

UK And European Gas Issues

A Report For The Confederation Of UK Coal Producers

By

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Executive Summary

1. The era of over supply of low cost energy that characterised much of the 1980s and 1990s has come to an abrupt end. Over the past two years oil prices have trebled and gas prices more than doubled. These higher prices come at a time when production of oil and gas from the UK Continental Shelf are nearing their peak and set to decline. In addition, the environmental policy objective of reducing emissions of CO₂ and SO₂ appears to be inconsistent with the energy policy objective of security, diversity and sustainability of energy supply at a competitive price.

2. New reserves of UK gas are not being found and proven to maintain the lifetime of reserves. Over the last eight years, the remaining lifetime of UK reserves has fallen by 19 years. We are using reserves very much faster than they are being replenished. The question has to be asked as to whether the increase in the use of gas in power generation over the last decade has been a prudent use of the UK's rapidly declining reserve base.

3. The UK is inevitably going to join most other European nations as net importers of gas. The International Energy Agency (IEA) forecast that OECD Europe imports of natural gas will grow from 107 mtoe in 1997 to 403 mtoe by 2020. The UK will be the most remote of the major users of gas from the sources of supply in Russia, the Middle East and North Africa.

4. Over the next few decades Norway will continue to be an important gas supplier to Europe, but it will only ever provide a small proportion of European supplies. The UK may not be the major export destination for Norwegian supplies. In 2000 the UK took only 4.3% of Norway's gas exports. Other countries, particularly Germany, France and the Netherlands will seek to retain the maximum diversity in their sources of supply to avoid, as much as possible, over-dependence upon gas from Russia. The UK must face up to the reality that a large

proportion of our gas imports will be sourced from Russia and other geopolitically unstable countries with inevitable implications for security of supply.

5. The IEA highlighted a year ago that the prospects for Russian supplies meeting Europe's requirements are highly uncertain due to the high level of investment required. Russian production is currently declining because of the lack of investment. Therefore, there must be serious concerns over the ability of exporters to meet the burgeoning European demand. Furthermore, Russia seems likely to increase levels of coal burn to make gas available for export to Europe, a switch that will bring no net benefit to the global environment.

6. One measure of diversity is the Evenness measure. In a perfect market with a multitude of suppliers having equal market shares, Evenness approaches one. In a monopolistic market with a very dominant supplier Evenness approaches zero. Analysis of the sources of gas and coal imports to OECD Europe by country results in an Evenness factor of 0.8 for coal against 0.45 for gas supplies highlighting the natural diversity in the international coal market.

7. One measure of the dominance of large suppliers in a market is the Herfindahl-Herschmann measure. In a perfect market the H-H measure is very low. In a monopolistic market the H-H index approached 10,000, the maximum level possible. In 2000, the sources of coal imports resulted in an H-H index of 1640 whilst the sources of gas imports resulted in an index of 4825. To set this into context, the electricity regulator determined in 1993 and 1997 that National Power and PowerGen were dominant in the price setting part of the UK electricity market when the H-H index in that market stood at 3000 to 4000. The high H-H index of gas imports should set the alarm bells ringing.

8. The extent of concentration in European gas imports would provoke regulatory intervention if it were under the jurisdiction of UK authorities. Dominant suppliers that are outside the reach of UK and European competition protection legislation should be treated with

extreme caution. Dti and Ofgem remain concerned over potential market abuse by UK generators but have expressed little public concern over the lack of a competition framework that would cover European gas imports.

9. The higher diversity of sources of coal imports to Europe should be fully taken into account in the development of energy policy in both the UK and Europe.

10. There is unlikely to be significant gas on gas competition in a liberalised European gas market. Small suppliers are likely to be price takers with Russian producers setting prices linked to oil prices. The UK, at the end of the pipeline network, will pay more for its supplies than many of its European neighbours and have a greater risk of supply interruption.

11. Energy Paper 68 (EP68) set out Government's energy projections through to 2020. Assessment of these projections shows that, by the second decade of the 21st century, the UK is set to return to the levels of diversity it last saw in the 1970s where there was massive dislocation to economic activity associated with the oil price shocks and the miners and power workers strikes. The EP68 scenarios are based on ludicrously low oil prices and the PIU should urgently set about developing a realistic range of scenarios that will enable a range of plausible outcomes to be assessed and appropriate policies developed.

12. Whilst there may be diversity in the nation's primary energy demand there is very limited flexibility in the short to medium term. Some sources such as nuclear and renewables operate at baseload and therefore there is no potential for increasing their energy production during periods of crisis. Similarly there is very limited flexibility in fuels for transport in the medium term. The largest degree of short/medium term flexibility exists in the electricity market where coal can displace gas generation at most times of the year provided there is adequate flexibility in environmental authorisations.

13. The flexibility in the electricity market has been admirably demonstrated over the past eighteen months. In response to nuclear breakdowns and rising gas prices, levels of coal fired

generation in 2000 rose by 14.9% over 1999 levels and in the first half of 2001 were 19.2% higher than a year earlier. However, a large proportion of the remaining flexibility could be lost over the next decade as existing coal plants close and gas reserves deplete. EP68 projects that the 25 GW of coal capacity in 2000 could fall to 12 GW by 2010 and 8 GW by 2020.

14 Consideration should be given to specifying a minimum coal component in the generation mix that would retain a high level of diversity in the electricity market. The proposed renewables obligation should be extended to cover coal fired generation. To ensure the attainment of sustainable and practicable environmental targets, the obligation should incorporate a growing obligation to purchase electricity from clean coal power stations.

15. It should be recognised that the option of increasing coal fired generation in the electricity market would make more gas available for other markets, such as the industrial and domestic markets. Mid merit coal operations therefore help support fuel security both within and outside the electricity sector.

16. The UK has a very low level of gas storage capability. Major gas users such as Germany, France, Italy all have a storage capability of over 20% of annual consumption. The UK has a capability of only 3.7%. This level of stockholding is woefully inadequate. Given the high dependency on future imports of gas there can be no excuse for failing to place equivalent obligations on gas suppliers and generators as apply to other fuel suppliers and generators. This obligation would be met by increased underground storage facilities and storage of LNG and medium distillate oil at terminals and power stations.

17. Contingency plans should be developed and reviewed on a regular basis to establish how the UK would respond to an interruption to gas supplies. In such an event the Secretary of State would need to invoke powers under the Electricity Act to direct which power stations operate. Are these powers adequate and are other powers required? Which customers would be disconnected? Who would control the process?

18. A new energy agency should be created that would absorb many of the existing authorities and ensure that, in the fields of licensing, regulation, security of supply and sustainability, Government policy is implemented consistently. In addition the energy agency would assess and report to Government on risks to the UK's security of energy supply.

19. There is a clear need for retention of coal capacity on the electricity system and the progressive replacement of existing coal capacity with new clean coal capacity to ensure that long term environmental objectives are met. Short term environmental constraints should not be imposed that foreclose the electricity market and constrain competition.

1. Introduction

1.1 This paper looks at the issues surrounding long term gas supply and has been produced in response to the PIU Initial Scoping Notes on Gas and Security.

1.2 The Government is right to take stock and review how the UK is placed to meet the challenges of energy supply in the early decades of the 21st century.

1.3 The growth in the use of gas in the UK over the past three decades has been dramatic. Europe is now set to rapidly increase its use of gas, particularly for electricity generation. However the reserves of gas are highly concentrated in Russia, The Middle East and North Africa, areas that are remote from the UK. This is in stark contrast to world coal reserves which are more evenly distributed around the globe.

1.4 Over 47% of the total world reserves of gas are concentrated in Russia and Iran, a greater concentration of reserves than is the case for oil. The distribution of reserves clearly demonstrates the implicit risk to European gas supplies. This concentration of gas reserves only tells a part of the story. There are inevitable pricing and security of supply risks that will accompany Europe's dependence upon imports from these and other sources of gas.

1.5 The UK has not needed to seriously address security of supply issues over recent years. The liberalisation of the energy markets, impending dependence upon imported energy and the change in the UK fuel mix reduces the control that Government and Regulators can have over supplies. What can and should be done to protect the diversity of energy supplies and enhance the flexibility of our energy systems?

2. UK Supply Position

2.1 UK Supply And Reserves

2.1.1 The UK has been fortunate to have considerable reserves of gas in the UKCS. Over the past three decades gas consumption has grown at 6.4% per annum. Excluding the use of gas in electricity generation, gas consumption has risen by 3.0% over the past decade.

2.1.2 However, the rate of finding new reserves has not kept pace with the rise in gas production and use. The reserve to production ratio gives a good indication of the state of remaining reserves. Whilst further gas may be found and proven to be economically and technically recoverable the proven, possible and probable reserves as quoted in the annual Dti Brown Books is a reliable and consistent source of information. Under Dti definitions, probable reserves have a greater than 50% probability of being won and possible reserves have a less than 50% probability of being won. Table 2.1 shows the position over recent years, covering the period since the take off in the use of gas in the electricity sector.

Table 2.1 - Remaining Lifetime of UK Gas Reserves - Years

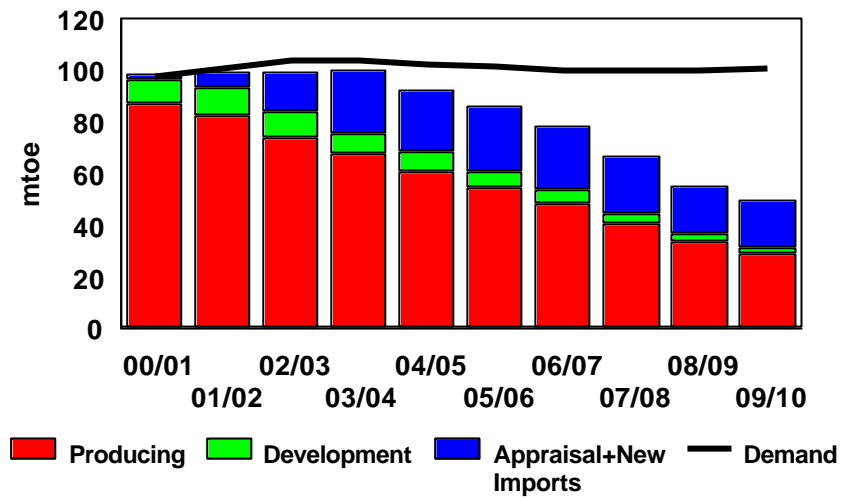
	1992	1995	1998	2000				
Proven Reserves	10.99	37.96	3.3	Plus Probable Reserves	24.1	19.6	14.0	10.4
Plus Possible Reserves	33.1	125.4	18.8	14.2				

2.1.3 The table demonstrates that new reserves are not being found and proven to maintain the lifetime of reserves. Over the last eight years, the remaining lifetime of reserves has fallen by 19 years. We are using reserves very much faster than they are being replenished. The question has to be asked as to whether the increase in the use of gas in power generation over the last decade has been a prudent use of the UK's rapidly declining reserve base.

2.1.4 The most authoritative view on medium term gas production from UKCS is contained in the Transco Ten Year Statement issued in 2000. The report shows that the UK is likely, taking

account of production from new fields that have yet to be developed and new imports, to have a significant supply shortfall within the next few years, see Figure 2.1.

Figure 2.1 - UK Gas Supply And Demand



Source: Transco Ten Year Statement 2000

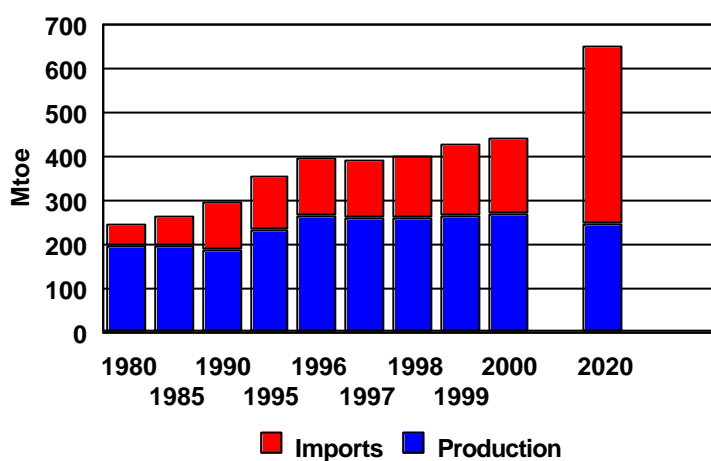
2.1.5 Dti expect that UK production will fall from a peak over 100 mtoe in 2003/4 to around 40 to 60 mtoe in 2010 and 10 to 20 mtoe by 2020, in line with Transco projections. UK imports could total up to 117 mtoe by 2020 on Dti projections.

2.1.6 The UK is inevitably going to join most other European nations as net importers of gas. The UK will be the most remote of the major user of gas from the sources of supply in Russia, the Middle East and North Africa. The issues raised by such import requirements cannot be answered on a UK stand alone basis and have to be considered on Europe wide basis.

3. European Supply Issues

3.1 This section is largely based on statistics for OECD Europe as produced by the International Energy Agency (IEA) in their annual statistics. The statistics are more comprehensive than the limited statistics available on an EU basis. Therefore when referring to Europe this is OECD Europe not the EU15 unless otherwise stated.

Figure 3.1 - OECD Europe Natural Gas Supply



Source: IEA Gas Information 2001 and World Energy Outlook 2000

3.2 European gas demand has grown at a rate of 3% since 1980 and, according to IEA forecasts is due to rise by 3.3% pa through to 2010 and by 2.8% from 2010 to 2020. Hence European gas demand will grow from 344 mtoe in 1997 to 650 mtoe in 2020. Based upon IEA assessments, import dependency is forecast to grow from 31 percent in 1997 to 62% in 2020. This equates to a growth in imports from 107 mtoe in 1997 to 403 mtoe in 2020, nearly a fourfold increase, as set out in Figure 3.1.

3.3 The IEA report highlights that the prospects for Russian supplies meeting Europe's requirements are highly uncertain due to the high level of investment required. As the Dti initial submission makes clear, Russian production is currently declining because of the lack of investment. Therefore, there must be serious concerns over the ability of exporters to meet the burgeoning European demand.

3.4 Russia seems likely to increase levels of coal burn to make further gas available for export. Such a switch will bring no net benefit to the global environment.

3.1 Norwegian Supplies

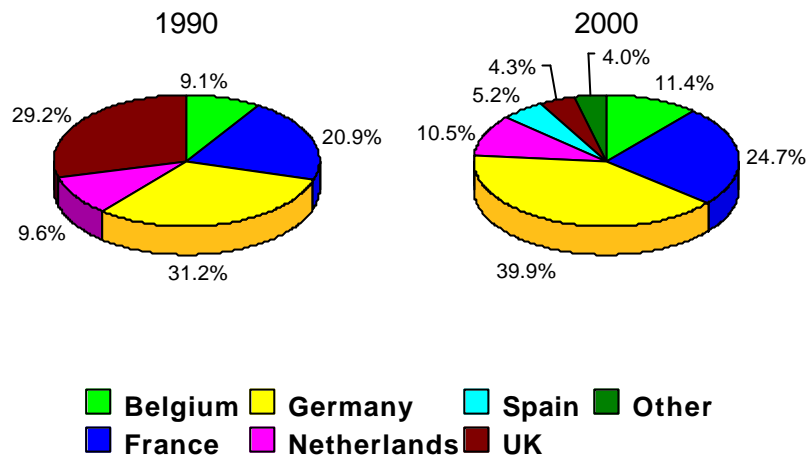
3.1.1 Norwegian supply is going to be a growing component of European production, to some extent offsetting the decline in UK production. There appears to be some uncertainty over Norwegian proven reserves. The BP Statistical Review of World Energy 2001 put the reserve figure at around 1150 mtoe, substantially lower than the 3420 mtoe estimated by Cedigaz and quoted in the Dti submission. Official remaining reserves and proven reserves in fields are put at 1845 mtoe by the Norwegian Petroleum Directorate.

3.1.2 The Dti initial submission argues that Norway can be expected to produce at least 85 mtoe through to 2050. This implies a fifty year production that is 3.7 times the level of proven reserves on the BP definition of reserves and 1.25 times the level of proven reserves on the Cedigaz definition.

3.1.3 In 2000 Norway produced 47 mtoe of natural gas with an indigenous demand of only 3.5 mtoe. In October 2000 Norway announced plans to use more natural gas within the country as a part of its energy and industry and transport policy. This will make less gas available for export in the medium to longer term.

3.1.4 Norway has been increasing its production of gas steadily from 25 mtoe in 1990 to 47 mtoe in 2000. Figure 3.2 shows the destination of Norwegian exports. As the table demonstrates, Norway is already a major player in the European gas market with its largest customers being France, Germany Netherlands and Belgium. Many customers in these countries will be supplied under long term contracts and it cannot be assumed that such gas will be available to UK customers. In 2000 UK took only 4.3% of Norway's exports.

Figure 3.2 Norweigan Gas Exports



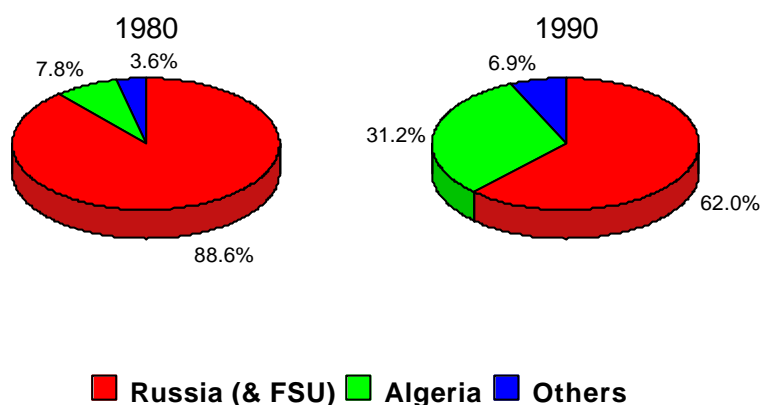
3.1.5 Over the next few decades Norway will continue to be an important gas supplier to Europe, but it will only ever provide a small proportion of European supplies. The Dti production figure of 85 mtoe equates to only 13% of forecast demand in 2020. Furthermore the UK may not be the major export destination for Norwegian supplies. Other countries, particularly Germany, France and the Netherlands will seek to retain the maximum diversity in their sources of supply to avoid, as much as possible, over-dependence upon gas from Russia. The UK must face up to the reality that a large proportion of our gas imports will be sourced from Russia and other geopolitically unstable countries with inevitable implications for security of supply.

3.2 European Imports

3.2.1 Over the past twenty years Europe has become a major importer of gas and coal with imports coming from only a few sources. Figure 3.3 shows the distribution of sources of imported gas. The figure shows that little has changed over the past 20 years, Russian and Algerian gas dominate Europe's supply. Gas imports are mainly by pipeline which restricts

imports to gas producers close to European borders. Coal imports come from further afield due to the low cost and simplicity of movement of dry bulk materials in large carriers.

Figure 3.3 - Source Of European Gas Imports



Source: IEA Gas Information 2001

3.2.2 The Dti has, over recent years, used a measure of diversity, the Shannon-Weiner index (S-W), in their annual Energy Reports. The mathematics of the S-W are set out in Appendix 1.

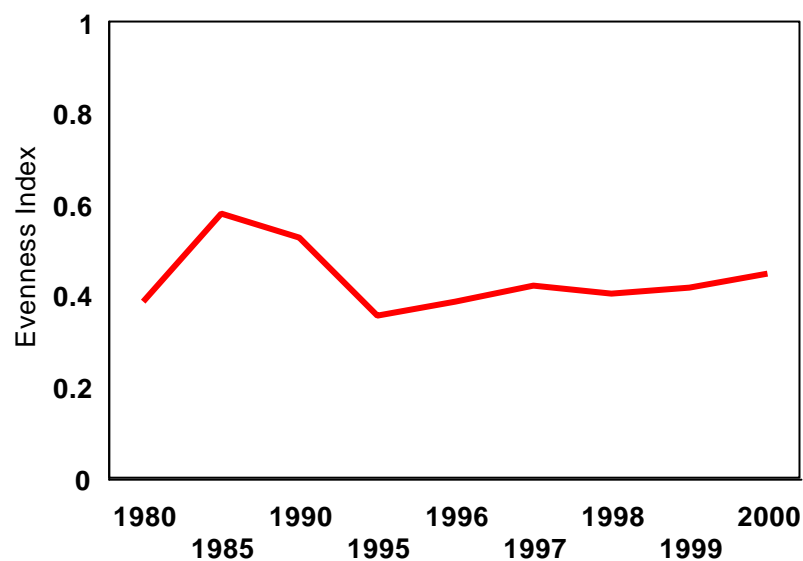
One advantage of the S-W index is that it places weight on the contribution of smaller participants in the market. The lower the S-W index the poorer the level of diversity. One problem with the S-W index is that it is not valid to compare the index between different markets since some markets have more sources or suppliers than others. Furthermore, comparisons over time within a market can also be misleading since new entrants may join the market adding to the S-W index without necessarily reducing the dominance of the major suppliers.

3.2.3 There is a variant of the S-W that allows for such comparisons to be made by normalising the number of sources, the Evenness measure (again the mathematics of this are set out in Appendix 1). Evenness varies between zero and one. In a perfect market, with a multitude of suppliers having equal market shares, the Evenness is one. In an imperfect market

with few suppliers and a very dominant supplier the index approaches zero. Hence the higher the Evenness Index, the better the diversity of suppliers.

3.2.4 Figure 3.4 sets out the Evenness of European gas imports since 1980.

Figure 3.4 - Evenness Of Gas Imports



Between 1990 and 1985 there was a rapid growth in imports from Algeria which improved the evenness of supply with the growth in the proportion of Russian gas after that time eroding the improvement. The modest increase in recent years is due to small imports of LNG from Nigeria and Qatar.

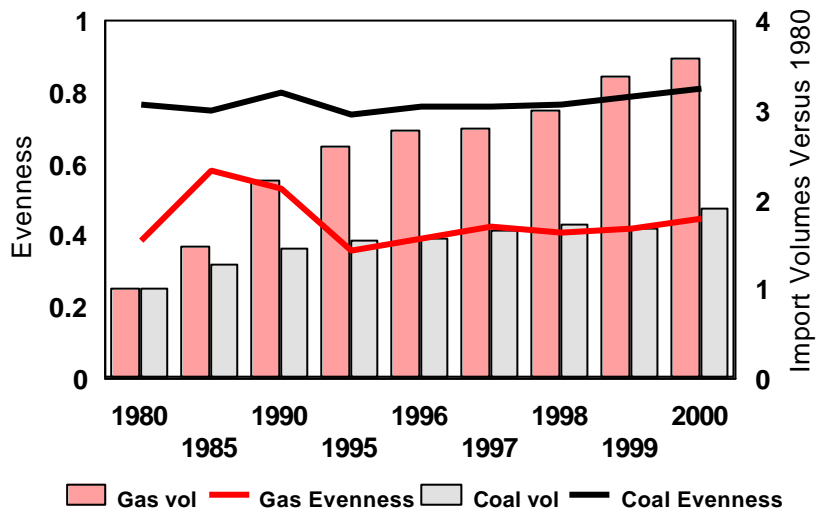
3.2.5 By comparison, the evenness of primary energy demand in UK is around 0.75 and the evenness of fuels for electricity generation around 0.7. Hence it is very clear that the diversity of supply of imported gas into Europe is a serious cause for concern.

3.2.6 It is also relevant to compare the evenness of gas imports with coal imports. The bulk of coal imports into Europe come from a diversity of sources including Australia, USA, South

Africa, Colombia, Indonesia and China. Figure 3.5 demonstrates that the evenness of coal imports is significantly greater than the evenness of gas imports.

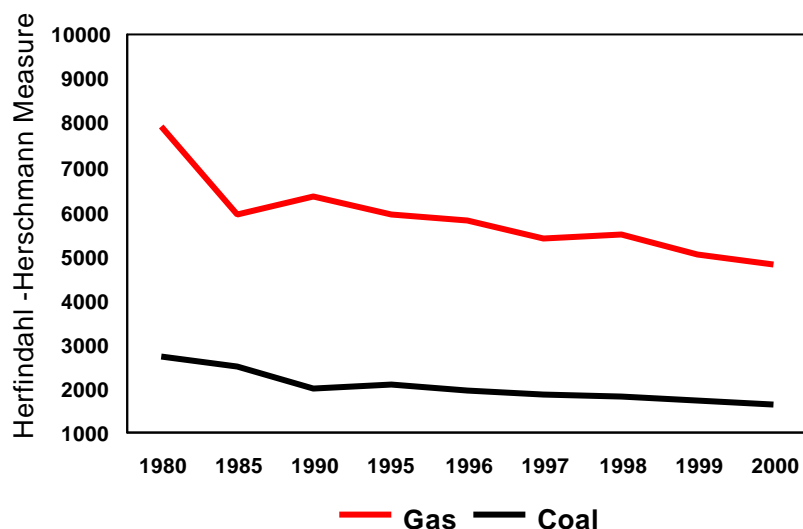
3.2.7 This analysis clearly demonstrates that there is considerably greater diversity in coal imports than gas imports. However, it has to be acknowledged that not only are gas imports concentrated in fewer suppliers, the risk associated with the gas exporting countries is also higher than from many coal exporting countries.

Figure 3.5 - European Gas And Coal Imports Evenness



3.2.8 A second measure has been used in recent Dti Annual Energy Sector Indicators, the

**Figure 3.6 - European Gas And Coal Imports
Herfindahl-Herschmann Measure**



Herfindahl-Herschmann (H-H) measure which is the sum of the square of the market shares.

The lower the H-H measure, the least concentrated is the supply and the better the diversity.

3.2.9 Figure 3.6 demonstrates that coal imports to Europe are significantly less concentrated than gas imports to Europe.

3.2.10 Both Dti and Ofgem (and its predecessor) have used the H-H measure in analysis of the electricity market. It is interesting to note that the degree of concentration in the electricity market was deemed to be unsatisfactory by the electricity regulator in both 1993 and 1997 when the H-H measure stood at around 2250 and 1750 respectively. Concerns were concentrated on the price setting ability of the generators. In 1993 the H-H index of the price setting generators was around 4000 and by 1997 it had fallen to around 3000. The dominant fossil generators, National Power and PowerGen, were required to give undertakings to divest coal plant in 1994 and 1998.

3.2.11 With an H-H index of 4825, it is clear that the concentration in sources of European gas imports would provoke regulatory intervention if it were under the jurisdiction of UK regulatory authorities. Dominant suppliers that are outside the reach of UK and European

competition protection legislation should be treated with extreme caution. Dti and Ofgem remain concerned over potential market abuse by UK generators but have expressed little public concern over the lack of a competition framework that would cover European gas imports.

3.3.12 If information was available on a company by company basis, the advantage for coal would be even greater since most gas is produced by national gas producers such as Gazprom in Russia whereas coal from Australia, USA and South Africa and elsewhere comes from numerous producers and traders. The higher diversity of sources of coal imports to Europe should be fully taken into account in the development of energy policy in both the UK and Europe.

4. Pricing Issues

4.1 UK Pricing And Contract Issues

4.1.1 With the opening of the Bacton/Zeebrugge interconnector, the UK is now connected to the wider European gas market. This led to a sharp increase in prices in 2000 that was exaggerated by high oil prices.

4.1.2 The argument in the PIU Scoping Note that, following the 1986 Gas Act, UK gas prices gradually de-coupled from oil prices to reflect market fundamentals has got to be challenged. The fall in UK gas prices to below 10 p/therm occurred because of oversupply in the isolated UK gas market. The problems of oversupply were compounded by restrictive take-or-pay contracts that left little flexibility, particularly the restriction on the resale of gas under British Gas Lti contracts. During this period spot gas prices were significantly lower than average prices, see Table 4.1, with most customers paying at higher long term contract prices. The fall in the price of gas to electricity generators in 2000 followed renegotiation of long term contracts with over £2000 million being paid to gas suppliers up front for lower future prices.

Table 4.1 - Comparison Between Spot Gas Prices And Prices To Electricity

Generators	1997	1998	1999	2000	IPe Spot Price p/therm
Trends	19.0	19.2	18.0	17.4	11.57
Dti Energy	11.4	19.9	18.7	9.3	18.79

4.1.3 When spot prices were low, generators were forced to use expensive gas rather than buy on the spot market. Electricity customers paid the excess bill. When spot prices rose (to nearly 32 p/therm in November 2000), generators could not sell gas into the wholesale gas market because of the restrictive resale provision in Lti contracts. Thus the high spot price was maintained to the advantage of the same gas producers who imposed the prohibition on the resale to other customers. It is also those same gas suppliers that invested in the interconnector, the link with Europe, that has brought a doubling of wholesale prices in the UK.

4.1.4 The UK coal industry sought to bring the issue of the anti-competitiveness of long term take-or-pay gas supply and electricity sales contracts and the prohibition on the resale of gas to competition authorities in the UK without success. Having failed to elicit any action from UK authorities it raised a formal complaint with EU competition authorities in 1997. The EU eventually rejected the complaint in December 1999 suggesting that “the complaint finds its origins in national regulation” and that the complaints “are clearly in the competence of the United Kingdom”. Despite the EU writing to the United Kingdom authorities, no action has been taken. The lack of action by Dti and Ofgem in this area is clear evidence of regulatory failure.

4.1.6 The low spot prices of under 10 p/therm were never sustainable. The Dti Brown Book sets out the total lifetime costs of UKCS fields as follows:

Table 4.2 - Unit Cost Of Gas Fields at 2000 Prices p/therm

Fields starting production before 1980	Fields starting production 1980-1985	Fields starting production 1986-1990	Fields starting production 1991-1995	Fields starting production 1996-2000	All fields in production
9	23	21	14	14	13.5

These figures exclude taxes and royalties. New gas fields in the UKCS are expected to be smaller and more remote than existing fields putting further pressures on price.

4.2 European Prices

4.2.1 Given the integration of the UK gas market into the wider European gas market, it is clear that prices will continue to be set on a Europe-wide basis. Those Europe-wide prices are inevitably going to be set by the major exporters to Europe ie Russia and Algeria. Other new suppliers are likely to be price takers, not price setters.

4.2.2 Major investments will be required to bring the additional gas required to the European market, investments in new fields and pipelines etc. It seems likely that the funding for such investments will have to be backed by long term take-or-pay contracts. Such contracts make the prospect for gas on gas competition unlikely in a liberalised European gas market. Furthermore there is real risk that major suppliers like Gazprom, who produce 95% of Russian gas, will seek an OPEC style body to control gas prices. The CEO of Gazprom made such a call at The Gas Executives Summit Conference in Paris in 1999.

4.2.3 If prices are set at the European borders then, in reflection of the cost of getting gas to the UK, the UK is likely to pay the highest price of major European gas users. As discussed in Section 6, UK users are also likely to be the most at risk of supply disruption.

4.2.4 As discussed in Section 3.1, Norwegian gas is likely to be strategically attractive to all major European users to minimise exposure to Russian gas and is likely therefore to command a premium over Russian prices. More than 95% of Norwegian exports went to customers in continental Europe in 2000.

4.2.5 The option of LNG becoming a major source of supply for the UK is an interesting development and will have implications on security of supply. However, in pricing terms, it is important to recognise that LNG is an expensive option, would require major investment and is priced and escalated in line with oil prices. Japan is the major world LNG importer and the BP Statistical Review of World Energy 2001 shows that LNG prices in 2000 rose by 50% over 1999 prices, reflecting the rise in oil prices. However, LNG could reduce the impact of any dominant suppliers or pipeline routes and offer a practicable storage option.

4.2.6 In Annex 1 to its Initial Submission Dti argue that gas prices are unlikely to return to the Spring 2000 prices of 25 to 30 p/therm and that prices have fallen to 16 to 18 p/therm. This is

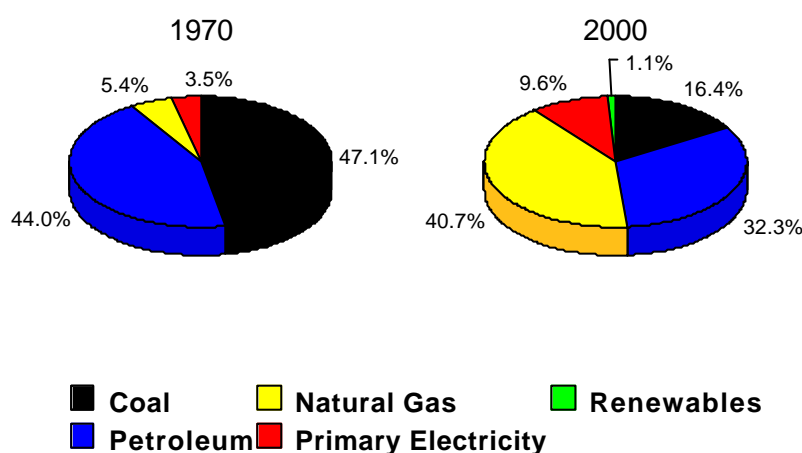
rather misleading. The International Petroleum Exchange (IPE) publish futures prices on a daily basis. As at 4 September the market price for gas is shown as 16.3 p/therm for the balance of September rising to 26.6 p/therm for January 2002 demonstrating the seasonality of gas prices. Daily prices will vary around these monthly figures dependent upon weather and other variables. The IPE quote prices of 21.3 p/therm for winter 2004, a figure substantially higher than the Dti figure.

4.2.7 There is unlikely to be significant gas on gas competition in a liberalised European gas market. Small suppliers are likely to be price takers with Russian producers setting prices linked to oil prices. The UK, at the end of the pipeline network, will pay more for its supplies than many of its European neighbours and have a greater risk of supply interruption.

5. Diversity Of UK Energy Demand

5.1 Over the past three decades the diversity of the UK's primary energy demand has improved. The over dependence upon coal and oil in 1970 has improved with the development of North Sea gas and the increase in nuclear generation.

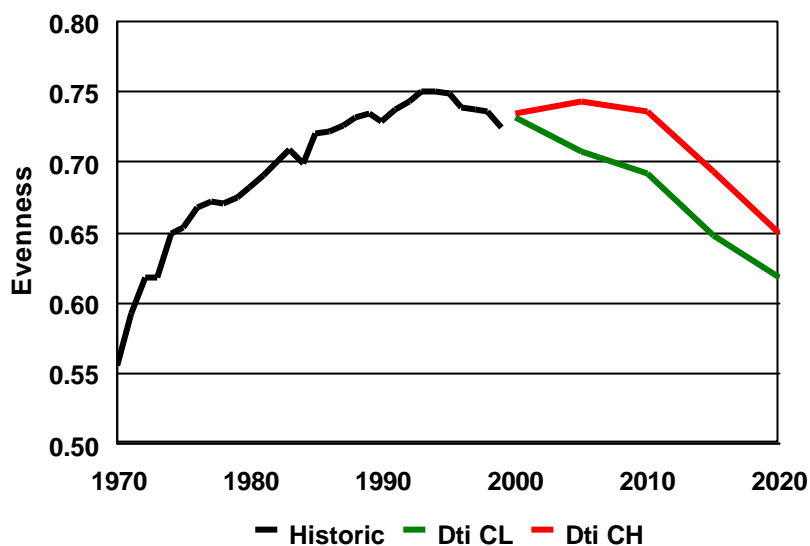
Figure 5.1 - Primary Energy Demand



However, as the pie chart for 2000 demonstrates, the UK has become overly dependent upon oil and gas, two fuels that are linked in their production and pricing.

5.1.2 In December 2000 Dti published Energy Paper 68 (EP68) which set out Government's Energy Projections for the UK. Section 9 sets out why great caution should be exercised in using any of the conclusions from EP68 since the input assumptions on which the projections are founded are heavily skewed in favour of low oil and gas prices. However, the projections do represent Government's official position and it is appropriate to assess how the diversity of primary energy demand is projected to develop. Figure 5.2 sets out the Evenness of primary energy demand through to 2020 on the two EP68 scenarios CH and CL.

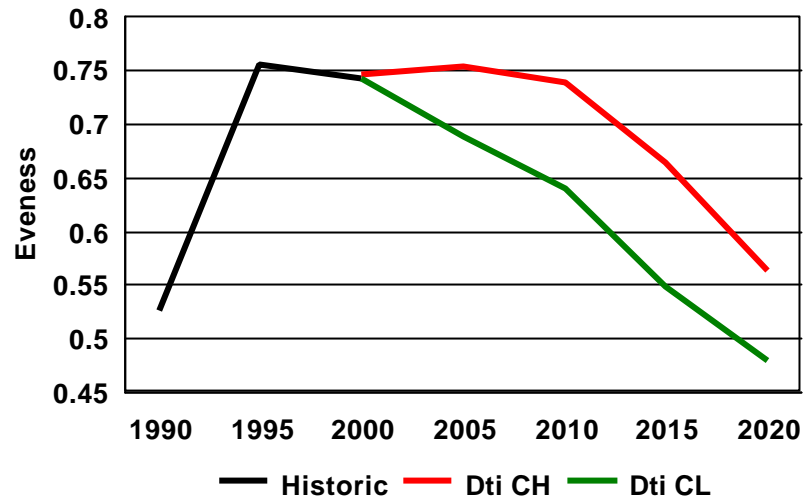
Figure 5.2 - Primary Energy Diversity



5.1.3 This drop in fuel evenness shows that the UK is set to return to the levels of diversity it last saw in the 1970s where there was massive dislocation to economic activity associated with the oil price shocks and the miners and power workers strikes. This time around the market power will rest with the gas producers of Russia and Algeria rather than UK unions.

5.1.4 As far as fuels for electricity generation the impact is even more pronounced.

**Figure 5.3 - Diversity Of Fuel Use
In The Electricity Market**



5.1.5 It is surprising that this dramatic loss in diversity in both the primary energy market and the electricity market has not been a cause of concern to both Government and Regulators. Both have supported the erosion of diversity through their actions over the past few years. Measures that have incentivised the ongoing displacement of coal by gas include the over capacity in many CHP schemes, the lifting of the stricter consents policy and the support for emissions trading.

5.1.6 The retention of coal fired generation is essential if the UK is to maintain its diversity of fuel use. The demonstration and deployment of clean coal technologies would enable diversity to be maintained whilst achieving significant reductions in emissions of CO₂, SO₂ and NO_x.

6. Security Of Supply

6.1 As the previous analysis demonstrates, the UK is moving into a period when it will be dependent upon large volumes of imported fuels from remote suppliers. This will introduce new issues that the UK has not had to face before. Other energy importing nations have developed strategies to reduce their over-dependence any single source of supply. Other nations place more importance on their coal fired generation plants and have not followed the UK lead on the dash for gas.

6.2 Some fuel supplies, particularly gas supplies, will come from countries where geopolitical risks are relatively high and pass through long and constrained infrastructure that crosses many national boundaries. There must be a real risk of disruption to supplies. Disruption could come in the form of plant breakdown, war, riot, strike, fire, flood or act of God. Such events would constitute force majeure in most long term contracts. Furthermore, there is always the risk of political interference through disruption to supplies, price fixing or additional taxes or royalties. The UK, at the end of long pipelines from Russia, the Middle East or North Africa, is at greater risk than countries closer to the sources of supply. Countries across which pipelines cross are unlikely to forgo gas supplies to ensure that UK lights are kept on. By the time they reach the UK, the pipes could be empty.

6.3 The best option for the UK is the building/retention of flexibility in its energy systems and the development of sensible fuel stocking policies.

6.1 Fuel Flexibility

6.1.1 Whilst there may be diversity in the nation's primary energy demand there is very limited flexibility in the short to medium term. Some sources such as nuclear and renewables operate at baseload and therefore there is no potential for increasing their energy production during periods

of crisis. Similarly there is very limited flexibility in fuels for transport in the medium term. The largest degree of short/medium term flexibility exists in the electricity market where coal can displace gas for generation at most times of the year provided that there is adequate flexibility in environmental authorisations.

6.1.2 The flexibility in the electricity market has been admirably demonstrated over the past eighteen months. In response to nuclear breakdowns and rising gas prices levels of coal fired generation in 2000 rose by 14.9% over 1999 levels and in the first half of 2001 it was 19.2% higher than a year earlier. Without this flexibility the impact of rising gas prices would have been more widespread and prices would have risen still further.

6.1.3 However, a large proportion of the remaining flexibility could be lost over the next decade as existing coal plants close and gas reserves deplete. EP68 projects that the 25 GW of coal capacity in 2000 could fall to 12 GW by 2010 and 8 GW by 2020. There is a clear need for retention of coal capacity on the electricity system and the progressive replacement of existing coal capacity with new clean coal capacity to ensure that long term environmental objectives are met. Short term environmental constraints should not be imposed that foreclose the electricity market and constrain competition. This applies to SO₂, NO_x and CO₂ emissions.

6.1.4 Consideration should be given to specifying a minimum coal component in the generation mix that would retain a high level of diversity in the electricity market. The proposed renewables obligation puts an obligation on electricity suppliers to purchase a proportion of their electricity supplies from renewable generators. This mechanism should be extended to the coal sector. To ensure the attainment of sustainable and practicable environmental targets, the obligation should incorporate a growing obligation to purchase electricity from clean coal power stations.

6.1.5 It should be recognised that the option of increasing coal fired generation in the electricity market would make more gas available for other markets, such as the industrial and

domestic markets. Mid merit coal operations therefore help support fuel security both within and outside the electricity sector.

6.2 Stocks

6.2.1 Stockholding is one measure that can protect against supply disruption. The international community holds stocks of oil, both crude oil and petroleum products. UK stocks of oil products at the end of Q1 2001 stood at 69 days, slightly higher than our obligation of 67.5 days.

6.2.2 In the electricity sector the Secretary of State has powers under the 1989 Electricity Act to require power stations to hold minimum fuel stocks. These provisions were partly in response to the supply disruptions in the 1970s and 1980s. At the end of Q1 2001 coal stocks at power stations stood at 9.25 Mt, equivalent to 75 days use. Gas fired power stations, many of which have interruptible gas contracts, have no stockholding obligation.

6.2.3 It has to be acknowledged that the UK has a very low level of gas storage capability. Major gas users such as Germany, France, Italy all have a storage capability of over 20% of annual consumption. The UK has a capability of only 3.7%. This level of stockholding is woefully inadequate. Given the high dependency on future imports of gas there can be no excuse for failing to place equivalent obligations on gas suppliers and generators as apply to other fuel suppliers and generators. This obligation would be met by increased underground storage facilities and LNG and medium distillate oil storage at terminals and power stations.

6.2.4 It has to be concluded that the gas supply industry has been free riding on the security of supply obligations of other sectors. Since the cost of storage of oil and coal have been borne by those sectors, gas suppliers and generators should bear the cost of holding equivalent levels of fuel stocks.

6.3 Energy System Redundancy

6.3.1 As well as having flexibility within the energy supply systems, there is also merit in ensuring an appropriate level of redundancy, particularly in markets like the gas market where stockholding is minimal. This could mean, for example, investing in excess pipeline capacity to ensure that if there is failure in one major pipeline then there is adequate redundant capacity in other pipeline systems to ensure security of supply. Since these pipelines could be outside the UK, and possibly even outside Europe, it is difficult to propose market mechanisms that would deliver the redundancy.

6.3.2 The structure of long term take-or-pay contracts may not be appropriate for the development of spare/redundant capacity. There should be a role for Government to review the need for redundancy in energy systems and to authorise the cost recovery mechanisms that will be necessary to secure the investments. Markets that are deemed not to be infrastructure constrained ie coal and oil markets (where significant supplies can be stockpile) do not require such investment in redundant capacity.

6.4 Contingency Planning

6.4.1 With gas becoming the dominant fuel in the UK energy mix and supplies going to the industrial, commercial and domestic sectors as well as the electricity sector, plans should be drawn up to establish how an interruption to supply would be handled. How would the UK handle a loss of 5, 10, 20% of its gas supplies? Which customers would be disconnected? Who would control the process?

6.4.2 It has to borne in mind that electricity supplies fail safe on interruption (for most customers) whilst gas supplies can fail unsafe. On the occasions that gas supplies to domestic customers have been lost it has taken many days or weeks to reconnect supplies to relatively small numbers of customers since all pipes have to be purged and pilot lights re-lit. Gas disconnections to domestic customers could not be undertaken on a rota basis as was the case

in electricity disruptions in the 1970s and 1980s. Therefore any domestic gas customers interrupted would in effect be disconnected for the duration of the emergency.

6.4.3 A number of electricity generators and large industrial customers are supplied with gas under interruptible contracts, taking advantage of reduction in price associated with such flexibility. These contracts are manifestly capable of being interrupted. However, some interruptions would have more of an impact on society than others. There have even been cases where hospitals have been supplied under interruptible contracts.

6.4.4 Contingency plans should be developed and reviewed on a regular basis to establish how the UK would respond to an interruption to gas supplies. In such an event the Secretary of State would need to invoke powers under the Electricity Act to direct which power stations operate. Are these powers adequate and are other powers required?

7. Regulation And The Role Of Government

7.1 The liberalisation of energy markets in the UK has led to disparate systems for setting standards, authorising developments and monitoring market developments. The philosophy of “the market will deliver” has worked adequately during the years of oversupply of low cost energy, but may not be appropriate for the decades to come when the UK will be a major importer of coal, oil and gas.

7.2 The energy markets are fragmented and it is no longer possible for Government to pass the supply obligation onto nationalised monopoly companies. It is inevitable that Government, with the support of Regulators and monopoly infrastructure providers, will have to take responsibility for assessing security of supply risks and, through the options identified in Section 6 above, set appropriate market rules.

7.3 Energy policy issues cut across numerous departments and regulatory bodies and there is a lack of joined up thinking or consistency between them. The coal industry can justifiably argue that it suffers from being outside the loop on electricity market or environmental matters that are key to its future. Coal industry calls for reform of the electricity market were ignored for a number of years by an electricity regulator that was not accountable for the impact that the distortions in the pool were having on coal producers. The Coal Authority has very different objectives from the oil and gas directorate at the Dti in promoting the extraction of national fossil fuel reserves. To what extent do the Environment Agency consider the energy policy implications of their authorisations?

7.4 A new energy agency should be created that would absorb many of the existing authorities and ensure that, in the fields of licensing, regulation, security of supply and sustainability, Government policy is implemented consistently. In addition the energy agency would assess and report to Government on risks to the UK’s security of energy supply.

8. UKCS Fiscal Regime

8.1 UKCS operators enjoy a very favourable fiscal regime. In an attempt to encourage investment new oil and gas fields, those approved since 1993 pay no royalty, petroleum revenue tax or any other tax other than the standard Corporation Tax. Therefore revenues from North Sea oil and gas activities have dropped dramatically.

8.2 It is understandable that during periods of low prices producers would argue that taxes and royalties were a barrier to development. However it is not appropriate for such leniency to continue during periods of high oil and gas prices. The UKCS are owned by the Crown on behalf of the nation and royalties and taxes should be set at a level that ensures that the benefits are more equitably shared between the nation and the oil and gas companies.

8.3 In Norway, as a consequence of the extraordinary profitability of petroleum production, a 50% special tax is levied on producers. This is in addition to normal Corporation Tax and Royalty. Those UK producers who argue that any windfall tax on UK producers would drive them overseas will presumably choose not to be active players in the expansion of Norwegian production.

8.4 By contrast, miners in the UK pay a royalty to the Coal Authority for every tonne of coal produced plus corporation tax on company profits. It is bizarre that the sector that has been reeling in recent years and in receipt of state aid, the coal production sector, is required to pay a royalty to the state whilst the highly profitable UKCS sector does not. This is another example of an inconsistent approach by Government.

9. Energy Paper 68

9.1 In December 2000, the Dti's published its long awaited energy projections in Energy Paper 68 (EP68). It would appear logical for the EP68 projections to form the basis of assessment of energy options over the next two decades. However, the assumptions behind EP68 are simply ludicrous. Flawed projections lead to flawed policies and EP68 fails to set a sensible framework in which to assess energy and environmental policies. A full critique of EP68 was produced by CLG Energy Consultants in May 2001 which sets out

- The oil price assumptions through of 2020 of \$10 per barrel in the low price case and \$20 per barrel in high price case do not reflect market fundamentals, cover a plausible range of possible outcomes, are inconsistent with other long term forecasters and are heavily skewed towards low prices. No other forecaster uses a low price case below \$15/barrel.
- Table 9.1 - Comparison Of Oil Price Projections 1999 US
\$/barrel Publication Date Scenario 2005 2010 2020 UK Dti EP 68 Dec
00 High 20.020.020.0 Low 10.010.010.0 IEA WEO 2000 Nov 00 Ref Case 20.020.027.2 US
EIA IEO 2001 Mar 01 Ref Case 20.821.422.4 High 26.026.728.4 Low 15.115.115.1 EU
Energy Outlook to 2020 Nov 99 Ref Case -20.424.3 Case 1-23.430.3 Case 4-19.223.0 Gas
prices follow on from these oil price estimates which again skew the analysis towards low prices.
- Coal prices forecasts are more realistic and therefore combining more realistic coal prices with unrealistic oil and gas prices skews the analysis against coal and therefore fails to value technologies such as clean coal or new nuclear capacity.
- The modelling methodology used in EP68 was self-fulfilling. By failing to consider a wider range of fuel prices and more realistic lifetime assumptions for coal plants, the study failed to identify the risks to the attainment of environmental and energy policy objectives.

- The shortcomings in EP68 are so fundamental that the projections should be formally withdrawn to prevent them being used by Government and other agencies in assessing the impact of policy developments.

9.2 In their initial submission to the PIU, the Dti argue “Dti and the oil industry consider that in the longer term oil prices are expected to average \$16 to \$18/barrel in real terms”. This is not consistent with the International Petroleum Exchange that show futures prices out to June 2004 above \$21/barrel for Brent crude.

9.3 In their initial submission Dti use the EP68 central economic growth scenarios combined with their low and high fuel price cases (so called for scenarios CH and CL) and undertake analysis on the basis of the average of those two scenarios. There is also evidence in the Project Scoping note that the PIU are following this approach. It has to be acknowledged that this averaging of scenarios CH and CL introduces significant bias into the analysis and should not be used.

9.4 In conclusion, the use of EP68 scenarios will discredit any conclusions from the Energy Review. The PIU should urgently set about developing a realistic range of scenarios that will enable a range of plausible outcomes to be assessed and appropriate policies developed.

Appendix 1 - Diversity Measures

1. Dti have used the Shannon-Weiner index (S-W) in recent annual Energy Reports and Energy Sector Indicators. The S-W is a measure of diversity within a market and can be summarised mathematically as

$$S-W = - \sum p_j \ln(p_j)$$

Where p_j is the market share of fuel j .

2. The S-W index is zero in a monopoly situation and rises dependent upon the number of fuels in market. The maximum level of diversity, $S-W_{max} = \ln(f)$ where f is the number of fuels.

3. A second measure, the evenness of diversity (E), allows comparisons to be made between sectors that have a different number of alternative fuels. The evenness of diversity in a market is defined as

$$E = \frac{S-W}{S-W_{max}}$$

Evenness can vary between almost zero and 1. An evenness of close to zero represents a monopoly situation with 1 representing a perfect market with all players having equal market shares. Using the evenness measure it is possible to compare markets with different fuel sources and market players.