

[2] The Susquehanna River Basin (SRB) is located in south central New York, nearly all of central Pennsylvania, and a small portion of north central Maryland. An economic trading area, consisting of 68 counties in these three states, conforms roughly to the SRB. Total population of the Region is about 8 million and Gross Regional Product about 200 million. The Susquehanna River flows 444 miles from Lake Otsego near Cooperstown in New York into the Chesapeake Bay and drains 27,500 square miles. The SRB accounts for 43 percent of the Chesapeake Bay's drainage area and is made up of 60 percent forest land. The Susquehanna River is the longest commercially non-navigable river in North America.

[3] Equivalent variation (EV) is a measure of the willingness to pay to avoid the policy or the equivalent amount of income households would be willing to give up to match the effect of the policy on their welfare. Convention is to express EV as a positive amount, but it denotes a decrease in welfare.

[4] The absence of a dynamic model is the reason we did not simulate corporate tax relief/revenue recycling as well. For an excellent example of such analysis see Bovenberg and Goulder (2002).

[5] Two additional simulations tested the sensitivity of the results to energy substitution elasticities. In the first, elasticities were reduced by 50 per cent, thus making it more difficult to minimize the impact of energy price increases in production costs. The result is an increase in negative impacts and a lower reduction in energy use compared to Case 0. Coal and Crude Oil outputs declined by less than in Case 0, and Natural Gas output slightly more because it became more difficult to shift to the latter (less carbon-intensive) fuel. However, the sectoral and price impacts are only slightly different from Case 0, and the overall impact on the economy was virtually the same. The long-run impacts were, however, significantly more negative than in Case 0, because decreased substitution possibilities were of a greater absolute magnitude. Our second simulation made it 100 percent easier to substitute away from energy, and therefore we would expect, and it is confirmed, that there are greater reductions in consumption of fossil fuels compared to Case 0. Overall, negative impacts on the economy were only slightly worse in the short run in this case than Case 0, while the long-run results were substantially less severe, reflecting significant nonlinearities in the model. Note also that the progressivity results are not due to any extreme values of elasticities of substitution between capital and labor. The capital stock declined by about the same amount as labor in the long-run, and the return rate declined by less or equal to the wage rate in both the short and long-run.

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[8] In this sense, managerial economies of scale are similar to economies of scope (Baumol, Panzar, and Willig 1982).

[9] Since nuclear units are considered "must-run" generation, lower capacity factors can be attributed to less efficient operation, rather than withholding.

[10] The moral hazard problem has no efficient solution (Ross 1973). The buyer can induce "good" behavior on the part of the generator, but at a cost (Holmström 1979).

[11] Further, these diseconomies of scope will increase as the generator becomes more risk-averse.

[12] However, this may also introduce an opposing moral hazard problem. For example, the utility might find it cheaper to purchase fuel on behalf of the generator, rather than compensate the generator for having to bargain for a good fuel price. In this situation, for example, the utility may not have any incentive to ensure that the fuel is of sufficiently high quality. These types of moral hazard problems should resolve themselves if the contract horizon is long enough (if the utility continually buys poor-quality fuel for the generator, the reliability of the plant will suffer).

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Gas Supply Security in Europe in the Long Term: Some Key Issues

*By Frits van Oostvoorn**

Introduction

The current trends and development of the European gas market in relation to a number of structural changes such as the creation of one single European gas market led to great reluctance to invest in gas production and pipeline infrastructure, which led to great concern in the EU that security of gas supply is declining to unacceptable levels for EU-30 consumers in the long term. It is expected that EU import dependency will strongly increase in the next decades from currently 40% to around 75% or more in 2030.

In its 2000 Green Paper on energy security[1], the European Commission identified the purpose of an EU gas supply security policy as securing the immediate and longer-term availability of a diverse range of gas supplies at a price that is affordable to all consumers while respecting the environment. In practice, this involves reducing to an acceptable level the risks and consequences of gas supplies not being available. Some of the risks of disruption in key supplies are analysed and discussed in the next sections.

Security of gas supply for consumers is basically an issue of risk. All energy supply systems inherently contain a certain level of risk for consumers, but the question is what level and type of risks are acceptable. This depends on the context in which the question is posed. The scope in this study is the medium and long-term gas market in Europe wherein the EU consumer is largely and increasingly depending on natural gas import. Moreover, he is mainly depending on a relative small number of key gas exporters with remote production locations. Furthermore, gas supply security is generally more important for political and economic reasons than supply security in other industries, because of the essential nature of gas. It is difficult to get alternatives and its supply depends on monopoly pipeline networks. Consequently there are high costs involved in gas supply interruptions. Adequate security levels for consumers depend very much on the perception of the consumers' willingness to pay for higher security levels, which tend to fall if risks are reduced and the 'costs of providing extra security' that tend to rise if risks are reduced. Unfortunately optimal levels of security are difficult to assess due to uncertainties and different perceptions of risks by the different stakeholders. What policy makers can do, however, is try to assess if security levels are within a certain and acceptable margin for a majority of consumers.

The paper is organised as follows. In the next section we present a recent view on the long-term developments of gas demand, supply and import dependency in Europe analysed with model and data support of the IEA. In the next section we analyse the role that Russia's gas exports play in securing the consumption of the EU and the final section we investigate the flexibility of the gas network connecting main suppliers with the EU by analysing the effects of unexpected supply interruptions to the EU on prices and trade volumes. We end with a brief summary of the key conclusions on the issue of long term gas supply security for Europe.

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Long Term Adequacy of Gas Supply in Europe[2]

Approach

The objective is to formulate different scenarios of natural gas supply in Europe for the period 2000-2030 and analyse their implications for supply security and policy. This study seeks to provide the European Union and particularly the candidate accession countries with recommendations for enhancing their gas-supply security, taking account of the enlargement of the EU and the liberalisation of the EU energy market. In the next section the risks and consequences of unexpected gas supply interruptions are presented. The focus of this section is on the long term and strategic natural gas supply security situation through to 2030 in the light of the implementation of EU Directives and proposed supply security policies in the EU-30 and specifically those implemented in the candidate accession countries. Scenarios were prepared for the European Union in aggregate in two different configurations, namely the current membership of states (EU-15) and for an enlarged Union of 30 member states (EU-30). The additional members include the ten accession countries that joined the Union in 2004 (Cyprus, Czech Republic, Estonia, Hungary, Latvia, Lithuania, Malta, Poland, Slovakia and Slovenia) and five other countries that might join at some time in the future (Bulgaria, Norway, Romania, Turkey and Switzerland).

The scenarios consider the balance of energy demand and supply under various assumptions concerning macroeconomic trends, population growth, energy prices, technology and government policies. Each scenario determines the gap between indigenous production of natural gas and demand for each configuration and the breakdown of net imports by region of origin.

In line with the approach adopted in the *World Energy Outlook 2002*, baseline or core projections for this study were derived from a Reference Scenario. The projection period is 2001 to 2030. The last year for which complete energy demand and supply data are available is 2000, although some preliminary data are available for natural gas for 2001. Modifying assumptions concerning energy prices and government policies on nuclear power, renewables and energy efficiency and conservation generated two variants of the Reference Scenario. Basic assumptions on macroeconomic conditions and populations are the same as for the Reference Scenario. These variants correspond to higher and lower gas imports into the European Union compared to the Reference Scenario. These alternative scenarios were designed so as to capture key uncertainties with respect to the evolution of European energy markets. These include the pace of liberalisation and the impact on energy prices and government strategies for dealing both with rising energy-related emissions of greenhouse gases and the prospect of increased dependence on imports of natural gas.

Key Assumptions

The Reference Scenario incorporates a set of explicit assumptions about underlying macroeconomic and demographic conditions, energy prices and supply costs, technological developments and government policies. It takes into account many new policies and measures in European countries and in other parts of the world designed to combat climate change. Many of these policies have not yet been fully implemented; as a result, their impact on energy demand and supply does not show up in the historical data, which are available in most cases up to 2000. These initiatives cover a wide array of sectors and a variety of policy instruments.

The Reference Scenario does not include possible, potential or even likely future policy initiatives. Major new energy policy initiatives will inevitably be implemented during the projection period (2001 to 2030), but it is impossible to predict precisely which measures among those that have been proposed will eventually be adopted and in what form. For that reason, the Reference Scenario projections should not be seen as forecasts, but rather as a baseline vision of how energy markets might evolve if governments individually or collectively do nothing more than they have already committed themselves to do.

Electricity and gas market reforms aimed at promoting competition in supply are assumed to proceed, although the emergence of effective competition is expected to be gradual. Energy taxes are assumed to remain unchanged. Likewise, it is assumed that there will be no changes in national policies on nuclear power. As a result, nuclear energy will remain an option for power generation solely in those countries that already have a nuclear industry and that have not yet officially abandoned it, namely Bulgaria, the Czech Republic, Finland, France, Hungary, Lithuania, Romania, Slovenia, Spain and the United Kingdom. Nuclear power is assumed to be phased-out progressively in Belgium, Germany, the Netherlands, Sweden and Switzerland. The key underlying assumptions about macroeconomic trends, population growth and energy prices are summarised below.

Economic growth is the most important determinant of energy demand. In the past, European energy demand has risen broadly in line with gross domestic product. Since 1971, each 1% growth in GDP has yielded a 0.47% increase in EU-30 primary energy consumption. Only the oil price shocks of 1973-1974 and 1979-1980 affected this relationship to any significant degree (Figure 1). Energy demand is expected to continue to follow economic activity over the next three decades. Consequently, all the energy demand projections, including natural gas, in this study are sensitive to underlying assumptions about economic growth. Economic activity in Europe has slowed considerably since 2000. GDP growth is now barely positive in many European countries, with overall growth of less than 1% expected in EU-30 in 2003. The Reference Scenario assumes that macroeconomic prospects in European countries will improve in the coming years: GDP growth is assumed to average 2.3% during the period 2000-2010 in both EU-15 and EU-30, see Table 1. In the longer term, however, GDP growth is assumed to trend down, averaging only 1.9% per year in the last decade of the projection period in both groupings.

Table 1
Average Annual Real GDP Growth in Europe

	1971-2000	1990-2000	2000-2010	2010-2020	2020-2030	1971-2030
EU-30	2.5	2.0	2.3	2.0	1.6	1.9
EU-15	2.4	2.0	2.3	2.0	1.6	1.9

Source: IEA analysis.

Energy Prices

Energy prices, exogenous variables in the IEA World Energy Model, are important drivers of total energy demand and supply and the fuel mix. Average end-user prices are derived from assumed fossil fuel prices on wholesale or bulk markets. They take into account current tax rates, which are assumed to remain unchanged. Final electricity prices are derived from marginal electricity-generation costs. The price trends assumed in the Reference Scenario reflect judgments about the prices needed to ensure sufficient supply to meet projected demand in Europe and in other regions. The smooth price trends assumed should not be interpreted as a prediction of stable prices, but rather as long-term paths around which prices could fluctuate. Indeed, oil and gas prices will probably remain highly volatile. The underlying assumptions for EU import prices for oil, natural gas and steam coal are summarised in Table 2 (in fuel-specific units).

Table 2
EU Fossil Fuel Import Price Assumptions ($2000)

	Units	1990	2000	2001	2010	2020	2030
Crude oil	Per barrel	27.30	28.00	23.39	21.12	25.00	29.00
Natural gas	Per Mbtu	3.27	3.00	3.63	2.76	3.29	3.80
Steam coal	Per tonne	62.62	34.61	37.28	38.84	41.21	43.60

Source: IEA (2002), World Energy Outlook

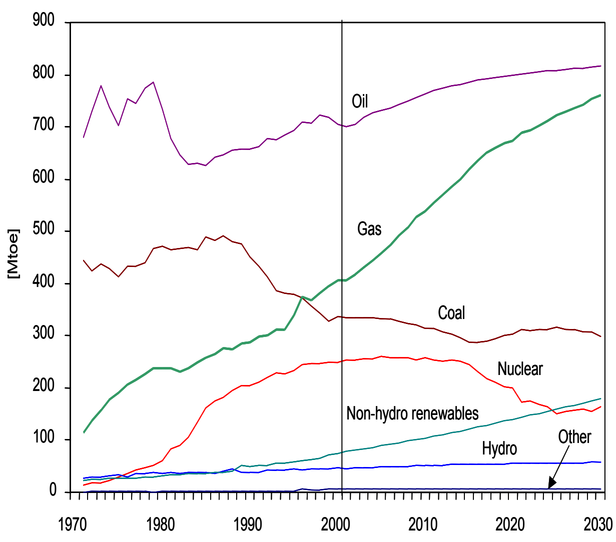
The assumed trend in European gas import prices to 2030 reflects the underlying trend in oil prices together with costs and market factors specific to the region. Oil and gas prices remain linked through price indexation clauses in long-term supply contracts as well as through inter-fuel competition between gas and oil products at the burner tip. Gas prices are assumed to remain flat at around $2.80/Mbtu in year 2000 dollars. Gas-to-gas competition is expected to put some downward pressure on border prices as spot trade develops. Lower downstream margins and efforts by national regulators to reduce access charges could further depress end-user prices. But the cost of bringing new gas supplies to Europe is expected to increase as the distances over which the gas has to be transported lengthen and project costs rise. This factor is assumed to offset the impact of growing competition. Prices are assumed to rise after 2010 in line with oil prices. As a result, the ratio of gas to oil prices remains flat throughout the projection period at around 80%, which is close to the average for the last decade.

International steam-coal prices are assumed to remain flat in real terms over the period 2002 to 2010 at $39/metric tonne, —the average for the preceding five years. Thereafter, prices are assumed to increase very slowly in a linear way, reaching $44/tonne by 2030. Declines in the cost of mining and increasingly stringent environmental regulations that restrict the use of coal in many countries are expected to offset to a large extent the impact of higher oil prices on the value of coal and, therefore, its price from 2010.

Development of Gas Demand and Import Dependency

Total primary energy demand in EU-30 is projected to rise by an average 0.7% per year over the projected period, well below the rate of 1.2% for 1971-2000. The fuel mix is expected to change markedly. An enlarged European Union faces the prospect of a substantial increase in gas imports in the next three decades in the absence of rigorous new government policies at EU and national levels. In a Reference Scenario, natural gas demand in EU-30 is projected to grow by an average 2.1% per year over the projection period - the most rapid growth rate of any fuel other than non-hydro renewables. The share of gas in total primary demand will continue to grow, from 22% at present to 33% in 2030. The power sector will be the main driver of gas demand, especially in the first half of the projection period.

Figure 1
EU-30 Primary Energy Demand



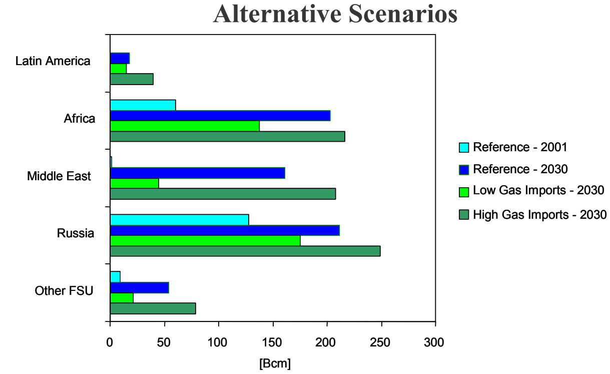
Source: IEA analysis.

Under an alternative *Low Gas Imports Scenario*, a combination of sharply lower gas demand, due to higher gas prices and policies that reduce gas demand, and slightly higher indigenous gas production, results in a significantly lower rate of growth in gas imports into EU-30. By the end of the projection period, imports in this scenario are little more than 60% of their level in the Reference Scenario. Most of this difference is due to lower gas consumption in the power sector which will use more coal and nuclear instead of gas. Gas imports nonetheless virtually double over the projection period. Imports are somewhat higher in a *High Gas Import Scenario*, mainly due to even more rapid growth in power-generation demand than in the Reference Scenario.

With indigenous production projected to stagnate, all of EU-30's projected increase in demand will have to be met by increased imports. *Net imports are projected to surge from 200 Bcm in 2001 to almost 650 Bcm in 2030.* The share of imports in the region's total gas demand will rise from 38% to just below 70% over the same period. The bulk of imports are expected to come from EU-30's two main, current suppliers, Russia and Algeria, and a mixture of piped gas and LNG from other African and Former Soviet Union countries, the Middle East and Latin America. The enlargement of the European Union to twenty-five countries will temporarily increase the degree of gas-import dependence, as eight new accession countries are net gas importers. But the enlargement to thirty countries would reduce the degree of gas-import dependence because of the inclusion of Norway. Both short- and long-term supply security concerns are likely to be exacerbated. The high degree of dependence of the candidate accession countries in Central and Eastern Europe and their unusually heavy dependence on imports from a single country - Russia - will have an impact on supply-security risks in the EU. Reliance on a single supply route in some accession countries adds to the short-term risks.

Imports are somewhat higher in the *High Gas Imports Scenario*, mainly due to stronger demand. Imports reach 400 Bcm in 2010 and 790 Bcm in 2030. The Middle East and Russia would account for most of the additional gas imports under this scenario compared to the Reference Scenario as most of the low-cost sources of supply in North Africa would have been committed by then. Such a large increase in dependence of supply in North Africa would raise enormous concerns about security of supply (see final section). Transit volumes across the accession countries would also be substantially higher.

Figure 2
Natural Gas Imports by Origin under Alternative Scenarios



Source: Menecon Consulting analysis based on IEA projections.

Implications for supply security and policy of the enlargement of the European Union would reinforce concerns about gas-supply security. Security risks fall into two broad categories:

- The short and medium term risk of disruptions to existing supplies caused by political events, strikes, accidents or technical failures.

- The long-term risk that new supplies cannot be brought on-stream quickly enough to meet growing demand for either political or economic reasons.

Potential of Russian Gas Supply to EU

Russia's view is that their gas export policy regarding Western and Eastern European markets depends on the gas market developments in neighbouring regions and the restructuring of the Russian gas industry. The export policy in the 'optimistic economic growth scenario' (if crude oil prices are high in world markets) is based on the assumption that Russia revenues for Russia support the economic growth and Russia will keep its share in the supplies to foreign markets and even continue to expand its market share if import demand rises. Russian gas export in this scenario is expected to grow from 139 Bcm in 2001 to 181 Bcm in 2020. At the same time gas reserves of East Siberia and the Far East will be mobilized to enter Asian-Pacific markets, first of all in China, Korea, and Japan.

In the pessimistic economic growth outlook for Russia, the so called 'Constrained scenario', (if crude oil prices are low in world markets) for internal reasons the gas export volumes to Europe will be constrained slightly in the short and medium term. However, if gas prices as a reaction to this development rise again to a relatively high level in Europe in the period 2010-2020, it will be possible to exploit the Shtockman gas fields and export these volumes to Western Europe. As a result gas export volumes might reach the levels of the 'optimistic scenario' again in 2020. At the same time, if gas prices in Asian-Pacific countries stay tightly linked to the low world crude prices, export projects in the Far East continue to be unattractive for investors. Gas deliveries to CIS and Baltic countries are expected to rise to about 62-69 Bcm, while the main demand comes from Ukraine and Belarus. West Siberia will remain the main resource base of the Russian gas industry. Its resources will dominate supply to all regions in Europe, the Ural and the industrial areas in the south of West Siberia. Gas from Tyumen will remain the main export source.

Finally, one should not underestimate the potential of gas production and exports of Turkmenistan and Kazakhstan via Russia and Ukraine to the EU. The production and export volumes in Turkmenistan might rise from 45-56 Bcm in 2005 towards around 85-100 Bcm in 2020 and in Kazakhstan from 16-20 Bcm in 2005 to 40-50 Bcm in 2020.

Investment Needs in the Russian Gas Sector

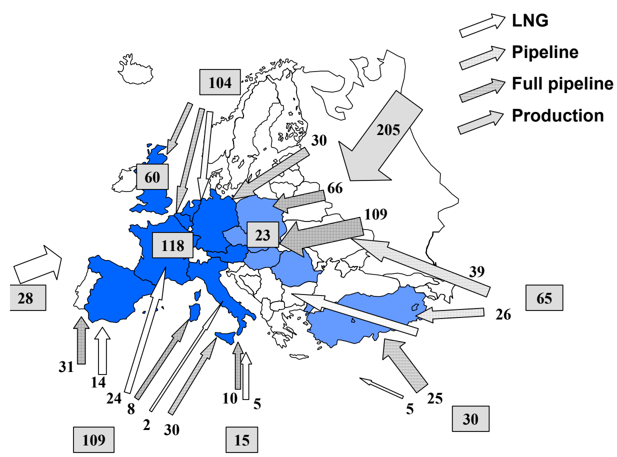
Gazprom's strategy for further development of their gas resource base, production, the reconstruction and extension of gas transport and distribution system, gas processing plants, and the construction of more underground gas storage facilities, requires large investments in the next decades. In the next five years (2001-2005), investments in gas production and transport are estimated at around $16-17 billion, and for the whole period till 2020 investments in the operation and further development of the industry are crudely estimated to be about $90-100 bln. Compare this with the investments by Gazprom PLC in 1999 of only $ 3.1 bln. and in 2000 of $3.2 bln. Conclusion is that to mobilise these large investments for the exploration and production of gas, foreign investors are needed. But currently their exist a hesitation to invest in the Russian gas sector.

Ukraine's Transit Issues

Currently, the Ukraine is clearly the most important gas transit country for Europe with an extensive gas network of pipelines and storage facilities in order to transport large volumes of gas mainly from Russia to Europe through Slovakia, Poland and Romania. It is, therefore, important that the Ukraine meets EU standards for safe and reliable transport of natural gas. Russian gas transit to Europe takes place in volumes of around 110 - 120 Bcm a year, while gas supply to Ukrainian consumers is currently around 65 - 70 Bcm per year.

Insufficient actions and financing of maintenance of Ukraine's gas transport system has led to a worsening of the network conditions in the last decade, which creates great doubts about reliability of gas supply to Europe in the next decade. It is one of the key reasons for developing alternative routes for gas transit from Russia to the European Union. Urgent measures are needed to keep Ukraine's pipeline system effective for gas transit to Western Europe.

Figure 3
Gas Production and Major Gas Flows to EU, CEEC and Turkey, in the Reference Case in 2020 [Bcm]



Resilience of the European Gas Transport Network

Next to insufficient supplies of gas from the key exporter Russia and its neighbouring countries another risk is increasingly looming, namely the declining and insufficient investments in pipeline capacity and related services to supply EU consumers in the next decades with gas from remote regions. In order to identify potential bottlenecks and risks in the future gas transmission system, we analysed some effects of sudden and prolonged 'gas supply disruption cases' for the year 2020. Four disruption cases are analysed. Without assuming any probability for these cases to happen, they merely are used as a tool to analyse the resilience of the European gas transport network. Figure 3 gives an overview of the main gas flows to Europe in the reference case in 2020. It shows production volumes in each region, as well as the LNG and pipeline flows to the countries considered. The darker countries in the figure are the consuming countries we distinguish (eight EU15 countries, five CEECs and Turkey). Note that production volumes in the EU and CEEC include exogenous production. The within each region capacity usage must be interpreted carefully. For example, EU15 internal flows use only 39% of available capacity. However, the capacity of 354 Bcm is a result of two-way counting; pipelines like the UK-Belgium Inter-Connector are counted for both directions.

The four disruption cases analysed are:

- Disruption of Russian supply through the Ukraine and the complete transmission-pipeline capacity across the Russian-Ukrainian border becomes unavailable (Russian/Ukraine Case) for exports to EU.
- Disruption of Algerian supplies to EU altogether (Algerian Case).
- Disruption of transits through Turkey, i.e., transit pipelines from Turkey to Greece and Bulgaria become unavailable (Turkish Case).
- Disruption of Norwegian supplies to EU altogether (Norwegian Case).

The main results of these gas disruption cases, evaluated with respect to a reference case in which there are no disruptions in gas supply to the EU in 2020, are summarised below.

Russian Case Impacts

In the reference case it is expected that about 50% of Russian exports pass the Ukrainian border in 2020. So Russian supplies decline by 97 Bcm in case of a disruption. Alternative routes, particularly Blue-stream and Russian LNG, absorb about 12 Bcm of gas diverted from the Ukraine route. The Baltic pipeline to Germany cannot be used as an alternative, since it is already fully used in the reference case. EU-30 demand is falling sharply due to the sharp price increases, caused by strongly rising costs of alternative supplies. But CEECs are hit most severely.

Algerian Case Impacts

In the reference case Algerian exports are at their maximum level, as pipeline and LNG exporting capacities are fully used. However if interrupted there is no alternative for the transport of Algerian gas to Europe, consequently countries currently directly supplied by Algeria (Spain, France and Italy) are severely hit, because alternatives are lacking. The reserve capacity for alternative supplies is very small and Spain and Italy will have to rely on additional LNG from more remote and expensive sources. About two-thirds of interrupted supplies is replaced by those expensive LNG alternatives. Therefore, gas price levels in these countries increase substantially. The CEECs however, are hardly affected by a complete interruption of gas exports from Algeria.

Turkish Case Impacts

The impact of the interruption of gas transit through Turkey, which mainly consists of Iranian gas exports to Italy, are relatively small, since transit volumes in 2020 are assumed to be rather small (about 10 Bcm). Since Iran can only supply the EU via Turkey, Caspian supplies are 'pushed out' of Turkey (and into the Ukrainian route). On the other hand the 'lost supplies' from Iran to Italy are partly substituted by additional Caspian supplies via Ukraine.

Norwegian Case Impacts

Norway supplies at almost full production capacity to the EU in the reference case in 2020. However, alternatives for disrupted Norwegian supplies are hardly available. Russia and Algeria are already exporting at full capacity to Europe. Therefore, LNG from remote regions is the most important alternative supplies available. The CEECs are hardly affected, except Czech Republic and Hungary, but other EU 30 countries are severely hit by a disruption in Norwegian gas supply.

General Conclusions Regarding the Flexibility of the European Gas Network

Existing and planned gas supply and transmission infrastructure (both LNG and pipeline) seems sufficient to meet expected gas demand in 2020. In case of disruption in one of the key supplies, the transmission network capacity is a constraining factor leading to price rises. In the Russian and Algerian cases, EU 15 gas consumption would be reduced by some 6%. Prices in eight selected Member States would increase between 10-40% in the Russian case and between 2-60% in the Algerian case. In the Norwegian case, EU 15 gas consumption would be reduced by some 13%. Prices in the eight Member States would rise between 5 and 60%.

Caspian gas supplies become increasingly important for CEECs and Turkey, assuming that pipeline capacity is expanded accordingly.

In the next decades LNG supplies from remote sources play an increasingly important role in filling the supply gap in any of the disruption cases. Consequently, investment in expanding LNG regasification capacity will be very important for ensuring security of gas supply to EU-30 in the medium and longer term.

The following bottlenecks are identified in the European pipeline transmission network:

- Iran into Turkey and further into Europe.
- Bulgaria and Romania into Europe.
- Cross-links between CEECs, which are important for mutual assistance in case of emergencies.
- From the west and south into CEECs. Trade flows and pipelines are currently dimensioned for deliveries from East to Western Europe. Spain, however, is addressing this by developing its LNG facilities.
- Belarus and Ukraine into EU-30.

Turkey's role as transit country for gas from the Caspian Region and Iran to Europe depends critically on:

- Development of domestic gas demand in Turkey,
- Further expansion of pipeline capacities from Turkey to Greece and Italy,
- Expansion of pipeline capacities from Turkey to Bulgaria and further to Romania, Hungary and Austria and thereby improving interconnections with West-European

markets,

- Availability for Turkey of gas supplies from the Caspian Region and Iran.

Conclusions

The projected increases in gas demand and imports in the Reference Scenario imply a need for substantial investment in gas production, transportation and storage capacity both within EU-30 borders as well as in those countries that will supply gas to Europe. *Just under $500 billion will need to be invested in gas-supply infrastructure in EU-30 countries and a further $190 billion in external supplier countries over the period 2001-2030.* The sheer scale of the capital needs as well as a number of developments, including longer supply chains, geo-political factors and energy-market liberalisation, raise question marks about whether this investment will be forthcoming in a timely manner. There is a risk that supply bottlenecks could emerge and persist for long periods due to the physical inflexibility of gas-supply infrastructure and the long lead times in developing gas projects.

EU and national policy makers will clearly need to tread very carefully in reforming their gas and electricity markets to ensure that the new rules and emerging market structures do not impede or delay investments that are economically viable. Policymakers will also need to take account of the increased risks facing both upstream producers and merchant gas companies as a result of energy liberalisation in setting rules for long-term supply contracts and joint marketing arrangements. An intensified political dialogue with the governments of supplier countries could support investment in certain high-risk, large-scale gas projects by lowering country and project risks. The development banks, including the European Investment Bank, as well as national and multilateral export credit agencies, will continue to play an important role in backing major cross-border pipeline projects in the future. The restructuring and privatisation of gas companies in major gas producing and transit countries may contribute to reducing future investment risks.

Footnotes

[1] European Commission (2000), *A Green Paper: Towards a European Strategy for the Security of Energy Supply*.

[2] Section 2 is based on a study of T. Morgan of Menecon on behalf of IEA Economic Analysis Group for ECN.

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[1] Van Oostvoorn, F. et al (2003): *Long-term Gas Supply Security in an enlarged Europe,* ECN-C--03-122, ECN, December 2003.

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