

**NORTH AMERICA'S
NATURAL GAS and ELECTRIC POWER
A DOUBLE WHAMMY!!
By Brian J Fleay
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BACKGROUND

Everyone knows the US is an extravagant consumer of oil. It produces less than 10 per cent of world oil but consumes 26 per cent and imports 55 per cent of its consumption (BP 2002). Its oil imports cost US\$330 million per day – the biggest component of its US\$435 billion trade deficit. US oil production peaked in 1971 and has now declined to about half the peak rate.

But the US is also the world's largest consumer of natural gas – over 25 per cent, and nearly 30 per cent with Canada included. US gas imports from Canada (some 60 per cent of its production) have increased fourfold since 1985 and now provide 15 per cent of its consumption. Yet these countries have just over four per cent of the world's gas reserves (BP 2002). So you would think people would be expecting gas supply shortfalls to emerge. However, much to everyone's surprise, the wellhead price of natural gas soared from US\$2.20 per 1000 c.ft to US\$9 during 2000 as static supply battled to match growing demand. This steep price increase contributed to California's electric supply disaster where up to 25 per cent of its electric power sources are gas fired. The prevailing US psyche is not used to adapting to such constraints.

The US has pioneered the large-scale consumption of oil and natural gas over the last 80 years, so we should not be surprised if it leads the world in their depletion. This paper summarises the state of play for US and Canadian natural gas and the implications for the immediate future. A steep production decline has begun that will force simultaneous declines in natural gas and electric power consumption. The US now has no alternative but to reduce consumption of both. An historical turning point has been reached.

THE EXISTING NATURAL GAS SYSTEM

The US has 360,000 gas wells, some 74,000 drilled since 1994, with 22,000 in 2001 in response to the 2000 supply crisis. Yet production has remained static over those years (Udall 2001, Simmons 2002). They were drilling new wells between the old ones. In 2002 early reports show production actually declined by 5-6 per cent (Lask 2003). Running faster just to stand still. It also takes 7,500 new gas wells in Canada every year to stop production declining there. Most production from new gas wells is rising quickly to a peak, then declining rapidly - by 60 per cent or more over two years. Around 80 per cent of discovered natural gas in the US has been consumed (Udall 2001). The principle gas fields are in Texas, Louisiana and the lower Mid-West. Transport of gas is by a network of pipelines.

Mexican natural gas is minor by comparison and production approximately matches consumption.

The US consumed 22.5 terra cubic feet (Tcf) of gas in 2000, importing 3.5 Tcf from Canada. An additional 0.2 Tcf was imported as LNG (BP 2002). Residential use consumed 22 per cent, commercial 14 per cent, industrial 28 per cent, electric power 28 per cent, while field plant and pipelines consumed 8 per cent. Electric power includes 'in-house' industrial generation as well as utilities, about half each (Simmons 2002). Throughout the 1990s Henry Hub gas prices ranged from US\$2-2.50 per 1000 c.ft.

71 per cent of US electric power generation capacity is obtained from ageing coal fired and nuclear power stations, hydro supplies 7 per cent and gas turbines about 20 per cent. Electricity consumption has been growing at 2-3 per cent per annum (BP 2002). Since 1999 installation of gas

turbines has surged for intermediate and peak power capacity, partly to meet a 3.5 million per year population increase, per capita consumption increases, and to replace ageing power plants. There has been rapid growth in residential air conditioning plants for summer cooling.

By early 2000 utilities had ordered since 1998 some 180,000 MW of new gas fired power plants for commissioning by 2006 (Udall 2001). Lask (2003) says these orders are now even higher. This surge was partly driven by the growth mania surrounding the information technology boom that collapsed in 2001. Some proposals were contingencies to block development by rival companies. Many orders were being cancelled by 2002. The recession lowered consumption expectations and doubts about gas availability increased. The optimistic expectation in 1999 was for gas consumption by gas turbines to double by 2010, when total consumption was expected to approach 30 Tcf per annum (Udall 2001, Simmons 2000). But there has still been a record growth in gas turbine capacity which is still increasing. Australia's installed generation capacity is some 42,000 MW, for comparison.

There are growing bottlenecks in both the electric transmission and natural gas pipeline networks arising from both this rapid growth and the changing patterns of supply and consumption.

The gas and electricity supply crises of 2000 provoked an across-the-board response that led to reduced gas consumption and increased gas well drilling rates. Fuel substitution, minimum use of gas turbines, conservation under the impact of high Henry Hub prices (up to US\$9 per 1000c.ft), reduced industrial use due to these high prices were responsible, together with mild weather in the 2001 winter and summer and the recession. North American consumption fell by 1.3 Tcf.

Operating drilling rigs increased from around 600 in 2000 to 1100 by mid 2001 leading to a 0.5 Tcf increase in North American gas production in that year (Simmons 2002, BP 2002). Henry Hub gas prices rapidly decreased as the year progressed reaching a low below US\$3 per 1000c.ft by autumn, when it was clear that gas storages would be fully recharged by winter. Operating gas rigs then declined to a low of 650 after mid-2002.

Figure 1 shows the plot of North American natural gas discovery shifted forward by 20 years compared to the plots of raw and dry gas production (Laherrère 2003). The aim is to show how the gas production profile is broadly mimicking the discovery profile with a time lag of 20 years. The dry gas profile is what is left after subtracting from the raw gas data liquids extracted from natural gas (eg ethane, butane and propane), and methane obtained from coal beds. Coal bed methane is not included in the discovered gas data for Figure 1. The small upturn in gas discovery since the late 1980s is from deep water fields in the Gulf of Mexico (>300 m. water depth). The production downturn shown for 2002 foreshadows the steep decline that has most likely commenced.

Natural gas flows more freely in geological formations than oil under equivalent circumstances, as it is a gas. Consequently it is possible to extract more of the gas-in-place from most gas fields than from equivalent oil fields – as much as 80 percent compared to 30-45 per cent for oil. There is less scope for enhanced production initiatives for gas in these circumstances as decline sets in. Also the higher cost of gas infrastructure ensures that maximum production profiles tend to be extended plateaus rather than the higher more sharply defined peaks common for oil. Decline for gas therefore begins at a later stage of field depletion. Both factors mean the production declines for natural gas are much steeper than for oil, and commences when about 70-80 per cent of the extractable gas has been produced. North American gas production has reached this stage.

NEW NATURAL GAS OPTIONS

The main options are deep gas below the existing fields in Texas and adjacent states, gas from the Arctic coast of Alaska, from the Mackenzie River Delta in N.W. Canada, from fields adjacent to the Rocky Mountains, and from imports of LNG. There is scope for more gas from deep water in the Gulf of Mexico

**NORTH AMERICAN NATURAL GAS PRODUCTION
AND SHIFTED DISCOVERY**
Laherrère 2003

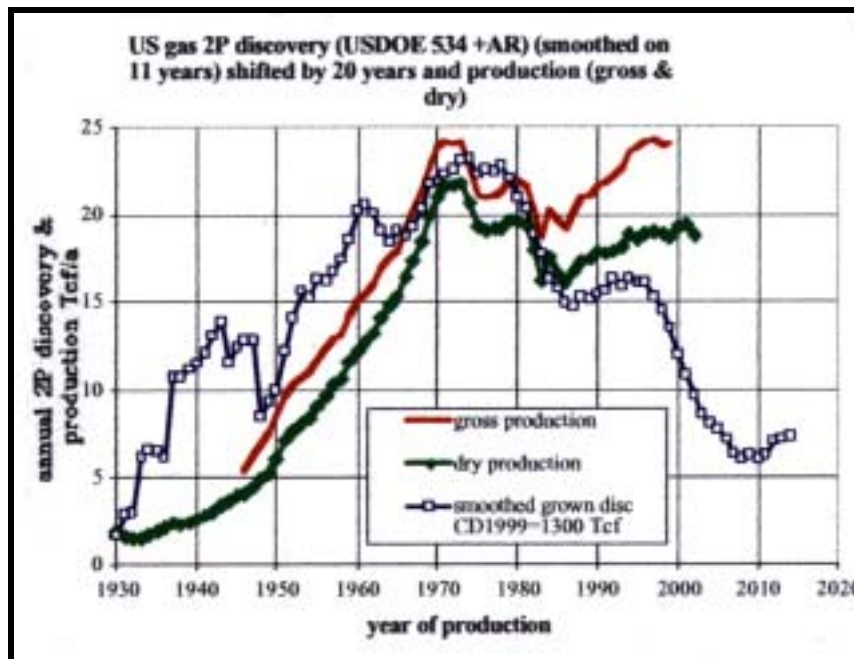


Figure 1

Since the mid-1980s the number of skilled drilling staff, petroleum geologists and geophysicists in the US petroleum industry has declined as exploration and development activity has fallen away in the low oil price regime and with declining opportunities for successful exploration. Most key staff are in their 50s and heading for retirement. Few students are training in these specialist fields at universities (Simmons 2000). This personnel shortage is a major constraint to the potential gas developments discussed below. Since the Enron financial collapse it has become harder for drilling contractors to obtain finance.

Texas Deep Gas

This is deep gas below existing fields. It involves drilling to a depth of 5 km, requires a new generation of heavy-duty rigs and will be very expensive. It is beyond the present capacity of rig manufacturers to build them in the quantities needed, even if contractors would buy them in anticipation of drilling contracts (Simmons 2000). It has yet to be proven that sufficient quantities of extractable gas are available from such a depth and the risks are higher. It would take a large effort and the best part of a decade to prove viability and ramp up production.

Arctic Coast Gas

The most viable project (US\$7.8 billion for pipelines alone) proposes a first stage 1400 km US\$2.6 billion pipeline from the Mackenzie River Delta linking to Alberta pipelines, followed by a pipeline from Alaska's North Slope linked to the Mackenzie system, then twin pipelines to Chicago as a third stage. To be viable the Alaska project needs gas prices above US\$3.5 per 1000 c.ft. The first two stages would take five years to build and the whole project would eventually deliver close to 2 Tcf per annum (Petroleum Economist 2003). Production from existing sources could decline by around 6 Tcf in that time frame.

Rocky Mountain eastern slopes

There is existing production from gas fields in this region but 40 per cent is public lands, mostly as conservation reserves where drilling is prohibited. There are conflicting claims on how much oil and gas there might be in these regions and how difficult it might be to develop.

LNG

Annual world exports of LNG are about 5 Tcf, half to Japan (BP 2002). The present available capacity of US receiving terminals is about 1 Tcf per year and imports have been less than that. But there is limited uncontracted LNG production capacity. Possible future supply sources are from the Caribbean and Nigeria (Oil & Gas Journal 2000). However, a gas pipeline from Nigeria to Algeria is mooted to supplement gas deliveries to Europe via existing pipelines to Italy and Spain. UK gas production will commence decline about 2006. Beyond that major LNG supply could only come from Iran and Qatar who have 24% of the world's reserves. However, major investment in LNG plants, tankers and receipt terminals would be required. These are expensive, though the cost of building LNG infrastructure has been reduced in recent years. For LNG imports to have any impact on falling US gas supply world LNG production and tanker capacity would need to at least double.

GAS STORAGE FOR WINTER DEMAND

Natural gas is the principal fuel used to keep North Americans warm in winter, when consumption can exceed production capacity by as much as 20-25 per cent. About half of US households depend on natural gas for winter heating. Surplus supply capacity in the warmer months – up to 2.5 Tcf in the past - is used to recharge salt domes and depleted oil and gas fields for later extraction in winter to meet this peak. The winter draw on storage can range from 1.5-2.5 Tcf depending on the winter's severity. The rapid growth of gas turbine capacity to meet summer electric power peaks is eroding the capacity to recharge these storages – e.g. for summer residential air conditioning in hot and humid weather. Now declining gas production is rapidly amplifying this recharge shortfall.

Figure 2 shows the working gas levels in underground storage from mid-April 2001 to mid-April 2003. The shaded band represents the range of storage levels over the previous five years. The gas supply crisis of 2000 and a mild summer led to reduced consumption of 1.3 Tcf in 2001 while a supply increase of 0.5 Tcf from the record number of new wells enabled some 2.5 Tcf of gas to be put in storage by November 2001 (BP 2002). There was a 1.2 Tcf decline in industrial consumption as industries became uncompetitive against imports due to high gas prices, such as nitrogen fertiliser manufacture (Simmons 2002).

**WORKING GAS IN UNDERGROUND STORAGE
COMPARED WITH 5-YEAR AVERAGE**
Energy Information Agency Washington

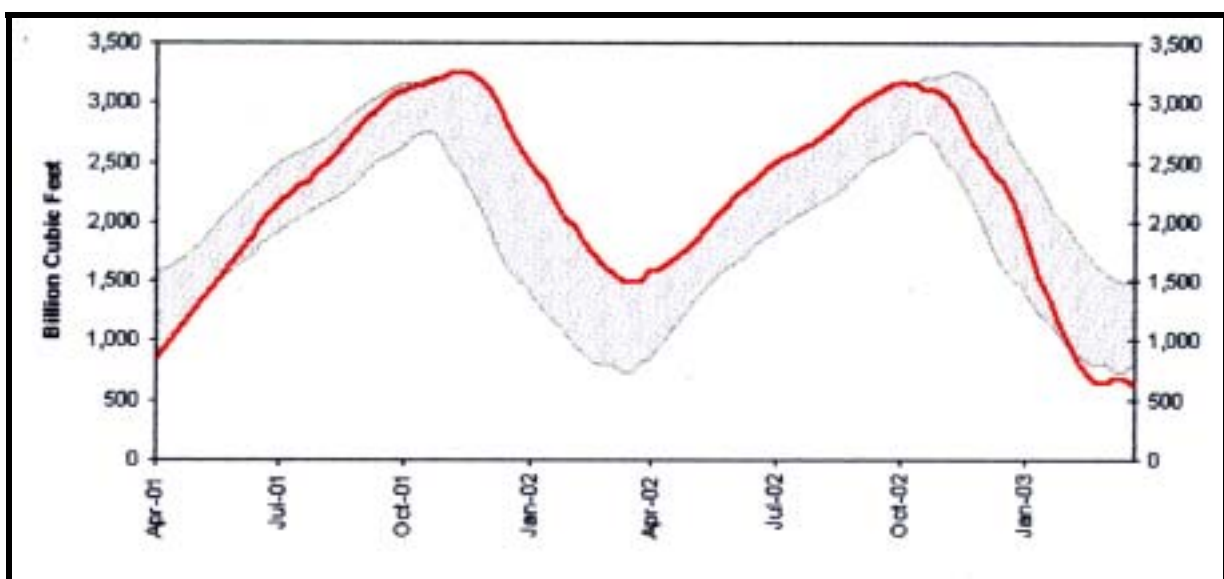


Figure 2

The 2001-02 winter was very mild, the economy was slack and the full effect of the drilling boom was being felt and the draw on storage was a low 1.65 Tcf, bottoming out at 1.55 Tcf in March 2002. The following summer was also mild and the slack economy continued. However, the drilling boom slackened in early 2002, falling from 1100 rigs to a low of 650 in August, foreshadowing a production decline by the years end. Nevertheless, storage peaked at 3.15 Tcf in October – a gain of 1.6 Tcf. However, US gas production may have declined by nearly 1 Tcf (~5%) in 2002 suggesting that this may have been close to the limit of the storage gain possible (Lask 2003, Simmons 2002). More reliable data on 2002 production levels, consumption and decline rates should be available in the next few weeks, when a better assessment can be made.

2003/2004 – Crisis Years?

The 2002-03 winter was early and severe with a storage draw down of 2.5 Tcf to reach a low 0.62 Tcf in early April. In February Henry Hub gas prices soared to US\$12.50 per 1000 c.ft, and the low storage levels reduced gas extraction rates. If 2003 is a repeat of 2002 – a mild summer and the same gas production – then peak gas storage in November could be as low as 2.2 Tcf. Even with a mild winter, March 2004 storage could be around 0.6-0.7 Tcf. But as a further production decline is likely storage could virtually be depleted with severe shortages of gas during the coming winter. Either a hot summer or a cold winter could lead to severe supply failures in early 2004.

This suggests that Henry Hub gas prices will soar this summer as the supply deficiency dawns on the market participants. Buyers will fiercely compete for a shrinking gas supply. Who will win? The electric utilities, industry, commercial users, or utilities with the task of supplying gas to keep people warm in winter? The gas traders will be making these assessments in the next few weeks.

Where are the uncertainties in this scenario? Some are listed below:

- Accuracy of the data – this is important when supply and demand are so finely balanced.
- Just how tight was gas supply in the last storage refill season for gas?
- Will the 2003 northern summer be hot and humid?
- Will the well decline rate increase in 2003 as the impact of the 2001 drilling boom recedes?
- Will there be a new drilling boom, how effective will it be and how soon?
- Will LNG imports make a difference?
- What is going to happen to industrial consumption of gas and the industries concerned?
- How effective will fuel substitution be – other electricity sources and oil products replacing gas? Are most of these short-term potential gains already achieved?
- How effective will further energy conservation initiatives be? Some are easy to apply, such as resetting of thermostats.
- How much new gas turbine capacity will come on line in 2003, how often will it be used, and how much older less efficient plant will be shut down?
- How cold will the 2003/04 winter be? A critical factor.
- Finally, as the gas supply shortfall becomes visible, what might be the political response to the prospect of people freezing next winter on the eve of a US Presidential election?

If there is not a major gas supply crisis during the 2003-04 winter there almost certainly will be in the following year.

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