A Graphical Technique for the Comparison of Carbon Dioxide Capture and Sequestering Costs in Coal-based Electrical Generation with Natural Gas Combined Cycle Technology under North American Conditions

(Web: pages.ca.inter.net/~jhwalsh/wcoalgas1.html)

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Abstract

The object of this paper is to present a simple graphical technique to illustrate the range of possibilities for the capture and sequestering of carbon dioxide from coal-based generation in relation to the natural gas-based combined-cycle process under North American conditions. The publication of an interdisciplinary study by the Massachusetts Institute of Technology in June of 2003 entitled *The Future of Nuclear Power* provided comparative data on the levelized cost of electricity produced in the NGCC process as a function of the delivered cost of natural gas. Data on conventional nuclear generation in PWRs included an assessment of the advances expected in the latter technology over the years for comparison. Cost data was also provided for electricity generated in modern coal-based pulverized fuel-firing combustion technology. This information allowed the preparation of a graph in which the cost of electricity was plotted as a function of cost of natural gas delivered to the generation facility. By extrapolating the data, it was possible to find the equivalence point for these other generating technologies in terms of natural gas cost on a self-consistent basis.

By comparing the average cost of natural gas delivered to electrical generating stations over a year to the average price of gas traded on the NYMEX Market over the same year, this equivalent price could be adjusted to trading prices that could be related in a consistent way to resource assessment studies. This procedure is now possible because the present generally higher price of gas makes the inherent variability in this adjustment less important than in the past. The extra cost of the capture and sequestering of carbon dioxide is assumed here to be two cents per kWeH which is added to the levelized cost of 4.2 cents/kWeH given in the report for a modern pulverized coal installation. Even with no increase in the real price of coal in the interim, an equivalence with the natural gas-based process is not reached until 2031 at a real price increase of 3% per year for liquefied natural gas (LNG) imported into North America from surplus countries by cryogenic tanker. Nevertheless, it is possible that delivered LNG prices could increase even faster due to the difficulties and delays in providing the necessary facilities for much increased shipments despite the adequacy of the resources of conventional gas around the world for many years. If not, a carbon tax or other similar financial supporting instruments will be needed to justify the provision of facilities for the capture and sequestering of carbon dioxide in coal-based generation.

Introduction

The Massachusetts Institute of Technology (MIT) released an interdisciplinary study entitled *The Future of Nuclear Power*[1] in July of 2003. This study was co-chaired by Professors John Deutch and Ernest Moniz who drew on the support of other well-known senior members of the MIT faculty. An estimate of the levelized cost of electricity generated by turbines fired with natural gas and operated in combined cycle mode (NGCC) for three different cost levels for gas was provided. Electrical cost data was also supplied for coal-based generation in a modern Pulverized Firing (PF) context and for nuclear power generated in conventional Pressurized Water Reactors (PWRs). In the latter case, projected reductions in cost were also estimated for specified advances expected in this technology.

In this paper, the levelized cost of generation in NGCC plants is plotted as a function of the delivered gas cost and the range of the data extrapolated to higher values. This plot is then modified to permit a comparison of conventional NGCC technology with the generation of electricity in coal-fired facilities equipped for the capture and sequestering of carbon dioxide. The aim is to answer the question as to how much the price of natural gas must increase to justify the adoption of this complicated and environmentally benign but more costly generating technology without other incentives such as carbon taxes. The NGCC process, because of its lower costs and other advantages, is considered here to be the means of generation the most likely to be employed to meet new market demands in the next decade or two under `business-as-usual' conditions. As the process at margin, it is the yardstick by which other technologies may be measured. However, because conventional natural gas production in North America is either near or past its peak, the increased natural gas supply at margin is that imported in liquid form (LNG) from gas surplus contries outside of North America by cryogenic tankers.

To interpret the cost of gas consumed for electrical generation in terms of its resource base and supply characteristics, it is necessary to relate its cost delivered at generation sites to its price on trading markets. To do this the following procedure was adopted: the average yearly price on the New York Mercantile Exchange (NYMEX) was subtracted from the average price paid for natural gas by generators of electricity that same year. Once determined, this difference may be added to the average Trading Price on the Exchange for the contracts based at the Henry Hub of pipelines in Louisiana to arrive at the expected yearly average gas costs paid at the various NGCC generation sites. It is recognized this procedure can only be approximate and that it may be subject to systematic errors as the years pass but these may not be large.

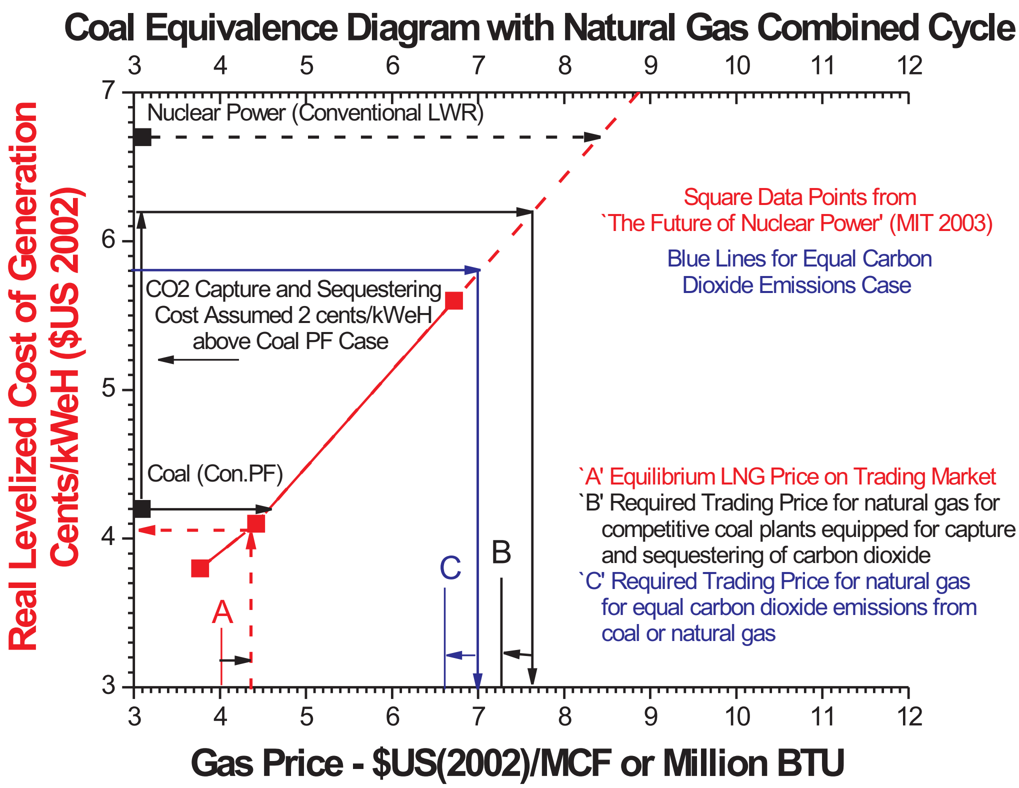
Once the peak in conventional gas production in North America is passed, as it may have already, the price for LNG, the next least costly substantive alternative, should set the price for all natural gas in North America. The other competitive non-conventional source, Coal Bed Methane (CBM), has much the same costs as LNG and thus its introduction to the market should not change this value very much although the supply locations are very different. The premises behind these assumptions are considered in more detail below.

Basic Premises

The North American market for natural gas is integrating among the three members of NAFTA.

This integration means that the price for natural gas should become related in a consistent and transparent way at every main location served by pipeline throughout the Continent. In consequence, the price on the NYMEX market in New York should determine the price paid by operators of NGCC generating facilities when adjusted for differences in the costs to reach specific locations. A strong relationship should then exist between the average NYMEX price and the average of all prices paid by individual generating stations over sufficient time such as one year. Yearly average NYMEX prices were taken from the *BP Statistical Review of World Energy*[2] and subtracted from the yearly averages of prices paid for natural gas by generating facilities obtained from data tables published by the *Energy Information Administration* for 2001 and 2002.[3] Data from earlier years was considered inappropriate because of the generally different and lower price environment in an era when there were local surpluses of gas. The average yearly cost of natural gas to generating stations exceeded the average yearly Trading Price on the NYMEX Market by $US 0.42 per million Btu in 2001 and $US 0.34 in 2002. An average value of $US 0.38 per million Btu was used to prepare the Figure. The generating facilities were thus assumed to pay on average $US 0.38 per million Btu more than the Trading Price on the NYMEX Market.

This price differential may deviate in a systematic way over time because new NGCC facilities are currently being installed with the result that average delivery costs may be continually being affected by growing gas consumption at new locations with different individual delivery costs. For this reason, it would be useful to track the change in the value of this differential to determine if this value follows a



consistent and thus extrapolatable pattern over time. Nevertheless, the error introduced by the expansion of NGCC facilities at new locations is not believed large. A greater source of uncertainty is likely the non-systematic error introduced by the continual mismatch between the peak in gas consumption for generation and that for other uses particularly the demand arising for space heating caused by changes in the weather. The differential in a cold year is likely to be different from that computed for a warm one. Because this value is a smaller component of the total delivered price at the generally higher prices at present than it was a few years ago, this uncertainty has lost some its significance.

Conventional natural gas production in North America is near a peak if it has not passed it already.

Though Canadian production has risen rapidly in the past decade, the total Continental production of natural gas has begun to decline slightly. The fall is more pronounced when non-conventional gas derived from Coal Bed Methane operations in the U.S. is deducted from the total. (CBM operations are just beginning in Canada.) The National Energy Board believes Canadian total gas production will reach a plateau of perhaps seven or eight trillion cubic feet per year.[4] If the peak in North American conventional natural gas production has not yet been reached, it seems almost certain that it will occur before 2010. The question then becomes what determines the price under equilibrium conditions, that is, when the supply satisfies the market demand?

The next least costly options for natural gas supply come from domestic CBM and imported LNG. The cost of each of these non-conventional sources is roughly comparable though the locations of these sources are very different – CBM is produced mainly in mid-Continental coal fields while LNG is delivered to special receiving facilities restricted to Coastal locations.

World resources of conventional natural gas are large and fairly well distributed. The peak in world production of natural gas is not expected until the 2040-2050 period. In essence, the peak in North American conventional natural gas production occurs before the peak in world production of conventional oil (expected about 2020) which in turn precedes the peak in world production of conventional natural gas.[5] A large flow of LNG to North America may thus be supported for some decades though there is the complication that oil products could be used for electrical generation in NGCC facilities in some circumstances in the early intervening period before the peak in world conventional oil production. It is quite possible a trading market will develop for international LNG movements to allow independent price discovery.[6] As there are many possible suppliers, the supply curve may well be quite flat. The international LNG price situation in the equilibrium case may well approximate that of coal whose real price is usually assumed to increase by no more than one per cent per year in most long-term studies.

The equilibrium NYMEX Trading Market equivalent price for LNG is assumed here to be $4.00/million Btu. For the eleven years inclusive from 1992 and 2002, the price in Japan on a cif basis is quoted as ranging from $3.18 and $4.72/million Btu. Under non-equilibrium conditions, which arise when demand cannot be met if it is not possible to deploy LNG facilities fast enough, the price is likely to be much higher. Nevertheless, with the current rapid advances in LNG technology, the large number of possible sources, and the ample conventional gas resources existing outside of North America, this price is considered plausible as it more than recovers the expected technical costs for this emerging supply option. When adjusted to an on site price by adding the $0.38/million Btu differential, the cost of electricity from NGCC produced from LNG is 4.06 cents per kWeH as illustrated by the lower dashed red lines in the Figure starting at `A'. In the future, the delivered LNG price on the Pacific side is expected to be somewhat lower than on the Atlantic side of North America.[7]

Generation from Coal-Based Facilities

The MIT Report gives the levelized cost of electricity from a modern pulverized fuel (PF) coal-burning generating station as 4.2 cents/kWeH. This value is somewhat higher than the cost of generating electricity in NGCC installations based upon LNG imported under equilibrium conditions (4.06 cents/kWeH). Adding the ability to capture and sequester carbon dioxide is assumed to cost an additional 2 cents/kWeH so that the levelized cost becomes 6.2 cents/kWeH. This is less than the 6.7 cents/kWeH given for nuclear generation in PWRs built with current technology in the Report. The average price of natural gas on the NYMEX Market required to be competitive with this cost is 7.28 cents/million Btu as shown by the solid black arrows ending at ‘B’ in the Figure after deducting the location differential adjustment cost of 0.38 cents/kWeH. If LNG prices increase only one per cent real per year as they might under equilibrium conditions, this required price would not be reached until after world conventional gas production reaches its peak even if the real price of coal remains the same throughout this period. If the increase under non-equilibrium conditions is 3% real per year, then equivalence is reached about 2031. It is clear that other measures such as a carbon tax or credit of some kind will be necessary to be competitive with the NGCC based upon LNG for some years, at least under some approximation to equilibrium pricing conditions.

If it is assumed that the capture and sequestering (C&S) technology removes 80% of the carbon entering with the coal and that overall conversion efficiency falls to 35% as compared to 40% in the conventional plant, the C&S plant will emit less carbon dioxide than the NGCC plant. It follows that there is a mix of conventional and C&S-equipped facilities that will equal the emissions from NGCC technology. In this example, the proportion is almost exactly 20% conventional and 80% equipped for C&S. This mix of levelized generating costs is 5.82 cents/kWeH leading to an equivalent natural gas price of 6.63 cents/kWeH at point `C' on the blue lines in the Figure. At three per cent per year real increase in the price of LNG, equivalence would be reached about 2027. In this calculation, no consideration was given to the possibility of capturing some carbon dioxide from the NGCC facility.

Generation from Nuclear Power (PWR)

For completeness, the horizontal dashed black line indicates the natural gas equivalence of nuclear generation in conventional PWR stations at a levelized cost of 6.7 cents/kWeH. The authors of the MIT report expect this value to be reduced to 5.5 cents/kWeH if construction cost could be reduced 25%, further to 5.3 cents/kWeH if construction time could also be reduced from five to four years, still further to 5.1 cents/kWeH if operation and maintenance cost could be reduced to 1.3 cents/kWeH, and finally to 4.2 cents/kWeH if the cost of capital could be reduced to be more comparable with coal and natural gas facilities.

Conclusion

The levelized cost of electricity in coal-based facilities equipped for the capture and sequestering of carbon dioxide is compared with generation in natural gas–based combined-cycle technology in a simple diagram in which the generation cost is plotted as a function of the price of natural gas. NGCC technology is used as the yardstick because it is the preferred method of generation at margin at the present time due to its lower cost and other advantages. Because the production of natural gas from conventional sources is either near or even past its peak in North America, gas imported in liquid form in cryogenic tankers (LNG) from surplus countries is the next least costly major new source of supply of this convenient fuel. The price of natural gas throughout the integrating North American market should therefore approach that of delivered LNG under market conditions approaching internal equilibrium. A technique was devised to adjust the average cost of natural gas delivered to generating stations to the average prices reported on trading markets. This procedure allows the linkage of the extra cost of capture and sequestering technology applied to generation from coal to resource issues and other factors bearing on the availability of natural gas.

It is shown that NGCC technology based upon LNG in equilibrium markets is somewhat lower that for conventional pulverized fuel (PF) coal-firing technology. After making an allowance for the added cost of capture and sequestering technology, it would be many years before the real price of gas would increase sufficiently to compensate for this extra cost even assuming the real price of coal did not increase during this period. Other measures, such as a carbon tax, would be necessary to close this gap.

It is unlikely LNG will be supplied under equilibrium conditions after the peak in North American conventional gas production is passed because of the difficulty in building and locating the necessary facilities to accommodate the much increased flow despite the adequacy of the gas resources in supplying countries. A non-equilibrium condition in this case may be expected with higher prices. Nevertheless, even with an increase of three per cent per year in real LNG prices, the cost equivalence would not be reached until as late as 2031. It is possible, however, that gas prices would increase even faster than this rate depending upon how much conventional gas may be found and delivered from Frontier regions to offset the decline in the older producing districts.

The graphical technique has the advantage of providing a visual method of testing the effects of various process options that may reduce costs in a very simple way.

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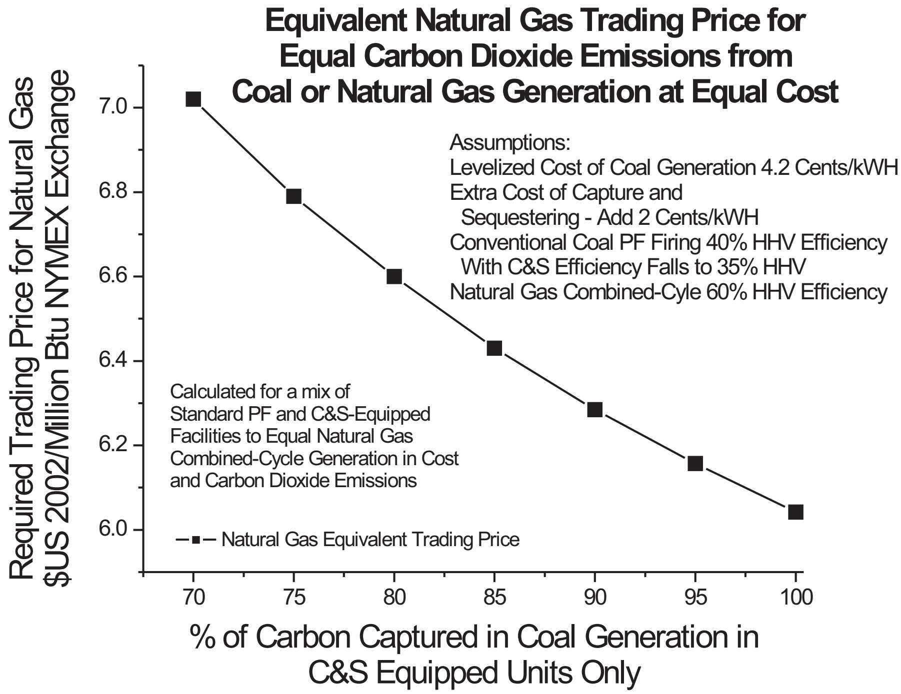
Appendix

Application of Natural Gas Equivalence Technique to Evaluation of Importance of Carbon Dioxide Recovery in Capture and Sequestering Processes

This appendix illustrates the application of the natural gas equivalence technique to the assessment of the importance of the degree of carbon dioxide recovery in capture and sequestering (C&S) processes applied to the generation of electricity in coal-based processes. The question addressed here is: What is the equivalent price of natural gas on trading markets for equal cost and carbon dioxide emissions from coal-based generation? The reference natural gas case is a combined-cycle facility operated at high efficiency (60% HHV) to represent a leading-edge facility expected to be in competition with coal in the near future. To provide an extra kWH, the NGCC facility is compared with a mix of conventional coal PF technology (40% HHV efficiency) and a C&S-equipped station operated at 35% HHV efficiency. The levelized cost of electricity in the conventional coal facility is taken as 4.2 cents(US)/kWH and in the C&S facility an extra two cents at 6.2 cents(US)/kWH. Combinations of the two classes of coal facility were then computed over the range of 70 -100% recovery of carbon dioxide in the C&S facility so that the total emissions equalled those from the NGCC plant. The average levelized cost was then calculated for each 5% increase over the range of interest of capture of carbon dioxide. The thermal efficiency of the C&S-equipped station was assumed unchanged over this recovery range.

The averaged levelized cost from the two classes of coal-based facilities was used to determine the equivalent natural gas price by employing the plot in the figure in the main text. This was corrected by subtracting 0.38 cents (US) to arrive at the equivalent trading price for the reasons given in the paper. This price was then plotted against the degree of recovery in the C&S-equipped facilities in the figure in this appendix.

It may be seen that the range of equivalent natural gas trading prices falls from about $7 (US) to $6 (US)/million Btu as the degree of recovery of carbon dioxide increases. This fall in equivalent trading prices is significant in that it is also the range of prices likely a few years in the future unless lower equilibrium prices for imported LNG prove attainable.



As an alternative strategy, it may be possible to remove about two-thirds of the carbon dioxide at reduced cost in the integrated-gasification combined-cycle process equipped with a physical sorbent separation step but without complex shifting stages. With a capture rate of 66.6%, such a coal-based plant would be equal in carbon dioxide emissions to a natural gas combined-cycle facility. If this limited rate of capture could be achieved for an additional cost of only one cent per kWH, the equivalent Trading Price for natural gas would be $5.68 per million Btu ($US 2002). This price is within the range of some generally accepted estimates for the future price of natural gas. Such a low-cost simplified process would then be competitive with the natural gas-based combine-cycle process in both cost and carbon dioxide emissions.