Finding the ‘Right’ Price for Exhaustible Resources: The Case of Gas in the Gulf

Produced as part of the Valuing Vital Resources in the Gulf series
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The Valuing Vital Resources Series

The Valuing Vital Resources initiative encourages incentives for the sustainable use of energy, water and food by furthering understanding of the economic and societal costs of their interlinked modes of use and production. It involves a series of dialogues, materials and country-focused reports to gather and make available international experience in cost-assessments, price reform and related policies. The aim is to provide tools and expert networks that can support countries which currently administer resource prices and are in the process of, or considering, price reforms.

This Research Paper

This paper, part of the Valuing Vital Resources research series, draws on expert opinion from the Arab Gulf region and international experience presented at three workshops in 2013. The initiative was a response to the strong interest expressed by experts from the focus countries in moving towards more effective pricing for nationally produced resources. Gas has no obvious benchmark price, yet is being consumed excessively in the region – an indication that its domestic price is too low. This paper looks at the theory and complexity of pricing gas with reference to country case studies – with the aim of highlighting key issues for ministries of finance and other relevant government bodies engaged in developing more efficient pricing and allocation systems. Much of the discussion is also relevant to other exhaustible national resources which do not have a natural price benchmark, including groundwater.
Summary

• Most of the Gulf countries are gas-rich but prone to shortages. Price neither properly reflects costs nor rewards sustainable use, and a lack of price benchmark inhibits policy and investment choices to address the problems this is causing.

• Deciding what gas should cost is complicated by several features: transporting gas and using it rely on expensive infrastructure, so gas does not have an fully international market like oil; it is often produced as a by-product of oil production, and, like other fossil fuels and fossil water, is an exhaustible resource.

• To find the ‘efficient’ price for gas (against which one can compare the price that is set by the state), a producer government will need to assess:
  • the current costs of producing the gas (including evaluations for energy and water inputs) and transporting it to its users domestically;
  • the capital investment requirements to bring on additional supply to meet expected demand; and, if applicable:
    • the export price for domestically produced gas and how much could practically be exported – often called ‘opportunity cost’; or similarly, the price of the substitute energy source;
    • environmental and public health impacts of production, the amounts and costs of these – e.g water pollution, NOx, SOx and fugitive methane emissions.

• Adding in a ‘depletion premium’ to reflect use of an exhaustible resource is sensible in theory, but given the challenges of its calculation, the end-goal of energy sustainability will be more practically met through a charge to incentivize conservation and prepare for switching to other forms of energy.

• Once the efficient price is ascertained, the decision on price is political. It may, for example, adjust price for national and social objectives, e.g. equity of energy access, competitiveness of domestic industry and environmental sustainability.

• An alternative to government price setting would be to ‘allow the market to set the price’ through some form of allocations system and a platform for trading.

• Getting the right market incentives for gas conservation and efficiency in producing countries such as those in the Gulf is complex, but critical; understanding and making transparent the full costs involved is a good way to start.
Determining the Price of Gas

The market is not working

The Gulf Cooperation Council (GCC) countries and Iraq hold a quarter of the world’s proven gas reserves, yet, with the exception of Qatar, face gas shortages. While there are many explanations for this contradictory state of affairs, at the heart of the issue is gas pricing. As Figure 1 shows, the region’s gas pricing is low, even compared with that of gas in the US domestic market.

Figure 1: Gas prices in the Arab Gulf with some international comparisons


It was reported that Kuwait would receive a special price of $6–7/mmBtu for imports of Qatari LNG in 2014. Interfax, ‘Natural Gas Daily’, Vol. 4, Issue 104, 5 June 2014. At the time of writing, Kuwait takes the Asian market price of around $15/mmBtu for imports of LNG from other countries.

But how should natural gas be priced?

The starting point is to establish the ‘efficient price’ of natural gas (see the Appendix for an explanation of this and other price terms). However, productive and allocative ‘efficiency’, which this term implies, are not the only objectives that should concern governments – Table 1 shows a list of other possible objectives for gas pricing. Therefore the next stage is to adjust the ‘efficient price’ to take account of these objectives. The virtue of this approach is that it indicates clearly what the cost of these other (perfectly legitimate) objectives might be.

1 This study is focused on the GCC and Iraq but does include a case study on Iran. If Iran’s gas reserves are included, the Gulf total jumps to 43% of global proven gas reserves.
In a perfect world, the ‘efficient price’ of gas would be set by the interaction of supply and demand in the marketplace. This assumes competition in the marketplace which would entail, for instance, a large number of buyers and sellers, no ‘sunk costs’ to enable production and use, the existence of perfectly substitutable products and no negative impacts from the production or use of gas (‘externalities’) not covered by costs, and no public goods\(^2\) dimension above and beyond a free market. However, if there is no market – no initial buyers but, for example, a state that wants to encourage gas use through building the infrastructure to supply consumers, then the owner of the gas – in most jurisdictions, the government – must set the price. This is the situation that has arisen in most gas-producing countries, including those in the Arab Gulf.

### A lack of ‘international price’

The conventional economic theory approach argues for using the ‘border price’ for gas (i.e. the internationally traded price of gas) within the relevant geographic market as the correct domestic price. This is simply because a cubic metre of gas consumed domestically could have been sold in the regional market at that ‘border price’.\(^3\) Therefore that price represents the opportunity cost of the gas and is, as such, the ‘efficient price’. However, the very high transport costs for gas (relative to other fuels) limits the degree of market arbitrage, and it is often difficult to determine what the ‘border price’ might be. There is an ‘international price’ for oil because relatively low transport costs allow for physical movements of oil between regions creating an international market, via a process of arbitrage. Gas, by contrast, is traded in regional markets rather than an international market, either by pipeline (almost always on a contract basis for a determined period) or by shipment of liquefied natural gas (LNG) (on a contract or spot market basis).\(^4\)

### Untransparent markets

This approach is further complicated by the existence of two types of gas market – a commodity supply market and a project supply market. In a commodity supply market, there are a large number

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\(^2\) Goods from the use of which it is impossible to exclude people, and where one person's use does not reduce availability to others.

\(^3\) For pre-tax gas subsidies, the IMF uses the IEA's formula to define natural gas benchmark prices. Like coal, these are defined differently for net importers and net exporters but based on the price at the nearest international market. The IMF does not specify what it does for countries that consume all their gas domestically but do not import any. IMF (2013), *Energy Subsidy Reform: Lessons and Implications*, pp. 42–43.

of buyers and sellers of gas with lots of transactions and good transparency on price. If this kind of market is geographically close to the country trying to set the price, then there exists a clear ‘border price’. In other words, the price the gas could fetch on the nearby market if exported (minus transport and possibly liquefaction costs) would represent the ‘opportunity cost’ of using the gas domestically instead of exporting, and therefore would be the efficient price. There are, however, very few commodity gas supply markets in the world – North America and the United Kingdom are the only obvious examples.

The second type of gas market, which characterizes the rest of the world, is the project supply market. Here there are few buyers and sellers of gas, a limited number of transactions and poor transparency on prices. In effect, there is no ‘gas price’ in project markets. However, price must be based upon something and generally this is the price of competing fuels. A good example is the Japanese Customs-cleared Crude (colloquially labelled Crude Cocktail) (JCC), which consists of a basket of oil prices and is used as a reference price index for long-term LNG contracts in Japan, Taiwan and South Korea. However, the exact price mechanisms (indexation formulas) are written into the contracts themselves and as such are often commercially confidential. In effect there is no obvious ‘border price’ to act as a reference point.

A practical approach: costs based on use or potential use

Given these problems with theory, efficient gas pricing needs to take a more practical approach. This depends upon the use to which the gas is being put, and is essentially an attempt to seek a value for what could have been done had the gas not been consumed domestically or produced at all. There are three basic ways to view this (as explained in a definitive paper by Robert Mabro5). The first and second approaches assume that natural gas or its substitutes are tradeable (in the international market). The third approach assumes that natural gas is not tradeable.

Using the price of substitute fuels

For gas produced and consumed domestically the obvious way to price would be according to the fuel displaced. Traditionally this has been oil. This concept was first used by the Dutch, following the discovery of the Groningen gas field in 1959. China’s coastal region offers a more recent example of this method (see Box 1). A complication, of course, is that as a result there should be different gas prices for different uses, reflecting differences in the fuel displaced (for example fuel oil and gas oil in the power generation sector, liquefied petroleum gas (LPG) and kerosene in the household sector, gasoline and diesel oil in transport, etc.). This might cause problems if gas in a lower price-use category can be moved to a higher one – effectively a form of ‘smuggling’. That is, if gas has a low price in economic activity A, then if economic activity B faces a higher price, it would act as an incentive for actors in B to pay – albeit illegally – to try to get gas at a lower price from sector A, and potentially for actors involved in A to buy more than they needed and sell it illegally. In similar vein, the argument would apply to regions rather than economic activities, provided transportation was not much of an issue.

Using formulas based on substitute fuels is also used by some gas-importing countries. In the Chinese case described in Box 1, an oil-product-linked formula has been used in some coastal provinces.

**Box 1: A formula for linking the import of oil products in China**

Since 2011, the government has moved towards a ‘netback pricing’ system with the city-gate price of gas in Shanghai set as the benchmark. This price is linked to the import price of oil products which is then ‘netted back’ to the upstream wellhead price. This reform has been carried out experimentally in Guangdong and Guangxi provinces – indexing volumes to the price of LPG and fuel oil. A price-setting formula is provided for the first time as follows:

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

where:

- \( P_{\text{gas}} \) – natural gas city gate price (tax included) in RMB/cm;
- \( K \) – discount rate, set as 0.9;
- \( \alpha, \beta \) – weighted percentage of fuel oil and LPG, 60% and 40% respectively;
- \( P_{\text{fuel oil}}, P_{\text{LPG}} \) – import price during the period in RMB/kg;
- \( H_{\text{fuel oil}}, H_{\text{LPG}}, H_{\text{gas}} \) – heat content of fuel oil, heat content of LPG, and heat content of natural gas are set as 10,000 Mcal/kg, 12,000 Mcal/kg and 8,000 Mcal/kg respectively;
- \( R \) – natural gas VAT rate, currently at 13%

In July 2013, the government rolled out this system nationally for incremental gas volumes (those in excess of the 2012 gas sales volume) while also raising the price for the existing volume with the aim of indexing its price to oil products by the end of 2015. Residential gas use has been excluded from this price exercise.


This has been a step forward and has chiefly reduced losses to the importer of the gas, China National Petroleum Corporation (CNPC). Rather than pricing gas at the wellhead and adding a pipeline fee, it is now marked at downstream costs (city-gate price) where demand occurs and where prices are relative to other energy sources (namely fuel oil and LPG).

**Using the export price**

For gas that can be exported the obvious way to price it domestically would be at the netback price to the point of domestic delivery. The netback price is effectively the sales price of the gas in the export market, less the cost of transportation, whether by pipeline or LNG. For example, this would be the international LNG, contracted pipeline or regional trade price minus the costs of production + processing + transportation.

The difference between export price and costs could be treated as effective ‘rent’ for the government. The actual domestic pricing, discussed further below, would then be for the government to decide, while it is fully aware of the subsidy, opportunity costs and amount of rent from exports that it has available to distribute in the economy.
Non-tradeable gas

The problem is that in some cases gas is not tradeable – in Saudi Arabia, for example, there are no pipeline routes or LNG terminals to allow mass export. Even Iran lacks the infrastructure to export all of its gas production. In such cases, the export price of gas would not necessarily be the correct ‘reference’ price against which to compare the domestic sales prices when calculating subsidy, for example.

One could argue in these cases that there is a rational link to the international oil price because gas is a substitute for oil in power generation (and potentially in transport), so it can free up oil for export. Others would argue that in these cases, the ‘efficient price’ should be the long-run marginal costs (LRMC) of producing the gas to the wellhead plus transport costs to the point of use (see the Appendix for an explanation of this concept).

The case of price-setting in Algeria given in Box 2 shows that even the wholesale price is just a fraction of the estimated long-run marginal cost. In Algeria’s case, this has led to a constraint on exports from domestic consumption growth, and returns do not reflect the investments needed to bring new tight gas supplies on-stream.

Box 2: Pricing domestic natural gas in Algeria

In Algeria, the supply price (prix de cession) is determined, exclusive of taxes, on the basis of current and anticipated costs and indexed to both the exchange rate and inflation along the following formula:

\[
P_{t+n} = P_t \times \frac{FX_{t+n}}{FX_t} (1+r)^n
\]

where:

- \( P_{t+n} \) is the supply price at year \((t+n)\) in Algerian dinars (DZD)/1000m³
- \( P_t \) is the supply price on the date of application
- \( FX_{t+n} \) is the USD-DZD parity on 1 January of year \((t+n)\)
- \( FX_t \) is the USD-DZD parity on the date of application
- \( r \) is a constant rate of inflation

This formula, first introduced in April 2005, was subsequently amended, adjusting the inflation rate, first from 5% to 3% in 2007, and then back to 5% in 2010. The decree introducing the second change also stipulated that the exchange rate index only applies when the DZD depreciates against the US dollar. Despite the upward adjustment, the supply price last notified was kept below what the formula actually suggested (see Figure 2 below).

Figure 2: Algeria – evolution of supply and wholesale prices, 2005–12
Is gas free if it comes out with oil?

Using export prices netted back or LMRC pricing formulas all require knowing the actual costs of domestic production. Problems in estimating gas production costs include the so-called ‘joint product problem’ whereby the gas is produced as a by-product of another activity. The most obvious example is where the gas comes out of the ground along with crude oil (‘associated gas’). The question arises how much of the cost of producing the oil can be attributed to the gas. Arguably, if the oil is to be produced anyway, then the marginal cost of getting the associated gas above ground to the wellhead is zero. In this case, the only cost is that linked to collecting the gas (rather than flaring it) and delivering to the consumer.

What cost to put on depletion of a national asset?

A further complication arises because gas as a natural resource is exhaustible. Thus, in theory, there should be a depletion premium added to the price. This is a way to factor in the opportunity cost of consuming an exhaustible resource now rather than in the future. It can also be seen as enabling at an economical price the inevitable transition to a substitute fuel over time.

The depletion premium should reflect the marginal costs of producing energy from the technology available at the point when the gas has become exhausted. This presents practical measuring problems of epic proportions. One example of an attempt to calculate it is given in Box 3. However, given the serious impracticality of this calculation, it may be more sensible to consider what the end-goal should be, i.e. sustainability of energy availability over time, and thus adjust prices to incentivize efficient use and reflect the need for investment in new supply.

Finally, if the production of the gas incurs environmental costs – for example, water pollution and fugitive methane emissions associated with production and transportation of gas – these externalities should be added to the price in order to internalize them. In practice this can be complex; for example, it would involve costing the impact of climate change and health costs of pollution-related illnesses and apportioning them per unit of gas. As with the depletion premium, this is rarely, if ever, added to the long-run marginal cost of the gas. As environmental sustainability and health are benefits to
society, there are two options: regulation to restrict the damage, e.g. legal restrictions which may add costs to production or limit it, or taxation (the SO₂ and CO₂ taxes in Norway, for example). In both cases, the costs of external damage would then pass into the overall cost of production.

Box 3: Possible factors in determining a depletion premium

A 2009 paper by Hossein Razavi attempts to calculate a depletion premium for Middle East countries based on an estimate of the year in which a country must begin switching from gas to a substitute fuel. He estimates this on the basis of current proven reserves plus 50% of probable reserves and a 15-year production plateau prior to decline. Placed alongside a country's consumption trends, this would give the year in which a substitute is expected to be needed to meet further growth in demand. Razavi assumes the substitute for gas to be oil, and so the price per unit is calculated using available oil price projections at the switching time, adjusted for relevant cost and efficiency differentials with gas. Then the difference between this price and the cost of the gas production at the switching time gives the depletion premium at the time of switching. In other words, in this year, the price of gas should be equivalent to its substitute. The depletion premium for previous years is calculated by 'discounting back' year by year to reflect the time value of money, using an appropriate annual discount rate (the author uses a high one of 10%).

It is worth noting three factors which would affect this calculation today. First, the 2006 oil reference case price projections of the Energy Information Administration (US Department of Energy) which the author employs remain between $50 and $60 per barrel (in 2005 US dollars) to 2030. But this scenario has not played out, with oil prices rising above $100 per barrel in recent years, indicating the impossibility of accurately forecasting future prices of substitutes.

Second, the substitute fuel would probably not be oil. Countries including Saudi Arabia and Kuwait which are still using oil in power generation are keen to replace it. It could be the cost of a basket of energy sources and energy-related investments including solar power and end-use technologies.

Third, gas demand has probably risen much faster than predicted. Razavi defines a 'gas short' country as one in which 'the potential demand for gas is already close to or above the potential supply', saying that '[i]n such a case, the economic price path for gas will follow that of the alternative fuel'. All Gulf countries with the exception of Qatar and possibly Oman would arguably fall into this category.

Complexity is no excuse

Gas pricing is complex, but getting it right is important. While it is difficult to be precise, bad gas pricing is rather like asking someone to define an elephant. The classic response is 'I can't define one but I know one when I see it.' The same is true for gas prices and most of the gas pricing in the GCC exemplifies bad pricing.

Adjusting the Price for National and Social Objectives

Once an efficient price has been determined, the next stage is to decide whether to adjust it to account for the other objectives listed in Table 1. These are political decisions and must take into account issues such as distributional considerations and income impacts: who should appropriate the net opportunity gain: the producer, the intermediate user (the power generator, for instance) or the final consumer? Adjustments based on these decisions can take the effect of targeted taxation and/or subsidy.

Regional industry competitiveness will be one such consideration for the Gulf region as there is no regional quoted price for gas, which forms a major input to (and therefore factor for) the petrochemical industry. The case of Iran’s proposed gas price reform in the face of petrochemicals industry competition from Saudi Arabia and Qatar (see Box 4) exemplifies this challenge. In the absence of regional standardization, one approach suggested for Iran would be to base its gas price on the real cost of gas production, refining and distribution, considering the economic value of the associated liquids plus an environmental tax to reduce waste in the domestic sector and encourage investment in gas supply industries.8

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**Box 4: The problem of petrochemicals competitiveness and the Iranian gas price formula**

For gasoline and diesel, the ‘subsidy’ is clear for Iran given its dependence on imports and status as an exporter of oil: it is the difference between domestic sales and export prices. The ‘reference cost’ of gas is less easy to define, but it is essential to get this right. Gas makes up nearly 65% of the energy basket in Iran. The targeted subsidies reform act of 2010 states that gas prices should gradually reach 75% of the ‘free on board’ (FOB) price of Persian Gulf oil minus transportation costs for households, and not be higher than 65% of the FOB Persian Gulf price for industry by 2015 (as the main recipient of Iranian gas exports is Turkey, the gas price to Turkey minus the transportation costs is considered a baseline). But implementation is being delayed because the government faces high inflation, unemployment and sanctions. If this gas price formula were to be enacted, it would make it very difficult for Iranian industries, especially petrochemicals, as gas feedstock would be five times the price in Saudi Arabia and Qatar. Yet the current limbo means that national economic and environmental pressures are increasing.


A key question for government will be whether everyone (or at least each consumer type) in a given country should pay the same prices for gas. Where transport costs are a significant component of the cost structure for gas, establishing ‘correct’ gas prices becomes incredibly difficult for large countries such as China. On the French basis of *péréquation* (equalization) of natural gas prices across a country, a cross-subsidization fund is needed for companies transporting gas. However, there may be strong calls for some groups to pay less according to need, e.g. where extremes in temperature require greater energy use.

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In countries in which provincial governments have some autonomy over the way in which energy policy is interpreted, different systems may evolve depending on local/state government priority. For example, in China, coastal areas are keenest to incentivize gas-based industries as there are no local coal sources and gas is therefore much more sought after. However, the economic diversity and size of China (which also produces gas domestically) mean applying an oil-linked formula country-wide may not make sense. It would seem inappropriate for provinces where the fuel to be displaced is coal, for instance, yet using the cheaper coal or coal-fired power price for sales of gas in those provinces may not compensate for the costs of supplying gas.

What can be said is that any sensible programme to incentivize sustainable consumption of a domestically produced good must have at its heart an effort to assess the value of the resource and the costs of the impacts of its production and use as well as awareness of its price on international markets.
Allocations as an Alternative

Where resources are difficult to value in monetary terms, governments are increasingly seeking to create new markets through the allocation of tradeable user rights – examples include European carbon trading of water markets in Australia and, more recently, South Africa. A learning curve is emerging. A particular attraction of this approach is the ability of government to set a cap or limit for resource use overall, but allow the market to allocate the resource within this envelope. This has the advantage of promoting awareness of scarcity as well as enabling a resource to gravitate towards more high-value uses in agriculture and industry, for example.

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Efficient prices, reference prices and opportunity costs

This paper uses the terms ‘reference price’ and ‘efficient price’, which have different meanings in economics.

The term ‘reference price’ can be applied in many different ways and usually refers to the price against which a customer estimates whether something is good value for money. This can also be called a benchmark price. However, in this paper we use it specifically for the appropriate price one could assume for the resource in question (energy type, water or food) were domestic prices not administered by government.

In this sense we are looking for what can be counted as the ‘efficient’ or correct price, sometimes called the shadow price in cases where it is not applied as the actual price but where the authority or business in question acknowledges it as the efficient one. The ‘efficient price’ in its most basic form is used in economics to mean the price at which producers are willing to produce and consumers are willing to buy – in other words, the price at which the market clears. This would usually be the price which covers the producer’s production costs (and potentially profit requirement and investment needs to enable supply to continue to meet demand) and is competitive compared with alternatives in the marketplace.

According to economic analysis developed by Little and Mirlees in 1968, the ‘correct price’ (efficient price) should be the border price. 10 For oil, this would mean the international oil price; for gas, the price at which it could be sold to another country. This is the concept or benchmark most commonly used (e.g. by the International Energy Agency) to assess resource subsidies (i.e. border price minus domestic price). 11 It is also widely employed as the ‘opportunity cost’ – in these cases, what one could have received for the good outside the country.

However, several cases defy this logic. One is where selling more of a good on the international market might lower its international market price and where goods are not easily tradeable. Because of these difficulties – particularly in the case of vital resources such as gas, water and electricity – several alternative benchmarks are possible. It could be the price in the nearest market, but it could also be a bottom-up calculation of costs involved in production.

The interesting question is what costs are taken into account in the bottom-up assessment. There are not only costs in terms of inputs into the extraction or manufacture of the product (i.e. capital investment, labour, material inputs etc.) but also the other costs of producing it and/or consuming it (e.g. environmental pollution and the depletion of national resource assets), often referred to by economists as ‘externalities’. These costs need to be incorporated as well to reveal the ‘efficient price’.

Once calculated, the ‘efficient price’ can be used as a ‘reference price’ for what a good ‘should cost’, all other things being equal. It is thus useful in determining the extent of a subsidy where pricing is fixed.

**Long-run marginal costs of resources as a reference price**

The long-run marginal cost (LRMC) is a complex calculation but aims to assess all the costs of bringing on an additional unit of capacity to produce, plus operating costs. So with gas it would be the cost of bringing an additional volume on-stream beyond what was already being produced. The period of time would be the time taken to explore for new gas, develop it and bring it to market. The costs would include all the investment needed to do that, as apportioned per unit of the total volume the development is expected to produce over its lifetime, plus operating costs.

For desalinated water, the LMRC would be the cost of a new desalination plant on top of its running costs. It could be argued that the LMRC for non-renewable groundwater would equal the cost of increasing desalinated water capacity and the cost of the infrastructure to bring that water to the market currently supplied by the groundwater.

The idea of using the LMRC to assist with pricing or ‘shadow’ pricing is to set the optimal system to support one’s production over the long run. For a depletable resource such as gas or oil, even given lower costs in some technologies, future costs might be expected to rise overall as a result of depletion. More accessible gas will have been produced first, so the remainder will tend to require more expensive inputs (e.g. reinjection and new drilling techniques) to maximize older reserves and exploit more difficult sources (e.g. where the geology is tight). Given the complexity of such a calculation, the most expensive unit currently under production is often used as a proxy for LMRC.

However, as noted, the costs of some technologies may also be reduced over time (e.g. hydraulic fracking techniques, solar desalination). It is important to note that a price set at the long-run marginal cost may still mean that demand exceeds supply. In economic theory, if this happens, the price needs to be increased to reflect the netback value of the gas to the marginal consumer (the price that the last consumer to enter the market wanting to buy gas would pay for it). This is not easy to determine.
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