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# The Policy Tightrope in Gas-Producing Countries: Stimulating Domestic Demand Without Discouraging Supply

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## EXECUTIVE SUMMARY

This study explores and assesses the policy options that gas-rich governments can use to develop domestic gas markets, with a focus on major Asian gas-producing countries.

### *Main Argument*

Governments of countries with substantial gas resources typically hope to harness their gas for domestic uses as well as for export revenues. However, the use of price subsidies to stimulate domestic demand in a variety of segments—including power generation, fertilizer manufacture, petrochemical production, transport, and residential use—has in a number of cases deterred the development of gas supply and led to shortages. Some countries have balanced political pressure for government intervention in the market with the need to reduce problematic distortions by setting up hybrid markets with both liberalized and planned components. Another challenge faced by gas-rich governments is how to mitigate risks faced by both prospective gas suppliers and prospective gas consumers in a nascent market, especially given the need for costly gas transport infrastructure.

### *Policy Implications*

- The excessive or inappropriate use of mandates requiring that gas producers supply domestic consumers at highly subsidized prices characteristically leads to the following negative impacts:
    - More limited gas supply
    - Heavy financial burden to the state
    - Overconsumption and misallocation of gas in the economy
    - Shortages
- While restricting uncommitted gas exports in the face of shortages may have limited negative impacts, major deviations from terms of existing contracts can cause severe reputational damage that affects future gas development, as in the case of Algeria.
- Creation of hybrid markets with both liberalized and planned components can be a surprisingly successful way to sidestep entrenched political resistance to reforms.
    - The liberalized portion of the market tends to grow over time.
    - Customers that are less politically connected are able to obtain gas.
    - The establishment of hybrid markets tends to create a momentum that leads to future reforms.
    - Liberalizing "non-strategic" industrial segments first can be effective because (1) gas already may be more competitive in these segments and (2) these segments are less politically fraught.
- Gas project outcomes are most favorable when the government works to mitigate supply and demand risks in tandem.

Natural gas can offer substantial environmental, energy security, and convenience advantages over competing fuels such as coal and oil.[1] Gas is relatively abundant in the world,[2] but the adoption and use of gas are hindered by its requirement for costly transport infrastructure. Because the pipelines or liquefied natural gas (LNG) facilities for moving gas are so expensive to construct, investors depend on many years of reliable operation to recover their upfront capital outlays. Governments hoping to fully develop their domestic gas resources must therefore offer a predictable investment climate and transparent regulatory framework to attract the needed capital and technology from domestic or foreign investors. Moreover, they must ensure that these expensive pipelines and LNG facilities will find consumers on the other end who are willing to pay prices for gas sufficient to enable long-term cost recovery.[3] Bringing new gas to market thus means solving a high-stakes coordination problem that spans the upstream (development of the gas field itself), midstream (construction of transport infrastructure), and downstream (provision of gas to end use customers) parts of the gas value chain.

Many Asian countries with sizeable gas reserves are striving to further develop domestic gas markets in order to realize a range of benefits:

- *Food security.* Natural gas is a major feedstock into the production of nitrogenous fertilizers, and governments concerned with feeding large populations may value self-sufficiency in fertilizer production.

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[1] Natural gas emits on average approximately 40% and 50% less carbon dioxide than fuel oil and coal, respectively, per unit of electricity and heat generated. See OECD/International Energy Agency (IEA), *CO2 Emissions from Fuel Combustion: Highlights* (Paris: OECD/IEA, 2010). In addition, natural gas has negligible sulfur and mercury content compared to coal.

[2] World natural gas reserves (conventional) as of 2009 stood at 187.5 trillion cubic meters (tcm) or 1,142 billion barrels of oil equivalent (boe), compared to 122.4 tcm or 745.2 billion boe in 1989. World oil reserves at the end of 2009 were approximately 1,333 billion barrels. See “BP Statistical Review of World Energy 1990,” BP plc, 1990; and BP “Statistical Review of World Energy 2010,” BP plc, 2010. Unconventional gas could significantly increase the recoverable amount of natural gas in the world, with estimates varying wildly from 60% of conventional reserves to over 200%.

[3] International spot trades of liquefied natural gas (LNG) have begun to connect regional markets through price arbitrage, but a liquid global market for gas does not yet exist to nearly the degree that it does for oil. The oil market was not always so liquid. For a discussion of how the state of gas markets today recalls that of oil markets before the 1960s, see Peter A. Nolan and Mark C. Thurber, “On the State’s Choice of Oil Company: Risk Management and the Frontier of the Petroleum Industry,” Stanford University, Program on Energy and Sustainable Development, Working Paper, no. 99, 2010.

- *Energy security.* Gas may be prized as an abundant domestic fuel or for its role in diversifying the energy supply.
- *Industrial competitiveness.* Cheap natural gas can be provided to industry as a source of energy or as a general petrochemical feedstock.
- *Pollution reduction and quality of life enhancement.* Gas is a clean and convenient household fuel. In addition, migration to gas from dirtier alternatives such as coal or oil in the transport, industrial, commercial, or residential sectors can help reduce urban pollution.
- *Climate change mitigation.* In electricity generation applications, natural gas typically emits around half the carbon dioxide of coal.

However, because of the unique challenges of building a viable gas value chain, policies to stimulate domestic demand in pursuit of these goals run the risk of discouraging supply. Keeping domestic gas prices artificially low, for example, to favor industries such as power generation or fertilizer production deters investment in infrastructure to supply domestic customers. It also encourages overuse of gas, which in combination with anemic supply leads to shortages. On the other hand, high domestic prices can make natural gas uncompetitive against cheaper options such as coal. They may also be politically untenable in major producing countries, where consumers may feel entitled to benefit directly from their nation's ownership of natural resources like gas.

Governments hoping to successfully develop gas resources and find substantial customers at home must deploy policies that harmonize and encourage the various investments required across the gas value chain. The exact policies through which governments try to do this depend on the specific goals of political leaders and various aspects of the particular country. Relevant country-specific factors include the nature of domestic gas resources (how easy is it to produce the gas and bring it to market), the mix of existing and potential gas-consuming demand segments (such as industry, households, and power generation), the availability of alternatives to natural gas, the country's population and level of economic development, and the political system in place.

Policies to develop gas and bring it to market in-country can be broadly divided into two types: centrally planned and market-oriented. **Figure 1** shows examples of policies in each category that can be applied in the different parts of the gas value chain.

The remainder of this essay considers a number of these policies and the experiences of gas-rich Asian countries (and, where instructive, countries outside Asia) in using them to balance the competing priorities of domestic market development and expansion of the gas supply. We start by focusing in turn on the upstream, midstream, and downstream pieces of the gas value chain, illustrating the way that incentives in one segment tend to fail if not supported by compatible policies in the other segments. We then turn to a characteristic "cluster" of policies across the upstream, midstream, and downstream that is often found in countries favoring centrally planned industrial development. This cluster of policies leads to market distortions that cause problems for these countries, so we consider how governments might transition to more market-oriented policies in order to ease some of these difficulties. Our ultimate goal is to help policymakers in gas-rich governments think through the trade-offs and pitfalls associated with different strategies for developing their domestic gas markets.

FIGURE 1 **Sample Policy Instruments in Each Segment of the Natural Gas Value Chain**

| | | | |
|---|---|---|---|
| Centrally-planned | Non-competitive hydrocarbon licensing<br>Fixed wellhead prices<br>Domestic market obligation<br>Export restrictions | Government builds infrastructure itself<br>Regulated transport tariffs<br>Restricted pipeline access | Planned prices by end use segment<br>Mandates for particular end uses<br>Low cost of capital for favored industries |
| Market-oriented | Competitive hydrocarbon licensing<br>Favorable tax and royalty terms for gas development<br>Unrestricted access to international or domestic gas markets | Open bidding for infrastructure contracts<br>Utilization ensured through long-term contracts for gas<br>Government may offer incentives/guarantees to reduce risk<br>Open pipeline access | End use prices based on supply and demand<br>Put environmental or other externalities into price |
| | Upstream | Midstream | Downstream |

## The Importance of Harmonizing Policies Across the Gas Value Chain

*Upstream Incentives*

One the most striking examples of the ineffectiveness of upstream incentives in isolation comes from outside Asia. Nigeria's development of natural gas has fallen far short of its potential despite generous incentives that were put in place in the late 1990s to encourage upstream investment in gas.[4] The international oil companies that extract Nigeria's hydrocarbons were granted tax and royalty terms for gas that were significantly more favorable than those for oil. Although one major gas export project, Bonny LNG, was brought online after a very long time in gestation, large non-associated gas resources remain untapped and Nigeria's domestic gas market is severely underdeveloped on the whole. The fundamental problem is that upstream incentives have not been matched by market-oriented policies in the downstream that would enable a genuine domestic gas market to emerge. Gas is sold by the Nigerian Gas Company (NGC), a subsidiary of the Nigerian National Petroleum Corporation (NNPC), at official prices that do not allow for cost recovery. Often NGC cannot even collect payment for gas from the national power company, which itself is forced to sell electricity below cost.[5] No oil company is willing to risk developing a gas field and the associated transport infrastructure aimed at domestic consumption with so little prospect that prices paid by consumers will actually enable cost recovery.

India's New Exploration Licensing Policy (NELP) in the late 1990s provides a counterexample of upstream incentives that were successful in generating investment, precisely because they were matched with appropriate midstream and downstream policies. In addition to opening oil and gas exploration blocks previously controlled by state companies to private bidders, NELP allowed these private entrants to sell their produced hydrocarbons to offtakers at negotiated prices rather than official prices set by the government.[6] NELP also permitted private players to make investments in gas

[4] M.C. Thurber, I. M. Emelife, and P.R.P. Heller, "NNPC and Nigeria's Oil Patronage Ecosystem," Stanford University, Program on Energy and Sustainable Development, Working Paper, no. 95, 2010.

[5] Thurber, Emelife, and Heller, "NNPC and Nigeria's Oil Patronage Ecosystem."

[6] A. S. Corbeau, "Natural Gas in India," IEA, Working Paper, 2010, 16; M.P. Jackson, "Natural Gas Sector Reform in India: Case Study of a Hybrid Market Design," Stanford University, Program on Energy and

transport infrastructure, including LNG import terminals. The resulting ability to manage the midstream and downstream as well as the upstream part of the gas value chain gave private companies confidence that they could put together profitable business models for selling gas. As we will discuss further, NELP has been a resounding success overall, as evidenced by the significant growth in the share of gas sold under its auspices.

*Midstream Incentives*

Governments may correctly perceive the important role of gas transport infrastructure and the obstacles to building it, and they may thus pursue what could be called an "if you build it they will come" approach to developing the domestic gas market. Certainly, building crucial pipeline infrastructure can help stimulate demand. Industries and power plants exploiting gas proliferated along the path of India's Hazira-Bijapur-Jagdishpur (HBJ) Pipeline from western gas fields through the northwest part of the country.[7] The existence of the pipeline now makes residential gas applications possible near the HBJ Pipeline as well, even though industry was the original driver of the pipeline's development.[8] China's West-East Gas Pipeline (WEGP) linking the Tarim Basin in Xinjiang Province to demand centers near Beijing and Shanghai seems to have had a major effect in fostering gas-based industrial activity along its route while enabling the development of additional supply in the west of the country. As gas began to flow, many city-gas distribution companies within tie-in distance of the WEGP also began to convert their pipeline networks and customer appliances, originally intended for town gas or manufactured gas, over to natural gas.[9] As of 2007, two years after the WEGP's

Sustainable Development, Working Paper, no. 43, 2005; OECD/IEA, *World Energy Outlook 2010* (Paris: OECD/IEA, 2010); and Wood Mackenzie, *South East Asia Upstream Service – India*, 2009. (The Wood Mackenzie report is available to customers of the company's Upstream Service, which provides country- and asset-level analysis of oil and gas exploration, development, production, and transportation.)

[7] S. Joshi and N. Jung, "Natural Gas in India," in *Natural Gas in Asia: The Challenges of Growth in China, India, Japan, and Korea*, 2nd ed., ed. J. Stern (Oxford: Oxford University Press, 2008), 66–115.

[8] Wood Mackenzie, *South East Asia Upstream Service – India*.

**[9]** See James W.K Wong, "City Gas Development in China—an NG Perspective," *Energy Policy* 38, (2010): 2107–9. Wong in fact points out that the proliferation of city gas—to the concern of regulators—has resulted in a directive to local governments to moderate gas growth lest demand become excessive.

completion, Chinese domestic gas production had roughly doubled relative to the pre-WEGP levels of 2003.[10]

At the moment, China's national oil companies are constructing natural gas pipelines and LNG receiving terminals at a breakneck pace. Gas supply projects in progress include the second and third West-East Gas Pipelines, with a fourth possible depending on the outcome of negotiations with the Russian and Central Asian governments on gas availability. Together with three LNG facilities currently operating and at least six additional planned regasification units, these projects could bring gas import capacity to 200 billion cubic meters (bcm) per year by 2020, which in conjunction with further development of domestic gas resources, including unconventional sources such as coal bed methane (CBM) or coal gasification, could in an optimistic scenario bring total expected gas supply to 400 bcm per year by the end of this decade.[11]

State-led infrastructure development efforts can founder in the absence of a customer base willing to pay adequate prices. However, Chinese state-owned enterprises (SOE) in energy have been able to pursue an aggressive infrastructure-oriented approach in part because the government ultimately underwrites the risk that demand will fall short of expectations. Because gas infrastructure is extremely expensive—an estimated $5.3 billion for the WEGP, compared with only $3.3 billion for the associated upstream development[12]—such projects typically only go forward with a group of partners sharing the risk. However, when a Shell-led international consortium pulled out of the WEGP in 2004 over concerns about the development of demand markets and the likely rate of return, the project proceeded anyway with 95% ownership by China National Petroleum Corporation (CNPC) subsidiary PetroChina.[13]

Nevertheless, even when infrastructure gets built, insufficient attention to issues of downstream demand can lead to disappointing results. At times, China has probably

[10] Wood Mackenzie, *South East Asia Upstream Service – China*, 2009.

[11] Author interview with Chi Guojing, Senior Economist of the China Gas Association, conducted in Beijing in October 2010.

[12] Wood Mackenzie, *South East Asia Upstream Service – China*.

[13] Wood Mackenzie, *South East Asia Upstream Service – China*.

suffered from an excessive focus on infrastructure development at the expense of demand cultivation. As described by David Fridley, a pipeline from Shaanxi to Beijing that came online in 1997 was intended to spur rapid fuel switching to gas in residential, power, and industrial applications.[14] Instead, actual volumes fell far short of capacity due to the failure to contract sufficient demand, underestimation of the costs of retrofitting the city's distribution system, and inadequate planning of storage to meet fluctuating demand.[15]

*Downstream Incentives*

The mirror image of a supply and infrastructure orientation is a policy focus on stimulating demand for gas. The most important downstream policies influencing gas demand are those related to pricing. Many Asian governments offer gas to domestic consumers at subsidized prices that vary by demand segment. Especially in India and China, with their large populations and memories of horrific famines, fertilizer producers have historically received some of the most favorable prices in the name of self-sufficiency in food production.[16] In cases such as Malaysia, India, and China, power generation has been granted favorable gas prices as a "strategic industry" that helps to fuel broader economic growth through low electricity tariffs. Certain populations in China, Indonesia, India, and Malaysia receive highly subsidized prices at the household level because their respective governments desire as a matter of social policy to provide a convenient household fuel to citizens who otherwise might not be able to afford the gas.

Artificially low prices certainly stimulate demand, but this kind of centrally planned approach leads to a host of problems that will be discussed later—not least the fact that it deters investment in both the upstream and midstream segments. A less

[14] D. Fridley, "Natural Gas in China," in *Natural Gas in Asia: The Challenges of Growth in China, India, Japan, and Korea*, 2nd ed., ed. J. Stern (Oxford: Oxford University Press, 2008), 7–65.

[15] Fridley, "Natural Gas in China."

[16] B. Jiang et al., "The Future of Natural Gas Consumption in Beijing, Guangdong and Shanghai: An Assessment Utilizing MARKAL," *Energy Policy* 36 (2008): 3286–99; and M.P. Jackson et al., "The Future of Natural Gas in India: A Study of Major Consuming Sectors," Stanford University, Program on Energy and Sustainable Development , Working Paper, no. 65, 2007.

problematic way to make gas more attractive in end-use applications is to incorporate environmental externalities into fuel price. Given that gas-fired power plants typically emit at least half the $CO_2$ emissions of generators running on coal, carbon pricing in the service of climate change mitigation would give a boost to gas. Because in most developing countries local air pollution is a more pressing concern than climate change, the regulation of smog precursor $SO_2$ is perhaps a more plausible scenario that might favor natural gas use. Such regulation is likely to take the form of explicit restrictions on emissions or mandates for emissions control technology rather than the use of a price-based instrument. Modeling by Jiang et al. suggests that $SO_2$ restrictions in major urban regions of China could spur appreciable fuel switching from coal to gas—for example, through replacement of industrial coal boilers in Shanghai.[17] Dhar and Shukla and Jackson et al. also find that $SO_2$ limits in India lead to some fuel switching to gas in their model scenarios, although the predominant approach to $SO_2$ control would be the use of flue gas desulfurization (FGD) technology in the power sector.[18] More direct price preferences for gas applications are also possible, of course, such as the granting of higher power tariffs for gas-fired generation, analogous to those received by renewable energy sources in China and various other countries around the world.

Another strategy for encouraging gas demand is to remove existing distortions in the financial or regulatory systems that create biases against investment in gas. In China the artificially low cost of capital for state-owned power companies is one such distortion. Gas power plants are significantly less capital-intensive to build than coal plants, but operating costs are higher because gas is more expensive than coal. As demonstrated by the modeling of Jiang et al., the low cost of capital for the power sector as a "strategic industry" thus has the effect of skewing power plant economics in favor of

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[17] See Jiang et al., "The Future of Natural Gas Consumption." Electricity generation, which would seem to offer large potential demand for gas in China, may not see near-term fuel switching to the same degree due to a lack of policy support. In 2007 the National Development and Reform Commission issued a policy statement on natural gas use that prioritizes the residential sector, suggesting that, in an environment where gas supply is highly strained, gas-fired generation capacity may not develop beyond peaking supply. See J.J. Tu, "Industrial Organization of the Chinese Coal Industry," Stanford University, Program on Energy and Sustainable Development, Working Paper (forthcoming).

[18] S. Dhar and P. Shukla, *Natural Gas Market in India: Evolution and Future Scenarios* (New Delhi: Tata McGraw Hill, 2010); and Jackson et al., "The Future of Natural Gas in India."

coal.[19] The fact that the price electricity generators receive does not reflect real-time, system-wide supply and demand in China also disadvantages gas by failing to properly account for the benefits of low-capital-cost gas turbines in peaking power applications. Reforms to address distortions in capital allocation and electricity pricing in China could thus benefit gas-fired power even if they are not intentionally directed at this goal.

Urban pollution concerns have led to direct mandates for gas in the transportation sector in several countries. Notably, several Indian cities have mandated the use of compressed natural gas (CNG) for their public transportation and taxi fleets. A citizen's lawsuit in 1985 over poor air quality in Delhi eventually resulted in a Supreme Court order to convert all public transportation (including buses, taxis, and rickshaws) in Delhi to CNG in 1998, followed by an additional order in 2003 to convert public transportation in 11 other cities.[20] Pakistan, which began to seriously pursue CNG conversion in the 1990s, now has over 2 million vehicles running on natural gas.[21] The success in Pakistan, which now has more natural gas vehicles than any other country, is the result of government policies that promoted fuel switching by keeping CNG prices cheaper than gasoline, encouraged the development of infrastructure (pipelines and refueling stations), and exempted CNG equipment and conversion kits from import and sales duties.[22] In fact, the development of CNG vehicles and technologies has been so successful that Pakistan has been helping Iran promote the use of CNG-powered vehicles.[23]

Motivated by worsening air quality, Indonesia too has been pushing CNG for transportation in its urban areas. The Indonesian government ordered public transportation vehicles in Jakarta to begin to switch to natural gas in 2001. However, due to a combination of slow policy implementation, lack of infrastructure, high prices for

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[19] Jiang et al., "The Future of Natural Gas Consumption in Beijing."

[20] S. Yeh, "An Empirical Analysis on the Adoption of Alternative Fuel Vehicles: The Case of Natural Gas Vehicles," *Energy Policy* 35 (2007): 5865–75.

[21] International Association of Natural Gas Vehicles, "Natural Gas Vehicle Statistics," December 2009, http://www.iangv.org/tools-resources/statistics.html.

[22] H.A. Raza, "Development of CNG Industry in Pakistan," Hydrocarbon Development Istitute of Pakistan, 2003, http://gee-21.org/publications/Development-of-CNG-Industry-in-Pakistan.pdf.

[23] "Pakistan to Cooperate with Iran in Developing CNG Industry," Pakistan Newswire, March 30, 2002.

conversion kits, and a general lack of public interest, the rate of CNG vehicle use has been stagnant. As of the end of 2007, there were only seven CNG refueling stations in all of Jakarta,[24] and the government has expressed doubt that its goal of converting all public and government vehicles to CNG by 2012 is feasible.[25]

As this example illustrates, mandates for gas use can prove highly counterproductive if policy commitment is lacking and especially if reliable gas supply fails to materialize. In the context of the HBJ Pipeline, India also created a situation in which its efforts to stimulate demand were out-of-step with the realities of supply at the time. The government strongly encouraged the development of gas-consuming industries along the pipeline route, but the unreliability of gas supply caused problems for customers, ultimately forcing many to build plants that could run on multiple fuels.[26] Because of its costly infrastructure requirements, gas more than any other fossil fuel requires careful efforts to harmonize supply, infrastructure, and demand within a pricing framework that assures market players an adequate return on investment.

## Central Planning Across the Gas Value Chain

As the above examples illustrate, policy choices in one part of the gas value chain have implications for the other parts. Many countries start with a central planning orientation in the downstream, which tends to create corresponding pressures for central planning and government control in upstream and midstream segments. The result is a characteristic cluster of interlocking, centrally planned policies across the gas value chain that is observed in many countries; unfortunately, this cluster of policies also introduces predictable difficulties.

As discussed in the preceding section, government goals such as food security, energy security, industrial competitiveness, quality of life enhancement, and pollution reduction can encourage the extension of price subsidies to favored industries or

[24] Mustaqim Adamrah, "Petrol Stations to Provide Natural Gas," *Jakarta Post*, November 19, 2007.

[25] "Government Fuel Conversion Policy Offers Business Market, Improves Air Quality," *Antara* (Indonesia), November 2, 2010.

[26] Jackson et al., "The Future of Natural Gas in India."

household consumers. These subsidies usually have broad populist appeal, but they introduce several characteristic problems that policymakers try to counteract with measures elsewhere in the supply chain. First, by lowering the expected return on investment, low domestic prices discourage the development of infrastructure to serve domestic markets. Where the state is able to put its own capital at risk, it may step in and finance the infrastructure itself, often through a national oil company (NOC), as occurred in the case of China's WEGP. Where the state is not able to put up its own capital, pipelines for the domestic market may simply not be built, as has happened in Nigeria. Second, low domestic gas prices discourage private players focused on returns from developing gas for local consumption. One way to address this problem is to put an NOC in charge of upstream development and simply order it to supply domestic markets. An alternative approach applicable in gas-exporting countries is to allow private players to develop gas fields for export but then require that they allocate a certain percentage of their production to the domestic market, thus essentially cross-subsidizing domestic consumption with profits from exports. This type of policy is known as a domestic market obligation (DMO).

Indonesia has incorporated a formal DMO in oil contracts since the mid 1960s,[27] requiring that the private participants in production-sharing contracts sell a portion of oil production, typically 25%, into the domestic market at below-market prices. In 2002, the new oil and gas law in Indonesia forced NOC Pertamina to relinquish its monopoly in upstream gas and at the same time created a DMO for gas to try to ensure that the domestic market would be served. The gas DMO in Indonesia is generally interpreted as requiring that about a quarter of production be reserved for domestic use, although the exact requirements have remained somewhat ambiguous.[28] Other Asian countries seem content for the moment to allocate subsidized domestic supply through their NOCs. The Oil and Natural Gas Corporation (ONGC) in India, Petronas in Malaysia, PTT in

[27] Wood Mackenzie, *South East Asia Upstream Service – Indonesia*, 2009.

[28] Wood Mackenzie, *South East Asia Upstream Service – Indonesia*. Indonesia has also taken tentative steps toward putting in place a DMO for coal. For further discussion see B. Lucarelli, "The History and Future of Indonesia's Coal Industry: Impact of Policies and Regulatory Framework on Industry Structure and Performance," Stanford University, Program on Energy and Sustainable Development Working Paper, no. 93, 2010.

Thailand, and CNPC and Sinopec in China, among others, all provide gas to domestic consumers at subsidized prices that vary by demand segment.

The use of DMOs or NOCs provides a superficial solution to the problem of how to supply the domestic market at subsidized prices, but it does not eliminate several basic problems associated with subsidies. First, subsidies still discourage development of new supply by lowering overall return on investment for both private and state-owned players. For private players subject to a DMO, the requirement to sell a portion of gas at low domestic prices mean more marginal projects will fall short of internal rate of return targets and thus not be developed. SOEs can in theory be forced to develop projects even with poorer economics, but in practice the managers of NOCs competent enough to develop gas in the first place strongly prefer to serve demand that boosts their bottom line.

Second, subsidizing gas use in the domestic market can be expensive for the state. When state energy enterprises of any kind take losses as a result of their requirement to sell energy at below-market rates, the state must find some way to make them whole, generally through formal or informal subsidies. In China's coal sector, for example, state power companies took massive losses on their books in 2008 when liberalized coal prices climbed significantly above the amounts that could be recovered through capped power prices.[29] The national oil company CNPC is reportedly absorbing large losses on gas. According to the China Gas Association, CNPC, which supplies some 90% of the natural gas in China, is losing as much as 1 renminbi per cubic meter of WEGP gas sold in Shanghai because the price it is allowed to charge does not cover the cost of the gas and the transport tariff. Petronas, Malaysia's NOC, has forgone 58 billion Malaysian ringgit in revenues since 1997 by subsidizing independent power producers.[30] India heavily subsidizes a range of hydrocarbon products, including natural gas, at an estimated cost in

[29] R. M. Morse, V. Rai, and G. He, "The Real Drivers of Carbon Capture and Storage at Scale in China and Implications for Climate Policy," Stanford University, Program on Energy and Sustainable Development Working Paper, no. 88, 2009.

[30] The Malaysian ringgit was worth roughly between $0.25 and $0.32 during this time. See S. Jayasankaran, "Gas Supply Hitch in M'sia Deters Foreign Investors; 8 Foreign Firms Defer RM8b Investments on Gas Supply Concerns," *Business Times Singapore*, Janurary 14, 2009.

2009 of just over $21 billion, or about 1.7% of India's GDP.[31] However energy subsidies are administered, they can be a substantial drain on state coffers and are frequently not sustainable over the longer term.

Third, mandating that cheap gas be provided to politically favored consumers can lead to overconsumption and serious misallocation of gas in the economy. Although the provision of cheap gas to domestic fertilizer producers in India appears politically sacrosanct, it is likely that the country could meet its food security goals more efficiently through fertilizer imports from the Middle East while freeing up significant additional gas for power and industrial applications.[32] Russia suffers from massive overconsumption of gas, the result of heavily subsidized prices for domestic industry. Cheap gas was one of the few sources of competitive advantage for Soviet-era industry; in a number of cases, legacy gas-consuming facilities are not metered at all.[33] The result is an astonishingly high gas intensity for the Russian economy: 349 cubic meters per $1,000 GDP in 2009, compared to 45 cubic meters per $1,000 GDP in the United States.[34]

Fourth, a predictable result of subsidized demand and unenthusiastic producers is shortages. Malaysia, a major exporter of LNG to other Asian countries, is facing tension between rising domestic demand and Petronas's obligation to deliver LNG abroad under long-term gas sales agreements. As a result, even domestic industry players preferred by the government, such as power producers and rubber glove makers, have difficulty obtaining additional gas supplies.[35] Even gas-rich Russia finds itself facing a major squeeze on gas supply despite its massive reserves. As a result, Moscow has leaned

[31] OECD/IEA, *World Energy Outlook 2010*.

[32] Jackson, "Natural Gas Sector Reform in India."

[33] N.M. Victor, "Gazprom: Gas Giant Under Strain," Stanford University, Program on Energy and Sustainable Development Working Paper, no. 71, 2008.

[34] Calculated based on 2009 IEA and World Bank data on gas consumption and GDP, respectively. See IEA, *IEA Natural Gas Information Statistics Database*, May 31, 2010, OECD iLibrary: DOI:10.1787/naturgas-data-en; and The World Bank, *The World Bank Data Catalog*, http://data.worldbank.org. Although the Russian government has steadily increased the price of natural gas since 2000, the subsidies remain significant. According to the 2010 World Economic Outlook, natural gas subsidies stood at almost $31 billion in 2008, dropping down to $19 billion in 2009 after world natural gas prices moderated. See OECD/IEA, *World Energy Outlook 2010*.

[35] R. Cheah, "Malaysia Says Has No Gas for New Manufacturers," Reuters, February 4, 2010.

heavily on Turkmenistan to supply gas to Russia even as it tries over time to rationalize its domestic pricing.[36]

When shortages become acute, governments in theory can respond by trying to severely or entirely curtail exports. China did this for coal in 2008.[37] The government of Indonesia has said that it will attempt to limit gas exports in order to satisfy unfilled domestic demand of approximately 71 million cubic meters per day.[38] Although the government has pledged to honor existing contractual obligations, it is nevertheless seeking to renegotiate export contracts. It was reported in June 2010 that Indonesia is seeking a deal with Singapore to reduce gas exports to the city-state, which currently receives over 22 million cubic meters per day.[39] Indonesia is wise to be wary of drastic action. While governments may have some room to limit exports of gas that are not already committed, taking the stronger step of defaulting on delivery obligations (or dramatically changing pricing terms on a unilateral basis) can have serious long-term costs for the gas producer and is thus generally avoided. In 1980 Algeria sought to massively hike gas prices with the threat of withholding deliveries; the resulting damage to its reputation severely harmed the country's LNG export business for many years to follow.[40]

For all the problems of mandating cheap supply of domestic gas through either an NOC or DMO, this policy strategy seems likely to persist for reasons including its broad populist appeal as well as the more targeted lobbying of industries that benefit from subsidies. Even in Australia, where oil and gas markets have been mostly liberalized since the 1980s, a form of domestic market obligation has been implemented in response

[36] Victor, "Gazprom: Gas Giant Under Strain," 15.

[37] China has traditionally used a quota system for coal which allows a select group of coal exporters to export according to quotas distributed several times per year. While the total annual export quota in recent years has been small compared to the total domestic demand (roughly 40-80 mt compared to nearly 3 Bt), government policy still tends toward restricting exports when domestic markets are tight by reducing the total quota to exporters.

[38] R. Sasistiya, "Gas Prices Will Have to Go Up, Govt Says," *Jakarta Globe*, May 18, 2010.

[39] W. Soeriaatmadja, "Jakarta Reassures Singapore on Gas Supply," *Strait Times*, June 18, 2010.

[40] M. Hayes, "The Transmed and Maghreb Projects: Gas to Europe from North America," in *Natural Gas and Geopolitics: From 1970 to 2040*, ed. D. G. Victor, A. M. Jaffe, and M. H. Hayes (Cambridge: Cambridge University Press, 2006), 87.

to pressure from gas-consuming industries, much to the consternation of upstream producers. With the strong support of a coalition of metals, mining, fertilizer, and power companies,[41] the state of Western Australia in 2006 put in place a "domestic gas reservation policy" as a way to insulate local prices from international markets.[42] The policy is somewhat flexible in implementation—it does not specify a price and is set up such that the government of Western Australia negotiates how the domestic requirement is to be met with LNG projects on a case-by-case basis.[43] Nevertheless, as an implicit tax on gas exports to subsidize domestic industry, the policy represents a kind of resource nationalism.[44]

The establishment of the gas reservation policy in Western Australia also highlights the importance of interest group politics in policymaking. In this case, the alliance of gas-consuming industries has come out on the winning side for the time being of a lobbying battle against gas producers, who suffer because domestic prices in Western Australia are lower than what they could fetch for LNG exports. In any country, groups with strong political connections tend to gain some influence over the shape of regulations, whether in the context of domestic market obligations or other policies. For example, independent power producers in Malaysia, which consume about half of all natural gas sold to generators, reportedly receive highly favorable gas tariffs in part as a legacy of their close relationship with the Mahathir government when it was in power.[45]

To the extent that the political logic of subsidizing gas for specific industries overrides other arguments against doing so, governments should at least proceed in as stable and transparent ways as possible to minimize the negative effect on the investment

[41] The "Domgas Alliance" of gas-consuming industries in Australia accuses a consortium of oil companies developing gas in the country of intentionally "stepping on the hose" to reduce domestic supply and keep domestic prices high, while diverting volumes to LNG cargoes destined for more lucrative locations, such as China and Japan; see Domgas Alliance, "Western Australia's Domestic Gas Security," Report, 2010, http://www.domgas.com.au/pdf/Other_reports/DomGas_Report_2010.pdf/.

[42] J.L. Hay, "Challenges to Liberalism: The Case of Australian Energy Policy," *Resources Policy* 34 (2009): 142–49.

[43] Department of the Premier and Cabinet, "WA Government Policy on Securing Domestic Gas Supplies," 2008, http://www.dmp.wa.gov.au/documents/DomGas_Policy(1).pdf.

[44] Hay, "Challenges to Liberalism."

[45] A. Netto, "Fuel on Malaysia's Political Fire," *Asia Times*, June 11, 2008.

climate and in turn on the development of domestic supply. Stable rules minimize the risk premium private companies need to build in to their evaluations of project attractiveness. Loosening the grip of NOCs in domestic hydrocarbon markets is generally seen as a reformist measure, but when a government remains determined to mandate domestic supply at a subsidized price, it may in fact be preferable to do this through an NOC in order to avoid entangling private players in the uncertainty of a DMO.

## Loosening the Grip of Central Planning

Government policymakers are often fully aware of the distortions introduced by centrally planned policies but struggle to overcome the power of entrenched interests that benefit from the status quo. The fact that central planning is often manifest as a cluster of policies spanning the value chain—for example, NOC extraction of gas, control over infrastructure, and allocation of gas to end users—can make it particularly hard to implement alternative policies in any one area.

Except in countries with a long history of open markets, governments typically only pursue some measure of liberalization when they are forced to do so by unpleasant consequences of central planning. Indonesia, Malaysia, India, and China are all raising gas prices closer to market levels to better balance supply and demand. China's policymakers today are wrestling with how to introduce market reforms into a planned system of gas pricing and allocation that is poorly adapted to an increasingly complex market. The current approach, with price tiers by demand segment layered on top of an essentially cost-plus pricing methodology, has difficulty accommodating the proliferation of different sources of gas, including international gas, at different prices.[46] In addition, regulated prices and control of gas allocations by China's NOCs have led to a situation of significant unmet demand. The National Development and Reform Commission projected a natural gas shortage of 20 bcm for 2010,[47] which is approximately one-fifth of all natural gas expected to be consumed in China. This means that during peak winter

[46] N. Higashi, "Natural Gas in China: Market Evolution and Strategy," IEA, Working Paper, 2009.

[47] G.H. Shi et al., "Development Status of Liquefied Natural Gas Industry in China," *Energy Policy*, 38 (2010): 7457–65.

demand, gas may simply be shut off to industrial users and even to cities if supply becomes sufficiently scarce.

As illustrated in the previous section with examples from Australia and Malaysia, the most stubborn barriers to full liberalization can be connected with the political influence of gas-consuming industries. The creation of hybrid markets in which unregulated gas exists side-by-side with centrally planned gas can be one of the most effective methods to sidestep the political power of incumbents, particularly state-owned ones.[48] Excellent historical examples of this strategy were seen in both the Indian gas market and the Chinese coal market. India's move to create a market-based gas investment and pricing framework as part of the New Exploration Licensing Policy (NELP) in 1999[49] (see the discussion above of upstream incentives) was in many ways analogous to China's opening of its coal sector starting in 1979.[50] In response to severe production shortfalls relative to demand, both governments created a new class of market participants to operate alongside the large state-owned companies that had dominated the respective sectors up to that point. In the Indian gas case, private oil companies were invited to bid on new oil and gas exploration blocks. In China, locally controlled coal mines were allowed to operate alongside the central state coal mines. In both cases the new entities were also allowed to charge market or near-market prices.

In effect, both India (for gas) and China (for coal) created hybrid markets where entities owned by the national government supplied preferred customers at highly subsidized prices and more autonomous, market-oriented players supplied anyone else willing to pay. Similar broad outcomes followed in both cases. First, production from the market-oriented part of the market grew rapidly while production from the central state entities stagnated or declined over time. Second, end-use customers previously cut off from supply by a lack of political connectedness had a greater ability to obtain fuel. In the

[48] Jackson, "Natural Gas Sector Reform in India."

[49] India invited private participants in gas production sharing contracts (PSC) as early as 1994, but the government did not grant the right for the private companies to market the gas. It was not until after the NELP that private companies began marketing gas under arm's length agreements. See Dhar and Shukla, *Natural Gas Market in India.*

[50] W. Peng, "The Evolution of China's Coal Institutions," Stanford University, Program on Energy and Sustainable Development, Working Paper, no. 86, 2009, 11–17.

case of Indian gas, the new supply of domestic gas and imported LNG has proven very attractive for industrial consumers for whom, even at high prices, gas is a cheaper feedstock than oil-based alternatives such as naphtha.[51] Third, the creation of a hybrid market set in motion a process of reform that inexorably advanced over time in response to predictable market pressures. In China the liberalization of part of the coal market in 1979 eventually led to its complete liberalization twenty years later: prices for the major state coal mines were liberalized in 1993 except for coal used in power generation,[52] and by 2002 coal prices had been completely freed from direct control by the Chinese government.[53] In India, too, there are signs that the gas market reforms started two decades ago have developed a momentum of their own (notwithstanding a recent reversal that has seen the Indian government move to reinject itself to a degree into pricing of gas from new discoveries).[54] Over time, the proportion of subsidized gas has shrunk as a percentage of gas supplied to the Indian economy. It is estimated that by early 2010 only 35% of the gas in India was still supplied under the subsidized administrative pricing mechanism (APM).[55] In May 2010, in the face of persistent shortfalls in quantities of APM gas, the Government of India substantially increased APM prices to a near-market level from $1.79 to $4.20 per mmBtu. The government recently announced plans to further increase APM gas prices for non-core consumers up to $5.25 per mmBtu.[56]

As demonstrated in these cases, creating a hybrid market can be an effective way to circumvent powerful incumbents and start a process of genuine reform.[57] Non-strategic

[51] The first LNG import terminals were built in 2004 (Petronet) and 2007 (Shell) only after the government gave incentives—for example, by waiving price controls on imported gas. See Dhar and Shukla, *Natural Gas Market in India*, 37.

[52] As one would expect, this two-tier system ultimately collapsed because there were no incentives to increase the supply of coal for power generation.

[53] Peng, "The Evolution of China's Coal Institutions."

[54] Corbeau, "Natural Gas in India."

[55] Corbeau, "Natural Gas in India."

[56] "India Hikes Administered Pricing Mechanism Gas Price for Non-core Sectors," *India Public Sector News*, September 15, 2010.

[57] Tarun Khanna has referred to this process as "parallelization."

segments of the industrial sector are often good places to start. Gas may initially be more naturally competitive in these segments, and there are typically fewer large, politically entrenched players with bargaining clout than in sectors such as electricity generation and fertilizer production. As described in the discussion of upstream incentives, Nigeria is a country whose gas market is stuck in neutral in large part because there is no prospect that the state electricity company will be a profitable customer to serve anytime in the foreseeable future. The country's "Gas Master Plan" appears to recognize the potential for industrial gas use to be a pathbreaking segment; it recommends that gas be made available for non-strategic industrial uses at "market-led" prices, which could help attract supply.[58] A business proposition like this, wherein industrial enterprises pay near-international prices for reliable supply of gas from producers, might help spur the construction of domestic infrastructure in Nigeria that would facilitate gas-fired power and city gas at a later stage of market development.

Likewise, China might benefit from introducing a hybrid market in natural gas just as it did in coal many years ago. Already, coal bed methane (CBM) produced at the local level and transported by truck provides an unofficial, limited alternative for prospective consumers who cannot obtain allocations of gas from the Chinese NOCs. As CBM is not regulated under the framework that covers pipeline gas, buyers freely negotiate with producers to arrive at what is effectively a market price. The production of CBM in China is decentralized, but estimates put current annual production between 1.5 bcm to 2.35 bcm.[59] Although the thin coal seams in China mean that CBM development is relatively difficult, newer technology, especially from Australian mining companies, seems to have ignited commercial interest. The recent listing of CBM companies on public exchanges suggests a boom in the production of gas from this alternative source. The China Gas Association estimates that by 2015 CBM in China will annually produce at least 10

[58] See a November 2007 presentation entitled "The Nigerian Gas Master-Plan" by Abubakar Yar'adua, then group managing director of the Nigerian National Petroleum Corporation, to the Gas Stakeholders Forum in Abuja, Nigeria.

[59] The lower figure comes from an interview conducted by Chang with the China Gas Association; the higher figure comes from data quoted by the Tsinghua-BP Clean Energy Research and Education Centre.

bcm.[60] Allowing CBM production to officially develop under an open market framework might advance China's efforts to transition away from its difficult-to-manage cost-plus pricing system toward pricing that is governed by supply and demand.

## Conclusions

Development of the domestic gas market in a large gas-producing country is invariably fraught with challenges. Laissez-faire economists and gas producers might applaud a completely open market, but consumers forced to pay perceived high prices for resources extracted from under their own nation's soil almost certainly will not. Moreover, gas markets rarely develop without at least some degree of government intervention; the risks associated with infrastructure development are simply too high. Because policymakers must balance so many different priorities and at the same time address all parts of the gas value chain, there is unlikely to be a perfect solution, and many policies will have something of a "second-best" character. However, it is possible to anticipate some of the pitfalls that will arise in connection with different policies and to try to mitigate them to the extent possible.

Several broad observations emerge from the examination of policy strategies here. First, risk mitigation is a crucial part of developing the full gas value chain from upstream through midstream to downstream. For gas producers, risk mitigation is about ensuring that any gas field that is developed will find suitable transport infrastructure for gas and a customer willing to pay a reasonable price on the other end. Tax and royalty incentives for field development are welcome, but the ultimate decision to develop a gas field or not depends much more significantly on the degree of certainty around infrastructure and demand. Governments can play an important role in underwriting the risks of infrastructure development themselves, as in China, or in establishing a sufficiently stable regulatory framework to provide confidence in long-term cost recovery for suppliers. On the demand side, prospective gas consumers must be reassured that planned gas supplies

[60] Interview with the China Gas Association. However, it is important to note that unconventional gas development in China will hinge on the government's pricing policy, which at the moment is to steadily raise natural gas prices annually. A high gas price environment is necessary for unconventional gas to flourish in China.

will indeed materialize before they will be willing to make major investments in gas-consuming facilities. Governments must simultaneously pursue risk mitigation for both gas suppliers and gas users; an overly narrow focus on either the supply or demand side can lead to major setbacks.

Second, the choice of centrally planned or market-oriented policies in the downstream tends to constrain the available options in the upstream and midstream. Many countries have chosen to subsidize gas prices to end users, but this makes it more difficult to attract investment in gas field development and transport infrastructure. In theory, governments in this situation can turn to NOCs to fulfill upstream, midstream, and downstream functions. In practice, however, this solution is imperfect. The investment capacity of an NOC is limited by the capital a state is able to put at risk. Furthermore, even NOC managers tend to be unenthusiastic about supplying domestic consumers if they can make a better return through exports. By contrast, when gas can be sold to end users at market-determined prices, it is much more straightforward to attract private investment into the upstream and midstream. At the same time, some form of government involvement to reduce the risk of major infrastructure development will likely remain important.

Third, policymakers may be able to find creative policy strategies that accomplish desired goals with minimal unintended consequences while skillfully working around political constraints. Realistically, it can be difficult to avoid some degree of government intervention in resource issues, even in traditionally free-market environments like Australia. As a response to this state of affairs, particularly where state-owned companies play a dominant role, the establishment of a hybrid market with both open-market and legacy planned parts has proven to be one of the more effective means to transition from a tightly controlled to a more flexible regime over time. Strategic segments such as power generation or fertilizer production attract the most political attention, which is precisely why other industries like petrochemical production might serve as a better platform for introducing market elements into gas allocation. Over time, these islands of open access can grow to attract more and more of the gas supply and the capital needed to develop it.