Prospects for the Electricity and Coal Sectors in Transition Countries[1]

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Executive Summary

1. The initial stage of transition was accompanied by falls of 35-40% in primary energy demand in South-East Europe (SEE) and CIS countries. The decline in energy demand in the Central Europe and Baltic (CEB) countries started earlier but was less severe. Following the initial shock, the energy intensity of GDP (measured by primary energy consumption per US$ million of GDP at PPP prices) has fallen by 3-4% per year throughout the region. Nonetheless, sustained economic growth means that since 2000 energy demand in the region has been increasing as fast as or faster than in Western Europe. The projections suggest that primary energy demand in transition countries will be 30-40% higher than in 2002, even though the energy intensity of GDP will continue to fall.

2. As in Western Europe, the composition of primary energy consumption has shifted towards gas and that trend will continue. By 2020 the share of gas in primary energy consumption will be more 30% in CEB & SEE countries and more than 50% in CIS countries. The growth in the share of gas has been and will continue to be largely at the expense of coal.

3. Electricity consumption fell sharply from 1990 to 1995 or 1997 throughout the region. Since the late 1990s, growth in electricity demand has matched that in Western Europe. As for primary energy, the electricity intensity of GDP has fallen steadily at rates of 2.5-3.5% per year. The electricity intensity of GDP in CEB countries now matches the average level for Western Europe, which has changed very little since 1990, so that future growth in electricity demand is likely to be close to GDP growth. The electricity intensity of GDP in SEE and CIS countries will continue to fall, though more gradually. Across the region, by 2020 electricity demand is projected to be 65-85% higher than in 2002.

4. The prolonged downturn in electricity demand has provided a margin of spare generating capacity in most countries for more than 15 years. Allowing for improvements in operating performance and some new investment in recent years, this margin will be eliminated not later than 2010 and, perhaps, as early as 2008 in CEB countries. The prospective shortfall of generating capacity in relation to electricity demand will be exacerbated by the need to catch up on the backlog of rehabilitation and environmental improvements.

5. Up until recently the fuel of choice for new generation has been gas. This continues to have significant advantages since gas-fired plants can be built relatively quickly, can be operated flexibly, and have low capital costs and emissions. However, many countries are reluctant to become more dependent upon Russian supplies of gas, so that the future of gas-fired generation may depend upon the development of alternative sources of supply. As or more important, the expected future price of gas has increased sharply from about $3 per GJ ($100 per mcm) to more than $5 per GJ ($175 per mcm).

6. For base-load plants, the levelised cost of electricity from coal-fired plants is cheaper than that from gas-fired plants at coal prices up to $2 per GJ, provided that there is no premium for CO2 emissions. Under normal market conditions, coal can be imported to coastal power plants from various sources at less than this cost. Domestic coal mines outside Russia and Kazakhstan would have difficulty in maintaining current levels of output and operating profitably at this price level,

unless there were large reductions in employment and improvements in the use of investment resources.

7. New nuclear power plants have a levelised cost that is very close to that for coal-fired plants with a coal price of \$2 per GJ and no CO2 premium, so long as the real cost of capital is no more than 10%. With a CO2 premium of \$25 per tonne (lower than the current price under the European emission trading scheme) nuclear power has a significant advantage over coal and gas for any real cost of capital less than 15%.

8. Economic concerns about climate change imply that the social cost of capital is much lower than 10% in real terms, perhaps no more than 5%. In that case, the economic advantage of nuclear power is very large – more than \$20 per MWh. There have, of course, been significant concerns about the safety of plants in the region and about the management of nuclear waste. Any expansion in nuclear power would need to be accompanied by the establishment or strengthening independent agencies to (a) regulate nuclear safety, and (b) manage the disposal of nuclear waste and the decommissioning of old plants. Adequate funds would have to be set aside from current and future revenues to provide the necessary resources. This is built into the levelised cost calculations. Hence, even after allowing for the long term costs of ensuring safety and managing nuclear waste, nuclear power has a large cost advantage, if it is assumed that the social cost of capital reflects the public commitment to reduce emissions of greenhouse gases.

9. Current producer prices for electricity will have to be increased substantially in most transition countries – by more than 100% in most CIS countries – in order to cover the levelised cost of electricity from new plants without any CO2 premium. The increases required would be much larger, except for nuclear power, if the current CO2 premium were to be applied.

10. Typical margins for transmission and distribution are more satisfactory, especially if physical and revenue losses are reduced. Nonetheless, the median level of the average end-user prices across countries is barely one-half of the level of about \$100 per MWh that would be required for full cost recovery excluding any CO2 premium and taxes. Hence, the process of adjusting end-user prices to reflect the cost of supply has a long way to go in most countries.

11. If residential electricity prices are increased to reflect the full cost of supply by 2010, then there would be significant problems of affordability for the lowest decile of households. This concern is most serious in SEE countries - especially Croatia, FYR Macedonia and Serbia & Montenegro – plus Georgia. Some form of lifeline tariff would be essential to mitigate the impact of higher electricity prices on low income and vulnerable households.

12. Large investments in power generation will be required in transition countries over the next 10-15 years. However, it is very unlikely that current market and regulatory arrangements are capable of sustaining an efficient mix of new generating capacity. Market incentives may be sufficient to underpin investment in small and flexible gas-fired units, but there is little prospect that new base-load coal or nuclear plants will be constructed without some adjustments in the way that markets operate.

13. Some form of public intervention in planning and financing new investment in power generation seems to be unavoidable. This may include either (a) centralised contracting of additional capacity through power purchase agreements or some form

of capacity payments, and/or (b) public-private partnerships to finance new plants, especially nuclear plants.

14. Policies to promote the development of renewable sources of energy have had a rather limited effect in the region. The main growth in electricity production from renewable sources has come from the rehabilitation of existing hydro plants or the development of new ones together with the completion of nuclear power plants.

15. In designing policies for renewable energy in the future countries must first decide their goals should be. If the primary intention is to reduce emissions of carbon dioxide, then the EU's emission trading scheme or a carbon tax are likely to be most effective. On the other hand, if the intention is promote the use of renewable energy in its own right, experience in other countries suggests the introduction of mandatory renewable obligations combined with tradeable credits is the most cost-effective approach. Such schemes require a fairly sophisticated infrastructure for monitoring and trading the credits, which may pose problems for some transition countries. Further, it is necessary to make long term commitments if any program is to have a significant impact. Under conditions of economic and market change or limited regulatory capacity, it may be more appropriate to adopt a simpler approach involving a form of output-based aid for new generating capacity and/or production using renewable sources of energy.

16. Aggregate consumption of coal has fallen by one-third to one-half since 1990 for different groups of transition countries, but consumption has stabilised since 2000 and is expected to grow until 2010. After that the prospects for coal consumption depend upon whether a premium on CO2 emissions is applied through the region and whether cost-effective technologies for reducing CO2 emissions from coal become available. Even without measures to reduce emissions of greenhouse gases, it is likely that domestic production will gradually be displaced by imports in many countries.

17. In Poland and Ukraine, the prospect for hard coal producers is one of continued contraction in levels of both output and employment. Current programs of restructuring are not sufficiently radical to offer a viable future. As a consequence it is likely that large amounts of public money will be wasted on supporting current production and uneconomic investments. Instead, hard coal mining should subject to real market discipline rather than the bureaucratic market management that persists in both countries.

18. Prospects for coal production in Kazakhstan, Siberia and the Far East are much better, especially for the large surface mines. Steam coal is competitive with gas as a regional fuel, while there are attractive opportunities to expand exports of metallurgical coals. However, the development of the coal sector East of the Urals depends upon the tariffs for and the operating performance of the rail network. The most attractive investment opportunities are likely to be in coal handling and transport.

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Prospects for the Electricity and Coal Sectors in Transition Countries

1 Introduction

This paper was commissioned by the EBRD as a Background Paper for its Energy Policy Paper due to be presented to the EBRD Board early in 2006. The paper reviews the prospects for the electricity and coal sectors in transition countries in the context of overall growth in demand for primary energy.

The sharp decline in energy demand that accompanied the early years of the transition meant that most transition countries have not faced any pressing need to make significant investments in these sectors, other than for environmental reasons, for a period of more than 15 years. However, the growth in demand for primary energy in general and electricity in particular since the late 1990s is rapidly reducing the margin of spare capacity. In addition, the age structure of generating plant in transition countries means that substantial investments will be required to replace plants that are reaching the end of their economic or physical life. The broad prospect, therefore, implies a much higher level of investment in electricity generation in the next 5-10 years than has occurred over the last decade.

The last 15 years has seen a major shift in the technology of power generation reinforced by institutional and regulatory changes that have rewarded flexibility and responsiveness in the composition of generating plant. Throughout most of this period, gas has been the dominant fuel for new generation – underpinned by large improvements in thermal efficiency, the relatively short time required to construct new plants, and limited economies of scale that permit plants to be developed and operated efficiently in a phased manner.

The shift towards gas-fired generation has been facilitated by increased supplies of gas made possible by the development of new fields, the extension of pipeline networks, and the development of LNG facilities. The growth in production was supplemented by the sharp decline in total consumption in the former Soviet Union, which freed gas for export to the rest of Europe. As a consequence, the average price of gas imported into Western Europe was roughly constant in nominal terms from 1987 to 1999.

However, the factors that underpinned this stability have now shifted. Even before the general increase in oil and linked energy prices in 2004 it had become clear that future gas prices will be much higher than in the second half of the 1990s – perhaps as much as 100% higher in real terms. In contrast, the price of coal was either stable or falling right up to 2004, so that there has been a fundamental shift in the relative prices of these and other fuels.

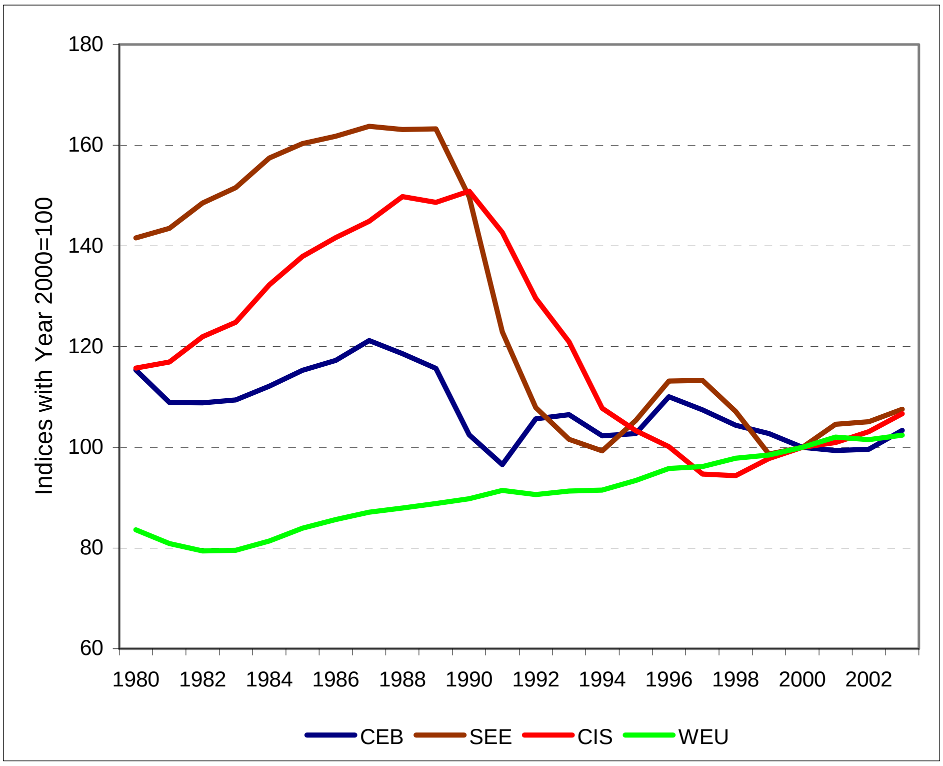
This change has major implications for the fuel mix of new investment in electricity generation over the next 5-10 years. Much of this paper focuses on examining the consequences of the shift in relative fuel prices, both for the electricity sector and for the coal sector, especially against the background of a revival of growth in demand for all sources of energy and for electricity in particular.

2 Demand for primary energy

As illustrated in Figure 1, total consumption of primary energy in the transition countries has followed quite different paths in the various sub-region country groups – see Appendix 1 for the definition of these groups and the sources of data used in this paper. The archetypal transition applies to the CIS countries with rapid growth in energy use up to

1988-90 followed by an abrupt decline that reached a trough in 1997-98. Since then energy use has been growing at a rate of 2.5% p.a. as a consequence of the recovery in GDP. This growth is not due to more rapid economic growth in Russia alone, since the growth in primary energy demand in the CIS excluding Russia has been 2.9% p.a. since 1998. This reflects the larger decline in energy consumption from 1990 to 1998 in these countries.

Figure 1 – Indices of total consumption of primary energy, 1980-2003



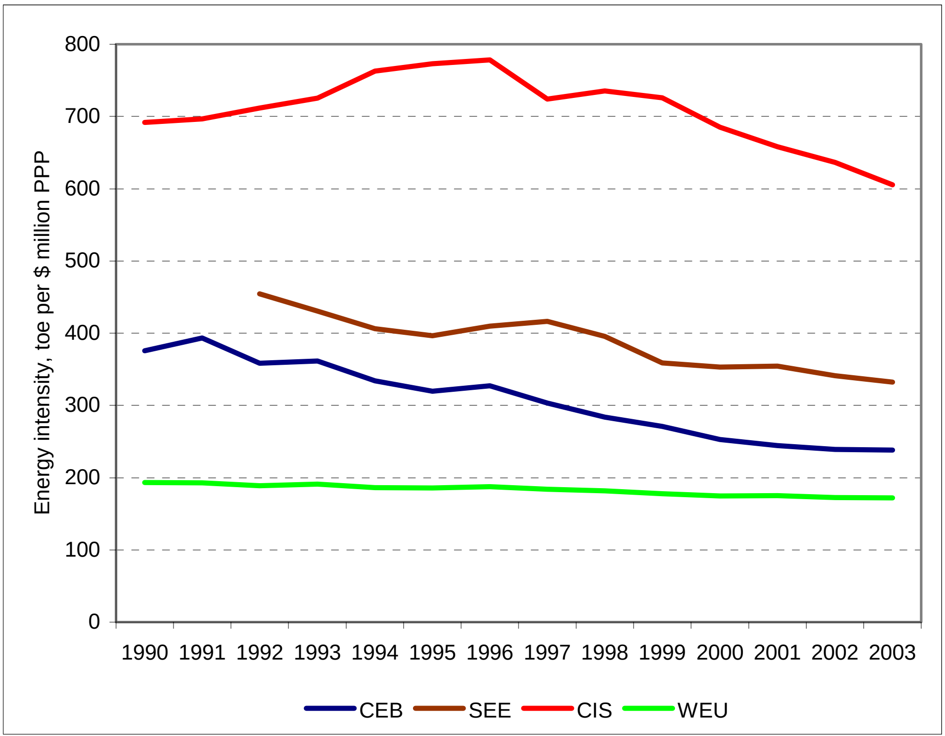
Source: See Appendix 1.

The decline from peak to trough was greatest and most abrupt for countries in South-East Europe (SEE). Much of the decline was associated with the wars following the break-up of the former Yugoslavia but the slow pace and disorganised character of economic reforms in other countries were also significant factors. For example, total primary energy use in Bulgaria and Romania together fell from about 160 million tonnes of oil-equivalent (Mtoe) in 1988-89 to 98 Mtoe in 1994. While this sharp decline has ceased, total energy consumption has not recovered and actually fell to only 92 Mtoe in 2003. The growth for all SEE countries shown in the graph is primarily a reflection of the recovery in energy use in Serbia & Montenegro following the end of the war in Kosovo.

The peak of energy consumption for countries in the Central Europe and Baltics (CEB) sub-region occurred in 1987, largely because the transition started in Poland in 1988. The decline of aggregate GDP in the CEB group was much smaller than for the other two groups and ended after 1991. Nonetheless, total energy consumption continued on a downward trend, despite occasional blips, right up to 2001-02.

This decline is reflected in the steady fall in the energy intensity of GDP shown in Figure 2. Since 1990 the amount of primary energy used by the CEB countries per $ million of GDP at constant 2000 PPP prices has fallen from 376 toe to 238 toe translating to an average rate of decline of 3.5% p.a. The equivalent figure for the West European countries is a decline of 0.9% p.a. It seems that the rate of decline may have slowed since 2001. This could be a delayed response to lower energy prices in the late 1990's and the former trend may reassert itself as a consequence of the much higher prices since 2003. In either case, the gap in energy intensity between Western Europe and the CEB countries has narrowed from about 95% (of the West European average) to 40%. It is not clear whether climatic and other factors will permit the CEB countries to reach the West European average level of energy intensity, but a clear pattern of convergence is apparent.

Figure 2– Energy intensity of GDP at constant PPP prices, 1980-2003



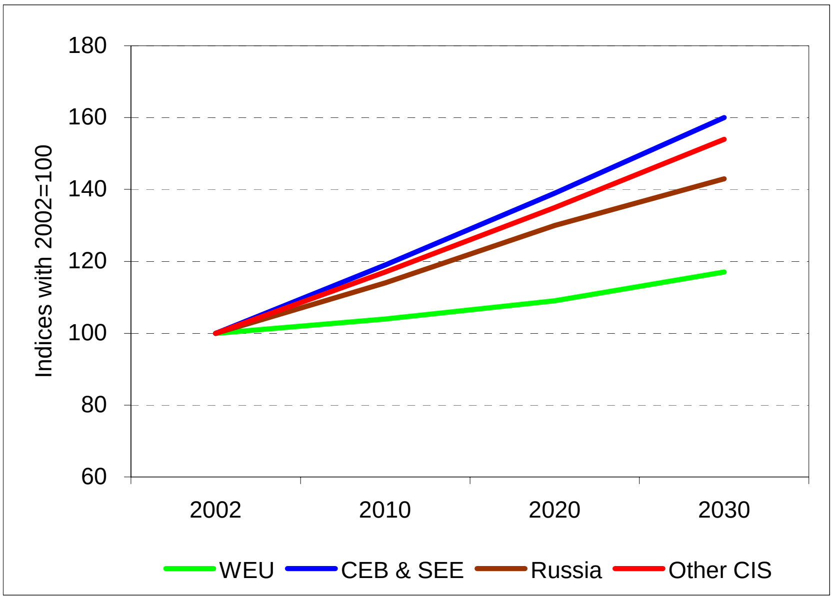
Source: See Appendix 1.

A similar, though slower, convergence has applied to the countries in South East Europe whose average energy intensity has declined at 2.8% p.a. since 1992. These countries have substantially lower incomes on average than the CEB countries but within the downward sloping section of the energy Kuznets or inverted-U curve, meaning that an increase in average income is usually associated with a lower level of energy intensity. There is no reason to believe that climatic factors would lead to higher energy intensity in the SEE sub-region, so that the decline in energy intensity may be expected to continue as long as incomes grow.

The future of energy intensity for the CIS countries is harder to predict. The very sharp decline in GDP of most countries following the transition was accompanied by a much slower adjustment in energy use. As a consequence, energy intensity rose up to 1996. Since then the CIS energy intensity has fallen at the same rate (3.5% p.a.) as the energy intensity for the CEB countries. Because of the rise in the early 1990's energy intensity in the CIS only fell below its 1990 level in 2000 and there is a long way to go before the overall decline matches that for the CEB countries. Nonetheless, provided that there is no reversal of the trend to link user prices to cost recovery or import/export parity levels, then it seems likely that the decline in the average energy intensity for the CIS countries will continue.

I have constructed a set of composite projections for primary energy consumption based upon recent sets of projections published by the International Energy Agency (November 2004) and the Energy Information Agency of the US Department of Energy (July 2005). These organisations adopt different ways of analysing and aggregating energy data so that it is not possible to compare them directly. A comparison of past and current projections presented as an appendix to the most recent EIA-DOE analysis suggests that, after adjusting for differences in data and projection dates, there are not large differences at the world level but there are significant differences for smaller groups of countries. This is particularly apparent for the CIS excluding Russia (Other CIS). These projections are shown in Figure 3.

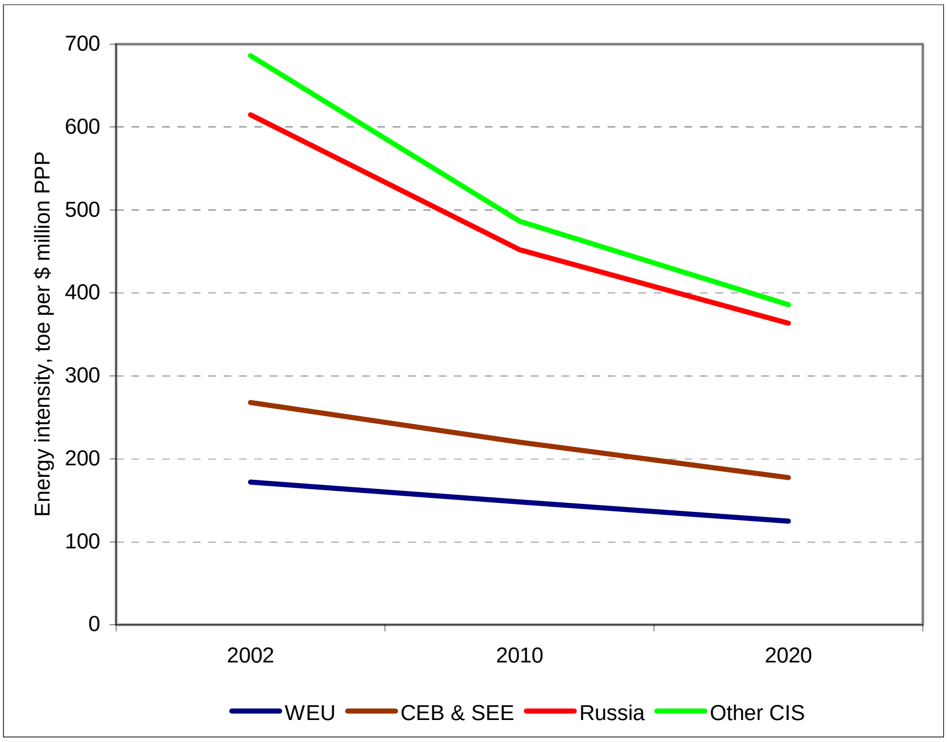
Figure 3 – Projections of primary energy consumption to 2030



Source: See Appendix 1.

Total consumption of primary energy is expected to grow much more rapidly in the transition countries than in Western Europe – at rates varying from 0.6% p.a. in Western Europe to 1.7% p.a. in the CEB & SEE countries. A large part of the dispersion is a consequence of the higher GDP growth rates in the transition countries - 4.2% p.a. in the CEB & SEE countries to 5.0% p.a. in the Other CIS countries as compared with only 2.3% p.a. for Western Europe. At the same time, as shown in Figure 4, the projections imply that levels of energy intensity will continue to fall and to converge as incomes grow. Since the gaps between the energy intensities of the CEB & SEE countries has narrowed substantially since the transition started, it seems reasonable to expect that this convergence will be slower than for Russia and the CIS. By 2020 the projections imply that the energy intensity of the CEB & SEE countries will be only two-thirds of its current level, but still 40% higher than for Western Europe. The fall in energy intensity in the CIS is expected to be even larger, but they will remain much larger users of energy in relation to GDP than countries in West and East Europe.

Figure 4 – Projections of energy intensity to 2020



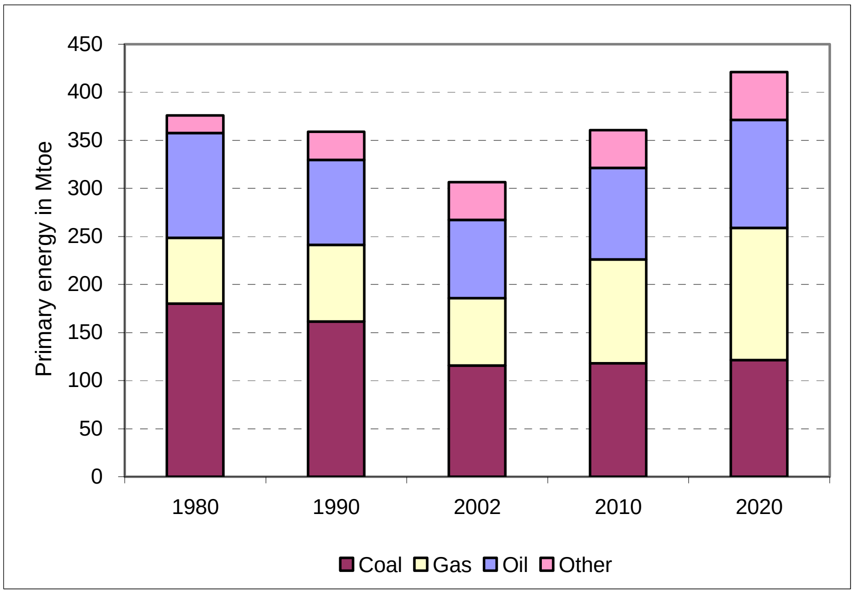
Source: See Appendix 1.

Figure 5 shows the evolution of the composition of primary energy use in Eastern Europe (CEB/SEE) since 1980 as projected to 2020, while

Figure 6 illustrates the equivalent figures for the CIS. In both cases, the share of coal has declined and this trend is expected to continue up to 2020. Coal accounted for almost one half (48%) of primary energy use in the CEB/SEE countries in 1980 but it will represent slightly less than 30% by 2020. The rate of decline the CIS is similar but from a lower initial share - down from 25% to 14% over the four decades. Natural gas has been displacing coal in primary energy use and this, too, will continue. The share of gas in primary energy use in the CEB/SEE was 18% in 1980 and should grow to 33% in 2020. In the CIS, natural gas accounted for more than one-half of primary energy use in 2002 – 52%, up from 30% in 1980. Its penetration will continue but much more slowly, reaching 56% of the market by 2020.

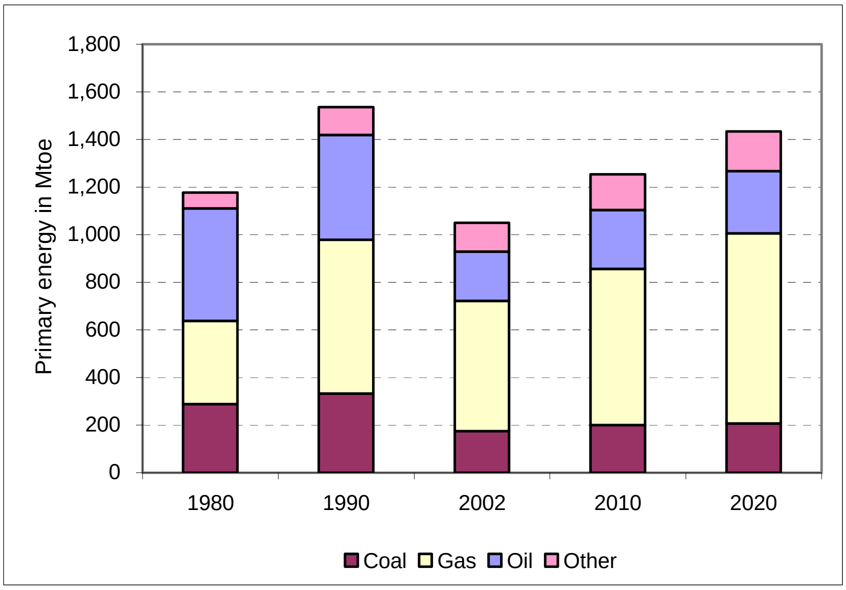
The category of Other primary energy includes hydro, nuclear and renewable energy. Its share has been increased in both the CEB/SEE and CIS countries from 5-6% of primary energy use in 1980 to about 12% in 2002. The increasing share is primarily due to the expansion of nuclear power, though the contraction in the use of fossil fuels has also been a factor. The projections suggest that the share of Other primary energy will not change significantly in either sub-region up to 15-20 years. Since there are limited opportunities for increasing the amount of hydro power, the growth in use of Other primary energy is expected to come almost entirely from new nuclear power plants. The proportion of primary energy supply represented by non-traditional forms of renewable energy is small – about 1.6% for the whole region – and is not expected to reach 2% before 2030.

Figure 5 – Composition of primary energy use in Eastern Europe



Source: See Appendix 1.

Figure 6 – Composition of primary energy use in the CIS



Source: See Appendix 1.

The forecasts of growth in primary energy demand take account of:

- Adjustments to income growth and energy prices as incorporated in the models of energy demand. Typically, these imply income elasticities that are significantly less than 1 and price elasticities (in the longer term) in the range -0.4 to -0.6.
- Existing programs designed to promote energy efficiency and existing taxes expressed as *ad valorem* tax rates.

- Forecasts of changes in economic structure, e.g. the gradual shift of the composition of output and value-added from industrial to service activities following the pattern that has occurred in the rich market economies.

It would be possible to reduce the growth of primary energy demand if more effective policies designed to improve energy efficiency were adopted and implemented. However, an essential pre-condition for such policies to be effective would be a commitment to increase and maintain the real level of energy prices charged to intermediate and final consumers. This is not really an issue for most petroleum products, whose average prices in transition countries are broadly in line with those in Western Europe. On the other hand, domestic prices for residential and industrial consumers of gas, electricity and heat are typically well below the levels paid by equivalent consumers in Western Europe.

In the case of gas, differences in transport and other costs would justify somewhat lower prices for all consumers in Russia and some other countries of the former Soviet Union. Further, it is often argued that prices must be kept down because otherwise people would freeze during cold weather. While this contains a kernel of truth, it masks the fact that the largest share of the benefits from low gas and other energy prices in Russia accrues to industrial and commercial enterprises plus households which could well afford to pay prices that reflect economic costs. The real problem is that administrative capacity to implement an effective social safety net is so limited that the provision of massively inefficient energy subsidies is seen as necessary to ensure that poor households can survive winter conditions.

Ultimately, this justification for maintaining low prices for gas and other fuels amounts to endorsing an extreme failure of governance. While the solution must lie in addressing this issue, the task may be made easier by dealing with other matters that may constraint the capacity of institutions, companies and households to respond to higher energy prices. There is, however, the classic chicken and egg aspect to implementing such programs. Projects designed to improve energy efficiency are only likely to achieve high rates of take-up if energy prices are high enough for consumers to consider that the potential energy savings justify the effort required. For example, most of the economic evidence suggests that commercial and residential consumers apply relatively high discount rates - 15-20% or more - in deciding whether to make investments in saving energy. Such returns may only be possible if energy prices have reached the levels that prevail in Western Europe. On the other hand, governments may be reluctant to raise energy prices by enough to justify investments in energy efficiency unless they believe that consumers can easily take advantage of programs designed to mitigate the impact of price increases.

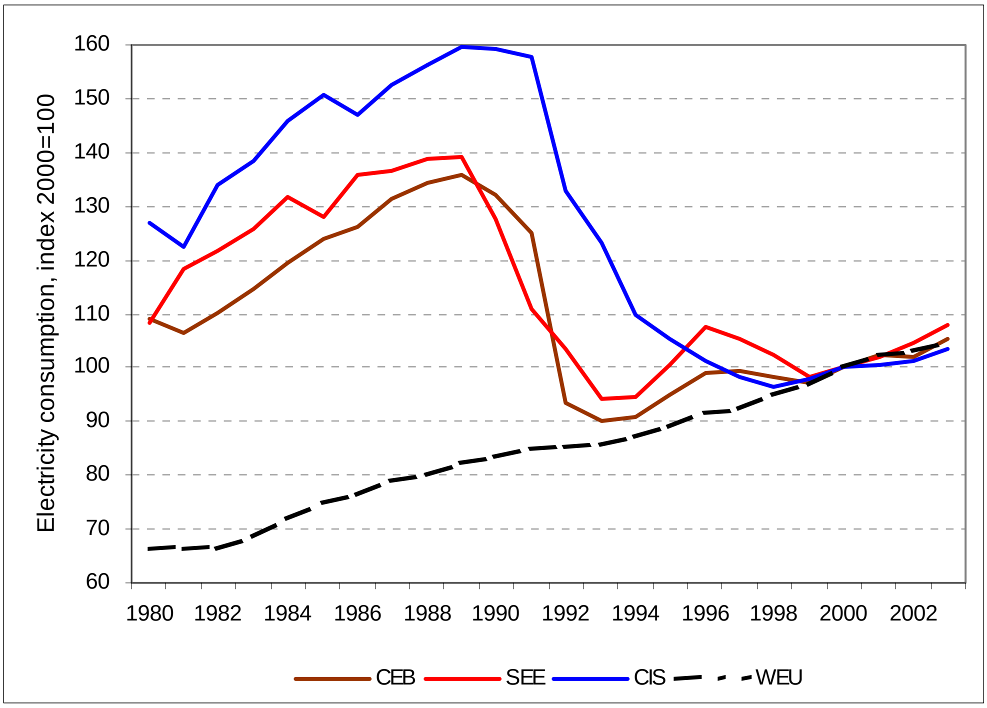
One option would be to rely entirely upon subsidising such investments but this will usually be a wasteful use of resources that most governments can ill-afford, since budgets are stretched in almost all countries in the region. Hence, strategies must be developed to ensure that energy prices and energy efficiency programs are implemented in parallel. These must involve a credible commitment to raise the prices of fuels such as gas, electricity and heat by 100% (or whatever is required) in real terms. Up to now such a commitment has been sadly lacking for political reasons, but governments can take advantage of the visible and unquestioned change in market conditions for oil and gas as justification of the need for change. The price increases should be accompanied by a combination of public information, technical assistance and limited subsidies for measures to improve energy efficiency, subject to the provision that financial assistance will only be made available for a limited period to ease the immediate impact of higher prices.

3 The electricity sector

3.1 Growth in demand for electricity

After steady growth during the period 1982-89, consumption of electricity fell sharply in most transition economies following the transition from 1989-91- see Figure 7. The troughs of consumption were reached in 1995 for the CEB and SEE groups but only in 1998-99 for the CIS group. Since 2000 all three groups of transition economies have followed a trend that is quite close to that for the West European economies.

Figure 7– Indices of electricity consumption, 1990-2003



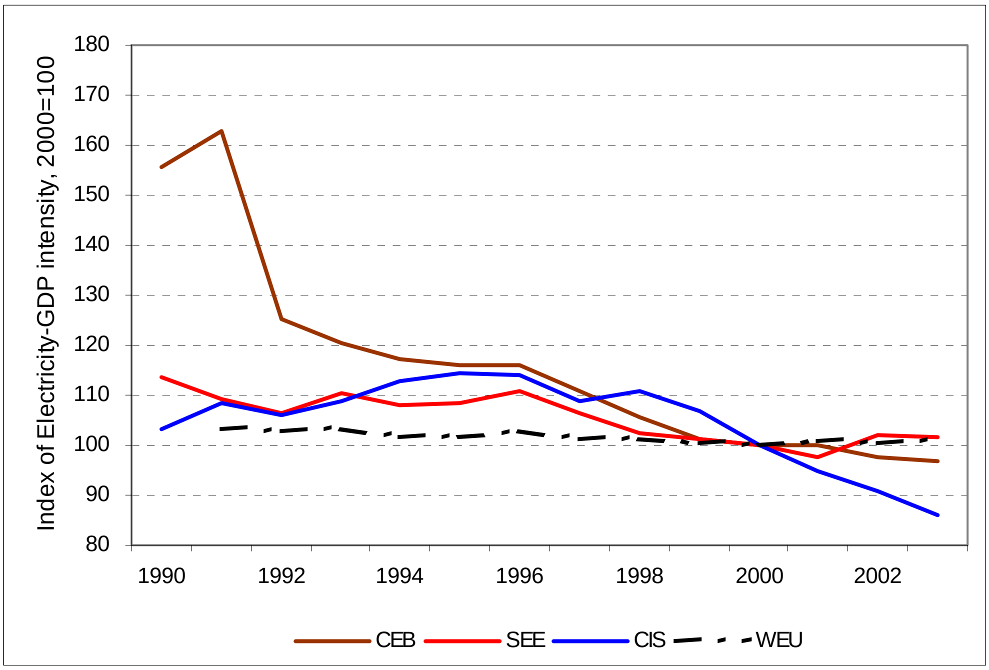
Source: See Appendix 1.

Notwithstanding the large falls in consumption, Figure 8 shows that the electricity intensity of economic activity – consumption of electricity in relation to GDP – remained roughly constant in for the SEE and CIS countries from 1991 to 1999. There was a slight downward trend for the SEE countries, while the electricity intensity for CIS countries initially increased and then fell as electricity consumption reacted to the decline in GDP with a lag. However, the electricity intensity of the CIS countries fell by 20% from 1999 to 2003. A crucial question for the future is whether this decline is simply a delayed reaction to the transition or represents an indication of a long term trend. As a comparison, the electricity intensity of the CEB countries fell by 27% in one year from 1991 to 1992. Thereafter, it fell by an average of 3% per year up to 1999 and by 1% per year since then.

There is a very large gap between all of the groups of transition economies and the West European economies in terms of the amount of electricity that they consume per US$ 1,000 of GDP (at constant 2000 prices). The average value for the Western European countries has been consistently in the range 300-310 kWh per $1,000 since 1991. Even after the reduction in electricity intensity over the past decade for the CEB economies their average of 660 kwh per $1,000 is still more than twice that of the West European countries. For the South-East

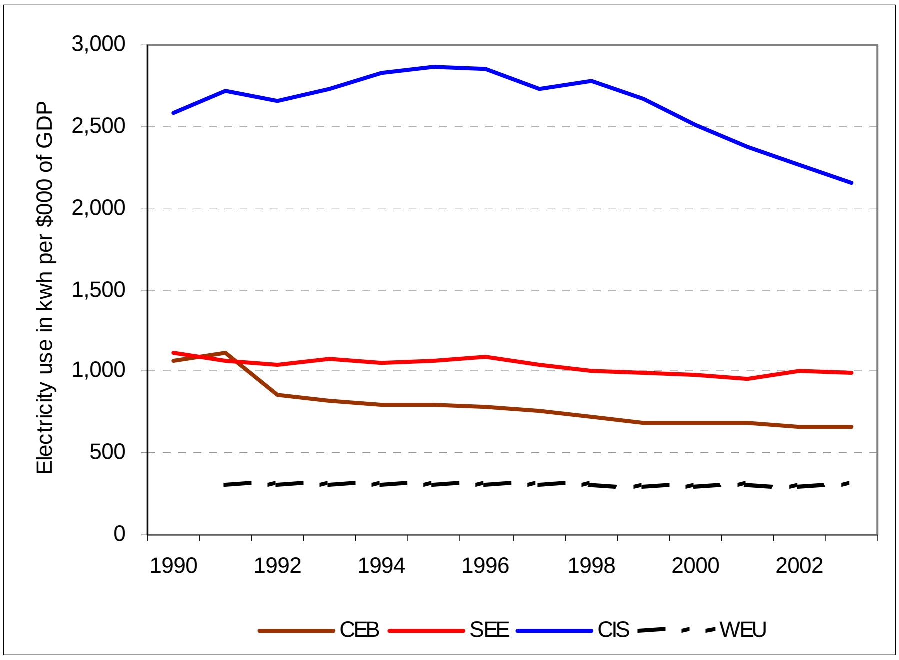
European countries the average has fallen within the range 950-1,050 kwh per $1,000 since 1997. Until the recent decline in electricity intensity the average for the CIS countries was well over 2,500 kwh per $1,000 and even now is over 2,000 kwh per $1,000.

Figure 8 – Indices of electricity consumption relative to GDP, 1990-2003



Source: See Appendix 1.

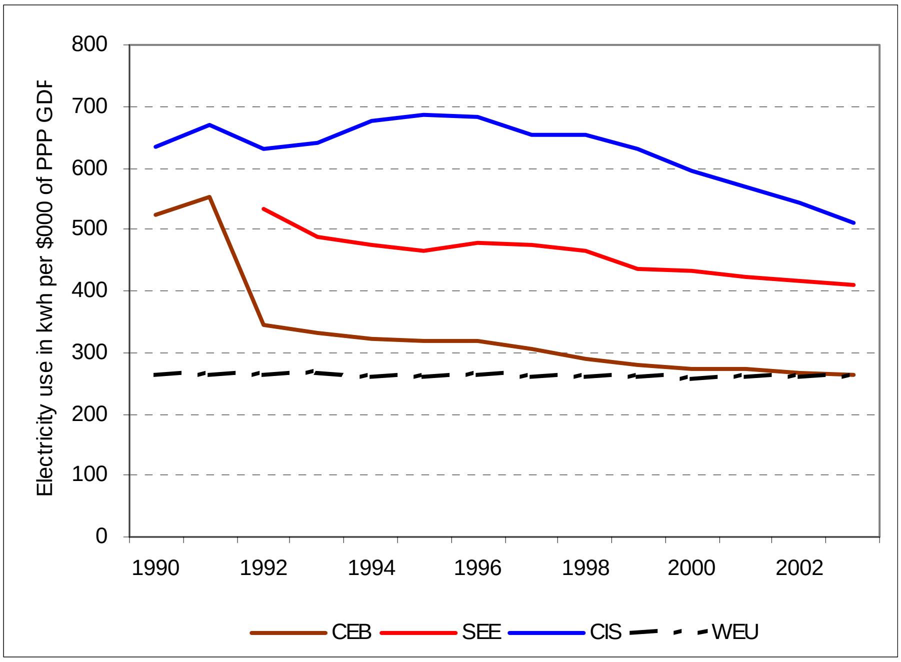
Figure 9 – Electricity consumption per $000 of GDP, 1990-2003



Source: See Appendix 1.

While average temperature, stage of development and other factors may explain a part of the difference in electricity use per $1,000 of GDP, there remains a very large unexplained component – see Figure 9. For example, the SEE countries are warmer on average than the CEB countries but they do not rely heavily upon air conditioning. Both groups of countries invested in centralised heating systems in urban areas during the socialist period, so that electricity is not required for space heating. Thus, an electricity use per $1,000 of GDP that is nearly 50% on average for the SEE countries than for the CEB countries and more than 3 times the average for Western Europe is both counter-intuitive and persistent.

Figure 10 – Electricity consumption per $000 of PPP GDP, 1990-2003



Source: See Appendix 1.

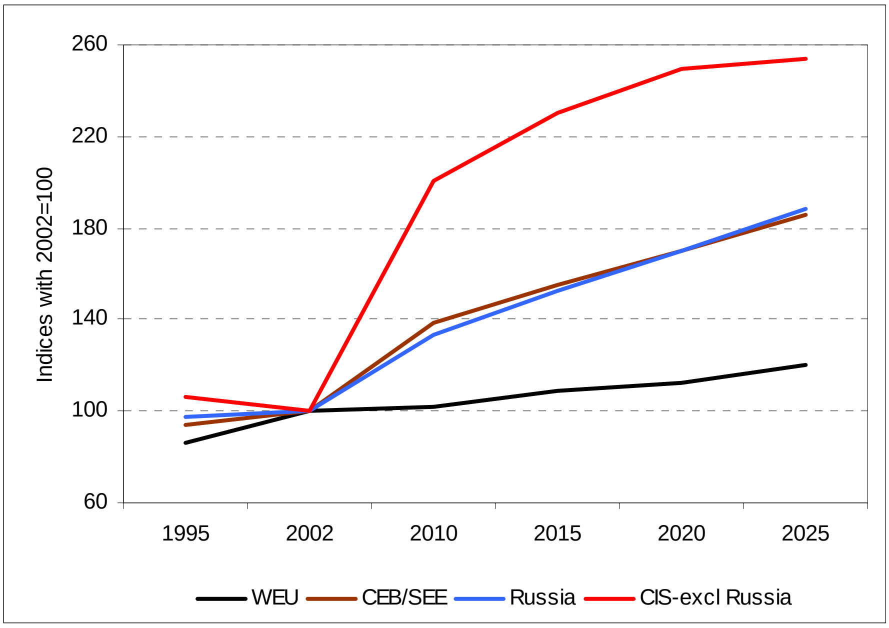
A rather different picture emerges when electricity use per $1,000 of real GDP on a PPP basis is examined – see Figure 10. For the Western European countries the average value has stayed within the range 260-265 kwh per $1,000 of PPP GDP since 1990. For the CEB countries the average value was twice this level in 1990 but it had converged to the West European level by 2002. Similarly, the gaps between the averages for the SEE and CIS countries and the average for the Western European countries have been narrowing since 1996. In particular, even if climatic conditions and, perhaps, other factors lead to a permanently higher average use of electricity per $1,000 of PPP GDP in the CIS countries than in Western Europe, it seems reasonable to expect that the relative gap will continue to decrease for some time.

The decrease in electricity intensity in the CIS countries proceeded at a rate of 4% p.a. for 7 years up to 2002. If this trend continued through to 2007, then the average electricity intensity in the CIS countries on a PPP basis would be only 50% higher than that for West and Central Europe. The downward trend has been less strong in the South-East European countries – 2.2% per year. A continuation of the same trend to 2007 would reduce electricity consumption to about 375 kwh per $1,000 of PPP GDP or a little more than 40% above the current level for West and Central Europe. These reference points are important because they provide a basis for assessing projections of the growth of electricity demand over the next 5-10 years, which underpin assessments of the need for investment in new capacity.

There are two sets of projections of energy demand and electricity consumption for combinations of transition countries published on a consistent basis.

- The EIA-DOE's *International Energy Outlook 2005* (released in July 2005). Its projections for electricity consumption in Western Europe and transition countries are shown in Figure 11. They envisage that electricity consumption will grow by 70% from 2002 to 2020 in both Central/South-East Europe and Russia. The projected increase is even larger - 150% by 2020 – for the rest of the CIS, but this is largely driven by an increase of 100% from 2002 to 2010. From 2010 onward the projected growth of consumption in the CIS excluding Russia is almost identical to that for Russia. Setting aside the projected growth in electricity consumption for the CIS countries excluding Russia from 2002 to 2010 as an aberrant number, the EIA-DOE projections imply a growth rate of 3% p.a. from 2002 to 2020. In contrast, electricity demand in Western European is expected to grow by a little less than 0.6% p.a. over the same period.

Figure 11 - EIA-DOE projections of electricity consumption



Source: See Appendix 1.

- The IEA's *World Energy Outlook 2004* (published in November 2004). This adopts a slightly different grouping of countries that has the disadvantage of combining the CEB countries with Western Europe. This is consistent with their accession to the European Union but it hinders the analysis of features that may be specific to transition countries. Further, it combines all of the other transition countries other than Russia into a singe grouping. The growth rate of electricity consumption for the WEU/CEB countries combined for 2002 to 2020 is projected at slightly less than 1.4% p.a. compared with 1.7% p.a. for Russia and 2.3% p.a. for the group including SEE and CIS countries excluding Russia. Even if we were to assume that the growth of electricity consumption in the CEB countries was identical to that for Russia, the

IEA's projected growth rate for Western Europe are considerably higher than the EIA-DOE's projection, whereas their projections for the transition economies are significantly lower. The difference between their average growth rates of 2% and 3% p.a. amounts to a difference between an overall growth of 43% or 70% in electricity consumption.

The underlying EIA-DOE and IEA projections of population growth and GDP in constant PPP prices are very similar if it is assumed that GDP per capita in the CEB countries will grow at a rate that is close to that for the SEE countries.[2] Hence, the crucial source of the different projections in electricity consumption lies in their assumed rates of decline in electricity intensity – electricity consumption per $1,000 of PPP GDP.

- For Western Europe, the EIA-DOE forecasts imply a fall of nearly 22% in electricity intensity from 2002 to 2020 (1.25% p.a.), whereas the IEA forecasts imply a fall of only 13% (0.7% p.a.). Small differences in this parameter compound to relatively large differences in the growth of total electricity consumption.
- On the other hand, the IEA projections imply a rather faster decline in electricity intensity for the SEE countries, Russia and the CIS countries excluding Russia. While there are small differences between the SEE/CIS group and Russia it is assumed that electricity intensity will decline by 27-29% from 2002 to 2020. In contrast, the DOE-EIA projections assume that electricity intensity will fall by 19-21% over the same period (discounting the aberrant projection for CIS countries up to 2010).

Figure 12 – Comparison of EIA-DOE and IEA electricity intensities

Source: See Appendix 1.

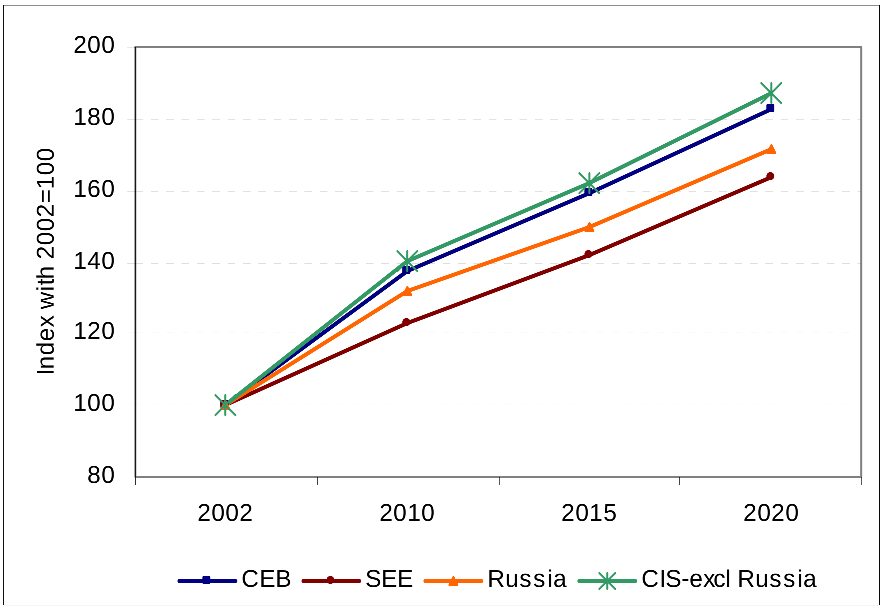
[2] Decomposing the IEA projections of GDP growth for the WEU + CEB countries by using the EIA-DOE's GDP projections for the CEB countries implies that GDP growth for the WEU countries will be 45% from 2002-2020 as compared with the EIA-DOE projection of 44%, though this relative gap is not uniform over sub-periods.

- In effect, the EIA-DOE projections imply that there will be limited or no convergence in electricity intensity in transition countries towards the levels in Western Europe, given that the gap has already been closed for the CEB countries. The IEA projections imply substantial convergence. This is illustrated in Figure 12 which shows indices of electricity intensity using the level in Western Europe in 2002 as 100.

I have highlighted the source of differences between the two set of projections because they drive conclusions about the need for and nature of future investment in electricity generation in transition countries.

Since there has been no systematic downward trend in electricity intensity in Western Europe since 1990, it seems unlikely that electricity intensity will fall as rapidly in the next two decades as the EIA-DOE projections imply. The IEA's projections allow for an upward trend in the real cost of electricity – either as a consequence of policies to reduce emissions of carbon dioxide or because of higher prices for gas and coal. Hence, it seems to be more reasonable to adopt their assumptions on electricity intensity for both Western and Central Europe, given that electricity intensity in the latter group of countries has already converged to that in their richer neighbours.

Figure 13 – Projected growth in electricity consumption, 2002-2020



Source: See Appendix 1.

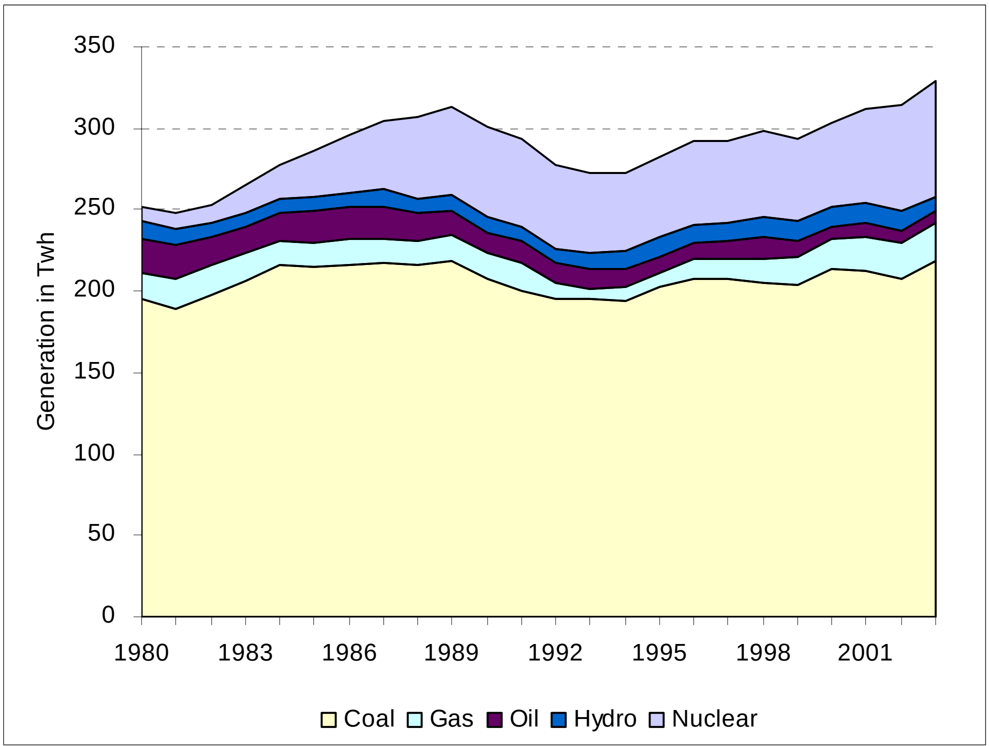
Again, based on recent trends it is plausible to argue that electricity intensity in the other transition countries may fall by 15% up to 2010 (equivalent to 2% p.a.) but this trend is unlikely to continue through the following decade. Instead, the decline in electricity intensity is likely to parallel that in Western and Central Europe at slightly less than 1% p.a. Together with the projections for population and GDP growth, these assumptions imply that the increase in electricity consumption from 2002 to 2020 will range from about 65% for the SEE countries to nearly 90% for the CIS countries excluding Russia – see Figure 13. Growth in electricity consumption in Russia is lower than that in Central Europe and the rest of the

CIS largely because it is expected that population will decline at an average of 0.6% p.a. throughout the period.

3.2 The composition of electricity generation

Figure 14 to Figure 16 show the evolution of composition of electricity generation in the different groups of transition countries from 1980 to 2003. Coal-fired thermal generation has dominated electricity production in Central Europe and the Baltics, but most of the growth has come from nuclear power with gas playing a secondary role. During the period 1990-2003 annual power generation increased by 27.8 Twh, of which 53% was accounted for by nuclear plants and 27% by gas-fired thermal plants. Countries in Central Europe have a strong preference to avoid too much reliance upon gas-fired generation because, at least up to now, this has implied a dependence upon Russian energy sources. For some countries, the construction of pipelines to import gas from Norway or elsewhere in Europe might reduce this historic reluctance to use gas for power generation, but the recent increase in world and European gas prices suggests that gas is unlikely to account for the major part of future incremental power generation. Hence, the central issue in assessing the prospects for power generation in Central Europe is likely to be the choice between coal-fired thermal generation or nuclear power.

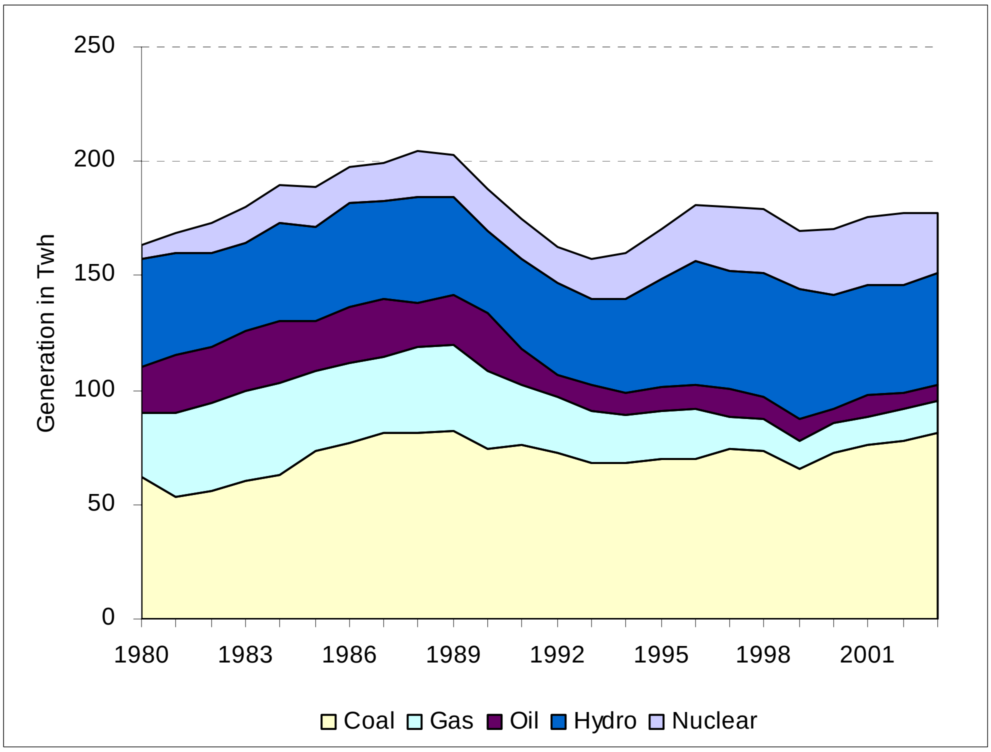
Figure 14 – The composition of electricity production in CEB countries, 1980-2003



Source: See Appendix 1.

The generation mix in the countries of South-East Europe is more balanced. Hydro resources are much more important than in Central Europe, but there are only limited possibilities for increasing hydro generation except by improving the utilisation of existing resources and plants. Total output has fallen by 12% since the peak in 1989. This fall has seen a large reduction in the use of gas and oil for thermal generation – amounting to 38 Twh per year - partly offset by an increase in the output from nuclear power plants of 7-10 Twh per year. The large reduction in the use of gas follows the elimination of subsidies and special arrangements that underpinned an artificially low price for gas used for power generation in several countries. While it is unlikely that the use of oil for power generation will increase in future, the prospects for gas are likely to depend upon prices and the development of the pipeline infrastructure required to import gas from a variety of sources. Parts of South East Europe – especially along the Adriatic coast - are favourably placed for the import of LNG but this will require investments in re-gasification infrastructure as well as pipelines.

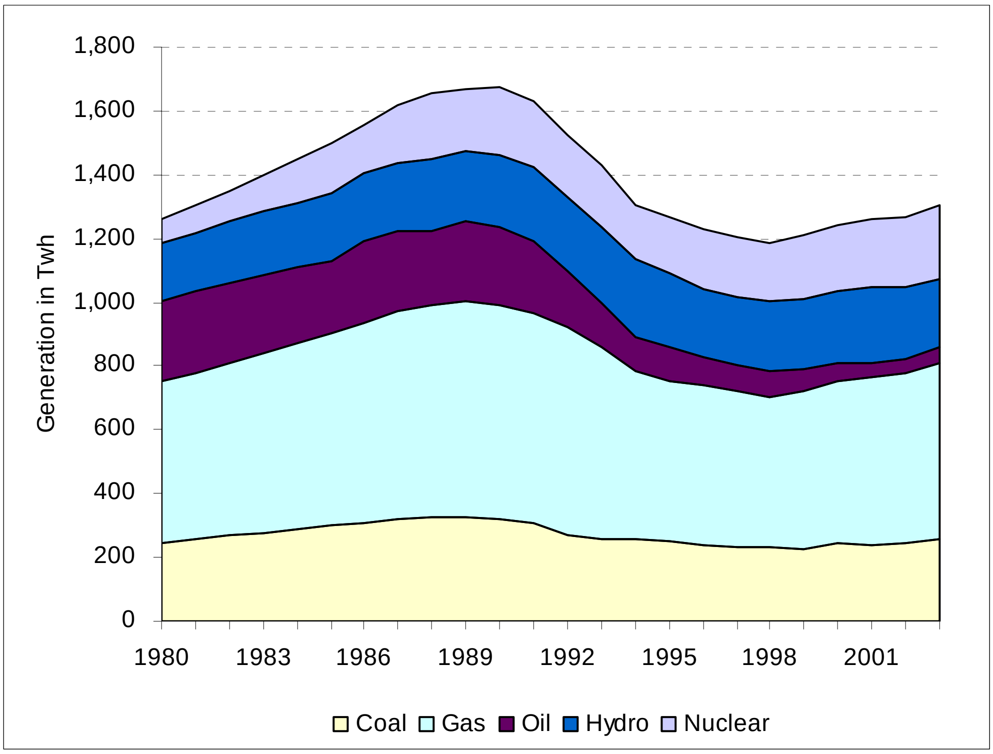
Figure 15 – The composition of electricity production in SEE countries, 1980-2003



Source: See Appendix 1.

Coal remains an important resource for thermal power generation in South East Europe, accounting for 46% of total electricity production in 2003. However, the general quality of local coals in the region is poor with primary reliance upon lignites and brown coals of low calorific value and relatively high sulphur content. It is necessary to invest heavily in emission controls in order to meet current environmental standards both at existing plants and, even more, at new plants. It is unlikely that there will be substantial growth in coal-fired power generation unless this relies upon imported coal either from the Black Sea region or, more probably, from large exporting countries such as South Africa, Colombia or the US. Since the existing port facilities and rail networks are not oriented towards large scale imports of coal, new coal-fired plants would have to be located in suitable coastal sites or it would be necessary to make investment in coal handling and transport comparable to those required for imports of LNG. Subject to market developments affecting the relative prices of coal and LNG, this will tend to count against any substantial growth in coal-fired generation.

Figure 16 – The composition of electricity production in CIS countries, 1980-2003



Source: See Appendix 1.

The dominant source of power generation in the CIS countries is gas, though coal, hydro and nuclear power all make substantial contributions in particular countries or regions of Russia. Most attention has focused on the prospects for the electricity sector in Russia, but in the longer term the other CIS countries are equally important since the growth in their consumption will outstrip that in Russia. Gas-fired thermal plants account for 44% of total generation in Russia and 38% in the rest of the CIS, though this share varies widely from less than 10% in Georgia and most of Central Asia to 90% in Moldova.

Coal is the second most important fuel followed by hydro and nuclear power in both Russia and the rest of the CIS. Despite the social importance of its coal mining industry, Ukraine is much more reliant upon nuclear power and gas for power generation, accounting for 45% and 31% respectively of total generation. Coal is essentially a regional fuel – it is very important in the generation mix in the Urals, Siberia and the Far Eastern regions of Russia, Eastern Ukraine and Northern/Central Kazakhstan. However, because of the large distances involved in transporting coal from the most productive coal basins to the main population centres, the use of cost of coal is constrained by the logistics and costs of transporting coal or transmitting power from region to region.

Similarly, hydro power is a regional fuel. It dominates electricity generation in Georgia, the Kyrgyz Republic and Tajikistan and it is important in Siberia and the Far East in Russia. There is significant potential for developing additional hydro resources in these regions/countries, but the economics of such projects is largely driven by the costs of transmitting the power over considerable distances to population centres. In the days of the Soviet Union there were large plans, which were partially implemented, for the development of very high voltage transmission lines from Siberia to the Urals and Western Russia. However, the economics and performance of transmission over such long distances remains uncertain. Countries like Brazil that rely heavily upon transmission of hydro power tend to have more dispersed resources relative to the centres of demand,

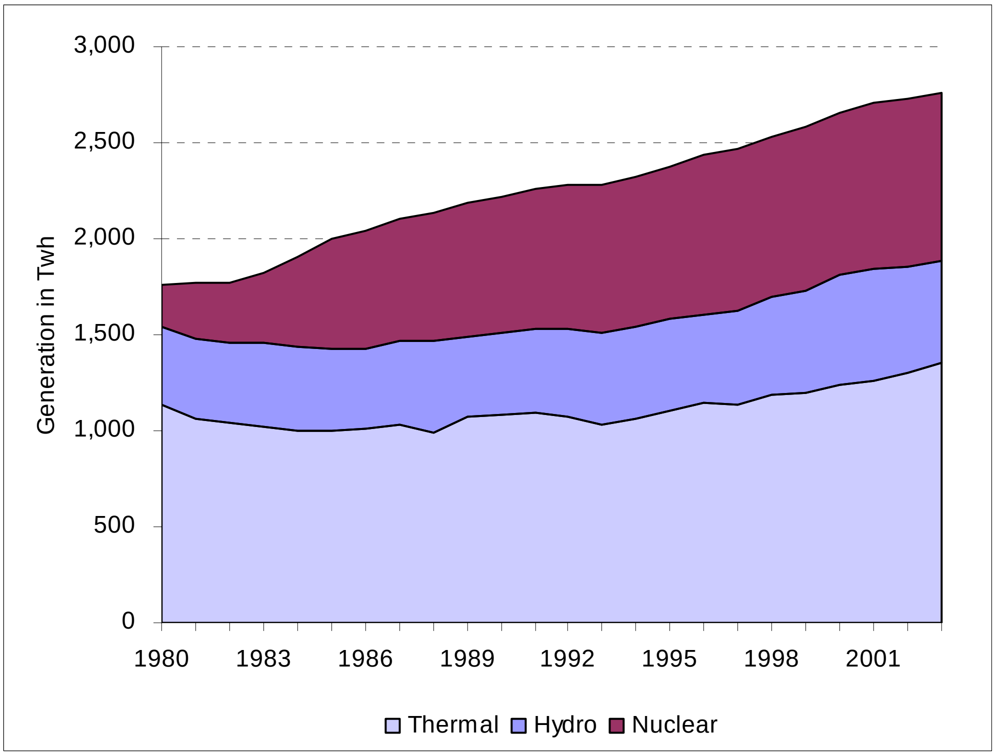
Apart from the single plant in Armenia, nuclear power plants are concentrated in the western region of Russia and Ukraine. In practice, therefore the competition between fuels – especially for new generation – in the CIS can be best understood in terms of different regional and country categories:

- Category A consisting of Russia west of the Urals, Belarus, Moldova and Ukraine. In this category the main sources of electricity generation are gas and nuclear power with a declining role for coal that will is unlikely to be reversed because of the poor quality and high cost of production of the coals from local coal basins. In future, the choice will be between these two fuels with, probably, a gradually declining role for coal in both Ukraine and western Russia. No major new investments in gas or electricity transmission infrastructure will be required to support increased use of gas for power generation, though this does not preclude substantial investments to upgrade and/or rehabilitate existing infrastructure.
- Category B consisting of the Urals and Western Siberia regions of Russia and the north of Kazakhstan (which, in energy terms, has historically functioned as an adjunct to the Urals region in Russia). Here, gas competes with coal for thermal generation. Currently, gas has a large cost advantage for new generating plants, even if gas prices reflect border parity prices, which is far from the situation in Russia today. The key issue in these regions is how far existing coal-fired plants should be rehabilitated.
- Category C consisting of Eastern Siberia and the Far East regions of Russia and the south of Kazakhstan. Here, the main choice is between coal-fired and hydro generation, though gas could become an option if pipelines being developed or considered for the purpose of exporting gas to China and/or Japan were to be used for transmission of gas to domestic power plants.
  - East Siberia and the Far East have large potential for hydro development but it is difficult to justify the investment required except for industrial use – e.g. aluminium smelting in Krasnoyarsk region – in which case any projects should financed on commercial terms by industrial sponsors. There are large reserves of coal that can mined at a very low cost, notwithstanding its relatively low calorific value, so that coal-fired plants may represent a more flexible alternative to hydro development.
  - In the case of the south of Kazakhstan, the primary sources of electricity are coal-fired plants using coal from the Karaganda and Ekibastuz basins in Kazahkstan plus imports of hydro electricity from the Kyrgyz Republic. Both of these sources can easily be expanded. Limited amounts of gas are imported from Uzbekistan but this cannot be relied upon in the longer term, whereas gas from the Caspian region could be used if/when the West-East pipeline is constructed.
- Category D consisting of the remaining countries in the Caucasus and Central Asia other than Armenia and Kazakhstan. Each of these relies predominantly on a single

type of power generation – hydro in Georgia, Kyrgyz Republic & Tajikistan, gas in Azerbaijan, Turkmenistan & Uzbekistan – that is unlikely to be displaced to any significant degree in the next 10-15 years. Since most of these countries have small populations and limited resources, it may be reasonable – as in South-East Europe – to promote a higher degree of integration of generation and transmission in meeting the growth of electricity demand.

Armenia is a special case because of the political factors that constrain its choice of fuels. It is likely to rely primarily upon its nuclear plant and supplies of gas from Russia for as long as its dispute with Azerbaijan remains unsettled. Neither of these sources can be regarded as safe or reliable, but the development of a reasonable strategy for power development is not possible for as long as the country is cut off from imports of gas or other fuels from most of its neighbours.

Figure 17 – The composition of electricity generation in Western Europe, 1980-2003



Source: See Appendix 1.

As a comparison, Figure 17 shows how the composition of electricity generation has evolved in Western Europe since 1980. The share of nuclear power rose from 12% of generation in 1980 to 31% in 1990. Since then, the contributions of thermal, hydro and nuclear sources have remained pretty much constant. Though not shown in the figure, gas-fired plants have accounted for an increasing share of thermal generation during the last 15 years. The transition countries as a group rely more upon thermal generation and less, in particular, on nuclear plants which only account for 15% of their electricity production. This may reflect a combination of relative fuel and factor prices that discouraged investment in nuclear power.

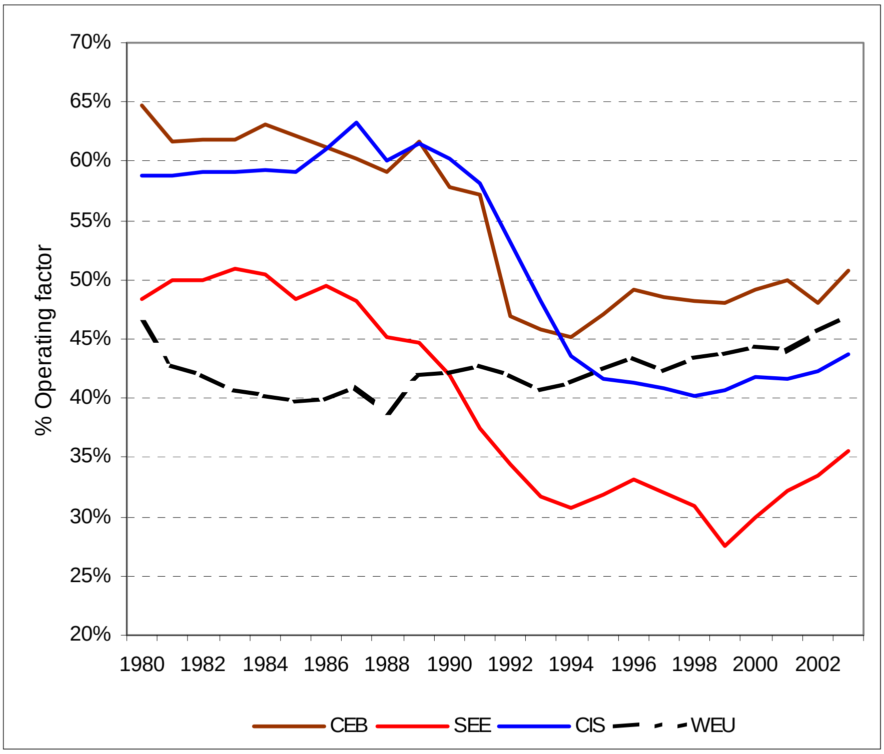
3.3 Operating performance and plant capacity

The balance between demand growth and capacity

The sharp decline in electricity consumption during the early transition years left all of the transition countries with substantial excess generating capacity. As a consequence, there has been relatively little investment in either new capacity or the rehabilitation of existing capacity. The reversal of the downward trend consumption since 1999 prompts the question of when it will be necessary to start investing again in generating capacity to meet the prospective growth in consumption.

Figure 7 above showed that electricity consumption in Central and South-East Europe in 2003 was about 20% lower than the peak in 1989. For the CIS, the decline has been even greater with 2003 more than 30% below the peak of 1989-90. Allowing for the projections of demand growth in Section 2 above, electricity consumption in the different groups will match the previous peak between 2008 and 2010, earliest in Central Europe and about two years later in Russia and South-East Europe. New generating capacity has come on stream in Central Europe in recent years, though this has partly been offset by retirement of older capacity – typically inefficient and with poor environmental performance. Thus, it may be necessary to start to consider the investment needs for new capacity throughout the region.

Figure 18 – Operating factors for thermal power plants, 1980-2003

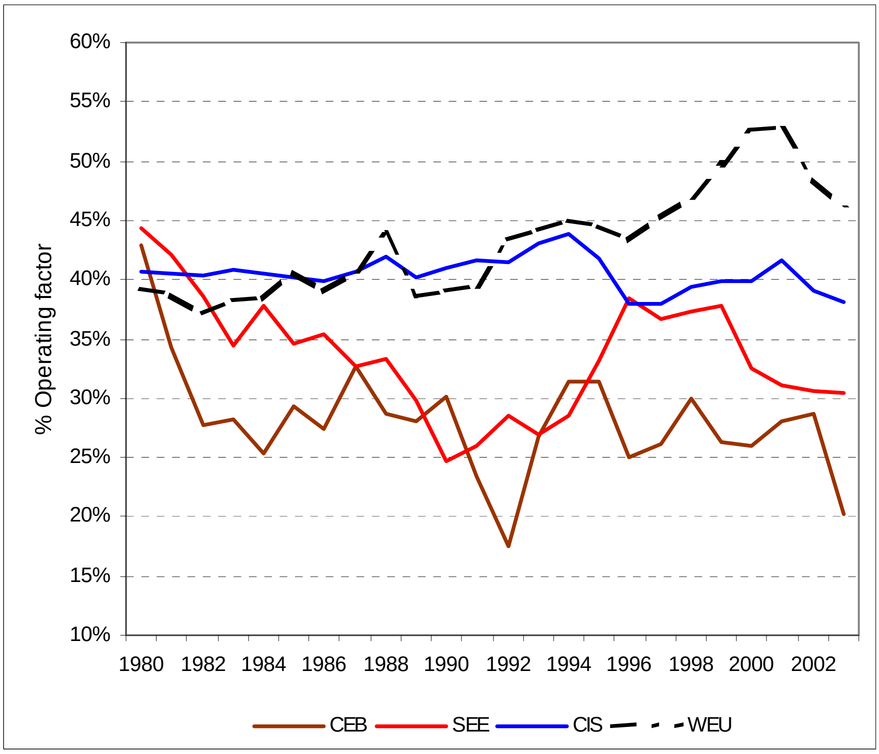


Source: See Appendix 1.

Figure 18 to Figure 20 show the average operating factors for thermal, hydro and nuclear plant for each group of countries from 1980 or 1992 to 2003 (depending upon data availability). These operating factors are expressed as the actual amount of power generated from the relevant plants divided by the power that would have been generated if they had operated for 24 hours per day, 365 days per year. Of course, the operating factors for all types of plant will be well below 100%, depending upon whether the plants are run primarily as base load, mid merit or peaking plants.

A standard reference point is provided by nuclear plants because all operators of such plants will try to run them for as many hours per year as possible. The performance of nuclear plants in Western Europe has gradually improved with their average operating factor increasing from about 72% in the early 1990s to about 78% 10 years later. In part, this reflects the tightening of the balance between demand and generating capacity in France which has the largest reliance upon nuclear generation in Europe. The average operating factor for nuclear plants in Central Europe and the Baltics has varied cyclically as a result of plant shutdowns and other factors but has averaged about 72%. The brief decline to 66% in 2001 is an artefact of the way in which the statistics were calculated when plant is newly commissioned. It should be possible for CEB nuclear plants to achieve the same operating factor as nuclear plants in Western Europe, but this would account for less than 1 year's growth in demand.

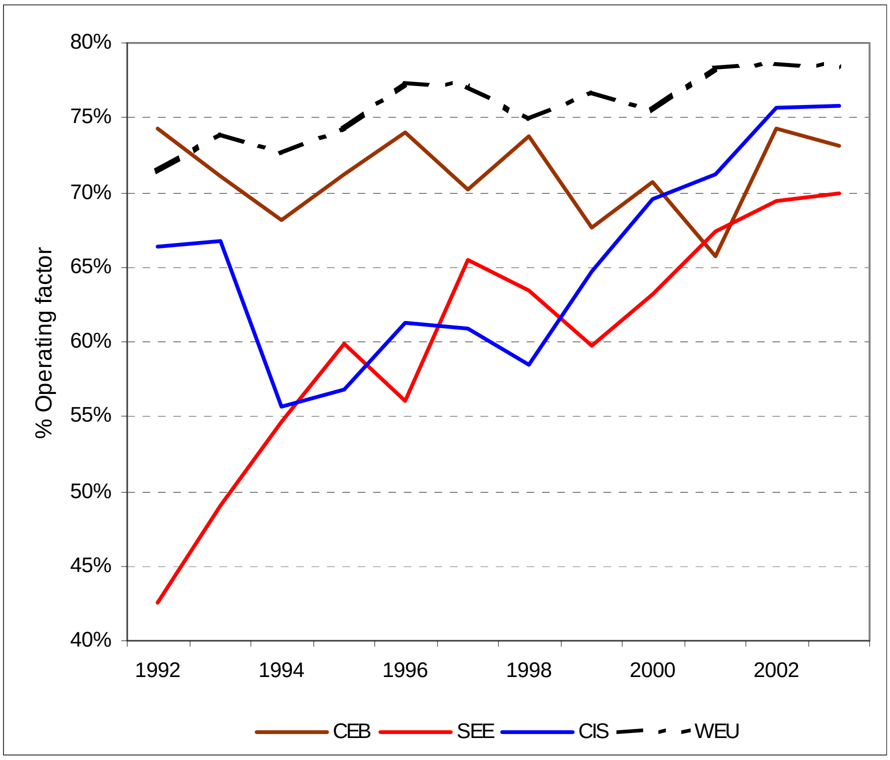
Figure 19 – Operating factors for hydro power plants, 1980-2003



Source: See Appendix 1.

The nuclear plants in South-East Europe and the CIS had relatively low average operating factors during the 1990s, in part because of prolonged plant shutdowns for safety improvements, but their performance has approached that of plants in Western and Central Europe in the current decade. There is still room for improvement in their operating factors, especially in South-East Europe, but again this would make no significant contribution to meeting the prospective growth in demand.

Figure 20 – Operating factors for nuclear power plants, 1992-2003



Source: See Appendix 1.

The average operating factors for hydro plants are determined by a combination of rainfall and design factors, so that they cannot easily be interpreted. Nonetheless, it is interesting to note that the average operating factor for hydro plants in Western Europe increased from about 40% in the 1980s to 48% in the early years of this decade. It seems reasonable to infer that the liberalisation of electricity markets in Western Europe has encouraged hydro generators to make better use of their plants. There is some indication of a decline in average operating factors for hydro plants in the CIS since 1994, which could reflect lack of maintenance, but the evidence is not decisive. There are large cyclical variations in the average operating factors for hydro plants in Central and South East Europe, but these seem to reflect investments in different types of hydro capacity together with rainfall and other exogenous factors.

The main burden of the decline in demand has fallen on the use of thermal generating capacity, which is as one would expect. The average operating factors for thermal plants in Central Europe and the CIS fell from about 60% in the late 1980s to 40-45% in 1994-98, but they are now gradually increasing again. An even more marked decline occurred in South-East Europe but from a lower starting point, though again there has been a significant recovery since 1999.

The critical question is whether, in the absence of investment in new capacity or rehabilitation, the average operating factors for thermal plant can recover to the levels seen during the 1980s. This seems unlikely: thermal generating plant tends to become less fuel efficient and more polluting as it ages. Technically, the deterioration is a function of the cumulative number of operating hours and, even more important, the cumulative number of starts and stops. The reduction in the average operating factor over the last ten years will not have been matched by a comparable reduction in the average numbers of starts and stops, so that existing equipment will be moving down the normal operating efficiency curve. This means that power companies would not wish to operate the existing capacity, now that it is older on average, for as many hours per year as 10 or 20 years ago. Either the plant will have to be replaced or supplemented by new generating units that can be operated as base load or high mid merit capacity.

Hence, for efficiency – and, probably, environmental reasons – power companies with the necessary resources will wish to invest in new plant before the average operating factors get back to the typical value of 60% that prevailed in the 19980s. I have assumed that the threshold for new capacity is an average operating factor of 55% for the existing, older plant.

- In the case of the CEB group of countries, after allowing for the potential improvement in the operating factor for nuclear plants the threshold for needing to bring new capacity on-stream would be a level of demand that is about 10% higher that in 2003. This brings forward the date at which new investment would be sought, may even required, to 2006 rather than the date of 2008 based on the demand projections alone.
- Historically, thermal plants in South-East Europe have had a relatively operating factor, in part because they have been used to supplement hydro capacity. If they are operated in a manner that is closer to the pattern in Central Europe, then it should not be necessary to increase capacity before 2012. On the other hand, if the threshold is an operating factor of 45%, then this brings forward the date for new capacity to come on-stream to 2009.
- For the CIS countries the average operating factors for thermal plant in 2003 were 47% in Russia but only 37% in the rest of the CIS. For Russia, the combination of improved nuclear efficiency and long operating hours for thermal plant could accommodate a growth in demand of about 12.5% above the level in 2003. On the demand projections given above, this margin will disappear not later than 2007. For the remainder of the CIS, the margin is close to 32% which will disappear by 2009.

In summary, allowing for a plausible limit on the average operating performance of existing thermal plant in future, it will be necessary to bring new generating capacity on-stream to meet the growth in electricity demand by dates as early as 2006-07 for the CEB countries and Russia, 2009 for the CIS excluding Russia, and a wider range of 2009-12 for South-East Europe.

Plant retirements and investment in replacement/rehabilitation

There is a second factor that must be taken into account in assessing the amount of investment required in plant generating capacity. In most transition countries a substantial fraction of the current stock of thermal generating plant is approaching an age at which it would normally be decommissioned. Coal-fired plants have a life of 35-40 years under a normal pattern of use, while gas-fired plants tend to be retired after 30-35 years unless they are run consistently as peak-load plants for very few hours per year. Oil-fired plants running on diesel or light fuel oil may be categorised with gas-fired plants, while those running on heavy fuel oil are more similar to coal-fired units.

A further difference between coal-fired and gas-fired plants is that the former will typically undergo a substantial rehabilitation after 20-25 years, perhaps involving the replacement of the boiler plus coal- and ash-handling equipment. In Western Europe such rehabilitations have usually been combined with the installation of pollution controls, such as flue-gas desulphurisation units, required to comply with tighter emission standards. This is driven by the way in which the grandfathering of existing plants under the EU's Large Combustion Plants (LCP) directive (see Appendix 2) operates. Any significant rehabilitation or re-powering of a thermal generating plant results in the application of new emission standards in place of those that applied when the plant was first constructed. At the same time, an operator which is obliged to install new pollution controls will wish to extend the life of the plant as far as possible in order to increase the period over which the cost of the controls can be recovered.

As an example, CEZ, the main power generator in the Czech Republic, implemented a large program to reduce emissions of SO2 and other pollutants from its power plants during the second half of the 1990s. This involved retiring older coal-fired plants and upgrading larger and newer plants. A number of large power plants in Poland have been upgraded and had pollution controls installed during the last 10 years, while projects of the same type are under way to upgrade some of the lignite-fired plants in Bulgaria. Over the region as a whole, there has been a relatively low level of investment in rehabilitation of the existing stock of generating plant except in the CEB group of countries. Generating plants built before 1980 are reaching an age at which either rehabilitation or retirement is unavoidable. Any assessment of the investment required in power generation must take account of this.

Consistent data on the age structure of existing plants is not is not available. I have adopted reasonable but simple assumptions for plants built before 1980 and have assumed that net additions to the stock of generating plant since 1980 can be assigned to the year in which the addition occurred. On that basis, the proportions of thermal generating plant for each group of countries that was more than 30 years old in 2003 varied from 47% for South-East Europe to 56% for the CIS - since the analysis relies in part upon data for the former Soviet Union, it is not possible to subdivide the CIS figures between Russia and the rest of the CIS. Further, 26%-32% of the existing stock was more than 40 years old, for which replacement or rehabilitation would be urgent if the plant is to be used to supply the growing level of demand over the next 5-8 years.

Allowing for what is known about the rehabilitation of generating plants over the past decade, the amount of thermal generating plant in transition countries that is (a) more than 40 years old, and (b) has not been rehabilitated in the last 10 years has a capacity of about 83,000 MW. The bulk of this – 70,000 MW - is located in the CIS with about 7,500 MW in SEE countries and 5,500 MW in CEB countries. There is an additional 74,000 MW that is more than 30 years old but less than 40 years old. Again, most of this plant – 55,000 MW - is located in the CIS.

Even if the replacement or rehabilitation of older plant is spread over a decade, the amount of investment required will match the investment required to cater for the growth in demand once the existing capacity is being fully utilised. As an illustration, assuming that the age structure of plants is similar across the CIS, Russia will need to rehabilitate or replace about 4,500 MW per year for the next 15-20 years to catch up with the hiatus that has occurred since the beginning of the transition. In addition, it will need to bring new capacity on-stream amounting to 4,000-4,500 MW per year from 2008 onwards. Under current conditions there is no sign that the electricity sector in Russia or the rest of the CIS has either the financial or institutional capacity to implement an investment program of this magnitude.

3.4 Competition between gas and coal in power generation

A significant part of the this investment will take the form of either replacing or rehabilitating existing thermal plants, which focuses attention on the competition between gas and coal in power generation. This competition will heavily influenced by environmental regulations designed to reduce the relatively high level of emissions from the existing coal-fired plants in some countries, especially in the CIS. Emissions from coal-fired in the CEB countries and in some of the SEE countries have been greatly reduced in the last decade. However, the costs of the emission controls are a significant factor determining both investment and operating costs for coal-fired plants.

The environmental requirements for new and existing coal plants are outlined in Appendix 2. From a cost perspective, the critical environmental standards are specified by the Large Combustion Plants (LCP) Directive of the European Union and the Multi-Effects Protocol of the UNECE Convention on the Long Range Transport of Air Pollutants (LRTAP). In particular, these effectively mandate the installation of controls at new plants and some existing plants to remove SO2 and NOx from power plant emissions.

One of the important characteristics of the flue gas treatment processes – FGD and SCR – that are required to meet the emission standards in the LCP Directive for emissions of SO2 and NOx from new plants is that there are substantial economies of scale in the costs of installing these controls as the size of plant increases. Under the Multi-Effects Protocol the most restrictive standards only apply to plants of more than 300 MW_{th} (equivalent to 115 MW_e for a new lignite power plant). However, the cost of installing a wet FGD falls from over $320 per kW for a plant of 100 MW to under $200 per kW for a plant of over 500 MW. Similarly, the cost of installing an SCR falls from over $90 per kW to $50 per kW for the same range of plant sizes. In addition, the basic cost of a coal- or lignite-fired power plant falls from $1,500-2,000 per kW for 100 MW to $1,000-1,200 per kW for 500 MW.

Taking these factors together the total cost of a new coal or lignite-fired power plant in the transition countries is likely to exceed $2,000 per kW for a plant of only 100 MW but falls to about $1,300 for large plants of at least 500 MW. This means that it is difficult to justify the construction of new power plants burning coal or lignite unless they are larger than 300-400 MW. As we shall see below, this conclusion is reinforced by the length of time required to develop new coal or lignite plants – usually a minimum of 4 years and often significantly longer.

Table 1 - Capital costs of new plants including pollution controls using conventional technology ($ per kW)

	100 MW_e	500 MW_e
Coal plants	2,150	1,300
Lignite plants	2,200	1,280
Gas CCGT	800	500

Source: Author's estimates based on Platt's Global Power database and IEA estimates

There are also economies of scale in the construction of gas-fired plants, but this is not influenced by the cost of pollution controls. Figures on the costs of new plants scheduled for commissioning between 2000 and 2004 taken from Platt's Global Power Project Database suggest that the basic cost of a CCGT of at least 300 MW was of the order of $450 per kW, whereas smaller plants of less than 100 MW had an average cost of over $900 per kW.

However, there are reasons to suspect that the cost of smaller plants is exaggerated by the rapid technological improvements that have occurred in such plants over the past decade, so I have used a range of $750-800 as being more representative of future costs. In addition, the development period for gas-fired plants can be as little as 2-3 years and they can be built in stages to match the expected growth in demand.

It is standard to compare different technologies and fuels used in power generation by calculating the levelised costs of production per MWh. However, such comparisons are fraught with difficulty because the results can be extremely sensitive to assumptions about variables such as the average operating load, the discount rate, operating life, construction time, etc. Since the balance between capital costs and operating costs is very different for gas and coal or lignite plants, it is likely that plants using the different fuels may be despatched on quite different bases over their lifetime, especially as they are taken out of base load generation. On the other hand, it is quite misleading to compare – as some do – the levelised costs of generation for different fuels using substantially different average load factors.

For the comparisons presented in this report I have estimated levelised costs for plants that start their operating life as

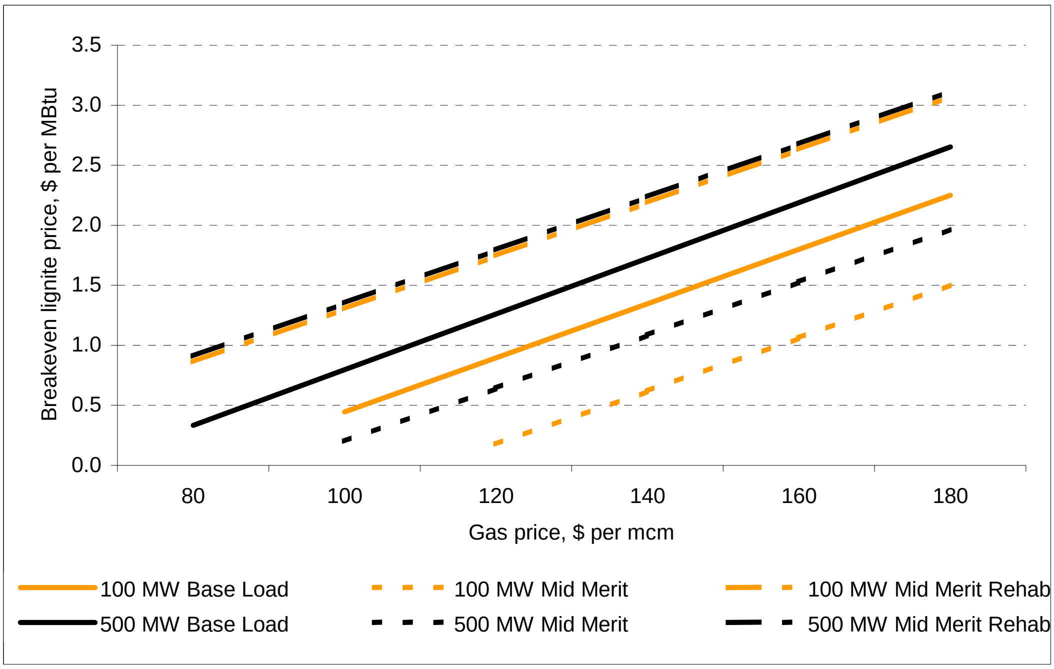
- Base Load plant with a load factor of 85% for 10 years, falling to 80% in years 11-15, 70% in years 16-20, 60% in years 21-25, and 50% in years 26-30.

- Mid Merit plant with a load factor of 60% for 10 years, falling to 50% in years 11-20, and 40% in years 21-30.

From one perspective, there is relatively little interest in examining the levelised costs of Mid Merit units because the lower capital costs of new gas-fired plants mean that these have a substantial cost advantage at practically any plausible prices of gas and coal/lignite. However, the interest in these units lies in the fact that rehabilitated coal plants may well be used primarily as Mid Merit plant, so that a utility may face a choice between either constructing a new gas-fired plant or rehabilitating an existing coal-fired plant. Since, under both the MEP and the LCP Directive, rehabilitated plants must meet the emissions standards prescribed for new plants, much of the cost of rehabilitation may due to the need to upgrade pollution controls to meet the stricter standards.

The calculations of levelised costs have been carried out for plants fired by lignite and gas with capacities of 100 MW, 300 MW and 500 MW. A spreadsheet giving details of the calculations is available from the author on request. The cost and technical parameters for new plants are derived from reviews undertaken by the US Department of Energy (in preparing its Annual Energy Outlook) and the US EPA. They do not take account of improvements in heat rates and emissions performance that might be offered by more advanced coal combustion technologies. In particular, supercritical coal-fired plants in Germany and Denmark achieve heat rates that can be 10-15% better than conventional sub-critical plants – i.e. thermal efficiencies of 42-44% for supercritical plants by comparison with 38-39% for sub-critical plants. However, these plants are difficult to operate and experience with them is limited to plants burning good quality steam coal rather than lignite. Equally, I have assumed that new CCGTs achieve a thermal efficiency of only 52%, even though 55% or higher can be achieved by the most modern plants in the US or Europe. Again, the difficulty and lack of experience of operating such plants means that countries in transition countries are likely to lag one generation behind the most advanced technology.

Figure 21 - Breakeven prices for coal/lignite in new power plants for various gas prices (No CO2 penalties)



Source: Author's calculations.

Figure 21 shows the results of these calculations. It focuses on the issue of the price at which lignite can compete with gas in new power plants, taking account of the cost of the pollution controls required by the LCP Directive.

As a basis for comparison, the average import prices for gas imported by pipeline in 2001 and 2002 into Austria and Germany were in the range $100-115 per mcm.[3] Import prices for Germany were an average of $82 per mcm for the period 1995-2000. Generally, it is expected that bulk gas prices in Europe will be higher than during the 1990s, so that it seems reasonable to use $80 per mcm as the lowest gas price in this comparison. On the other hand, the availability of large potential supplies of LNG as well as new supplies of gas from Russia is likely to put a cap on gas prices in the longer term. In current market conditions, LNG can be imported into Western Europe from the Middle East or Africa at prices between $120 and $140 per mcm after re-gasification. This limits the price that can be charged for pipeline supplies of gas and should ensure that the countries in Central and South-East Europe will not face import prices of gas much higher than $140 per mcm in the medium and longer term.

Coal and lignite prices paid by the electricity sector vary great across countries in Central and South-East Europe depending upon the quality of the coal, the extent of protection or subsidies for domestic producers, and the cost of transport. The highest price is about $1.90 per MBtu, paid by the Turkish power company TEK for brown coal and lignite, while CEZ in the Czech Republic pays about $0.90 per MBtu for the brown coal that it uses. The average price of steam coal in Poland is $1.55 per MBtu. This is slightly lower than the

3 It is usual to quote gas prices in international markets in $ per million Btu (Mbtu). I have converted all such prices to $ per 1,000 m3 (mcm) by applying the average gross calorific value for Russian gas of 8270 kilocalories per m3 which is equivalent to 32.82 Mbtu per mcm.

average prices paid in West European countries for imports of steam coal from Australia, South Africa and Colombia, which have been in the range $1.60-1.70 per MBtu in recent years.

The break-even prices of lignite are almost identical for 100 MW and 300 MW plants, so that the figure illustrates breakeven prices for lignite in 100 MW and 500 MW plants. It confirms the expectation that lignite cannot compete with gas for small or medium mid merit plants unless the price of gas is very high. In small or medium base load plants, the breakeven price of lignite is less than $1.00 per MBtu unless the gas price is expected to be at least $130 per mcm in future. Thus, lignite or brown coal can only compete with gas for such plants if it is priced at or below the level that prevails in the Czech Republic. This is possible, because Powder River Basin coal in the US is sold at prices as low as $0.70-0.80 per MBtu to power plants in the Mid West that are located within 400-500 miles of the coal mines.

However, for the more plausible range of gas prices of $110-130 per mcm, lignite is only likely to be competitive in large power plants operating on base load. For such plants it can compete at prices from $1.00-1.50 per MBtu, which should be feasible for power plants located very close to the mines relying upon conveyor systems rather than rail to transport the lignite from the mine to the power plant.

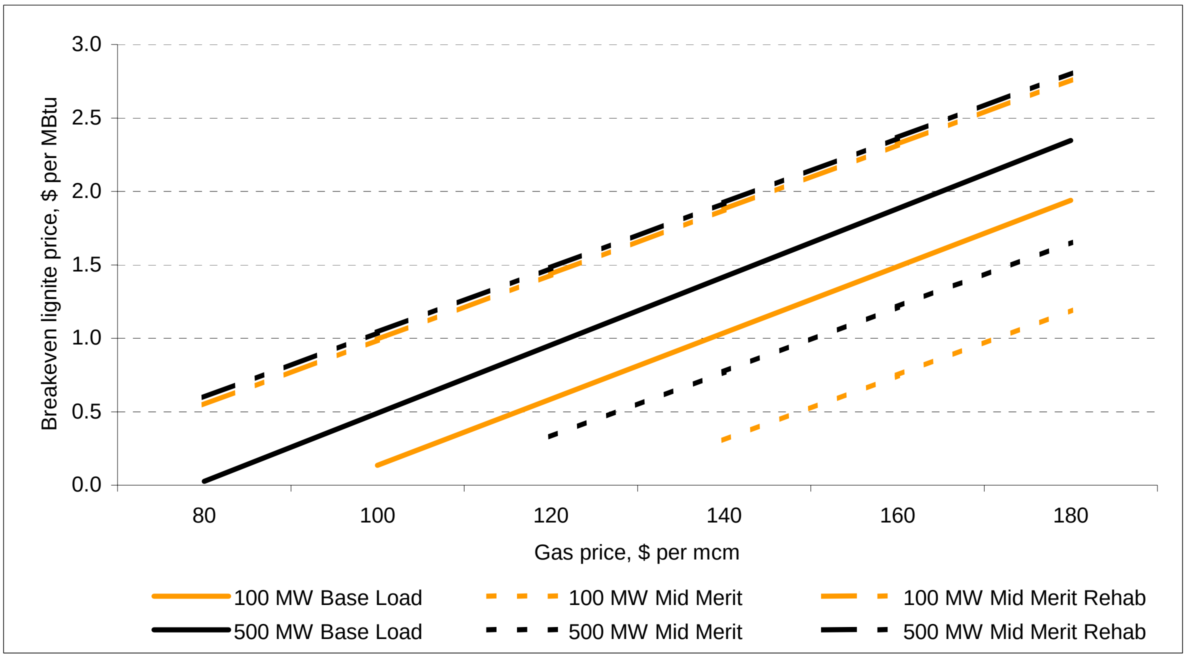
The penalty on the breakeven price of lignite as a result of the extra pollution controls required for a new lignite-fired plant rather than a gas-fired plant varies from $0.50 per MBtu for a 500 MW base load plant to $0.67 per MBtu for a 100 MW base load plant and up to $0.90 per MBtu for a 100 MW mid merit plant. This reinforces the point that it is only likely to be viable to build new lignite-fired plants if they are to be operated on base load, whereas gas has a huge advantage for mid merit capacity.

This leaves the question of whether it is worth rehabilitating old lignite plants to operate at mid merit rather than building new gas-fired plants. The answer to this question is inevitably complex and site-specific, because it depends upon the opportunity cost of rehabilitating such plants – i.e. the value of the power that they would generate if they continued without investments in upgrading and life extension. I have not attempted to take account of this opportunity cost, but have instead assumed that the cost of rehabilitation is 50% of the cost of a new plant of equivalent size. This is probably on the high side, which corrects to some degree for the omission of the opportunity cost. In addition to the cost of the basic rehabilitation the calculations allow for the costs of installing the same pollution controls as would be required for a new plant.

Figure 22 shows that the breakeven prices for lignite in rehabilitated mid merit 100 MW and 500 MW plants are very similar. If the average gas price is expected to be $100 per mcm, the breakeven price for lignite is about $1.30 per MBtu, while for an average gas price of $120 per mcm the breakeven price for lignite is about $1.75 per Mbtu. Hence, it seems that the cost of pollution controls is not so large as to rule out the rehabilitation of existing plants if it is planned to operate them at mid merit in future.

These calculations assume that there are no penalties for the level of CO2 emissions from the plants. This is reasonable on the grounds that none of the countries in SE Europe is likely to be constrained by overall limits on CO2 emissions during the next decade. On the other hand, the European Union is establishing mechanisms for trading CO2 emission permits and these arrangements may well be extended to cover candidates for membership of the EU. This would mean that reductions in CO2 emissions from large combustion plants in some transition countries will have a future value linked to the price of tradable CO2 permits in the EU.

Figure 22 - Breakeven prices for coal/lignite in new power plants for various gas prices for a CO2 penalty of $5 per tonne



Source: Author's calculations

To take account of this factor the analysis of levelised costs has been extended to allow for a penalty on CO2 emissions. The penalties are calculated by assuming the following levels of CO2 emissions per unit of fuel input:

Gas	46.61 kg per Mbtu,
Lignite	96.51 kg per Mbtu.[4]

The levelised costs are computed by assuming the effective price per MBtu of using either gas or lignite is equal to the market price in $ per mcm or Mbtu plus the CO2 penalty calculated at either $5 per tonne of CO2 or $10 per tonne of CO2. These penalties correspond to the range of values that are thought to be plausible market outcomes once trading in CO2 permits has been fully implemented in the EU on the basis of the overall emission targets under the Kyoto Protocol and EU directives to implement it.

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4 These emissions coefficients are taken from the assumptions used by the Carbon Dioxide Information Analysis Center at Oak Ridge National Laboratory in the US, which has compiled the most extensive figures on CO2 emissions by country. In calculating emissions for solid fuels they rely upon an assumption that the amount of CO2 emitted is proportional to fuel used measured in units of tonnes of coal equivalent (tce). However, there are differences between CO2 emission rates per tce according to the quality and combustion characteristics of different fuels, because these influence the amount of carbon that is left in the boiler ash. Little information is available about the level of actual CO2 emissions for the type of low quality lignites used in SE Europe, so I have chosen to adopt the standard assumptions. Other analyses have adjusted the CO2 emission rates for similar fuels downwards by 5-10% to allow for carbon in residual ash.

The breakeven prices for lignite for different types of power plant on the assumption that the CO2 penalty is $5 per tonne. The higher level of CO2 emissions for lignite-fired plants mean that the breakeven curves for lignite are all shifted leftwards. For a 500 MW base load plant and a gas price of $120 per mcm, the breakeven price for lignite is $0.95 per MBtu as compared with $1.26 per MBtu with no CO2 penalty.

Table 2 - Breakeven prices for coal/lignite for various CO2 penalties ($ per MBtu)

Gas price ($ per mcm)	No CO2 Penalty		CO2 penalty of $5 per tonne		CO2 penalty of $10 per tonne	
	100 MW Mid Merit Rehab	500 MW Base Load	100 MW Mid Merit Rehab	500 MW Base Load	100 MW Mid Merit Rehab	500 MW Base Load
80	0.86	0.33	0.55	0.03	0.23	
100	1.30	0.80	0.99	0.49	0.68	0.19
120	1.75	1.26	1.43	0.95	1.12	0.65
140	2.19	1.72	1.88	1.42	1.56	1.11
160	2.63	2.19	2.32	1.88	2.01	1.58
180	3.07	2.65	2.76	2.35	2.45	2.04

Source: Author's calculations.

Clearly, if the introduction of trading in CO2 emissions permits implies a significant penalty for additional CO2 emissions, then there will be more incentive to use gas rather than lignite for any given level of gas prices. Equally, the effect of this penalty may be partially – perhaps even wholly – offset by an increase in the price of gas because the shift from coal or lignite to gas will occur throughout Europe.

Table 2 shows how the breakeven price for lignite changes as the CO2 penalty is increased from zero to $10 per tonne for the two categories that are likely to be of most interest in SE Europe – the rehabilitation of a 100 MW unit or the construction of a new 500 MW unit. In both cases, an increase of $5 per tonne in the CO2 penalty implies a reduction of about $0.30 per MBtu in the breakeven price of lignite.

3.5 The choice between thermal generation and nuclear power

The International Energy Agency has recently published a study of the prospective of electricity generation using a wide range of technologies.[5] Their figures are based upon the reported costs of projects planned in 2003 that would generate electricity starting from 2008-2010. While their figures span a wide range of different circumstances, the median values provide a reasonable indication of the costs that would apply in transition countries. They

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[5] IEA, *Projected Costs of Generating Electricity – 2005 Update*, Paris: OECD, 2005. To increase the robustness of the calculations, all of the assumptions related to capital and operating costs used in this paper are based on the averages of the 5 (for gas and coal) or 3 (for nuclear power) observations spanning the median value of the actual cases for which detailed information was obtained by the IEA.

illustrate the key point that the choice between thermal and nuclear power generation is in essence a choice between capital costs and operating costs.

Setting aside interest during construction, the typical capital cost – referred to as the "total overnight construction cost" - for a gas-fired power plant including emission controls falls in the range $500-600 per kWe. Such a plant can be constructed in 2-3 years as measured by the period accounting for at least 90% of the overnight construction cost. Hence, a new plant on which construction work started in January 2006 could supply power not later than January 2009. Some countries take much longer, but in the United States and Canada it is routine to construct a gas combined cycle unit in less than 2 years (though the time required for planning and licences may be much longer). The equivalent ranges for coal-fired plants are a capital cost of $1,200-1,300 per kWe including all emission controls and a construction period of 3-4 years, though 4 years is the most common time.

The construction costs for new nuclear plants span a wide range. In the Czech Republic and South Korea the costs are put at $1,100-1,200 per kWe, though it should be noted that South Korea has very low costs for all types of power plant. The more typical costs fall in the range $1,700-1,900 per kWe. The standard construction period is 5 years.

The IEA computes the levelised cost of electricity from different prospective plants using costs of capital of 5% and 10% in real terms. The lower cost of capital is reasonable for large power utilities in Western Europe, but a cost of capital of 10% is much closer to a realistic level for transition countries. In some cases, it may be argued that the actual cost of capital is as high as 12-15% once country-specific risks are taken into account. There is a question, which I will return to below, as to whether the cost of capital for nuclear power plants should be the same as that for thermal plants. The levelised costs allow for the estimated full costs of managing waste nuclear fuel and decommissioning old plants using a 5% cost of capital to ensure that costs far in the future are not discounted too heavily.

Using the fuel prices and other operating costs provided by each country, the results of the IEA's analysis suggest that the levelised costs of electricity generated from coal and nuclear plants at a discount rate of 10% are almost identical – at about $42.5 per MWh – whereas the cost of electricity from gas plants is about 20% higher at about $51.5 per MWh.

However, these results cannot be accepted without qualification. The IEA assumes that each plant will be used for base load generation (an 85% load factor) for 30-35 years for gas and 40 years for coal and nuclear. The utilisation figures presented above demonstrate that this will not happen, even for nuclear plants. Even if there is an improvement on existing utilisation in Western Europe, nuclear plants are unlikely to achieve an average operating factor over their lifetime that is significantly above 80%, while the lifetime operating factors for coal and gas plants may be no better than 50%. Quite separately, the fuel costs for the coal and gas plants are based on a varying set of fuel price assumptions that do not seem to reflect a consistent view of the prospects for the relevant markets.

Table 3 – Levelised costs of electricity from coal, gas and nuclear plants

	Basic IEA parameters	Cost of capital = 12%	Cost of capital = 15%	Adjusted cost of capital & coal price	Adjusted coal & gas prices	Adjusted cost of capital and CO2 charge = $40 per mt	Adjusted cost of capital and CO2 charge = $10 per mt
Discount rate	10.0%	12.0%	15.0%	12.0%	10.0%	12.0%	12.0%
Fuel prices in $ per GJ							
Coal	1.97	1.97	1.97	2.95	2.95	1.97	1.97
Gas	5.36	5.36	5.36	5.36	6.70	5.36	5.36
CO2 charge in $ per mt	25.0	25.0	25.0	25.0	25.0	40.0	10.0
Levelised cost without CO2 charge in $ per MWh							
Coal	44.7	49.0	55.9	56.9	52.7	49.0	49.0
Gas	51.8	53.5	56.4	53.5	61.3	53.5	53.5
Nuclear	45.2	52.6	64.9	52.6	45.2	52.6	52.6
Levelised cost with CO2 charge in $ per MWh							
Coal	63.0	67.2	74.1	75.2	70.9	78.1	56.3
Gas	60.6	62.4	65.2	62.4	70.1	67.7	57.1
Nuclear	45.2	52.6	64.9	52.6	45.2	52.6	52.6
Fuel prices to match nuclear levelised cost in $ per GJ							
Without CO2 charge							
Coal	2.03	2.42	3.08			2.42	2.42
Gas	4.44	5.23	6.56			5.23	5.23
With CO2 charge							
Coal	-0.23	0.17	0.83			-1.19	1.52
Gas	3.20	3.99	5.31			3.24	4.73

Source: Author's calculations.

I have constructed a framework for calculating levelised costs relying upon more plausible parameters, including

- an 80% load factor for all plants up to 20 years and then gradually declining for thermal plants after that date;
- a normalised fuel price for each fuel that is constant in real terms over the life of the plant but which is equivalent to the average price path in the IEA calculations;
- the incorporation of a charge for CO2 emissions at various levels; and
- alternative costs of capital that apply to investment and operating costs, but which do not reduce the levelised cost of dealing with nuclear waste.

The levelised costs computed in this way under a range of alternative assumptions are shown in Table 3. The first column shows the results of adopting the typical assumptions underpinning the IEA calculations. The cost of capital is 10%, the long run equivalent prices of coal and gas are $1.97 and $5.36 per GJ and the CO2 charge is $25 per tonne. The equivalent price for steam coal is somewhat below the current market price. In the last year the spot market price for coal imported into Europe has gone above $2.75 per GJ, partly as a consequence of the fall in the dollar relative to the euro and partly as a result of demand factors. Hence, it seems reasonable to examine the levelised cost of electricity generated at coal-fired plants with a long run coal price of $2.95 per GJ, a price at the top end of recent experience. On the other hand, the equivalent price for gas is comparable to the current market price for pipeline imports into Western Europe – it translates to $5.65 per MBtu or $185 per mcm. Since the transition countries will incur lower transport costs for gas from Russia, the domestic price of gas for power generation should not be greater than this level unless there is a significant further increase in the price of internationally traded gas in Europe. To allow for this possibility I have looked at the effect of a long run gas price of $6.70 per GJ, which is 25% higher than the IEA typical price.

Setting aside any charge for CO2 emissions, the levelised cost of electricity from coal-fired and nuclear plants are almost equal under the IEA's typical assumptions, whereas raising the cost of capital from 10% to 12% shifts the cost of nuclear power to match that from gas-fired plants, while coal-fired plants remain somewhat less expensive. If the cost of capital is raised further to 15%, then nuclear power is clearly more expensive, whereas coal and gas plants have very similar levelised costs.

While the cost of capital for transition countries that have joined the European Union may be less than 10%, many of the other countries in the region have country risk assessments that imply domestic costs of capital that are 2-4% above the cost of capital for countries in Western Europe. The creditworthiness of electricity utilities in these countries is reduced by public resistance to electricity tariffs that are sufficient to cover incremental generating and distribution costs. Hence, I consider that it is appropriate to adopt a cost of capital greater than 10% in comparing alternative options for expanding electricity generation. A cost of capital of 12% seems reasonable and is consistent with estimates for a variety of middle income countries in Latin America as well as South East Europe and the CIS.

With this cost of capital, all three generation options have similar levelised costs if the long run price of coal is about $2.40 per GJ and the price of gas is $5.25 per GJ, provided that there is no CO2 charge. These prices are 20-30% higher than the IEA's long run projections for imports of coal and gas into Europe - $1.80-1.85 per GJ for coal and $4.0-4.4 per GJ for gas at 2005 prices for the period 2020-2030. Hence, even allowing for the cost of domestic transport, thermal generating plants burning coal and gas should have a lower levelised cost than nuclear plants if CO2 emissions are not a consideration.

The choice between coal and gas will depend upon location, in particular with respect to the delivered price of coal. Power plants located near coal basins that would otherwise be exporting coal should be able to contract for coal at a price well below $1.80-85 per GJ. On the other hand, countries that are relatively close to export pipelines from Russia to West Europe should be able to contract for gas at prices that may be $0.3-0.5 per GJ less than the import prices in Western Europe because of differences in transport costs.

On the other hand, if charges for CO2 emissions are a relevant consideration, then the choice of generating technology looks radically different. It does not matter whether the country is itself constrained by emission limits under the Kyoto Protocol or any likely successor. If there is a market in emission permits that enables current or future generators to monetise the benefits of reducing CO2 emissions – or requires them to pay a penalty for increasing emissions – the potential value of the different levels of emissions for different technologies must be taken into account. The calculations are most readily understood by considering the fuel prices at which the levelised costs for different technologies are equal, given different CO2 emission charges.

With an emission charge of $25 per tonne of CO2 (the IEA's primary assumption) the cif price of coal at the power plant would have to be no more than $0.17 per GJ for a coal-fired plant to match the levelised cost of a nuclear plant. Similarly, the delivered price of gas should be no more than \$3.99 per GJ. The full range of estimates shown in the table demonstrate that any emission charge greater than \$10 per tonne of CO2 effectively renders coal-fired plants uneconomic relative to either gas-fired or nuclear plants. New gas-fired plants could be economic so long as the emission charge is less than \$25 per tonne, but at \$40 per tonne the price of gas necessary to match the levelised cost of nuclear power is less than any plausible estimate of the future import price or opportunity cost of gas outside Russia and countries in Central Asia that export gas.[6]

There is a further consideration. CO2 emission charges at \$25 or \$40 per tonne will prompt utilities in Western Europe to adjust the merit curve for existing plants, so that gas-fired units will be operated for more hours per year and coal-fired units for fewer hours. This will push up the demand for gas imports and the likely future price. Coal prices may fall somewhat, but the main effect is likely to be a reduction in the volume of coal imports from sources such as Australia, South Africa, Colombia and the US. By pushing up the demand for imported gas when alternative sources of supply are limited, this short run adjustment will discourage investment in new gas-fired power plants in transition countries. This tendency will only be counteracted if alternative supplies of imported gas – primarily LNG from Africa or the Middle East – come onto the European market. The delivered cost of LNG imports is likely to be in the range \$4.5-5.0 per GJ, which would give a large cost advantage to nuclear power.

The most attractive alternative to nuclear power without CO2 emissions is wind generation. The average overnight construction cost of wind plants is a little higher than that for coal-fired plants at about \$1,390 per kWe. Because of the limited number of hours of operation the average levelised cost of electricity from wind plants is \$92.5 per MWh at a cost of capital of 12%. This makes no allowance for the opportunity cost of back-up power sources and other costs of integrating wind power into a power system. Appendix 9 in the IEA study suggests that such costs might fall in the range €5-15 per MWh of wind power with lower estimates depending upon the use of hydro power for balancing. Even at the bottom of this range the full cost of wind power will be about \$100 per MWh, nearly twice the cost of nuclear power.[7]

In summary, the levelised cost of nuclear power is higher than that of power from thermal plants in transition countries so long as CO2 emissions are not a consideration. However, plausible estimates of a charge for CO2 emissions reverse that conclusion. New coal-fired plants will not be economic at any charge more than \$10 per tonne of CO2. New gas-fired plants might be competitive with nuclear plants up to a charge of \$25 per tonne of CO2, but constraints on the availability of additional supplies of gas mean that the price of gas is

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[6] Within the European Union the fixed penalty for exceeding CO2 emission limits has been set at €40 per tonne of CO2 for 2005-2007 and at €100 per tonne for 2008 onwards. This puts a cap on the emission permit price but experience in similar markets (e.g. SO2 trading the US) and most predictions suggest that the permit price will be some way below this level once the firms affected have adjusted to the new regime.

[7] At current levels of wind generation it may be argued that the marginal cost of back-up power sources is purely notional on the grounds that there is ample spare thermal generating capacity, in particular gas-fired plants operated at mid-merit, to provide back-up. This may be correct in the short run, but it is misleading as a basis for judging the relative costs of alternative generating technologies over the longer run, which is the purpose of the comparisons. It is equivalent to arguing that there is no need to take transmission costs into account because the transmission system has spare capacity.

likely to increase as a result of increased demand in Western Europe. Thus, in practice nuclear power is likely to have a much lower levelised cost than power from thermal plants in all countries other than Russia and other gas exporters. The alternative of wind power is much more expensive than power from nuclear or even gas-fired plants unless the CO2 charge begins to approach $100 per tonne.

There is a further issue concerning the choice of the appropriate discount rate for calculating the levelised costs of different generating technologies. This is addressed in Section 2.9 below since it is intimately linked to the relationship between public and private investment in power generation.

3.6 Pricing electricity

A common theme in policy advice throughout the region has been the importance of ensuring that the prices paid by end-user cover the marginal cost of supply. In the short run it has been sufficient to ensure that these prices cover incremental operating costs, so that electricity utilities can at least generate sufficient revenue to pay their fuel and other bills. However, the analysis presented in this section poses a rather different problem. The impact of the transition has meant that there has been no requirement for substantial new investment in electricity generation for most countries in the region. There has been limited investment in transmission and distribution system, since a complete cessation of such investment was never possible if reasonable reliability of supply was to be maintained. But, in essence, the story has been one of living off the excess capacity that was constructed before the transition.

The analysis shows that the margin of spare capacity is being eroded and will disappear entirely within 5-8 years in different sub-regions. At that point, the prices will have to be sufficient to cover the cost of new investment in generating capacity plus supporting transmission and distribution infrastructure to ensure that electricity networks can handle the increased loads. Few countries are close to a level of prices that would cover the marginal costs of new generating capacity.

Even before the increase in fuel prices over the last 12-18 months the expected levelised costs associated with new base load generating capacity were estimated to be $35-45 per MWh at a discount rate of 10%. Applying the higher discount rate of 12% adopted for this paper, the bottom of the ranges of levelised costs would start at $40 per MWh for gas and at $45per MWh for coal. These cost estimates relies upon gas being available at a cost of no more than $3.50 per GJ and coal at $1.50 per GJ. At current fuel prices, the range of generating costs is $45-55 per MWh depending upon the discount rate and fuel used. If an additional allowance is made for the opportunity cost of CO2 emissions under an emissions trading scheme, then the range would be $50-70 per MWh. Hence, an expected producer price of $50 per MWh would be the absolute minimum required to ensure that investment in new generating capacity is economically viable.

Countries with relative efficient transmission and distribution systems that implement pricing mechanisms designed to achieve cost recovery for network infrastructure typically have margins between average prices for wholesale (large industrial) and residential customers equivalent to $45-50 per MWh to cover distribution & supply costs while transmission costs (including system operation) would be of the order of $5 per MWh. Thus, the minimum wholesale price to underpin new investment would be $50 per MWh (excluding taxes) and the minimum retail price for end-users would be $100 per MWh (excluding taxes). A more cautious estimate that allows for the cost of CO2 emissions would be $120 per MWh (excluding taxes). This should be contrasted with the level of $80 per

MWh that has often been taken as the minimum level of the tariff for residential consumers necessary to ensure cost recovery in most of the region, other than in Russia.

Table 4 shows the average prices for electricity received by producer and paid by different classes of customer in 19 transition countries – including Mongolia. This data is taken from the database collected by ERRA and is based on report average prices at the end of each quarter. The figures have been averaged over two years in order to mitigate the effects of currency changes and missing data. The conversion from national currencies to US dollars is based on actual rather than PPP exchange rates. This is appropriate because the costs of generating and distributing electricity are closely linked to international prices.

Table 4– Average prices for electricity in 2002-03

	Average pre-tax prices for 2002-03 in $ per MWh				
	Producer	Wholesale	End-users		
			All	Non-Residential	Residential
Albania		14.3	44.6	59.6	36.2
Armenia	13.6	17.1	30.8	27.9	35.8
Bulgaria	21.5	23.8	41.1	43.2	38.0
Croatia	31.5	38.0	66.2	67.0	75.0
Czech Republic	28.7	28.7	61.0	55.8	69.1
Estonia	26.6	44.5	47.7	45.5	47.7
Georgia	10.6	15.8	28.2	18.1	34.4
Hungary	46.5	43.7	72.0	67.1	81.8
Kazakhstan	17.4	15.5	25.2	25.7	24.5
Kyrgyz Republic	4.0	4.6	11.5	15.9	9.3
Latvia	19.5	45.8	50.9	46.6	55.7
Lithuania	24.8	35.1	62.7	60.7	67.9
Moldova	24.4		50.3	50.3	50.6
Mongolia	24.7	27.5	40.2	40.2	40.2
Poland	34.6	30.1	62.8	59.2	73.0
Romania	30.7	30.7	52.2	50.8	62.0
Russian Federation	13.5	14.2	20.7		
Slovak Republic	35.5	54.8	77.6	79.7	72.8
Ukraine	17.3	22.3	27.4	28.4	22.5
Median	24.5	28.1	47.7	48.4	49.2
% > $40 / $45	6%	11%			
% > $80			0%	0%	6%

Source: EBRD and ERRA data supplied by national regulatory agencies.

The median producer price received by electricity generators is just under $25 per MWh and only one country – Hungary – had an average price greater than $45 per MWh. A total of 7 countries had an average producer price below $20 per MWh – less than one-half the level necessary to ensure that new generating capacity would be economically viable. The situation is slightly better at the wholesale level with 2 countries (Latvia and the Slovak Republic) having average wholesale prices greater than $45 per MWh and two more just below $45 per MWh.

At the retail level, the median price is less than 50% of the minimum estimate of the long run marginal cost of electricity. Indeed, the figures in the table give a somewhat optimistic picture because the median post-tax price for 9 additional transition countries for which only post-tax prices were obtained was $23.1 per MWh. Only one country – again Hungary – charged an average price for residential consumers of more than $80 per MWh. In comparison, only three West European countries – Finland, Greece and Norway - had average residential prices including taxes of less than $100 per MWh in 2002-03.[8] Of these both Finland and Norway have a long history of low cost power generation.

Despite the progress that has been made in adjusting electricity prices to eliminate the worst distortions caused by socialist practices and hyperinflation it is clear that there is still a long way to go to establish an economically sustainable basis for the electricity sector. A further comparison is illuminating. OLADE reports average electricity prices including taxes for end users in 25 (mostly middle income) countries in Latin America and the Caribbean region at the end of 2003. The median price for residential customers is $85.60 per MWh, while the median price for industrial consumers is $72.0 per MWh. The average level of taxes on electricity in Latin America is somewhat lower than the level in transition countries, but so that the median price excluding taxes is not far short of $80 per MWh. The median residential price including taxes is more than 80% higher than the equivalent median for all transition countries.

This illustrates how far the transition countries still have to go in establishing a reasonable level for electricity prices. Concerns about affordability are no different in Latin America from those in transition countries and electricity is not used in fundamentally different ways. Electricity is used for heating in some countries in both regions but it is not the predominant heating fuel in either region, so different climatic conditions cannot explain the greater reluctance to set tariffs at a level that reflect long run marginal costs.

The central point is that many of the transition countries have had something close to a free ride over the past 15 years because of the legacy of excess capacity resulting from over-investment during the socialist period and the modest or abrupt fall in demand following the transition. It should also be noted that the average prices of electricity in the region tend to highest in countries that had the smallest amount of spare domestic capacity – mostly CEB countries plus Croatia (which relies heavily upon imports of electricity from a shared nuclear plant in Slovenia).

The end of the free ride is rapidly approaching and countries will have to increase prices if they are to generate the financial resources and provide the incentives required to sustain new investment. Since the gap between current prices and long run marginal costs is so large in the majority of countries, it will be necessary to phase any adjustment over a period of 5 years or more. In that respect it would be encouraging if the trend in prices had been upward in recent years, but sadly that is not the case. The median changes in average pre-tax prices from 2002 to 2003 varied from -3.1% for producer prices to -4.4% for average end-user prices. Since the dollar weakened against the currencies of many transition countries from 2002 to 2003, this represents an even worse trend in terms of real domestic prices.

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[8] Typical rates of VAT applied to electricity prices range from 16% to 22%, so $100 per MWh including taxes translates to more than than $80 per MWh before taxes.

3.7 Concerns about affordability

One important factor underpinning the reluctance of governments in transition countries to permit electricity and other utilities to charge tariffs that recover the long run costs of new supply has been the assumption that many households – and enterprises - cannot afford to pay such high tariffs. This concern rests, in part, on a kind of low equilibrium trap. The history of low tariffs over many decades has undermined incentives to use electricity and other fuels more efficiently. Thus, electricity and fuel consumption relative to income remain relatively high in most of the region. Any sharp increase in tariffs will fall heavily on poor households who may feel that they have few options for economising on consumption in the short run. On the other hand, the continued failure to signal that tariffs must rise – and by a lot – reinforces the inertia that underpins the present structure of tariffs.

Sooner or later this cycle must be broken, if new investment in power generation is to be economically viable. A recent EBRD study by Tepic & Fankauser attempted to assess how severe the resulting problems of affordability might be.[9] For electricity they assumed a residential tariff of $80 per MWh for cost recovery with any allowance for CO2 costs, below the minimum level of $100 per MWh that would seem to be required at current fuel prices. Their analysis assumes that (a) tariffs are increased to achieve cost recovery in either 2007 or 2010, and (b) the income and price elasticities of electricity consumption are 0.3 and -0.4 respectively.

They conclude that there is no substantial issue of affordability for households at the median level of household expenditure. However, there may be a serious problem for households in the bottom decile of the household expenditure distribution and for certain vulnerable groups. Electricity bills would exceed or be very close to 10% of total household expenditure for the bottom decile in 2007 in most countries in South-East Europe, the exceptions being Albania (somewhat surprisingly) and Romania. Even if the target for cost recovery is extended to 2010, the expenditure shares of electricity would exceed 10% for the lowest decile in Croatia, FYR Macedonia and Serbia & Montenegro. The other country that stands out as having a severe affordability problem for the bottom decile is Georgia.

The Tepic & Fankhauser's calculations can be adjusted to reflect a target of achieving an average residential tariff of $100 per MWh by 2010. This produces results that are very similar to those for the lower tariff in 2007. On average, electricity bills for the poorest decile of households in South-East Europe would account for 11.4% of household expenditure. In three countries – FYR Macedonia, Serbia & Montenegro and Georgia – the average expenditure share for the poorest decile would exceed 15%. The situation for vulnerable groups – pensioners and recipients of social benefits – is likely to be even worse.

Various approaches have been adopted to mitigate the impact of tariff increases on poor or vulnerable households. Few have been successful, largely because most transition countries lack the administrative capacity to implement effective programs of targeted assistance. As a consequence the choice tends to lie between measures that are not well targeted and tend to imply heavy costs in terms of either (a) public spending or (b) utility revenues. Increasing the overall general level of pensions and social benefits is an example of the first category, while tariffs with a lifeline block – i.e. a low tariff for the first x kWh of consumption per month - are an example of the second category.

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9 S. Tepic & S. Fankhauser, 'Can poor consumers afford to pay for energy and water? An affordability analysis for transition countries', EBRD Working Paper 92, May 2005.

Given budgetary constraints and the total number of potential beneficiaries in most countries, there may be little leeway to increase pensions and social benefits to compensate for higher electricity and other utility prices. This leaves lifeline tariffs as the primary option. Almost all households have electricity meters that are read at regular intervals, unlike district heat and water, so that the size of the lifeline block could differentiated to target particular categories of consumers or to reflect seasonal patterns of consumption – e.g. as is already the case in Bulgaria and Georgia.

3.8 Can liberalised markets deliver new investment in generating capacity?

During the past decade the emphasis in reforming electricity markets has been on unbundling potentially competitive activities and promoting competition in the market, especially for power generation and supply. A variety of traditional arrangements or substitutes including the role of vertically integrated utilities and the reliance on long term power purchase agreements (PPAs) are seen as inhibiting the efficient operation of power markets. However, not enough thought has been given to the way in which liberalised markets will respond when circumstances and economics require adjustment to a new combination of generation technologies.

This was apparent in several middle income developing countries - e.g. Brazil and Chile - which ran into major problems in managing the transition from generation systems dominated by hydro plants to systems that involve a much greater role for thermal, especially gas-fired, plants. In those cases the issue was that the marginal cost of power from hydro plants is much lower than from gas-fired units, so that merit order despatch will ensure that, after completion, gas-fired plants have a low operating factor so that prices during peak and, perhaps, mid-merit hours have to be very high to make investment in gas-fired plants financially viable. But, then, the incentive for storage hydro generators will be to conserve their water to run as far as possible during peak or mid-merit hours.

Developing market instruments that provide the appropriate incentives for managing water and to stimulate investment in alternative forms of generation has proved to very difficult. The solution that emerged in Brazil relied heavily upon the quasi-monopoly exercised by Petrobras, which wished to ensure markets for gas imported from Bolivia under take-or-pay contracts. In effect, Petrobras became the primary sponsor of several new gas-fired power plants through a combination of investment funding and guaranteed off-take contracts for the power generated. This was certainly not a desirable outcome from a market perspective, because this vertical integration strengthened the control exercised by Petrobras over the gas market and extended this into power generation.

The problems that may arise in CEB and SEE countries that have liberalised arrangements for power trading can be understood by considering the experience of deregulated markets in the UK (especially after the abolition of pool trading in 1997) and the US. In both countries, the average wholesale price of power has been below the long run marginal cost of generation from new plants for long periods of time. The incentive for investment in new capacity is then the prospect of earning large returns during peak periods (daily or seasonal) or when the balance between supply and demand shifts in favour of suppliers. However, experience shows that the price spikes necessary to stimulate new investment are very unpopular with industrial and residential consumers with the result that governments come under large pressure to suspend trading arrangements or cap wholesale power prices. This consumer resistance to boom or bust pricing undermines the incentive to invest in merchant generation capacity and increases the risk premium that will be demanded by potential investors.[10]

Under a regime of power trading, gas-fired generation has the advantage that the fixed costs of building a new plant are relatively low, while plants can easily be taken out of operation when variable operating costs exceed the wholesale power price – i.e. when the relationship between gas and electricity prices is unfavourable. Cautious investors will invest in new gas-fired plants only if they believe that the investment will earn an adequate return with an operating factor of 60% or even lower.

These characteristics of gas-fired power plants should not be under-estimated. They provide an important element of flexibility for power systems which may be over-reliant upon plants that were designed to operate at base-load and may be relatively inefficient when operated intermittently. However, most transition countries do not wish to become too dependent upon gas-fired generation, especially when they have limited opportunities to diversify sources of gas supply.

Many of the power plants that will be required to replace the older units currently in service as well as to cater to the projected growth in demand will be constructed as base-load units, at least for the first 20 or more years of their operating life. As demonstrated above, under reasonable economic assumptions the least cost option from a national perspective, though perhaps not from the point of view of the individual investor, would be to concentrate on either coal or nuclear plants. Purely market-driven investment decisions would be unlikely to deliver this outcome because of the asymmetric impact of risks associated with future market arrangements and contracts.

These risks should not be lightly discounted. They encapsulate genuine economic uncertainties concerning the future demand for power and the evolution of efficient technologies for power generation. Planning practices that relied upon demand, price and technology forecasts for 30 or more years ahead were the source of the rigidities and inefficiencies in the power sector that deregulation was designed to address. Hence, it is important to avoid re-establishing such practices on grounds of alleged market failure in financing or developing new power plants.

Despite this warning, there are strong grounds for concluding that the market will tend to under-invest in coal-fired or nuclear power plants relative to gas-fired power plants. The central issue is the availability of long term contracts for either power purchase or generating capacity. It would be entirely reasonable for governments to adopt a requirement that some minimum proportion of expected demand should be covered by such contracts. The exact mechanics would depend upon the design of market arrangements in each country, but key features would need to cover the following points:

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10 As an illustration of the problem, most of the UK's independent power generators effectively went bankrupt in the years following the adoption of the New Electricity Trading Arrangement (NETA) as a result of legacy contracts and the downward pressure on wholesale prices. Even in 2005, after prices had recovered from their trough, the enterprise value of the largest coal-fired generator (Drax Power) is little more than one half of the replacement cost of its capacity – even adjusted for age and efficiency - despite the fact that coal-fired generation has benefited from the increase in the wholesale price of gas relative to that of coal. The situation of the main nuclear generator (British Energy) is even worse.

- The fixed costs of the contracts should be distributed across all consumers in a transparent manner. Usually this would be administered by the transmission system operator.
- Despatch should be based on avoidable operating costs with commitments under power purchase agreements or capacity obligations settled via contracts for differences or similar arrangements.

3.9 The role of the public sector and the discount rate

The question of whether competitive markets for electricity generation with new plants funded by private investors will yield an efficient mix of generating technologies is particularly acute if it is believed that nuclear power should be a part of that mix. The central issue is that a combination of regulatory, market and technical risks means that the private cost of capital for nuclear power projects is likely to be much higher than the social cost of capital. Some of this margin may reflect real costs that have to be addressed. Even so, much of the differential may reflect the fact that countries are unable to make credible commitments to future policies – for example, concerning the disposal of nuclear waste and the decommissioning of old plants as well as future regulatory and market arrangements. Such uncertainties are a form of market failure that warrant corrective measures to ensure that economic incentives properly reflect social costs and benefits.

On the other hand, there is a strong view in many countries that decisions about nuclear power cannot be left to private investors or market forces. This is often expressed as claims that a lack of regulatory capacity will permit privately-owned plants to operate in an unsafe manner. Such assertions run counter to the strong evidence that state enterprises and power operators tend to have much a worse safety and environmental record than their private counterparts. A more realistic fear is that private operators may not have the resources to fund the proper decommissioning of old plants.

These concerns reflect a fundamental ambivalence about leaving nuclear power strictly to the private sector. It is almost certain that two matters - (a) the handling of nuclear waste, and (b) the underwriting of decommissioning liabilities - will require a high degree of public sector responsibility. On the other hand, the overall record of nuclear power plants in transition countries financed and operated by public enterprises is relatively poor in terms of operating efficiency, environmental performance and safety. This is not inevitable. There are examples of well run publicly-owned plants in both market and transition economies.

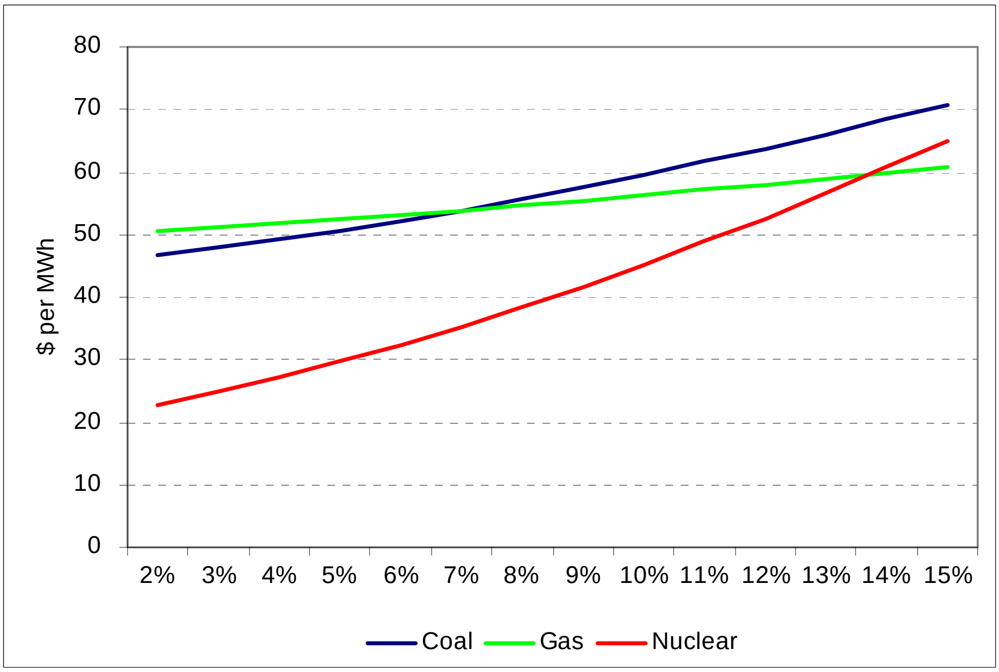
Still, it is likely that the best solution will involve some kind of partnership between state companies and private operators, who should be expected to provide some of the finance. There should be explicit arrangements to put aside – relying upon an effective escrow mechanism - the funds required to fund long term liabilities linked to the management of nuclear waste.

As indicated above, it may be necessary to put arrangements in place that provide some measure of certainty concerning power purchase prices. This is essentially a financial issue. The more assurance that investors and financing institutions have about the power price in the future, the greater can be the share of debt in the overall financial package and, thus, the lower the cost of the power that is supplied from new plants. From a purely financial point of view, the ideal pricing regime would correspond to tariffs set to guarantee a rate of return.

However, whether it is appropriate to transfer all pricing risk on to other parties and for how long is a question that cannot be answered in general terms. It is important to seek a reasonable balance between (a) providing operational flexibility and incentives to ensure an efficient mix of fuels and/or generating technologies, and (b) minimising the cost of expanding power supply. The potential costs of offering guaranteeing long term prices for new power plants that are expected to operate at base load are likely to be less in relatively large power markets. On the other hand, it may be more necessary to transfer pricing risks in markets for which a new base load plant of efficient scale represents a non-marginal increment. In such cases, there is no alternative to a detailed exercise of modelling the best way to deal with the risks and costs of adopting alternative generating technologies. In practice, that will be a comparison between the developing gas-fired units of small or moderate size and coal or nuclear plants that are more lumpy.

The potential disconnect between the public (or social) and private costs of capital as a result of regulatory and market risks becomes even more of problem when concern about emissions of greenhouse gases is taken into account. Tradeable emission permits are a standard economic instrument designed to internalise the external social costs of emitting carbon dioxide or other greenhouse gases. But, they are only part of the adjustments to incentives that may be required in order to promote an efficient outcome.

Figure 23 – Levelised costs for new power plants vs the cost of capital
(US$ per MWh including a CO2 charge of $20 per mt)



Source: Author's calculations

Economic models of the long run costs and benefits of climate change show clearly that it would make no economic sense to go far in attempting to mitigate climate change if the social discount rate is, say, more than 5%. Indeed, some economists who have examined the problem argue for hyperbolic discounting under the year-to-year discount rate becomes very low after a period of 20 or more years. Hence, if governments commit themselves to policies that can only be justified on such a basis, logic dictates that similarly low discount rates or functions should be applied to the choice of between fuels or generation technologies that have expected operating lives of 30 or 40 years.

The implication is clear. Most transition countries have agreed to take action to reduce emissions of greenhouse gases. That is reflected in the premium on carbon dioxide emissions included in the levelised costs shown in Table 3. However, the logic that underpins the use of the carbon dioxide premium necessarily means that the social cost of capital should be much lower than the value of 10% used for the main figures in the table. Figure 23 shows the levelised cost of power from new base load plants computed using the standard IEA assumptions but for different costs of capital. It shows that the cost advantage of nuclear power over other fuels would be more than $20 per MWh at a cost of capital of 5%.

To be clear: the economic models underpinning the imposition of restrictions on greenhouse gas emissions that lead to a premium on carbon dioxide assume that the social cost of capital is low. The price for trading emission permits for carbon dioxide or other greenhouse gases reflects the value of reducing emissions at a particular date in time, based upon the ***private*** cost of capital (for banking or inter-temporal transactions). However, for intertemporal efficiency it is also necessary to adjust the cost of capital used for long lived investment decisions. This will greatly strengthen the case for nuclear power, though almost certainly with a large element of public involvement. Of course, the same logic implies that the economic costs of disposing of nuclear waste will also loom much larger, so that the public sector will have to allocate more time and resources to this issue.

3.10 Promoting generation from renewable sources of energy

It is routinely assumed that renewable sources of energy are uneconomic because private discount rates are too high. For power generation in general, this is not correct for current costs and performance, even when compared to the levelised costs for electricity generated from fossil fuels with a premium on carbon dioxide emissions.[11] Thus, the primary reasons for promoting the generation of electricity from renewable sources would rest on the expectation that there are specific opportunities for economies of scale or learning as a result of expanding the use of renewable sources that do not apply to traditional forms of generation.

This assessment may be correct. The levelised costs of power generated by different renewable technologies have fallen substantially in real terms over the last three decades. But, so too has the cost of power from fossil fuels and that decline is likely to continue. In absolute terms, the reductions in unit costs are smaller but that merely reflects the much higher initial cost of electricity from renewable sources.

There is another point that is relevant to transition countries. The economies of scale or learning that may be obtained by wider deployment of renewable technologies for power generation depend, for the most part, on the scale of total investment and use at the international level. The benefits that accrue are a classic external benefit, for the countries as

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[11] This general statement should not be taken as implying that electricity generation from renewable sources is always uneconomic. That is not correct. Under appropriate conditions, power or heat plants fuelled by bio-fuels, waste or geothermal sources can be fully competitive with alternative forms of generation. Similarly, in isolated locations it can be economic to rely upon wind, wave or solar power for small scale electricity generation in preference to diesel plants or large investments in expanding transmission and distribution networks.

well as the operators concerned. To the extent that there are no specific local conditions to which the technologies must be adapted, the transition countries will benefit as much by allowing the rich market economies to take the lead in developing the technology for the economic generation of power from renewable sources.

Note, again, that this is not a suggestion that transition countries should ignore or reject the use of renewable energy. Where and when it is cost effective, projects should be implemented as speedily as possible. There are, for example, opportunities to improve or extend the utilisation of hydro resources in some transition countries. However, domestic budgetary resources are scarce in many countries, so that caution must be exercised in making commitments to projects that will only be viable with a continuing flow of public subsidy.

Equally, it would be inappropriate to transfer the cost of such subsidies to electricity or energy consumers in general – for example, via levies on the generation of power or heat from non-renewable sources. The logic is standard public economics. Any such levy or arrangement is simply equivalent to a special excise tax. A shortage of budgetary funds means that the social cost of raising taxes is high and the social benefits of competing uses of the funds should also be high. All direct or implicit subsidies for energy, including maintaining prices at levels that do not cover opportunity costs, compete with alternative uses of public funds for a variety of social and other purposes.

The range of efficient instruments for promoting the use of renewables for power generation can best be understood by comparison with similar experience in the design and implementation of environmental policies, especially for mass pollutants such as sulphur dioxide. However, before reviewing the options available it is important to clarify the purpose of adopting such policies.

In most cases it seems that greater use of renewables is seen as being a politically feasible way of reducing emissions of carbon dioxide. If that is correct, then policies that focus on renewables will inevitably be less – perhaps much less - efficient than well-designed policies that target emissions of greenhouse gas directly. Since EU member countries are covered by the new CO2 emission trading scheme, it might be better to concentrate on extending similar arrangements to other transition countries rather than introducing specific policies targeted at renewables whose impact will probably be much less significant. For example, the Australian government appears to have decided that it would be better to replace schemes designed to promote the development of renewable sources of energy by a more coherent set of incentives designed to reduce emissions of greenhouse gases.[12]

To the extent that the promotion of renewables is a policy goal on it own, there are three broad types of policies that can and have been adopted:

- Standards – the classic command and control approach of environmental policy. Typically, these impose an obligation on electricity producers that at least x% of all delivered power must come from renewable sources (either directly or via contracted generation). As in the environmental sphere, the arbitrary imposition of targets can be very costly, so policies based upon simple standards have tended to evolve in the direction of tradeable permit schemes so as to provide incentives for targets to be met in the least costly manner.

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12 I. MacGill, H. Outhred & K. Nolles, 'Some design lessons from market-based greenhouse gas regulation in the restructured Australian electricity industry', *Energy Policy*, Vol 34, 2006, pp. 11-25.

- Tradeable permits under which electricity producers are required acquire permits - renewable obligation certificates – equivalent to x% of the power that they generate from non-renewable sources. The resulting trading arrangements are directly analogous to emission trading schemes for sulphur dioxide or NOx in the US.
- Levies (taxes) on the production of energy from non-renewable sources, which may be offset against the extra cost of purchasing power from renewable sources. Though the arrangement was not structured in this way, the obligations imposed upon US electricity producers under the PURPA legislation were in practice almost equivalent to such a policy. In principle, a tax on electricity generated from non-renewable source is a transparent expression of the premium that a government attaches to diversification away from fossil fuels. But, while transparency may be attractive from an economic and market perspective, it is much less so to politicians. The cost of PURPA obligations was far from transparent and, indeed, the policy proved to be unsustainable as the purchase costs that it imposed on utilities became apparent.

Of the policies that have been adopted, the least costly is the enforcement of renewables obligations through tradeable certificates - ROCs. This is a market driven approach that provides relatively transparent incentives for increasing production of electricity or heat from renewable sources. However, the difficulties of implementing such a scheme in an effective manner should not be under-estimated. The review of the Australian Mandatory Renewable Energy Target (MRET) program cited above highlighted a number of problems, while other lessons can be drawn from experience with similar trading schemes for both renewable energy and environmental goals. The key issues include:

- It is usual for ROCs to be linked to electricity output. This is understandable if the goal is to displace electricity generated from fossil fuels, though always subject to the proviso that policies directed at CO2 emissions would be more appropriate. However, if the goal is to promote the installation of generation capacity using renewable sources, a better instrument would be ROCs linked to (available) capacity rather than output. Since renewable plants tend to have lower levels of availability, capacity incentives will be more effective than output incentives. In most cases, the marginal costs of operating renewable plants are low so that it is efficient to despatch them whenever they are available.
- The life of most investments in power or heat generation is relatively long, so that any incentive for new investment in renewable energy must be either guaranteed to operate for an extended period of time or very substantial if provided at the beginning or for a short period. As a result, some countries have provided incentives for initial capital investment, often through favourable tax treatment. The disadvantage is that once new capacity is installed, there may less incentive to maintain or increase operating availability. On the other hand, it may be difficult to make a credible commitment to the continuation and value of incentives linked to either output or capacity over many years. The record of policy-making in this area is one of regular changes in priorities and approach resulting in the abolition or radical revision of incentive schemes. If, for reasons of efficiency, it is desirable to move away from capital subsidies towards either capacity or output incentives, then there must be guarantees that the position of existing beneficiaries is grandfathered if or when arrangements are changed. Unfortunately, the difficulty is that some schemes have turned out to be absurdly inefficient, so that abolition or radical change was essential to re-establish control over costs.

- The focus of many schemes has been to promote new production of electricity from renewable sources. For example, the Australian MRET program provided credits only for production from plants that entered service from January 1997 onwards. Plants operating at that date had an annual baseline established and can earn credits if their output exceeds that baseline. There are clear problems in establishing the baseline for renewable plants that are subject to significant annual variations due to weather or other factors, such as hydro plants. However, government usually wish to avoid giving windfall gains to existing plants. To limit the length and cost of any commitment to new plants, it is desirable to include sunset provisions in any scheme. The Australian program is due to expire in 2020, which is bound to alter the incentives for new producers after 2010 unless the scheme is revised or extended well before that date.[13] An alternative approach is to specify that new sources will receive credits for a limited period of, say, 10 or 15 years – sufficient to recover the extra costs of using renewable energy on reasonable terms but without giving an indefinite commitment into the future.
- A related problem in the UK has been the treatment of output from nuclear plants and, even more, from nuclear plants in France. This highlights the difficulty of implementing national trading schemes when electricity can be imported or exported, since the EU's internal market and energy policies prohibit discrimination by the location of production within the EU.
- Most schemes with tradeable ROCs include a penalty for any shortfall between the number of ROCs acquired by a generator or supplier and its target. In effect, this penalty sets a cap on the value of ROCs. Its level must be considered very carefully since it ought to reflect the maximum social benefit that can be placed on marginal production of electricity from renewable sources. Under usual economic assumption, the size of the penalty should fall as the targets are increased – reflecting a declining marginal benefit curve. On the other hand, the marginal cost curve is likely to be rising, so advocates of more renewable energy will argue that the penalty should rise over time. This illustrates the difficulty of reconciling an economic approach to promoting renewable energy with the position of those who believe that expanding the use of renewable energy should be a goal in its own right.
- Finally, the introduction of tradeable permits is a complex operation that relies upon a sophisticated infrastructure of data collection, monitoring and trading. The classic example is the sulphur emissions trading scheme in the US. An important reason for its success was the fact that the EPA and utilities had developed arrangement for collecting and monitoring emissions of SO2 over a period of more than a decade under previous legislation. Further, the development of trading in emission permits was a relatively step for the large commodity exchanges in the US. Little of this infrastructure exists or works in comparable manner in many transition countries.

Experience shows that it is very difficult to design programs that promote the use of renewable energy in an efficient manner. Too many arrangements have been introduced in haste without adequate consideration of costs and interactions with other policy objectives. The PURPA amendment was a classic example of a legislative initiative whose

[13] But, equally, program reviews create uncertainty and tend to slow up both futures trading and investment decisions. In Australia this has happened during a program review in 2003 and as a result of a reappraisal of policies focusing on emissions of greenhouse gases.

consequences were not properly thought out. However, it is also true that the consequences of the PURPA provisions were greatly worsened by the way in which state regulatory authorities implemented it, thereby stimulating contractual commitments and investment in uneconomic generating capacity that became stranded assets as a result of technical and market changes.

Few transition countries can offer the clarity of policy objectives and stability of market arrangements that are required to develop sophisticated and efficient mechanisms to promote the use of renewable energy. Hence, in the immediate future it may be best for the EBRD to promote incentives designed as a form of output-based aid. Assuming that targets for the production of electricity from renewable sources have been set, one tender or a series of tenders would invite proposals with support provided in the form of payments per available MW or per MWh of output over a period of 5-8 years. The winners would be the bidders requiring the lowest level of support subject to a cap on either the total amount of financial support or on the total volume of output receiving assistance. The cost of the program could be met either from budgetary resources or, more likely, from a levy on all sales of electricity.

3.11 Regulatory issues

Various aspects of progress in transition countries towards the development and implementation of effective regulatory arrangements for the electricity sector were reviewed in the Transition Report 2004. Progress in establishing credible regulatory regimes has often been slow and there have been notably episodes in which governments have undermined regulatory decisions or failed to honour contractual commitments. The weakness of regulatory systems is important because the alternative is reliance upon the independence and effectiveness of judicial scrutiny of administrative decisions, which is weak or absent in many transition countries.

Without going into the details of regulatory arrangements, all too often there is a mantra of the importance of regulation without a clear identification of what is at stake. The energy sector is highly capital-intensive. Regulatory effectiveness matters because it has a direct – and often large – impact on the cost of capital for existing and new investors. In countries such as Australia, Hong Kong, Japan, the US and the UK the real cost of capital for regulated businesses such as transmission and distribution typically falls in the range 4 – 6% post-tax, reflecting a cost of equity of 6 – 8%. In contrast, investors in transition countries are likely to apply much higher costs of capital, even for investments in transmission and distribution that carry little market risk and can support relatively high levels of gearing.

Conventional assessments of the cost of capital rely heavily upon the CAPM model. For transition countries such estimates take account of country risks as reflected in long term bond rates – either in local currency terms or in Euros. However, it is much more difficult to assess sector risks because local stock markets are typically small and there are few or no reliable benchmarks for calculating the portfolio risks attached to utility investments. The less confidence that there is in the regulatory framework, the higher will be the premium attached to the possibility that investors may lose a significant part of their return as a result of decisions which reduce the return earned on sunk investments. Investment treaties and other forms of legislative protection may provide some assurance against the possibility of partial or complete expropriation, but they are little assistance against the progressive erosion of returns due to the re-interpretation of contracts and regulatory rules.

Another factor is that politicians and bureaucrats are usually ignorant of basic financial economics. Since the cost of debt is low, they argue that the cost of capital can be reduced by favouring reliance upon debt finance. Setting aside tax considerations, that belief is, of course, mistaken because financial structures shift the allocation of risks but not their overall magnitude, but the belief may be very hard to alter. As a consequence, government officials may be outraged at the high rates of return expected and, perhaps, earned by equity investors in highly leveraged structures, especially in retrospect.

There is no simple remedy to this problem. Confidence in regulatory regimes can only be built slowly and depends upon the competence of regulatory agencies as well as the rules that they are required to operate. However, an overriding concern must be the stability and consistency of market rules. The difficulty in the electricity sector is that too often new markets arrangements are introduced with insufficient analysis of their consequences or with too much emphasis on short term benefits.

This mistake is remarkably common in rich market economies as well as in transition countries. The deregulation of California's electricity market was a disaster, but not an unexpected one. A series of economic studies warned of the weaknesses of the system that was adopted and were duly borne out - not that observations that politicians and officials had been amply warned were well received after the event. Similarly, the introduction of NETA in the UK had the effect of bankrupting much of the independent generation sector in the UK, again something that could have been foreseen. For the short term benefit of reducing power prices the regulator, encouraged by the government, has significantly increased the future cost of capital for all forms of generation, including the cost of meeting the government's own targets for reducing greenhouse gas emissions.

The lesson is that regulatory change is enormously difficult in the electricity sector because of its long planning horizons and asset lives. The characteristics of the industry means that the cost of capital may be a matter of over-riding importance. There is an ever-present tension between measures designed to ensure that existing capital and resources are efficiently used and those required provide efficient incentives for the development of new generating capacity and network infrastructure. Until recently the surplus of generating capacity in transition countries has meant that efficiency gains in the use of that capacity were a matter of primary concern. In the future, however, it may be more important to ensure that regulatory actions focus on the need to bring down the cost of capital for investment in the new capacity that will be required.

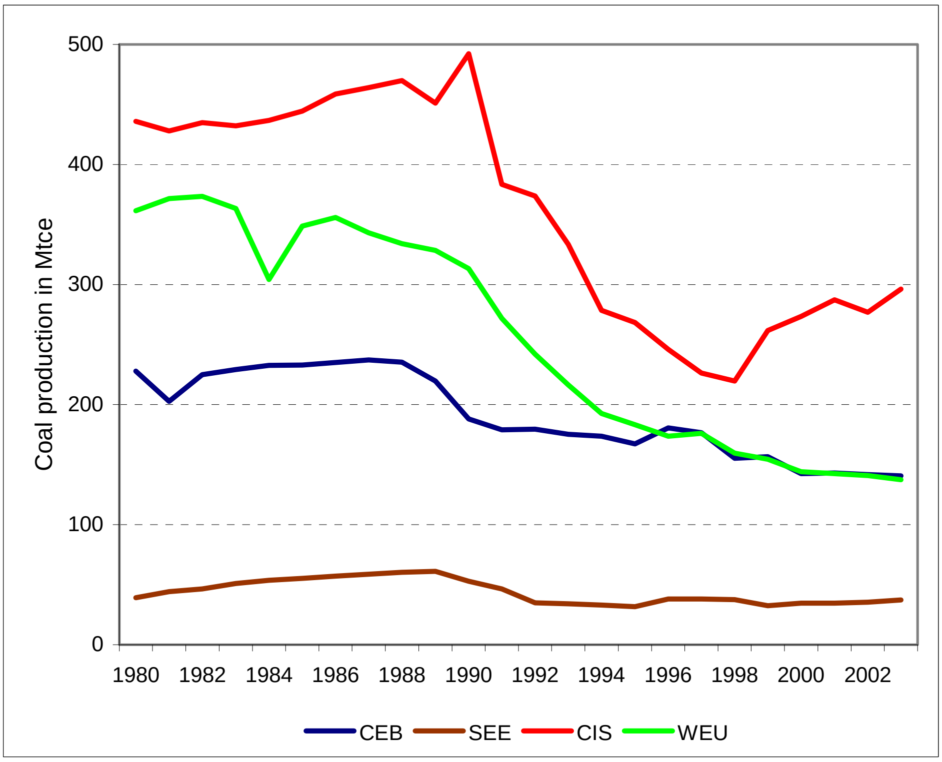
4 The coal sector

The future prospects for the coal sector in transition countries flow directly from the analysis of the choice between coal, gas and nuclear power in the expansion or replacement of generating plants. The demand for coal is dominated by the use of steam coal in power plants. If transition countries participate fully in the EU's trading scheme for CO2 emissions, then coal will have no long term future as a fuel for power generation outside Siberia and, perhaps, Kazakhstan. The key issue will be how to manage the unavoidable contraction and closure of the industry in the remainder of the region.

The prospects for coal in the metallurgical industry are little different. Producers of coking coal have enjoyed a temporary but very profitable upswing over the past two years because of the boom in the steel industry underpinned by the rapid growth in demand for steel in China. However, the implementation of emission trading for CO2 in Europe without comparable penalties on CO2 emissions in countries such as China, India and Brazil must lead to a contraction of steel production within the region, displaced by imports of either steel or steel-intensive products from the rest of the world. Transport costs will provide temporary protection in some countries, but the underlying economics point in one direction only.

This assessment is stark but it is important to inject an element of economic realism into policies that have tended to rely upon wishful thinking rather than a proper appraisal of the economics of supply and demand. Further, it would be misleading to focus solely on policies for CO2 emission as the reason for the future decline of the coal sector in the region. The problems faced by the coal sector are similar to those which led to the more or less rapid contraction of coal production in countries such as France, Germany, Spain and the UK from 1980 to 2000.

Figure 24 – Coal production by country group, 1980-2003
(million tonnes of coal equivalent)



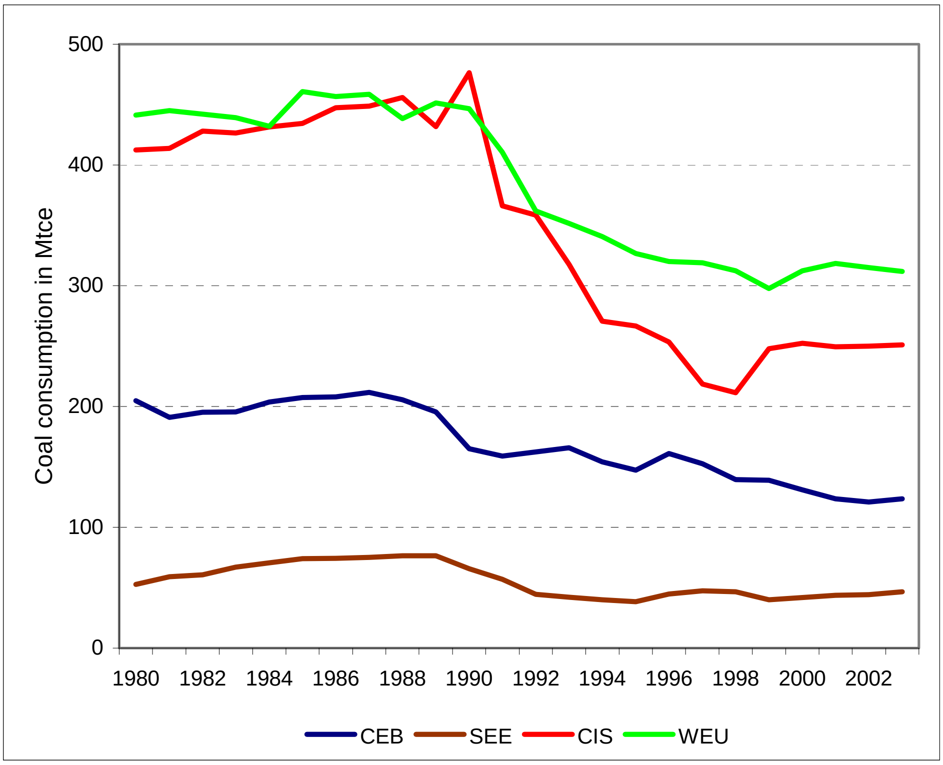
Source: See Appendix 1

In a world market that is dominated by a combination of low cost production from surface mines and very high quality coal from underground mines, the majority of the European coal sector is no longer economic. The cost of transporting coal from low cost sources has steadily fallen, so that the locational protection for underground mines in Europe has declined *pari passu*. The surface coal resources in Siberia and Kazakhstan are the exception to this analysis. If these were located in the United States, then the coal sector would be thinking in terms of a new Powder River Basin. Unfortunately for the industry, the reserves are located 3,000-5,000 km from major sources of demand and in the country that is - and is likely to remain for the next century - the dominant gas producer in the world.

To provide the context Figure 24 & Figure 25 show the evolution of coal production and consumption since 1980 by country group. They illustrate the steady decline in production in Western Europe from 370 million tonnes of coal equivalent (Mtce) to less than 140 Mtce.

There were periods of (sometimes sharply) falling production in each group of transition countries starting between 1988 and 1990, but production has either stabilised or grown since about 1999. The recovery in production has been particularly marked in the CIS countries with an increase from 220 Mtce in 1998 to 297 Mtce in 2003.

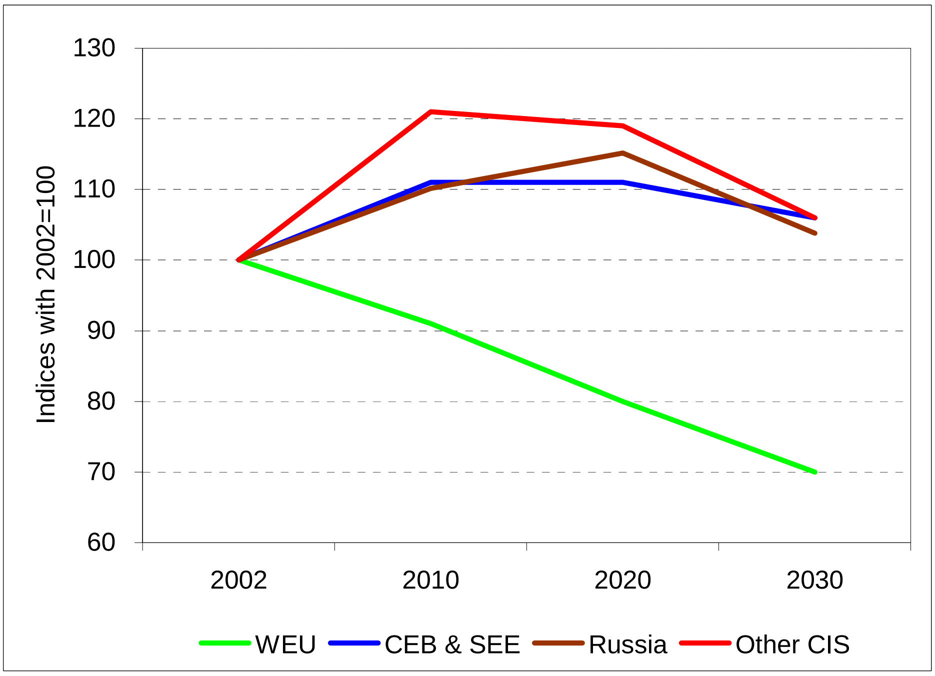
Figure 25 – Coal consumption by country group, 1980-2003
(million tonnes of coal equivalent)



Source: See Appendix 1

The decline in West European production has not been accompanied by an equivalent decline in consumption, so that net imports of coal have risen from 17% of consumption in early 1980s to 55% of consumption 20 years later. The SEE countries are also net importers of coal, but their consumption has fallen roughly in line with production, so that net imports remain a little over 20% of consumption. Similarly, production and consumption have both declined in the CEB countries while net exports of coal, largely from Poland, have fluctuated around an average of 14% of total production. The dramatic fall in CIS coal production from 1990 to 1998 was matched by a fall of about 56% in coal consumption. Since then coal consumption has recovered somewhat, but the continuing increase in production is now driven by net exports, consisting primarily of steam coal from Russia, which have increased from 8 Mtce in 1998 to 45 Mtce in 2003.

Figure 26 – Projections of coal consumption for power & heat generation



Source: See Appendix 1

The power & heat sector accounts for 75-80% of coal consumption in the transition countries, so the prospects for demand for power & heat generation are crucial in assessing the future demand for coal. Figure 26 shows a composite set of projections based on combining figures from the IEA and EIA-DOE forecasts. They suggest that use of coal in power & heat generation will fall steadily in Western Europe at an average of 1.3% p.a. over the next three decades. Since coal consumption in Western Europe has declined an average rate of 2.2% p.a. for the last 15 years, the projection seems rather conservative in view of the penalty on the use of coal-fired generation implied by the new CO2 emissions trading scheme.

The projections also imply that coal consumption for power & heat generation in transition countries will rise over the next decade and start to decline after 2020. While these forecasts are consistent with recent experience, they do not seem to take sufficient account of the impact the EU's emissions trading arrangements. The CEB & SEE countries that are members of the EU will have strong economic incentives to reduce their consumption of coal, presumably by investing in gas-fired power plants and operating their nuclear plants as fully as possible. It seems rather unlikely that there will be any significant new investment in coal-fired power or heat plants, though for social reasons the government of Poland may encourage generators to burn more coal in existing plants and to extend their life where possible.

4.1 Managing the decline of coal in Central and South-East Europe

The aggregate amount of coal consumed in the CEB countries is much larger than that consumed in the SEE countries, so the future prospects for coal consumption in Eastern Europe as a whole will primarily be driven by trends in Poland and the Czech Republic. While the recent period of stable levels of consumption may continue for some years, the economic fundamentals point to a substantial shift towards either gas or nuclear power throughout Eastern Europe. Hence, I conclude that the decline in coal consumption will start earlier and proceed much more rapidly than the IEA/EIA-DOE forecasts suggest.

This decline in coal consumption will fall directly on domestic production. Opportunities to export coal from Eastern Europe are limited. Steam coal produced in Poland's underground mines is not competitive in the world market outside Europe, while the decline in coal consumption in Western Europe is likely to be reflected in lower imports as a whole. Hence, Poland will not be able to shelter its underground mines from the decline in domestic demand. Surface mines throughout Eastern Europe produce brown coal or lignite of low calorific value and, typically, high sulphur content. There is usually no market for these fuels outside the domestic market and even that is increasingly restricted by environmental requirements. Poland exports small quantities of coking coal that may continue to find markets, but this is a minor consideration set against the poor prospects for country's mining industry.

It is clear that the major adjustment will have to take place in Poland. The physical volume of Polish coal production has declined slowly from 266 million tonnes in 1988 to 161 million in 2004, but other countries including Germany, the Czech Republic and Ukraine have made faster progress in reducing output and employment to reflect the new circumstances of the coal industry. The political power of coal miners is formidable, as demonstrated by the recent legislation allowing miners to retire even earlier on a full pension. The resistance to change in the underground mining sectors has been reflected in the very slow implementation of programmes to merge and close mines.

The gradualist approach to reducing output and operating mines has somewhat mitigated the social impact of the contraction of coal mining by comparison with what has happened in Ukraine and Russia. Unfortunately, it has imposed a large fiscal burden on the state and has sheltered the mining sector from the reality of longer term trends. There are a number of lessons from the decline of mining industries elsewhere in Europe that must be taken into account in designing and implementing future policies.

- ***Lignite mining***. The reduction in output has occurred primarily in the hard coal segment of the industry, while output of sub-bituminous coals and lignite has fallen by much less. This may be ironic, since the hard coal is much more marketable, but the production of lignite has been protected by the decision to rehabilitate large lignite-fired power plants in the mid-1990s. The future of lignite mines seems relatively stable for the next 10-15 years but after that there will be major decisions about the replacement of generating capacity at lignite-fired power plants (including Belchatow, Turow and Patnow) that account for about 10,000 MW of thermal capacity.
- If the impact of CO2 emission charges means that it is uneconomic to replace these plants, then the problem of how to replace them must be addressed within the next 5 years. This is linked to the issue of compliance with the LCP Directive. Under the various provisions that concern "existing" plants the lignite plants should be able to comply with the Directive's requirements up to the end of 2015. However, the combination of stricter standards for SO2 and NOx emissions plus the gradual lowering of national limits on these emissions will require substantial further investments to modify combustion equipment and install pollution controls at these plants before 2016.
- Labour productivity in Poland's lignite mines is far below productivity levels for surface mining in other coal industries. The most recent figures show an average productivity of 3,100 tonnes per worker per year. In contrast, the average

productivity at surface mines in the Eastern United States (which produce much higher quality coal) is over 10,000 tonnes per worker per year and in the Powder River Basin it is over 65,000 tonnes per worker per year. Since the average calorific value of the lignite is about 9.3 GJ per tonne, this level of productivity translates to a labour cost of $0.52 per GJ with an average cost per worker of $15,000 per year. At a minimum it will be necessary to increase labour productivity by 100-200% within 10 years if the lignite mines plus their associated power plants are to have any chance of remaining competitive after 2015. This will imply a loss of 5-10,000 jobs plus substantial investment in new equipment to extract and transport lignite.

- ***Hard coal.*** In 2004 the Polish government adopted a program to continue the restructuring of the hard coal sector up to 2010.[14] It is based upon a continuation of the relatively slow adjustment that has characterised reform of the Polish mining industry over the past 15 years. Total demand for hard coal is projected to decline by about 3% per year, driven by a progressive reduction in domestic demand combined with a modest reduction in exports and a continuation of existing restrictions on imports. It is envisaged that production capacity will be reduced from 102.6 million tonnes per year (Mtpy) in 2003 to 88.6 Mtpy in 2006, though this includes 3.7 million tonnes of new capacity as result of investments by mining operations that are not part of the three main mining companies. In fact, almost all of the capacity reduction will be at the largest mining company – Kompania Weglowa SA – which will go from 58.0 Mtpy to 42.4 Mtpy.

- The capacity reduction will be accompanied by a reduction in employment in hard coal mining of about 25,000 down to 111,000 at the end of 2006. If mines were operated at full capacity, this would imply an increase in labour productivity from 754 tonnes per worker per year in 2003 to 800 tonnes per worker per year in 2007. Again, these levels of productivity are far below what is achieved in underground mines in the US and other countries. In the Appalachian mining basin, the average productivity in 2000 was about 6,700 tonnes per worker per year. In practice, the difference will be larger because the capacity will not be fully utilised while the reduction in employment is likely to proceed more slowly than the programme assumes.

- Labour productivity in Poland's underground mines is a little higher than productivity in Russian underground mines in the Kuzbass. However, wages and associated social costs are much lower in the Kuzbass and much of the coal produced in these mines is high quality coking coal which commands a premium price. The restructuring program relies upon a continuation of a significant level of exports – about 17.5 Mtpy – to slow the decline in output and employment. However, it is unlikely that exports of steam coal to Baltic Sea or North Sea destinations will be economic in competition with exports from Russia, South Africa or Colombia.

- In the years up to 2003 it has consistently been the case that Polish mines can produce coal at prices that are less than import parity (delivered to power plants in Northern or Central Poland) but greater than export parity (fob Gdansk). Some exports are despatched by rail to Germany and other countries in Central Europe. Poland's location provides natural protection for such exports. Hence, even if the

[14] Ministry of Economy, Labour and Social Policy, 'Restructuring of the hard coal mining sector during the period 2004-06 and Strategy for the period 2007-10', document adopted by the Council of Ministers, Warsaw, 27 April 2004.

assumed rate of decline in the Polish market has not under-estimated, the assumed level of exports is only reasonable if the government is permitted to continue with the subsidies that underpin such exports. In view of the pressure on State Aid in other countries and sectors this seems to be open to challenge.

- The programme provides for state subsidies to the industry amounting to PLN 9.6 billion - just less than $ 3 billion – over the period 2004-10. This figure substantially understates the amount of support received by the industry. It is not required to pay any royalties for mineral extraction and surface access rights on its coal output. In the UK such royalties can easily amount to $4 per tonne, while in Australia and the US they are often calculated as 5-7% of the ex-pit price of coal. A modest royalty of $2 per tonne of coal output would represent lost revenue to the government of more than $1.2 billion for the period. On top of that there are a variety of social, environmental and other programmes that effectively transfer costs from the mining industry to the national budget. The true level of state support to the hard coal industry will probably exceed $ 5 billion over 7 years.
- During the period 2004-10 it is envisaged that the industry will incur capital expenditures of PLN 9 billion. State subsidy and capital expenditure are not directly linked, since a significant proportion of the state subsidy takes the form of non-cash transfer via writing off or postponing past debts. Notionally, the capital expenditure will be financed out of cash flow and equity, but the financial reality is that the state is funding a large program of investment in hard coal mining equivalent to $27,000 per employee in 2007. This is a basic mistake because it repeats the error that has been made in Germany, the UK and Spain of funding large amounts of investment in an industry that can and will not use the investment productively.
- All mining industries have to incur regular capital expenditures to replenish reserves and replace equipment that is either worn out or abandoned. A simple but critical test of the viability of a firm or industry is whether it can finance this expenditure out of regular cash flow, since reliance upon borrowed funds is not sustainable in the long term. The revenue and expenditures statements for the three main companies presented in the Restructuring document show that the industry is not able to do this unless market prices for coal are close to the levels that have prevailed in 2004-05. In particular, export sales are highly unprofitable and domestic sales are only profitable at prices above a level of about $1.60 per GJ.

Overall, different studies of the Polish hard coal industry over the last decade have shown that there is market demand to sustain a viable group of mines but at a substantially lower level of production and employment. The scale of the contraction required will depend upon market circumstances, since the economics of marginal production is highly sensitive to the future level of coal prices. For understandable political reasons the Polish government has been extremely reluctant to acknowledge the scale of the adjustment that is required. Instead, like many other countries, it has sought to slow the rate of decline by providing huge sums of state support for a combination of redundancies, retraining and new capital investment. Just as elsewhere, its policies have failed to meet their stated objectives – doing little to mitigate the social and political costs of change while failing to help the viable core emerge like a butterfly from the pupae of the existing industry.

While it is difficult for outsiders to give advice on such loaded issues, there comes a time when it is essential to be honest and assert what experience in Western Europe has clearly demonstrated. The Polish mining industry will inevitably contract by much more than current plans admit. The use of state fund to underpin a large program of capital expenditure is simply a waste of money. These funds could be better used to finance a much larger program of redeployment of workers out of the industry and the promotion of alternative sources of employment. In one respect Poland is unusual and fortunate. As compared with many other parts of the country, Silesia is neither poor nor does it have a high level of unemployment. The region can easily absorb the loss of 50-80,000 mining jobs, while there is no justification for continuing to pour subsidies into a region with good economic prospects.

The situation of the coal mining sector in most other countries in East and South-East Europe is very similar to that in Poland. Mines producing lignite and brown coal, which are oriented to supplying local power plants and account for most coal production other than in Poland, have reasonable prospects for as long as the associated power plants are not forced to make large investments in environmental improvements unless such investments are funded as a matter of social policy to preserve mining operations. However, as they reach the end of their operational life it is most unlikely that it will be economic to invest in new generation capacity.

Bulgaria provides an example. The country produces about 26 million tonnes a year, almost entirely consisting of low quality lignite from the Maritsa basin. The output is used in a complex of power plants close to the mines, which are currently the second largest source of SO_2 emissions in the EU plus accession countries. There is a project – partly financed by the EIB - to fit emission controls on the various units at the power complex, which would involve rehabilitation of the combustion and generating equipment. The project makes limited economic sense and has proceeded very slowly. But, equally, the government is reluctant to contemplate drastic contraction or closure of the mines that would follow re-powering the power units with gas, which would almost certainly be the better option in the medium and long term. A further complication is a very strong local lobby for the construction of a new nuclear power plant which would provide base load power in place of a rehabilitated Maritsa complex. Eventually, it seems likely that some or most of the Maritsa complex will be upgraded but after that there will be no further investment in lignite-fired generation, so that the mining industry will gradually decline and then close.

Subject to local variations, a similar story can be told for several other countries in East and South-East Europe. Hard coal production is uneconomic, while lignite and brown coal production continues to supply nearby power & heat plants. This market will gradually decline as such plants are replaced by gas or nuclear power. Stricter environmental regulations or the ability to sell CO_2 emission permits under an EU-wide emissions trading system will simply accelerate this process.

Among the CIS countries it is Ukraine that is closest to East and South-East Europe in terms of the prospects for its coal industry. It has experienced a more rapid decline in production than Poland, largely because the government has not had the administrative or financial resources to underpin a more gradual process of adjustment. Production fell from 165 million tonnes in 1990 to 76 million tonnes in 1996. Since then production has been fluctuated in a range from 77 to 85 million tonnes per year. The recent trend has been downwards, but the high level of coal prices in 2004 appears to have underpinned a small increase in output.

Ukraine is unusual in that nearly 50% of its current output consists of coking coal. There is a large domestic market for coking coal in its steel industry – sufficient to require nearly 3 million tonnes of imported coking coal. This means that mines producing coking coal can operate at import parity prices, which are very attractive in current market conditions. Mines producing steam coal face much poorer economic prospects because coal used in power & heat plants has to compete with Ukraine's nuclear plants as well as Russian gas, whose price is significantly lower than that of gas in Europe – when/if Ukraine pays for it!

Unfortunately, mining conditions in Ukraine's underground mines are terrible. The safety record of the country's mining industry is among the worst in the world with an average of 250 deaths annually for the last 15 years. Geological conditions are steadily deteriorating as mines have to go deeper in search of coal seams. As a consequence, labour productivity in the mining sector is far below that at underground mines in Poland or Russia – about 340 tonnes per worker per year. The poor mining conditions inhibit the use of modern mining equipment and the equipment that is used must often be abandoned when seams collapse or are exhausted.

Despite the local demand from the steel sector for coking coal and existing thermal power plants for steam coal, Ukraine's coal industry would come close to closing down completely if it were in Western Europe – or even Poland. This poses an enormous dilemma for the government. Coal is Ukraine's only significant energy resource, other than nuclear power. The industry employs about 450,000 workers (down from 650,000 workers in 1995), although the average wage is low at UAH 1400 ($280) per month. The government's public statements suggest that it is planning to increase production to 91 million tonnes by 2010 and to 110 million tonnes per year in the longer run by large investments in new production capacity. These plans include about $ 900 million of budgetary support in 2006 for a restructuring program costing $ 1.5 billion. At the same time, the government has announced a target of privatising the two-thirds of the sector that remains in state ownership within 6-12 months.

These plans can be little more than good intentions. The private sector – through private ownership, leases, joint ventures and other arrangements – has already selected the enterprises that were thought to be profitable or could easily be turned round. The remaining enterprises will require drastic consolidation as well as reductions in output and employment before they are likely to attract private interest. Equally, public investment in mining companies that have not been restructured will simply be a waste of resources.

Even more than in Poland, it is most important to focus the government's limited resources and administrative capacity on mitigating the costs of reducing non-viable capacity and employment in the industry. Analysis carried out in 1995 suggested that approximately 60% of production at that time – corresponding to 40 million tonnes per year of output – had a unit cost that was less than the import parity prices of coking and steam coal. Total employment at mines that could break even at import parity prices was about 250,000. Since that time, the real costs of mining in Ukraine have increased relative to international coal prices, at least prior to 2004. Hence, it is likely that a similar analysis today would show that the sustainable level of employment in the industry is well below 200,000. Comparisons with Poland suggest a sustainable level that is less than 100,000 after allowing for differences in real incomes and wages.

There are still more than 170 mining enterprises in Ukraine, far more than in Poland or Russia which produce two to three times the volume of coal mined in Ukraine. The degree of concentration of hard coal mining in Poland is perhaps excessive, but it is difficult to justify the continued existence of more than 20-30 mining enterprises in Ukraine.

Overall, Ukraine has made very limited progress in restructuring its coal industry. As in Poland, the regional and political dimensions of structural change exacerbate a normal reluctance to implement painful policies. But it is time to recognise that the industry is in a deplorable state that will only be altered by radical surgery. Pouring more state funds into operating and investment subsidies simply worsens the situation by encouraging mine management and workers to compete for public assistance rather than improving their operational performance. Ten years of half-hearted and incompetent reform while their neighbours have moved on mean that the industry has worse prospects today than in the mid-1990s. Now, there is little hope of preserving a viable industry with significantly more than half its current level of output and perhaps one-quarter of current employment. But failure to act in the near future will mean, equally, that the long term prospects will continue to deteriorate.

4.2 Coal in Russia and Kazakhstan

In many respects Russia provides an example of how not to manage the adjustment of a large mining industry. Initially, it provided large recurrent subsidies that simply disappeared before they reached the intended beneficiaries. Then, it embarked on a disorganised programme of mine closures followed by mass redundancies without much social support or (except very belatedly) the allocation of funds for economic regeneration. The consequence was a dramatic decline in production accompanied by an even larger fall in the number of people working in the industry. Yet what has emerged from this mess is a coal industry that has the capacity to operate profitably at prices driven by market factors and that is gradually developing a substantial export business. Finally, all of this has been achieved against a background of an energy sector that is hugely distorted by the reluctance of the Russian government to permit Gazprom to charge economic prices for gas.

Prospects for the coal industry in Russia are discussed in detail in Appendix 4. This section covers Kazahkstan as well as Russia because coal mining in Kazakhstan is inextricably tied to the coal sector in Russia. In essence, Kazakhstan's coal industry consists of two coal basins/mines.

- Ekibastuz - one of the largest mines in the world producing massive quantities of sub-bituminous coal of poor quality at extremely low cost. Much of this coal used to be exported to power plants in the Urals that were designed around the specific qualities of Ekibastuz coal. Now, more of it is used for domestic power generation.
- Karaganda – this basin produces good quality steam and coking coal that is either exported for metallurgical use in Russia's steel industry or consumed in domestic power plants and blast furnaces. Again, mining costs are relatively low.

As in Russia, coal production fell sharply after 1991 because higher charges for rail freight and lower demand from Russian utilities reduced exports from about 45 million tonnes in 1992 to only 14 million tonnes in 1999. The main impact was on production at Ekibastuz. More recently, exports and domestic consumption have been growing in a somewhat erratic manner but with an average growth of nearly 4% p.a. over the last 4 years. Thus, the factors that have underpinned the recovery in Russia coal production – growth in domestic demand for power & heat generation, buoyant prospects for the metallurgical industry, and exports – apply equally to Kazkhstan.

Another common feature of recent developments in the coal sector in Russia and Kazakhstan has been the involvement of investors with upstream interests in the power and metallurgical sectors. The prospect of liberalisation of the Russian power market has prompted various industrial-financial groups to acquire majority holdings in coal companies that are important suppliers to local utilities in the Urals and Siberia with the intention of acquiring power plants, distribution companies and even railway freight operations. There are concerns that this could lead to the emergence of vertically-integrated companies that are able to exercise substantial monopoly power in local electricity markets. This may be a realistic concern in East Siberia and the Far East because of the large distances between cities and mining basins as well as the limited options for transporting fuel. On the other hand, the extension of gas pipelines in these regions will tend to limit any monopoly power from the ownership of mining companies.

At current domestic prices for gas and coal only the most efficient coal mines are capable of competing with gas in the generation market and even then on the basis of supplying mine-mouth power plants or ones located at some distance from the gas transmission system. Detailed analysis of competition between gas and coal for new generation suggests that coal would have to be priced at no more than $10 per tce or about $0.40 per GJ to compete with gas priced at $80 per mcm on an export-parity basis. For a rehabilitated coal plant the breakeven price of coal would be about $25 per tce or $1 per GJ. In fact, gas is typically sold to power plants at prices in the range $40-60 per mcm – provided that Gazprom will agree to a supply contract. This price reflects the discrimination between the domestic and the international market implied by the regulated prices that Gazprom is allowed to charge. On the other hand, Gazprom has been increasingly reluctant to sign supply contracts for new power plants on the grounds that its marginal cost of gas – especially from the Yamal Peninsula – is sharply increasing so that it has no interest in increasing its supply to the domestic market at regulated prices.

In 2000 two mining companies in the Kansk-Achinsk and East Siberian coals were capable of supplying steam coal at less than $10 per tce. Allowing for potential savings, a total of 9 mining companies in Kuzbass, Kansk-Achinsk and East Siberia might be able to supply steam coal at prices that could justify investment in coal-fired generation – but only on the assumption that the coal was not to be transported any substantial distance. This implies that coal is competitive with gas as a fuel for new power generation only in Siberia. It would not be economic to rehabilitate coal-fired plants in Russia west of the Urals, while it would be economic to rehabilitate coal-fired plants in the Urals but not to build new plants burning coal.

These results seem clear enough. Steam coal has a long term future in Siberia, but it cannot compete with gas in the rest of the country. The market for new power generation is distorted by regulated domestic prices for gas, which discourage Gazprom from entering into long term supply contracts, but it is common ground that these price distortions must be eliminated over time. Yet, the actual market for coal seems to reflect a rather different view of the industry's prospects. Not only has there been a substantial increase in production, but more importantly it seems that private investors are willing to commit substantial resources to opening up new mines or expanding production at existing mines.

With a few exceptions of companies that are hopelessly uneconomic and are kept open for social reasons, the mining industry has been fully privatised. Nor are new owners simply interested in operating the mines to extract profits by running down their reserves without investing in replacing capacity. Newspaper reports provide examples of investment projects running to more than $550 million in the period 2003-05 in new underground and surface mines plus coal beneficiation plants. Some of this investment is driven by the growth of steel production that has prompted vertically-integrated producers – Severstal, Mechel, Yevraz – to invest in additional capacity for the production of coking coal. Similarly, there are examples of investors in power plants (in the Urals and Siberia) switching to coal in order to surmount restrictions on gas supplies. Since much steel production is located in the west of Russia, producers of coking coal in the Pechora basin and the Kuzbass have benefits from the growth in steel production. At the same time, the rapid increase in demand for coking and steam coal in the Asia-Pacific region has stimulated private investment in new mining projects plus associated rail infrastructure in Yakutia and the Far East.

These investments reflect the emergence of a competitive, market-driven, coal industry that is increasingly focused on specialised markets rather than the volume-driven production of steam coal for power and heat plants. This phase of the transition is far from complete. Many – perhaps all - underground mines producing steam coal do not have a long term future. Labour productivity in both underground and surface mines is far below the levels achieved in the United States. Together, these factors imply that up to 100,000 jobs in the mining industry (out of a total of about 250,000 in 2001) may be at risk over the next 5-8 years, while it is unlikely that the industry will employ more than one-third of its current number of works in 2020.

The other major factor that will shape the future of the coal industry in both Russia and Kazakhstan is the management and development of the railway network. In all countries, the key role of transport costs means that the economics of coal mining cannot be separated from the costs of rail freight. However, the huge distances between centres of production and consumption in the north of the Eurasia land mass means that this relationship is critical to the future of coal mining in Siberia and Northern Kazakhstan.

The restructuring and liberalisation of the railway sector in Russia has proceeded more slowly than changes in the coal industry. Coal producers still benefit from tariffs that discriminate in favour of bulk freight hauls over long distances. This cannot persist if the railway companies are to have an incentive to maintain and replace their infrastructure in Siberia. On the other hand, the management of rolling stock and the efficiency of operations are far below best practice in rail systems oriented to long distance haulage of bulk freight.

There are signs that the coal companies may be interested to take advantage of opportunities to invest in rolling stock and rail operations under a regime of more open track access. However, there are large opportunities for improving all aspects of the logistics of transporting coal from mines to beneficiation plants and on to customers. These include coal storage and handling as well as rail transport. Adopting more efficient arrangements for handling and transport coal could make as large an impact on the prospects for remote mines as improvements in mining performance.

Appendix 1 – Notes on data sources, etc

The data examined in this paper has been compiled from a number of sources. The primary sources are:

- The database of international energy production and consumption that is compiled by the Energy Information Agency of the US Department of Energy (EIA-DOE) for their International Energy Outlook. I have relied upon this data because it contains data up to 2003, whereas the other main source – in particular the database of the International Energy Agency (IEA) – extends only to 2002, though it will be updated later this year.
- Older data compiled by the IEA especially in relation to energy production and consumption up to 1991 for countries that were part of the Former Soviet Union, the former Czechoslovakia and the former Yugoslavia. The EIA only publishes aggregate data for these predecessor countries, whereas the IEA has made various estimates of energy variables for the separate countries prior to the dissolution of these countries.
- The World Development Indicators (WDI) database maintained by the World Bank, which contains a number of energy variables plus macroeconomic and related data.
- Where possible, I have filled in missing data using (a) other sources of information – primarily local statistical sources, and (b) interpolation of data for short periods. However, in some cases there is no reliable way of rectifying the absence of data. For example, there are no generally accepted estimates of the aggregate GDP (using SNA conventions) for most of the separate republics of the Former Soviet Union prior to the late 1980s.[15] In such cases I have not attempted to fill the gap, so that my analysis is restricted to years from 1990 or later onwards.

Various statistical organisations share the data that they collect, but detailed comparisons of published estimates of what should be identical variables. For example, there can be significant differences between estimates of total energy production and consumption for a particular country in a particular year or period of years. In part, these discrepancies reflect different methods of treating losses in production, transmission and distribution as well as different assumptions in accounting for the conversion from net primary energy to gross heat values for, say, primary electricity generation from hydro, nuclear, geothermal and similar power plants. There are also the usual problems of ensuring the accuracy of large databases for variables whose values may be subject to significant revision over time. These differences mean that it is important not to attach too much weight to individual pieces of data. In this paper I have focused on trends and patterns for groups of countries rather than individual countries in one or two years.

Finally, I should note the conventions that I have adopted in grouping countries.

- The Central Europe and Baltics (CEB) group consists of Czech Republic, Estonia, Hungary, Latvia, Lithuania, Poland and the Slovak Republic. I have not included

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[15] Various issues of the World Bank publication *Historically Planned Economies – A Guide to the Data* included estimates of GDP at market prices using SNA principles for 1980 and 1985 onwards for some of the republics. These were based on conversion of MPS accounts using a variety of different price bases. In recent issue of the WDI the World Bank's Data Group have included estimates of GDP and related indicators only from 1990 onwards.

Slovenia in this group because of data issues concerning the former Yugoslavia. I have subtracted data for Estonia, Latvia and Lithuania from overall statistics for the Former Soviet Union in compiling my datasets.

- The South-East Europe (SEE) group consists of Albania, Bosnia & Herzegovina, Bulgaria, Croatia, Macedonia, Romania, Serbia & Montenegro, Slovenia and the former Yugoslavia.
- The CIS group consists of the former Soviet Union excluding the Baltic republics.
- The WEU group includes all of Western Europe excluding Andorra, the Faeroe Islands, Gibraltar, Liechtenstein, Monaco, San Marino and the Vatican. In several cases, energy data for these countries or territories are included in the data for neighbouring or surrounding countries.

Appendix 2 - Environmental regulations and fuel choice for power generation

There are two major sets of constraints on national environmental regulations for the power sector in Central and South East Europe.

- The provisions of various UNECE Protocols under the Convention on Long Range Transport of Air Pollution (LRTAP), the most recent of which is the Multi-Effects Protocol signed in Gothenburg in 1999, which in turn incorporates the provisions of the earlier Second Sulphur Protocol signed in 1994. Some of the countries in SE Europe have signed one or more of these Protocols (depending upon when they came into existence), but none of them have yet ratified the Multi-Effects Protocol and only Croatia has ratified the Second Sulphur Protocol. In formal legal terms, they are not bound to comply with these Protocols until they are ratified. Still, they are subject to considerable diplomatic and other pressure to adopt regulations and implement other measures that will bring their environmental performance into line with the provisions of the Protocols.

  The situation is broadly similar for the Kyoto Protocol to the UN Framework Convention on Climate Change concerning emissions of greenhouse gases. However, the decline in emissions of greenhouse gases (GHGs) from all of the countries in the region since the base year (1990 in most cases) has been so great that there is little likelihood that target limits on GHG emissions for 2008-12 will be binding.

- For those countries that have either signed agreements with the European Union (EU) or hope to become members of the EU within the next decade, there is an explicit or implicit obligation to bring their environmental regulations into line with the *Acquis Communitaire* over a transitional period. For practical purposes, this means that they are expected to ensure that new power plants comply with the provisions of the EU's Large Combustion Plants (LCP) directive (2001/80/EC) from the date at which they start operation, while existing plants will have to come into compliance with the directive over a longer period to be agreed with the European Commission.

  The Large Combustion Plants directive was originally enacted in November 1988. The current version dates from October 2001; it incorporates stricter emission targets and limits that go beyond the provisions of the Multi-Effects Protocol agreed two years earlier.

Limit values for emission concentrations

There are two distinct strands to the environmental regulations embodied in both the Mult-Effects Protocol and the Large Combustion Plants directive. The first strand specifies limit values for the concentration of various pollutants emitted by combustion plants with a thermal input of 50 MW_{th} or greater. These limit values differ according to (a) the fuel used, (b) the size of the plant, as measured by its thermal input in MW_{th}, and (c) the date at which the plant first came into operation or was subject to either a major rehabilitation or expansion of capacity. The limit values established in the LCP directive are consistent with those in the Multi-Effects Protocol for plants that came into operation between July 1987 and November 2003. In addition, the LCP directive includes stricter limit values for plants that will come into operation after November 2003 plus special provisions for older plants, i.e. those which started operation before July 1987, depending upon their expected life and number of hours of operation per year.

The limit values on the concentrations of SO2, NOx and PM (dust) in emissions from large combustion plants under the Multi-Effects Protocol and the most recent version of the LCP Directive are shown in Table A2.1 to A2.3. The SO2 limit values for existing installations under the Multi-Effects protocol correspond to the limit values under the earlier Second Sulphur Protocol.

The history of the LCP Directive means that it adopts a different terminology in referring to existing and new plants from that implied by the UNECE Protocols. In the LCP Directive, 'existing plants' means plants that started operation before July 1987, whereas 'new plants' refer to all plants that started operation after July 1987. With certain exceptions the Directive requires that 'existing plants' should either comply with the emission limits for 'new plants' by 1 January 2008 or be subject to the provisions of a plan to reduce total emissions.

For practical purposes the distinction between plants that started operation before or after July 1987 is largely irrelevant for countries in Central and South East Europe. In any negotiations concerning either EU accession or EU partnership agreements with countries in SE Europe, the EU will expect countries in to implement environmental regulations for large combustion plants which are equivalent to those under the LCP Directive for EU plants that started operation after 1987 with exceptions only for the oldest plants which operate for no more than 1,500 to 2,000 hours per year. As a result, this report has adopted the following terminology:

- 'existing installations' refers to all plants at which operations started before November 2003, while
- 'new installations' are those that will start operation after November 2003.

The tables omit details of various special provisions for plants that burn gas of low calorific value (i.e. from blast furnaces or refineries) or petroleum gases.

Table A2.1 - Emission limit values for SO2 from major stationary combustion sources

		Thermal input	Limit value	Alternative rate of SO2 removal	Notes
		(MW_{th})	(mg/Nm3)	(%)	
A. Multi Effects Protocol, 1999					
Solid fuels					
	New installations	50 – 100	850	90	
		100 – 300	850 - 200	92	Linear decrease
		> 300	200	95	
	Existing installations	50 – 100	2000	40	
		100 – 500	2000 - 400	40 - 90	Linear decrease/increase
		> 500	400	90	
Liquid fuels					
	New installations	50 – 100	850	90	
		100 – 300	850 - 200	92	Linear decrease
		> 300	200	95	
	Existing installations	50 – 300	1700		
		300 – 500	1700 - 400		Linear decrease
		> 500	400		
Gaseous fuels (excl special cases)			35		

B. Large Combustion Plants Directive, 2001				
Solid fuels				
New installations	50 – 100	850		
	100 – 300	200	92	Max of 300 mg/Nm3
	> 300	200	95	Max of 400 mg/Nm3
Existing installations	50 – 100	2000	60	
	100 – 500	2000 - 400	75 up 300 MW, 90 > 300 MW	Linear decrease
	> 500	400	92 / 94	Depending on age of FGD
Liquid fuels				
New installations	50 – 100	850		
	100 – 300	400 – 200		Linear decrease
	> 300	200		
Existing installations	50 – 300	1700		
	300 – 500	1700 - 400		Linear decrease
	> 500	400		
Gaseous fuels (excl special cases)		35		

Source: UNECE and EU websites.

Table A2.2 - Emission limit values for NOx from major stationary combustion sources

	Thermal input (MW_{th})	Limit value (mg/Nm3)	Notes
A. Multi Effects Protocol, 1999			
Solid fuels			
New installations	50 - 100	400	
	100 - 300	300	
	> 300	200	
Existing installations		650	
Existing installations burning fuels with < 10% volatile compounds		1300	
Liquid fuels			
New installations	50 - 100	400	
	100 - 300	300	
	> 300	200	
Existing installations		450	
Gaseous fuels			
New installations burning natural gas	50 - 300	150	
	> 300	100	
New installation burning other gases		200	
Existing installations		350	
B. Large Combustion Plants Directive, 2001			
Solid fuels			
New installations	50 - 100	400	
	100 - 300	200	
	> 300	200	
Existing installations	50 - 500	600	

	> 500	500	200 after 1-1-2016
Existing installations burning fuels with < 10% volatile compounds		1200	up to 1-1-2018
Liquid fuels			
New installations	50 - 100	400	
	100 - 300	200	
	> 300	200	
Existing installations	50 - 500	450	
	> 500	400	
Gaseous fuels			
New installations burning natural gas	50 - 300	150	
	> 300	100	
New installations burning other gases		200	
Existing installations	50 - 500	300	
	> 500	200	
Gas turbines (single cycle, excl turbines for emergency use)			
New plants burning natural gas		50	
New plants burning other fuels		120	

Source: UNECE and EU websites.

Table A2.3 - Emission limit values for dust from major stationary combustion sources

	Thermal input (MW_{th})	Limit value (mg/Nm3)	Notes
A. Large Combustion Plants Directive, 2001			
Solid fuels			
New installations	50 - 100	50	
	> 100	30	
Existing installations	50 - 500	100	
	> 500	50	100 for high ash/moisture fuels
Liquid fuels			
New installations	50 - 100	50	
	> 100	30	
Existing installations	50 - 500	50	100 for high ash fuel
	> 500	50	
Gaseous fuels			
New installations		5	
Existing installations		5	

Source: EU website.

For SO2 the Multi-Effects Protocol and the LCP directive specify both limit values for emission concentrations and desulphurisation rates. The way in which these alternative provisions are implemented seems to depend upon national interpretation, but the usual practice seems to regard the desulphurisation rate as the maximum value required. Hence, if the sulphur content of fuel is such that the limit value of the concentration can be attained with a level of desulphurisation that is less than the rate specified then the limit value on

SO2 concentration applies. Otherwise, for fuels with higher sulphur content the desulphurisation rate applies. As a result, high sulphur fuels are not penalised by a requirement to achieve levels of desulphurisation above the point at which costs are thought to increase very sharply (90% in the past, 95% today). This protection is important for those countries in South East Europe, including Bulgaria, Croatia, Serbia and Turkey, which have substantial deposits of high sulphur brown coal or lignite.

Comparison of the limit values on concentrations of SO2, NOx, and particulates lead to a number of observations that may be important for countries in SE Europe.

- The limits on SO2 emissions are substantially stricter for new installations under the Multi-Effects Protocol than they were under the earlier Second Sulphur Protocol. The more recent LCP Directive is even more restrictive. The lowering in the limit values for emissions is especially severe for small plants from 100 to 300 MW_{th}, i.e. from about 40 to 120 MW_e. These plants are too small to be economic in most EU electricity systems but plants of this size have been and may in future be important in some of the smaller SE European countries.
- The limits on NOx emissions for new plants burning coal are also much stricter than those for existing plants under the Multi-Effects Protocol – a reduction from 650 mg per Nm3 to 200 mg per Nm3. However, as discussed in Section 2.2 below there have been large improvements in the performance of standard combustion equipment over the last decade, so that the cost of meeting the standard for new plants should not be any greater than the cost of meeting the earlier standards.
- Many plants in SE Europe burning solid fuel rely upon lignite rather than coal. Such plants are covered by the special NOx limit values for existing plants burning solid fuels with less than 10% volatile compounds. The technical literature provides little information on the performance of modern combustion equipment in lignite-fired plant, but the LCP Directive have effectively provided a lengthy derogation in respect of the application of the NOx limit values to existing lignite-fired plants. Since there are enough lignite-fired power plants in Europe to represent a sizeable market, equipment manufacturers will have ample incentive to develop combustion equipment that can meet the stricter standards at reasonable cost within this time period.
- The limit values for particulates have been tightened, but, again, they contain special provisions for existing plants burning the types of low quality solid fuel that are common in SE Europe. Most existing power plants in SE Europe should be able to meet the limit value of 100 mg per Nm3 for high ash/moisture solid fuels provided that they maintain and operate their electrostatic precipitators (ESPs) properly. Effective control of particulates is often a matter of operating practice rather than the technical specification of the pollution controls. If new equipment is required to meeting the limit values in the LCP Directive, this is likely to involve upgrading existing equipment rather than the installation of new pollution controls.
- The EU has granted derogations from the application of some provisions of the LCP Directive in special cases – e.g. small power plants on islands in Greece and in 'Outermost Regions', whose definition cover French Overseas Departments, the Azores and the Canary Islands. It is possible that the EU might recognise that the full implementation of the Directive would impose an excessive burden on countries such as Albania, Bosnia & Hercegovina, and FYR Macedonia. Thus, it might allow some form of derogation, though the more usual approach in other countries has

been to provide grant assistance or heavily subsidised loans to offset the costs of installing stringent emission controls.

- More broadly, the EU agreed to a lengthy derogation from the application of the 1988 LCP Directive to Spain at the time of Spain's accession to the EU. The derogation was carried forward into the 2001 version of the LCP Directive. It was partly an acknowledgement of the fact that emissions of SO2 and NOx from the Iberian peninsula have little impact on sensitive areas in Scandinavia and Central Europe. From the Spanish government's perspective the pressure for the derogation was driven by the particular circumstances of Spain's coal industry. The EU has tried to resist granting similar derogations for the countries that will accede to the union in May 2004 and would be reluctant to grant them for the countries in SE Europe. On the other hand, the accession agreements contain a variety of special provisions on the implementation of EU Directives, so that limited derogations may be regarded as negotiable.

- The definition of a combustion plant in the LCP Directive states that

  "Where two or more separate new plants are installed in such a way that, taking technical and economic factors into account, their waste gases could, in the judgement of the competent authorities, be discharged through a common stack, the combination formed by such plants shall be regarded as a single unit;"

  The implication is that a power plant with, for example, 4 200 MW_{th} boilers that could be discharged through a single stack would be subject to the limit values applicable to a plant of greater than 500 MW_{th} rather than each boiler being subject to the limit values for a unit of 200 MW_{th}. For new plants this will normally not matter, but this interpretation would make a large difference to an existing plant for which the SO2 emission limit is 1600 mg/Nm3 for a 200 MW_{th} unit rather than 400 mg/Nm3 for a 800 MW_{th} unit.

- The 1988 Large Combustion Plants Directive included a footnote that specified when modifications to or rehabilitation of an existing plant – in that case one built or licensed prior to 1 July 1987 – would mean that it became subject to the limit values that applied to new plants. This footnote has been dropped from the current version of the LCP Directive, largely because the licensing of all new industrial sources is subject to the provisions of the 1996 Directives on Integrated Pollution Prevention and Control (96/EC/61 and 96/EC/62). While there is limited scope for differences in interpretation, this is likely to mean that any power plant that undergoes significant modernization or rehabilitation of its boilers and combustion equipment would be subject to the limit values applicable to new plants in the current LCP Directive. The implication is that the rehabilitation of small or medium-sized existing plants burning coal or lignite will be relatively expensive because this will almost certainly involve the installation of expensive controls to reduce emissions of SO2. The additional cost of reducing emissions of NOx and particulates will be much less. Indeed, in the case of NOx any extra cost may be offset by the improvement in combustion performance and thermal efficiency associated with the use of low-NOx burners.

Limits on total emissions

The second strand of these regulations specifies targets for reductions in the aggregate national level of emissions of various air pollutants. The targets apply to sulphur dioxide, nitrogen oxides, ammonia, and VOCs. The specific requirements for power plants are intended to contribute to meeting these emission targets, though the contribution of the power sector to total emissions varies greatly across countries and pollutants. In practice, the power sector is an important contributor to emissions of sulphur dioxide and nitrogen oxides (usually measured in terms of NO_2).

There is a particular provision of the LCP directive that explicitly links the two strands together. This requires EU countries to define and implement national emission reduction plans under which the total level of emissions from plants that started operations before July 1987 is reduced by 2008 to no more than would be emitted by these plants if they complied with the limit values in force for plants which commenced operation between July 1987 and November 2003. In effect, the 'grandfathering' of emissions from older plants is restricted by a requirement that puts a cap on the aggregate levels of such emissions.

This provision would be particularly important if it were applied in countries in SE Europe because much of their generating capacity is old and has emissions that far exceed the limit values specified in the LCP directive. However, the directive specifies that a particular plant can be exempted from this provision so long as the operator gives an undertaking that the plant will not be operated for more than 20,000 hours in the 8 years 2008-15.

There is also a clause that gives a specific derogation for existing plants of 400 MW_{th} or greater that do not operate for more than 2,000 hours per year on average up to 2015 and 500 hours per year on average after 2015. For countries with a clear winter or summer peak 2,000 hours is sufficient to allow the plants concerned to operate for an average of 16 hours per day from mid-November to mid-March or late-May to late-September so as to cover peak heating/lighting or air-conditioning loads. On the other hand, 500 hours per year is what might be expected for pure peak load capacity, which is unlikely to be attractive for plants of this size other than gas turbines fuelled by diesel oil.

Tables xx and xx show the emission levels and targets under various Protocols for SO2, NOx by country. There is almost no information on emissions of SO2 and NOx for Albania as it is not a signatory to the LRTAP Convention and it has not attempted to compile any kind of inventory of such emissions until very recently. Similarly, FYR Macedonia and Serbia & Montenegro are not signatories to the Multi-Effects Protocol, so that they have not agreed to emissions targets for 2010 for any of the pollutants covered by this protocol.

With respect to the countries in SE Europe which did sign this Protocol (even if they have not ratified it yet):

- Bulgaria's emissions of SO2 have been falling steadily since 1995, in part because of a shift from the use of lignite or brown coal (often as briquettes) to gas by small sources and district heating boilers. The rehabilitation of various units of the Maritsa and Maritsa East power plants will substantially reduce emissions of SO2 from these sources. Hence, the country should not face any significant problem in meeting the 2010 SO2 limit. Similarly, its emissions of NOx have also been falling from large sources, so that even a significant growth in traffic volumes will be consistent with meeting the 2010 NOx limit.

Table A2.4 - Emission targets for SO2 by country

	Emissions of SO2 in kt per year								
	Actual				Ceilings under SSP			Ceiling under MEP	Allowable growth rate
	1980	1990	1995	2000	2000	2005	2010	2010	2000 -2010
Albania (1)	-	-	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Belarus	740	637	275	143	456	400	370	480	12.9%
Bosnia & Herzegovina	-	480	-	-	n.a.	n.a.	n.a.	n.a.	n.a.
Bulgaria	2,050	2,008	1,476	982	1,375	1,230	1,127	856	-1.4%
Croatia	150	180	70	91	133	125	117	70	-2.6%
Czech Republic	2,257	1,876	1,091	265	1,128	902	632	283	0.7%
Estonia	287	252	119	95	n.a.	n.a.	n.a.	n.a	n.a.
Greece	400	479	528	531	595	580	570	546	0.3%
Hungary	1,633	1,010	705	485	898	816	653	550	1.3%
Latvia	-	119	59	18	n.a.	n.a.	n.a.	107	19.5%
Lithuania	311	222	94	43	n.a.	n.a.	n.a.	145	12.9%
Macedonia, FYR (2)	65	132	123	105	n.a.	n.a.	n.a.	n.a.	n.a.
Moldova	308	265	64	12	n.a.	n.a.	n.a.	135	27.4%
Poland	4,100	3,210	2,376	1,511	2,583	2,173	1,397	1,397	-0.8%
Romania (3)	1,055	1,311	932	-	n.a.	n.a.	n.a.	918	-
Russian Federation	7,323	4,671	2,969	1,997	4,440	4,297	4,297	n.a.	n.a.
Serbia & Montenegro (4)	345	432	393	-	n.a.	n.a.	n.a.	n.a.	n.a.
Slovakia	780	542	239	120	337	295	240	110	-0.9%
Slovenia	234	196	125	96	130	94	71	27	-11.9%
Turkey	205	765	1,007	1,347	n.a.	n.a.	n.a.	n.a.	n.a.
Ukraine (5)	3,849	3,782	1,639	-	n.a.	n.a.	n.a.	1,457	-

Source: UNECE/EMEP; European Environment Agency; Black Sea Energy Review.

Notes: - denotes no data; n.a. denotes not applicable.

(1) Albania is not a signatory to the UNECE LRTAP Convention and has not prepared national inventories of SO2 or NOx emissions. A partial inventory for 1994 yielded an estimate of total emissions of 18 kt of NOx.

(2) Estimates for 1980-95 based on share of total emissions for the former Yugoslavia pro-rated according to energy use. The 2000 estimate is derived from a partial inventory for 1998 excluding mobile sources.

(3) Most recent data for SO2 emissions is 898 kt for 1997.

(4) Estimates for Serbia alone. Most recent data for SO2 emissions is 443 kt for 1998.

(5) Most recent data for SO2 emissions is 1,132 kt for 1997.

Table A2.5 - Emission targets for NOx by country

Emissions of NOx in kt per year

	Actual				Ceiling under MEP	Allowable growth rate
	1980	1990	1995	2000	2010	2000 – 2010
Albania (1)	-	-	-	-	n.a.	n.a.
Belarus	234	285	195	135	255	6.6%
Bosnia and Herzegovina	-	-	-	-	n.a.	n.a.
Bulgaria	-	361	266	184	266	3.7%
Croatia	60	88	66	72	87	1.9%
Czech Republic	937	742	412	398	286	-3.2%
Estonia	-	68	42	41	n.a.	n.a.
Greece	-	311	309	340	344	0.1%
Hungary	273	238	190	187	198	0.6%
Latvia	-	92	42	34	84	9.6%
Lithuania	152	158	65	48	110	8.8%
Macedonia, FYR (2)	91	45	44	30	n.a.	n.a.
Moldova	58	100	38	17	90	18.1%
Poland	1,229	1,280	1,120	838	879	0.5%
Romania (3)	523	546	420	-	437	-
Russian Federation (4)	1,734	3,600	2,570	2,357	n.a.	n.a.
Serbia & Montenegro (5)	40	56	50	-	n.a.	n.a.
Slovakia	-	215	174	106	130	2.1%
Slovenia	51	63	67	58	45	-2.5%
Turkey	364	644	801	951	n.a.	n.a.
Ukraine (6)	1,145	1,097	531	-	1,222	-

Source: UNECE/EMEP; European Environment Agency; Black Sea Energy Review.

Notes: - denotes no data; n.a. denotes not applicable.

(1) Albania is not a signatory to the UNECE LRTAP Convention and has not prepared national inventories of SO2 or NOx emissions.

(2) Estimates for 1980-95 based on share of total emissions for the former Yugoslavia pro-rated according to energy use.

(3) The most recent data for NOx emissions is 330 kt for 1997.

(4) The MEP target for the Russian Federation applies only to a small part of the country.

(5) Data for Serbia alone. The most recent data for NOx emissions is 56 kt for 1998.

(6) The most recent data for NOx emissions is 455 kt for 1997.

- Croatia's emissions of both SO2 and NOx fell sharply after the break-up of the former Yugoslavia but have risen in recent years. The country will have to retrofit pollution controls to several of its thermal power plants and/or switch small and medium sources to gas in order to comply with both the SO2 and the NOx limits.
- Romania's emissions of both SO2 and NOx fell during the 1990s and were below its 2010 emission limits in 1997 (the latest year for which data is available). The regional trend away from coal or lignite in small and medium sources together with a reduction in the SO2 content of petroleum products (to comply with EU standards on fuel specifications) mean that the country should face little difficulty in complying

with the SO2 limit. Similarly, the existing headroom for NOx emissions combined with reductions in the average amount of NOx emitted per vehicle-km will allow for rapid traffic growth without threatening to breach the limit on NOx emissions.

Thus, Croatia is the only country likely to have to take additional measures to ensure compliance with the overall emission limits for SO2 and NOx that might affect the balance between the demand for coal or lignite and gas. Serbia & Montenegro might find itself in the same position if it decides to accede to the Protocol, though this would depend upon the emission limits that it accepts. In both cases, the planned rehabilitation of some existing lignite-fired power plants, which would involve the retrofitting of these plants with flue-gas desulphurisation and low-NOx burners, will probably be sufficient to ensure that the countries can meet the emission limits in the Multi-Effects Protocol.

Table A2.6 – Emission targets for CO2 by country

	Total emissions of CO2 in million tonnes			% change in CO2 emissions, 1990-99	Kyoto Protocol reduction in GHG emissions	Notes
	1990	1995	1999			
Albania	7.27	2.09	1.51	-79%	n.a.	
Bosnia & Herzegovina (1)	7.16	4.26	4.82	-33%	n.a.	
Bulgaria	103.86	62.33	48.44	-53%	-8%	
Croatia (1)	25.49	17.76	20.80	-18%	-5%	
Macedonia (1)	16.13	10.69	11.38	-29%	n.a.	
Romania	155.07	119.28	81.21	-48%	-8%	CO2 from fossil fuels
Serbia & Montenegro (1)	67.81	39.77	39.53	-42%	n.a.	

Source : UN Statistical Office; Carbon Dioxide Information Analysis Center.

Note: (1) The emissions of CO2 for the former Yugoslav republics in 1990 were estimated by dividing the total emissions of CO2 for the former Yugoslavia minus Slovenia in 1990 pro-rata to the reported emissions by republic in 1992.

All of the countries in SE Europe are signatories to the UN Framework Convention on Climate Change, but only Bulgaria, Croatia and Romania have agreed to limits on emissions of greenhouse gases under the Kyoto Protocol. Details of total emissions of CO2 and the Kyoto limits are given in Table . Total emissions have fallen substantially since 1990 for most of the countries, so that Bulgaria and Romania are unlikely to face any difficulty in meeting their Kyoto reduction targets. Total emissions of GHGs would have to grow at more than 5% p.a. from 1999 to 2010 in both countries to exceed these targets. Since both countries are still going through the process of restructuring their industrial sectors and improving energy efficiency, any growth in fossil fuel consumption is likely to be much less than 5% p.a. Further, the longer term shift from lignite or brown coal to gas that has been under way during the last decade will decrease the average level of CO2 emitted per unit of fossil fuel energy that is consumed.

Again, the country that faces the greatest challenge in meeting its Kyoto target for reducing GHG emissions is Croatia. It can only permit total emissions of CO2 to grow by 1.4% p.a. from 1999 to 2010, which is significantly below any plausible “business as usual” growth rate given reasonable rates of economic growth over the next decade. On the other hand, the country was relatively slow in adopting a program of economic reform and industrial restructuring, so that there may be considerable improvements in overall energy efficiency over this period. Still, Croatia is the country in the region most likely to promote fuel switching for large combustion plants in order to reduce CO2. However, given its configuration of power and CHP plants any switching would focus initially on converting oil-fired or oil/gas-fired units to operate solely on gas. The country has two coal-fired plants – Plomin 1 & 2 – accounting for 315 MW of installed capacity. These units were privatised recently with RWE taking a 50% share in the operating company (TE Plomin d.o.o.), so it is not clear what its plans might be.