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Electrifying Integration: Electricity Production and the South-East Europe Regional Energy Market

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Abstract The paper provides an overview of the generation of electricity in 10 countries in South East Europe during 1995-2004. Using the latest available statistics the potential of the nascent integration of the electricity markets in South East Europe is explored. We conduct a cross-country analysis of electricity production based on different types of fuel used. The region has a low level of gasification combined with few nuclear power generation facilities, while some countries heavily rely on hydro electric generation. Differences in countries' resource endowment and the possibility of intertemporaral substitution between electricity generated from various fuels could stimulate a regional trade in electricity. Such trade could displace a proportion of the required investment in the construction of generation facilities, as an alternative to nationally independent energy policies. Finally, we consider the environmental impact of electricity generation, and identify some of the key trade-offs between different policy objectives.

Keywords Electricity, Generation, ECSEE

JEL Classification L94, Q40, R12

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INTRODUCTION

During the last decade South East Europe (SEE) witnessed the collapse of the socialist system and several wars, which deeply affected the social and economic life of people in the region. The last conflict ended in 1999 and was followed by peacekeeping operations in Bosnia, Kosovo and a limited NATO engagement in Macedonia. The years of war damaged and in places completely destroyed electricity generation and transmission infrastructure that was already suffering degradation due to economic decline. Finally, after a long period of turbulence, the South East Europe (SEE) region enters a period of economic growth and investment opportunities. Currently, significant attention is focused on the energy sector and, particularly, on electricity, which is vital to economic growth and the prosperity of the region.

The history of regional integration in SEE has been outlined earlier in this volume[1]. Critically, in 2005 the nations and territories of the region entered a legally binding agreement, the Energy Treaty which established the Energy Community of South East Europe (ECSEE), and committed the parties to the formation of a regional electricity market. All are new or aspiring members of the European Union (EU), and are therefore implicitly or explicitly required to implement EU Energy Policy, at to pursue its three fundamental objectives, competitiveness, security of supply and sustainability.

This paper provides an overview of electricity generation in 10 countries[2] in SEE between 1995 and 2004. We conduct a cross-country comparison of electricity production based on fuel type, then consider the environmental impact of electricity generation, and outline some of the key trade-offs between different policy objectives. This enables us to explore regional as well as national questions and to discuss potential demand and supply risks that the region and each country separately might face in the near future.

Economic development in SEE has been and remains a focus of activity by several international organizations including the World Bank, European Commission (EC), European Bank of Reconstruction and Development as well as development agencies in the USA, Germany and Canada. The energy sector has been the subject of particularly active engagement and a series of influential studies has ensued.

A World Bank working paper by Kennedy and Besant-Jones (2004) sets out the strategy of the Bank with respect to the development of the SEE regional electricity market, focusing on risks the region as whole might face, and possible ways to deal with them. The South East Europe Generation Investment Study (GIS, 2005) and the subsequent updated version (GIS Update, 2007) present forecasts of demand and generation to 2020 for

[1] Forthcoming in Utilities Policy, 2008. See also EPRG0725 Michael Pollitt
Evaluating the evidence on electricity reform: Lessons for the South East Europe (SEE) market http://www.electricitypolicy.org.uk/pubs/index.html?year=2007

[2] Albania, Bosnia, Bulgaria, Croatia, Greece, FYR Macedonia, Romania, Serbia and Montenegro, Slovenia, Turkey.

several plausible scenarios and from their simulations, generate estimates of required investments in electricity infrastructure in the region. The reports cover nine territorial entities: Albania, Bosnia, Bulgaria, Croatia, Kosovo, Macedonia, Montenegro, Romania, and Serbia. Kennedy and Besant-Jones (2004) and GIS (2005) report that there was very limited investment in generation capacity during the 1990s; currently the average age of electricity generation plants is around thirty years. Therefore, without significant investment in refurbishment and new plant, and the improvement of interconnections between countries, the region will become increasingly dependent on imported electricity or even face shortages. Indeed, in late 2005 Tirana experienced widespread power cuts of up to 18 hours duration due to poor reliability and particularly dry hydrological conditions (Economist, 2006).

Academic studies of the restructuring of electricity markets in both developed and developing countries are numerous. Davies, Wright and Waddams Price (2005) outline various privatization and regulation issues that developing countries may face, with a particular focus on the sequence of reforms. Both Tompson (2004) and Pittman (2007) provide a detailed description of the restructuring of the electricity sector in Russia. Other studies identify useful lessons which could be drawn from the developed countries that recently liberalized, privatized and restructured their electricity sector. Arocena and Waddams (2002) empirically assess differences between state and private electricity generating companies in Spain. Using data on physical units, the authors show that privately owned generating companies are moving faster toward the efficiency frontier. Jamasb (2002) and Jamasb, Mota, Newbery and Pollitt (2005) review different reform experiences in developing countries, and stress the importance of effective institutions in achieving desirable outcomes.

In this analysis we used the International Energy Agency (IEA) data on annual national electricity production and consumption for OECD and Non-OECD countries for the period of 1995-2004. [3]

We briefly consider examples of electricity market integration in Europe, and against this background, provide an overview of the rationale for electricity market integration, an exploratory analysis of electricity generation in the region and consider the potential environmental impact of pursuing a generation expansion plan of the required magnitude to meet demand growth.

INTEGRATING NATIONAL MARKETS

In 1991 Norwegian electricity markets were deregulated and competition was introduced in generation and supply.[4] In 1996 Sweden took up the challenge of deregulation, a common spot-market, NordPool became the first multi-national power exchange and steps were taken to reduce barriers to cross-border trade. Finland completed the deregulation process in 1997, and finally

[3] The access to the IEA database was kindly provided by the UK Economic and Social Data Service (www.esds.ac.uk).

[4] Transmission and distribution remained regulated monopolies.

in 2000 the Nordic market was fully integrated when Denmark East became a NordPool power exchange area.

There are several important things to note about this process and local conditions. First, it took almost ten years to complete integration, and as late as 1998 the Nordic Electricity Market was regarded as an 'emerging' market (Amundsen et al., 1998). Second, prior to 1991 trade between Norway and Sweden was conducted through bilateral contracts, and while NordPool Spot is now a liquid market and trading volumes are over 60% of total electricity consumption in the Nordic countries,[5] as in 1998 less than 20% of total electricity consumption of Norway, Sweden and Finland was traded in the spot market (Bergman and Vaitilingam 1999).

Third, although the received wisdom holds that the key driver for integration was legislation by the European Commission, there is increasing recognition of the view that the establishment of the Nordic Market was the outcome of a 'gentleman's agreement'; it suited the strategic plans of the market participants and governments concerned (Lundberg 2007). Fourth, the integration of the Nordic Market was initiated at a time of relative surplus in generating capacity and transmission constraints were not generally binding.

Integration of electricity markets in Belgium-France-Netherlands, the so-called trilateral coupling (TLC) started in November 2006. By early 2007 these markets were already exhibiting a considerable degree of price convergence, and for the period November 2006 – August 2007, the region shared a single price for 58% of hours (APX, 2007). In February 2007 proposals were announced for Germany and Luxembourg to join, to form the Central West European market. It is worth noting that the time taken to operationalise integration appears to be significantly different in the two cases considered. A single price area in the Nordic market was established over many years, while it apparently evolved in a matter of months in the TLC. There may be many reasons for this difference, but critically, the TLC involved the integration of markets where actors were already accustomed to trading electricity; wholesale market competition was introduced in 1998, and perhaps more importantly, the market infrastructure and rules were well established and market participants had built up a body of experience. It is therefore arguable that the integration process took place over a comparable period of time[6].

The fundamental motivation for trade is to minimise costs by dispatching the cheapest plant available for each period, and the rationale for integrating national electricity markets is to maximise cross-border capacity and adopt rules and procedures for efficient cross border trade such that the consumers of the nations concerned benefit (CREG 2005). Benefits accruing from the effects of market integration can be thought of as falling into three groups. First, in terms of developing competitive (cost-reflective) prices. Where vertically integrated systems are too small for intra-national competition to be workable, integrating national networks inevitably reduces market

[5] http://www.nordpoolspot.com/about/

concentration and may constrain the potential to exercise market power. Amundsen et al. (1998) find that in the presence of market power and monopolistic pricing, free trade in electricity between nations might provide an effective substitute for competition at the national level, particularly where there is considerable variation in prices. Additionally, larger markets can support more liquid wholesale markets which discipline market participants and encourage cost-reflective pricing.

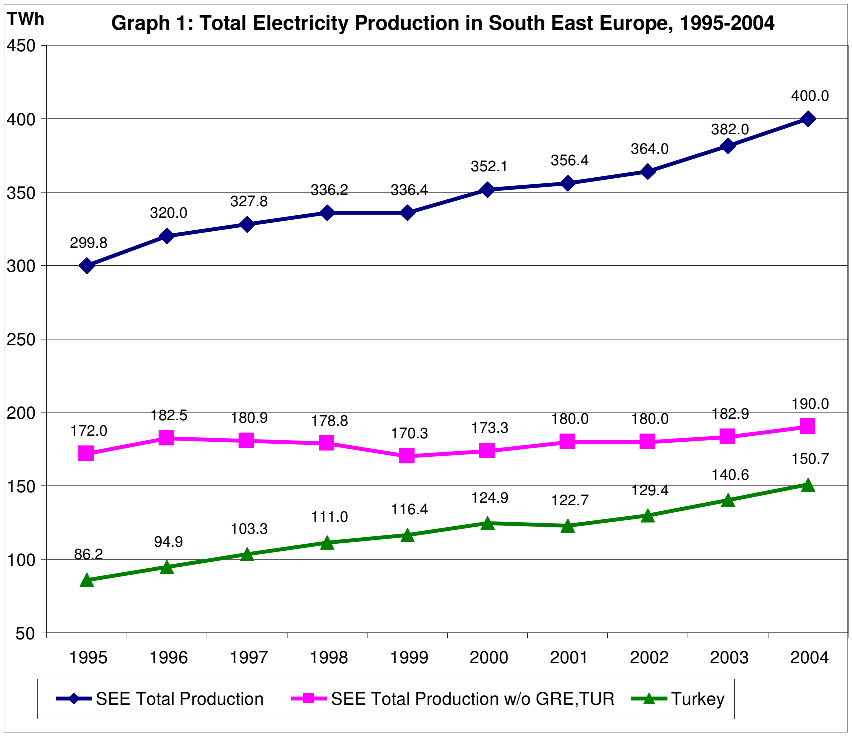
A second group of effects concerns security of supply. Centrally co-ordinated dispatch over a region with a non-synchronous peak requires, on average, a lower reserve margin than required under national operation. Similarly, diverse resource endowments and generating technologies across the region could offer greater resilience to external shocks, given adequate interconnection capacity. For example, a system in which a substantial proportion of electricity is generated from hydro may be vulnerable to persistent dry hydrological conditions, as in the case of Albania mentioned above. Lastly, the failure of a reasonably sized generator in a small system would compromise the stability of the entire system but may have only a modest impact in a larger system.

The last effects we consider concern sustainability. Stewardship of scarce (fossil fuel) resources can be improved if the optimal fuel mix is considered at a regional level. For example, nations relying heavily on coal generation could import from nations with surplus power generated from, say, hydro, simultaneously minimising CO_2 emissions and utilising a renewable energy source. An expanded market also offers increased opportunities for innovation (Neuhoff, 2006) and the adoption of low-carbon technologies that may not be feasible for small system.

ELECTRICITY GENERATION IN SOUTH EAST EUROPE

Generation by Volume

The generation of electricity in South East Europe increased from 299.8 TWh in 1995 to 400.0 TWh in 2004, i.e. 33% increase over 10 years. However, most of the growth in the generation of electricity in the region is attributed to Turkey and Greece (see Graph 1).



Between 1995 and 2004, the greatest increase in generation was achieved by Turkey, which raised output from 86.2 TWh to 150.6 TWh (74% increase). Greece increased its production by 43% from 41.5 TWh to 59.3 TWh over the same period. Therefore, the additional production of Turkey and Greece together accounted for 82% of the total increase; 82.2 out of 100.2 TWh.

In Turkey this was achieved largely through the increased use of gas fired plant. In 1995 Turkey produced 16.6 TWh from gas, but by 2004 this had risen to 62.2 TWh (287% increase). The additional gas fired generation was therefore 45.6 TWh, while the total increase in the production of electricity in Turkey using all types of fuel over the 10 year period was 64.4 TWh. Thus, natural gas accounts for 70% of the increase in the overall electricity production in Turkey. The realisation of plans to build gas pipelines from Russia and the Caspian region would facilitate the further expansion of generation capacity, and potentially increase the share of gas-based electricity in Turkey in the short-run.

Taken together, the remaining eight countries in the region increased generation by 18.0 TWh over the last 10 years. However, between 1995 and 1999 overall electricity production in these countries stayed almost unchanged (171.9 TWh in 1995 and 170.2 TWh in 1999), and only after 1999 did we begin to observe growth in electricity production in these countries, from 170.3 TWh in 1999 to 190.0 TWh in 2004 (i.e. extra 19.7 TWh over 5 years).

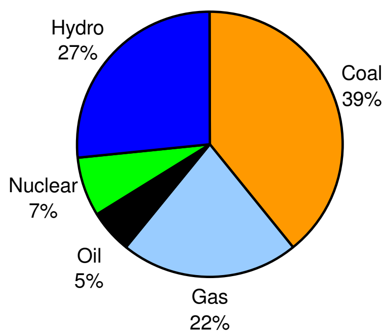
After the end of the war in 1995, Bosnia and Herzegovina increased production from 4.4 TWh in 1995 to 7.3 TWh in 1996 and then to 12.9 TWh in 2004 (186% increase over 10 years). Croatia also slowly recovered after years of war and economic embargo; electricity production increased from 8.8 TWh in 1995 to 13.3 TWh in 2004 (49% increase over 10 years).

Romania initially experienced a sharp decline in electricity production between 1995 and 1999 and only in 2000 did this trend reverse. A similar pattern of decline and increase is observed in Bulgaria and Serbia. In the mid-1990s all three countries experienced an economic slow down, which was exacerbated by the 1998 financial crisis in Russia, an important supplier of natural resources and a major trading partner. Additionally, Serbia's involvement in military conflicts prompted the United Nations impose an embargo upon it. However, since the end of the last war in the region in 1999, all three countries have increased their electricity output, while over the same 10 year period production remained almost unchanged in Albania, Macedonia and Slovenia.

Generation by Fuel Type

The structure of the production of electricity by different types of fuel in South East Europe in 2004 is the following: 39% coal, 27% hydro, 22% gas, 7% nuclear, and 5% oil (in 2003 the numbers respectively were 40%, 23%, 23%, 7% and 7%).

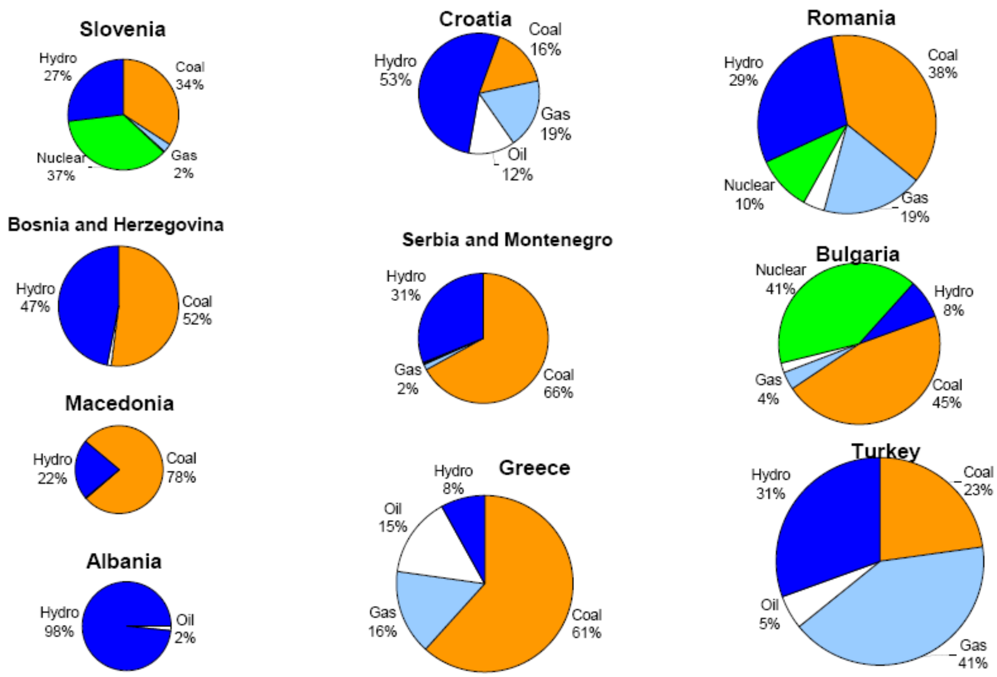
Graph 2: SEE electricity production by type of fuel, 2004



As we explained above, the main producer of electricity using natural gas was Turkey. In 2004 the SEE region produced 86.5 TWh from natural gas including Turkey's contribution of 62.2 Wh (i.e. 71% of the total). Moreover, Turkey has the highest gasification of the electricity production in the region, with natural gas accounting for some 41% of Turkish production in 2004. Other countries that produce significant proportions of their electricity from natural gas are Romania (19%), Croatia (19%) and Greece (16%) (see Graph 3). Gasification in the remainder of the region is low, and here gas plants are supplemented with nuclear power generation facilities. Three countries in SEE that have nuclear power stations: Bulgaria, Slovenia, and Romania, although the Krsko nuclear power plant in Slovenia is jointly owned by Croatia and Slovenia and the generated electricity is equally split between them. In Bulgaria, the nuclear plant in Kozloduy produced 16.8 TWh, which contributed 41% to the country's electricity production in 2003. It was agreed with the European Commission that two units of the nuclear plant would be retired in 2006, while the other two units will remain available till 2020 (GIS, 2005).

Romania has one unit at its Cernavoda nuclear power station, and might build another two units at the same location (680MW each).

Graph 3: Production of Electricity by Type of Fuel (%) in 2004



As Graph 3 shows, most of the countries in SEE rely heavily on coal (lignite and brown coal) based generation.. For example, Macedonia produced 78% of its electricity using coal in 2004; while the figures for Serbia and Greece are 66% and 61% respectively. The dependency on coal for generation in other countries is as follows: Bosnia 52%, Bulgaria 45%, Romania 38%, Slovenia 34%, Turkey 23% and Croatia 16%. Most of the coal burned in thermal power plants is domestically supplied, however, high costs of production caused by low productivity and lack of investment in equipment and technology render many mining companies (which are typically state owned) unprofitable. Nevertheless, governments are forced to continue to subsidize the sector in order to prevent numerous lay-offs and the consequential social problems.

Albania is the only country in the region that does not burn a significant amount of coal for electricity production. The country relies completely on hydro power plants while Croatia and Bosnia produce 53% and 47% of their electricity from hydro. Other main producers of hydro electricity are Serbia (31%), Turkey (31%), Romania (29%), Slovenia (27%) and Macedonia (22%).

Differences in countries' resource endowment and the possibility of intertemporal substitution in the fuel mix could stimulate a regional trade in electricity, potentially reducing the required investment in new generation capacity. A typical substitution is between hydro and thermal power in peak and off-peak periods. Reservoirs are filled during off-peak hours and water is subsequently released to meet the peak demand. Such substitution would facilitate matching supply and demand at peak periods, so improving system reliability and region-wide capacity reserve. In addition the GIS (2005) reports differences in fuel costs across countries, so there is potential to utilize the comparative advantages of some countries in the production of relatively cheap electricity for later consumption in other countries. Such types of regional electricity cooperation and trading could provide great benefits to consumers through lower prices and more reliable electricity supply, though crucially, would require the adoption of an alternative model to historical nationally independent energy policies [7].

In common with the Nordic countries at liberalization, reserve margins in SEE as a whole are apparently comfortable (SEETEC 2006), though anecdotal evidence suggests that the level of available capacity is, in some countries, far below installed capacity, which makes national systems vulnerable to supply shocks, such as the low Albanian rainfall in 2005 noted above. If the Nordic experience of a virtual halt of investment in generation and transmission during and immediately after market liberalisation was to be repeated in the SEE region it would have a catastrophic effect on the ability of the system to meet peak demand. Experience of more advanced transition economies and of regional economic growth implies sharply increasing demand for electricity and recent studies have highlighted the urgent need for substantial investment in generation and transmission capacity, especially investment in cross-border interconnectors, if the electricity sector is to underpin rather than constrain future economic growth.

DRIVERS OF DEMAND

Understanding the drivers of demand allows us to consider the potential implications of market liberalisation and the development of a regional market for electricity. The expected change in the pattern of demand will have a significant impact on the timing and nature of required investment in generation capacity. Given the imperative of achieving real-time balance, investment in generation capacity is driven by peak demand. In the context of rising base-load demand associated with economic growth, increased peakiness implies earlier investment in new plant if system stability at peak hours is to be maintained (Stoft, 2002). Fundamental to this will be the exposure of all consumers to cost reflective prices, inducing demand side responses relating to the availability and relative prices of substitute fuels. Plans for market opening will be determined nationally, and are not yet synchronised, which may exacerbate the volatility of demand.

The region currently experiences a winter peak though there is considerable variation at national level (Greece and Turkey are summer peaking systems).

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[7] The experience of the USA shows that while increased cross-border trade has lots of potential to lower prices and costs overall, there are losers, at least in the short term, who will fight this reform (for instance, the current customers of low-cost power whose supplies may be diverted to higher-priced neighboring areas). Of course they could be compensated from the gains in efficiency and profits, but they fear that they won't be, and it has significantly slowed state-level reforms.

In the long run, there is an expectation that ECSEE nations will converge on the Croatian seasonal pattern: summer demand as a proportion of the total increasing, winter as a proportion falling, and fairly stable demand in autumn and spring. This greater seasonal variation, which may be exaggerated by variance in the speed of convergence to a regional pattern, will depend on both macroeconomic factors, notably realised economic growth and structural shifts, and the degree of effective energy market restructuring.

Average annual load growth is 1.3% in the main UCTE block,[8] though for 2005 in SEE variation from 2004 levels ranged from +2% in Bulgaria to +7.8% in FYR Macedonia. The pace of growth may be expected to increase after 2010; prior to this, improved energy efficiency and reduced energy intensity are expected to partially offset increasing demand (Kennedy, 2004).

As discussed above, the region's non-synchronous peak load may permit more efficient use of generation and transmission assets if dispatch is coordinated regionally rather than nationally, mitigating the implied requirement for early investment. Further, centralised dispatch of the heterogeneous regional generation mix may reduce the reserve capacity required and improve security of supply associated with any given load.

The precise effect of energy efficiency measures on demand is difficult to determine though can be approximated by trends in electricity intensity. However, three sources of energy efficiency are worth noting. First, more advanced transitional economies have experienced substantial improvements in energy efficiency (EBRD, 2006), partly as higher (cost-reflective) prices have driven substitution and investment towards less energy intensive processes and partly from increased awareness of the opportunities and the implementation of energy-efficiency measures introduced through regulatory and policy reform.

Second, efficiencies derived from reduced losses. The development and implementation of robust collection mechanisms at the supply level is expected to reduce non-technical losses from relatively high current levels measured on a regional basis. Investment in transmission and distribution networks and interconnector capacity is expected to reduce technical losses. The most efficient countries in the region in terms of distribution losses of electricity are Greece and Slovenia with 8% and 4% of distribution losses, respectively. In a sharp contrast to these two countries, Albania is losing more than 30% of its domestically supplied electricity due to inefficient transmission and distribution networks. For the remainder of the region this ratio lies in the interval of 10-20% of losses.

All countries in the region have experienced increased in the use of electricity per capita over the period we consider.[9] This ratio is considered to be a good

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[8] The "Union for the Co-ordination of Transmission of Electricity" (UCTE) is the association of transmission system operators in continental Europe.

[9] This parameter is calculated as a ratio of domestically supplied electricity to the size of population in a country. Domestically supplied electricity is equal to the totally produced electricity in a country adjusted by the net export of electricity. However,

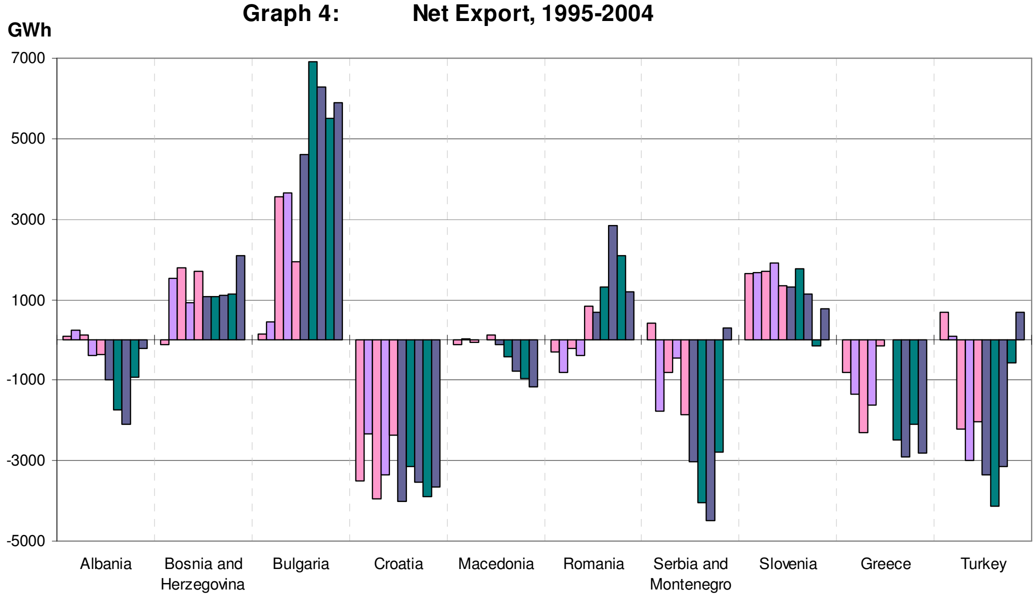
proxy to the economic development of a country, since it captures a disposable volume of electricity for all types of economic activity . Turkey and Albania are characterized by a very low domestic supply of electricity per capita, and while per capita consumption of electricity in these two countries is almost three times lower than in the most economically developed countries in the region (Greece and Slovenia), they are net importers. Thus, the anticipated economic development in Turkey and Albania will increase the demand for electricity and, absent significant investment in generation and transmission capacity, their dependence on imported electricity must also rise, and is expected to converge to the regional and European average. Bosnia and Romania are in a slightly different situation. While domestic supply per capita is also low, they are currently are net exporters of electricity. It follows from the logic above, that without expansion of generation facilities, the export potential of Bosnia and Romania will decrease over time, and at some point could become net importers of electricity as Slovenia did in 2003.

TRADE

The varied import/export status of countries implies different policy choices, for example, choice of tariff regulation regimes, ownership structure, sequencing of reforms, the degree of liberalization, and the choice of pricing mechanism.

The region as a whole and most countries within it are net importers of electricity, including the biggest producer , Turkey. The largest exporter, Bulgaria was the only country to export on a monthly basis throughout 2005. The other net exporters are Bosnia and Romania. Slovenia was a net exporter for all years in our dataset except 2003. It is interesting to note that three of the four net exporters in the region are also nuclear energy producers.

Graph 4: Net Export, 1995-2004



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domestically supplied electricity includes both technical and non-technical losses that occur at the stage of transmission and distribution to final consumers.

SEE as a region is a net importer. There was a dramatic increase in import volumes between 1995 and 2002, from 1837 GWh to 5549 GWh, followed by a decrease to 2657 GWh in 2003. The recent substantial decrease in the electricity dependency of the region can largely be explained by a significant improvement in the net export of electricity to Turkey, which reduced its negative electricity trade balance from -3000 GWh in 2002 to +681 GWh in 2003.

Cross border flows inside SEE and with Central Europe have improved since 2004 as a result of the reconnection of the two UCTE zones. As discussed above, introducing competition into electricity markets relies significantly on fostering competitive pressures that derive from diverse resource endowments and comparative advantage. Thus cross border trade will be crucial to the liberalisation of electricity markets in SEE. A recent simulation modelling exercise of the SEE system excluding Turkey and Greece generated some tentative conclusions regarding possible outcomes of a competitive, fully liberalised wholesale market (REKK, 2007). Key results were that Bulgaria and Romania are low-cost exporters within the region, that prices in central and western parts of the region are strongly influenced by those in neighbouring countries outside the region, and that under certain conditions, weak interconnection and inadequate domestic generation capacity results in Macedonia and Albania becoming a high-priced sub-region.

INSTALLED CAPACITY AND MARKET POWER

In order to maintain an economic growth in South East European countries there is an urgent need to increase electricity generation, improve efficiency and find reliable partners to supply deficient amounts through import. As a result of these considerations the prime concern of the countries and international bodies involved is to create the conditions such that domestic and foreign investors are willing to build new generation facilities and rehabilitate the existing ones. However, not much attention is paid to a potential problem of the abuse of market power within each country as well as across the whole or part of the region The companies in possession of marginal generation capacity might exercise their market power at the time of peak demand by withholding electricity from the market or artificially creating congestion in the transmission system. Such strategic behavoir would enable companies to profitably increase prices above competitive levels.

Table 1 presents the largest power stations in each country in terms of installed capacity, approximate market shares as well as fuel type. Traditionally, nuclear, coal and run of river hydro facilities usually run as baseload, while gas/oil plants and hydro with storage ponds are more flexible and therefore distpatched mid-merit and to meet peak demand. In a competitive market then, these plants could be dispatched in response to price signals. We note that generation facilities in SEE commonly operate well below their installed capacity due to poor reliability, including degraded infrastructure. Another issue is that a hydro power station might be a part of a large hydro complex (cascade) therefore in case of privatization it would be sold as one package, and the total installed capacity of the newly created entity would be much greater. Therefore, this table indicates just a potential for the exercise of the market power in each country.

Table 1. Largest power stations in each country in 2005 by installed capacity, approximate market share and type of fuel used.

Albania	MW		
Total	1520		%
Komani	600	hydro	39
Fierze	500	hydro	33
vauDejes	250	hydro	16
UlzaShkopet	50	hydro	3
		total	92

Croatia	MW		
Total	3984		%
Zakucac	486	hydro	12
Sisak	420	oil/gas	11
ZagrebTE-TO	345	oil/gas	9
Rijeka	320	oil	8
		total	39

Turkey	MW		
Total	38802		%
Ataturk	2405	hydro	6
Karakaya	1800	hydro	5
Afsin-Elbistan	1715	lignite	4
Gebze	1595	gas	4
		total	19

Bosnia	MW		
Total	3714		%
Tuzla3,4,5,6	715	Lignite	19
Kakanj5,6,7	450	br coal	12
Capljina	420	hydro	11
Visegrad	315	hydro	8
		total	51

Macedonia	MW		
Total	1486		%
Bitola	675	lignite	45
Negotino	210	oil	14
Vrutok	150	hydro	10
Oslomej	120	lignite	8
		total	78

Serbia	MW		
Total	7647		%
NikolaTesla1-8	2892	lignite	38
Djerdap 1	1058	hydro	14
Kostulac1-4	1008	lignite	13
BajinaBasta1,2	978	hydro	13
		total	78

Bulgaria	MW		
Total	10917		%
MaritsaEast1-3	2280	lignite	21
Kozloduy5,6	1440	nuclear	13
VarnaTPP	1260	coal impoı	12
Chaira	864	hydro	8
		total	54

Romania	MW		
Total	17589		%
Turceni	1650	lignite	9
Portile de Fier	1398	hydro	8
Mintia-Deva	1274	black co:	7
Rovinari	990	lignite	6
Ludus	800	gas	5
Cernavoda1	700	nuclear	4
		total	39

UNKosovo	MW		
Total	1513		%
Kosovo1-7	1478	lignite	98
		total	98

Montenegro	MW		
Total	840		%
Piva	342	hydro	41
Perucica	307	hydro	37
Pljevlja	191	lignite	23
		total	100

Source: GIS (2005) and national electricity regulators' websites.

In most small countries there are just a few generation facilities and the biggest four producers control a significant proportion of the total installed capacity. For example, in Montenegro there are only 3 producers and in Kosovo one. In Albania, Macedonia, Serbia the largest 4 producers hold 92%, 78% and 78% of the total generation capacities respectively. While in Turkey, Romania and Croatia the top four producers hold less significant proportions of the total generation capacity (19%, 30%, 39% respectively).

As we noted above, it would be difficult or impossible to develop a competitive electricity market within smaller SEE systems, but competition could be introduced to these through participation in the regional electricity market. As a consequence we might expect the biggest supporters of the regional market to be industrial and residential consumers and policy makers in these small countries, because it would be one of a very few ways to put a competitive pressure on dominant players in their countries. Obviously these groups will face a strong resistance from dominant players, who will try to protect their market power. Larger countries (Turkey, Romania, Bulgaria, Serbia, Greece) do have sufficient scale to develop a competitive market within their borders. Policymakers should take careful steps while privatizing and reforming the electricity sector in these countries to minimize chances of the abuse market power by a newly created or reformed companies, that might obtain an ability to strategically exercise market power through marginal capacities within countries' borders.

Another important issue is that, as privatization is rolled out across the region, large multinational energy companies, for example, ENI, ENEL and CEZ are investing in generation facilities as well as distribution companies. ENEL is active in distribution and generation in Bulgaria, Romania and Greece. CEZ (a Czech Republic based energy group) acquired generation and distribution facilities in Bulgaria and Romania. ENI is building stakes in generation, transmission and distribution electricity and gas companies in Turkey, Romania, Croatia, Slovenia and Greece. Given the limited scale of privatization in the region, these energy companies are not as yet able to exercise market power in each separate countries or the region. However, with the opening of national markets and the establishment of the regional market, they might acquire marginal capacities across a country or the whole/part of the region, enabling them to manipulate prices. Those who design and implement regional market policies should be aware of this fact and put safeguards in place to minimize competition problems in the future.

ENVIRONMENTAL IMPACT OF ELECTRICITY GENERATION

Consideration of environmental impacts is critical to a comprehensive study of electricity generation, but is particularly appropriate where the market under consideration includes transition economies. Power generation in OECD countries accounts for some 38% of energy related CO_2 emissions, a share that is expected to remain approximately stable to 2030. But in transition economies, the share in 2002 was some 52%, and IEA data shows that by 2030 it will still represent 47% of the total (IEA, 2004). Given the impending generation gap in the region, and the implied generation expansion, this suggests that the power sector has the potential to make a meaningful contribution to a reduction in regional emissions of green house gases (GHG).

In accordance with Decision 2002/358/EC , Directive 2003/87/EC requires that, by 2008 to 2012 the Community and its Member States (MS) collectively reduce anthropogenic GHG emissions by 8% relative to 1990 levels, and recognises the longer term requirement to reduce GHG emissions by 70% relative to 1990 levels. The key mechanism for achieving this commitment is the EU Emissions Trading Scheme (EU ETS) for CO_2, introduced in 2005. Others include targets for electricity production from renewable energy sources and energy efficiency. While MSs are obliged to implement EC legislation in full, many of the ECSEE members are not as yet MSs, so do not share this obligation. However, we note that the prospect of membership is an incentive for would-be MSs to adopt emissions reduction targets and measures that would bring them into compliance with the Directive by some date after 2012.

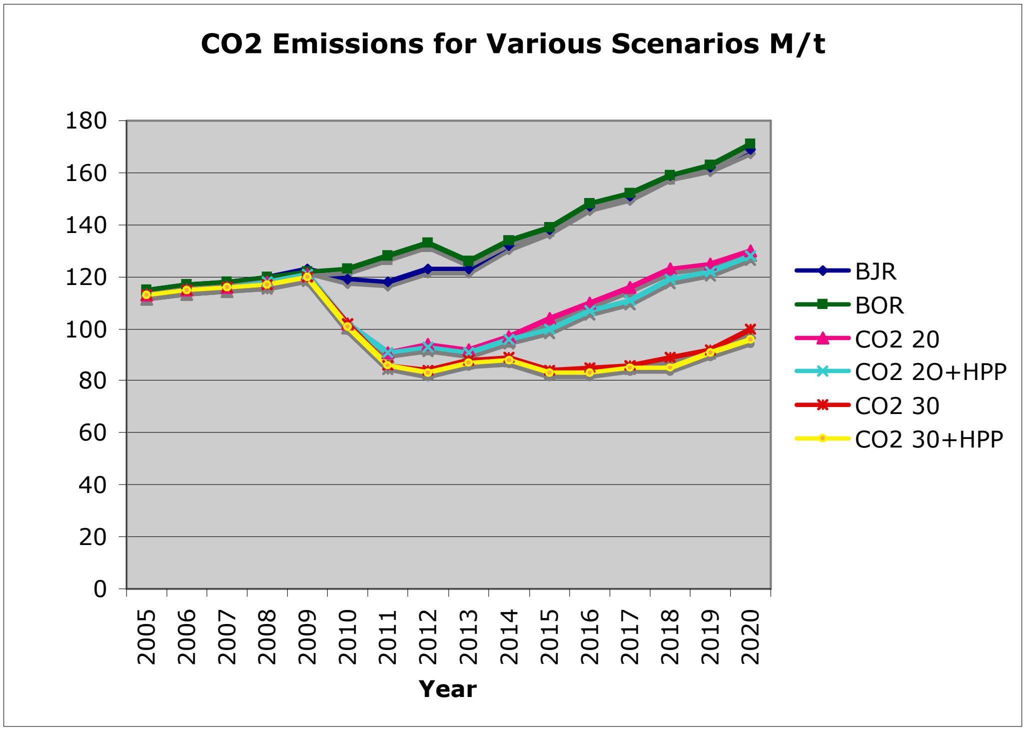
We now discuss the factors that have the potential to influence progress towards these challenges and objectives in a competitive market. The drivers of demand for electricity were outlined above, and clearly policies and actions that influence these drivers will have an impact on system load and hence on total emissions. However demand is not the subject of this section. On the supply side, upgrading transmission and distribution infrastructure would reduce losses, and investment in low carbon generating technologies would reduce emissions associated with a given capacity. Taken together, such investments could substantially improve the productive efficiency of a system, particularly if the infrastructure is partially degraded and where generation plant is old and possibly unreliable.

However, it is the generation mix, not the capacity mix, that determines realised emissions. Under standard economic assumptions generators can be expected to minimize long-run costs, and since electricity generation is very capital intensive, with capital costs amounting to around 50% of total costs, marginal costs of production are dominated by fuel and operations and maintenance costs. Which brings us to the third factor, the price mechanism. At the most basic level, price competition is a mechanism for matching demand and supply, and the efficiency of this mechanism rests absolutely on the correct pricing of externalities. Moving to a carbon-constrained environment therefore requires that CO_2 a damaging externality of industrial production, and of electricity production in particular, enters generators' cost function, so inducing a shift towards less carbon intensive electricity production over time. Thus policies that bring about closer alignment between true social costs and prices will improve efficiency. The EU ETS is an example of just such a policy as are schemes to support renewable energy sources (RES) such as Germany's Feed In Tariff.

We will return to discuss the feasibility of assuming that a nascent market such as that in ECSEE can deliver the emissions savings promised by a competitive market. Next we shift focus onto the projected impact of planned capacity expansion on the generation mix in SEE and hence actual emissions.

Graph 5 charts projected total CO_2 emissions for the ECSEE under a range of scenarios presented in the recent GIS Update (2007)[10]. The study simulated a least cost power development plan for ECSEE given a loss of load probability of less than one day per year and certain assumptions regarding existing committed expenditure on rehabilitating existing plant and investment in new plant and for a plausible range of fuel prices. It is worth noting that the study assumed operating the system as one integrated regional system. One objective of the study was to calculate the impact implied by specific carbon prices on the amount of CO_2 generated and on the change in the technology mix.

[10] Unfortunately the GIS data does not cover Greece or Turkey, and it should be stressed that this analysis therefore does not include the impact of these countries.



Graph 5. CO_2 Emissions for Various Scenarios
Data source: GIS Update (2007)

Graph 5 shows the two reference cases, basecase with justified (on a least cost basis) rehabilitation and official investment plans (BJR and BOR), which can be regarded as 'business as usual' in that they focus on rehabilitation of existing thermal power plants (TPP) and investment in new TPP. From a total capacity in 2005 of around 42,817 MW , the simulation for BOR resulted in 11,574 MW rehabilitation (BJR 9,361), and 11,022 MW new capacity (BJR 12,696) all of which burn fossil fuels. Unsurprisingly, both generate projected increases in emissions for the region as a whole, but the degree of increase, some 60% over the planning period (to 2020) is alarming.

A further two scenarios assume carbon prices of €20 and €30 CO_2/t. A CO_2 price of €20/t is associated with 4,573 MW rehabilitation and 16,634 MW new build. Of this capacity expansion suggested by the simulation, all is TPP[11]. What the scenario suggests then, is that compared with no carbon price, less than half the rehabilitation of existing TPP is cost effective, but rather it becomes efficient to invest in new technologies with comparatively lower carbon footprints. These include 2.500MW Kosovo lignite, 7,900 MW combined cycle gas turbine (CCGT) and 3,000MW imported coal.

The model then associates this capacity mix with a large increase in (relatively clean) gas and a reduction in lignite production. At this carbon price fossil fuels account for 51.7% of capacity, but only 42.5% actual generation.

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[11] With the exception of pre-committed and financed nuclear plants Belene in Bulgaria (960MW) and Cernavoda in Romania (2x680MW).

This is largely explained by the share of nuclear capacity of 10.4% but generation from nuclear plants of 19.9%. While the model does not suggest additional investment in nuclear at €20 CO_2/t, there is about 2,400 MW nuclear pre-committed and pre-financed.

At €30 CO_2/t., no rehabilitation is cost-effective so the simulations suggest existing TPP would be retired instead, and to maintain the LOLP assumed 21,259 MW new capacity would be installed over the planning horizon. Additionally, 5,000 MW of new nuclear is built, along with 7,900MW CCGT, 2,500 Kosovo lignite and 2,500MW imported coal. While in this scenario 64.9% installed capacity is fossil fuel, only 53% generation is in TPP. Again the suggested production from nuclear, at 27%, is disproportionate to installed capacity at 14.8%. At this price, for all other fuels, the model resulted in production approximately proportionate to installed capacity.

Given the potential for hydro power plants (HPP) in the region, the model was also run for scenarios in which around 2,000 MW HPP were 'forced' into the system. As Graph 5 shows, this made almost no difference to total emissions under either of the CO_2 price scenarios. This is due to the comparatively low contribution relative to the system size.

So what can we conclude from this analysis? As discussed repeatedly throughout this and other papers in this volume, electricity market integration in South East Europe has the potential to deliver significant benefits relative to the operation of separate national systems. But even assuming optimising at a regional rather than national level, CO_2 emissions implied by the two business as usual scenarios shown in Graph 5, BOR and BJR, are some 60% higher than those in 2005. The mechanisms by which this increase in emissions may be mitigated in a competitive market were discussed above, and it is clear from the GIS Update that introducing a price for CO_2 has a significant effect on the investment decisions of generators such that emissions may be controlled and potentially even reduced.

There are, however, obstacles to realisation of these potential gains. First, as the recent Quarterly Report on progress in electricity published by ECS makes clear, there is, as yet, limited progress in putting in place a framework that might incentivise generators to produce from RES. The heterogeneous nature of the systems in the region, and the fact that only the larger nations are MSs of the EU contribute further complexity to the task of developing a coherent regional policy on which all can agree. The development of effective policy in this area is challenging, but particularly so when set against the backdrop of market liberalisation and the introduction of competition into national markets. The second possible problem relates to the CO_2 price. The model developed in the GIS Update (2007) shows that a CO_2 price of €30 would be required to keep emissions at approximately current levels. As we ener the second trading period of the EU ETS, we observe that over the 12 months to 17 January 2008 EU Emissions Allowance (EUA) futures for 2009 delivery have climbed from a low of approximately €12 to around €23[12]. While it is still early days, clearly the EUA price is moving in the right direction.

Environmental sustainability is an explicit objective of EU energy policy, and thus of ECSEE nations. Indeed the majority have ratified the Kyoto Protocol or expect to do so. But we argue that it may be at odds with other policy objectives. Or to be more precise, that there is a significant trade-off to be made between the objectives embodied in EU energy policy (Roller, et al. 2007) as well as between EU energy policy and EU competition policy which is primarily concerned with the creation of a Single European Market, and implies reduced prices. We suggest that the approach to energy policy formulation outlined in the Electricity Transition Strategy is likely to prove insufficiently robust to the significant challenges posed by these trade-offs.

Competitiveness is commonly associated with low prices, however it would be more useful to place emphasis on cost-reflective prices that fully internalise externalities. The EU ETS is an efficient mechanism for ensuring that the polluter pays but in heavily fossil-fuel based systems, it implies increased electricity prices. This raises concerns about the possiblility of a loss of industrial competitiveness. To the extent that the electricity component in total costs varies by sector, and depending on the distribution of free emissions allowances and the level of cost pass-through, increased prices may have an asymmetric impact on competitiveness from sector to sector (Hourcade et al., 2008). Given the diverse resource endowments in the SEE region, with for example Albania meeting almost 100% of electricity demand through hydro generation and Serbia 60% through coal, there appears to be little incentive for governments to adopt policies that will minimise regional emissions. The sustainability objective is therefore strongly associated with the energy mix since different sources of electricity have different CO_2 intensities.

The interaction between policies supporting environmental sustainability and security of supply are also complex. Energy security is again intrinsically linked with the generation mix. Most nations have a preference for energy independence, though the SEE region is, and is likely to remain, a net importer of energy. While the GIS forecasts increasing generation from gas, which is less carbon intensive than coal, there is little gas in the region which implies increasing import dependency. Furthermore, there is an expectation that long term gas prices in this region will remain indexed to the oil price, so this expansion path implies increased regional exposure to both supply and price shocks.

In sum, the optimal generation mix will be quite different depending on which objective is being optimised, competitiveness, security of supply or sustainability. And the position will vary from country to country according to resource endowment, existing generating plant and attitudes to, for example, nuclear power. It is difficult to see how energy policy controlled at national

[12] Source: European Energy Exchange website http://www.eex.com/en/Market%20Information/Emission%20Allowances/EU%20Carbon%20Futures%20%7C%20Derivatives accessed 08-01-17.

level can result in a coherent regional energy policy that reconciles the three objectives.

RISKS ASSOCIATED WITH DIFFERENT TYPES OF FUELS

As we described above, the region as a whole has the following generation mix: 40% coal, 23% hydro, 23% gas, 7% oil, and 7% nuclear. Most of the coal used in electricity production is domestically supplied and according to the GIS report its price remains relatively constant through time. The technological characteristics of nuclear plant suggest that it is dispatched as base-load generation, with constant output. Nuclear plant is particularly capital intensive, and costs also remain relatively constant due to the low proportion of total cost accounted for by fuel cost, and long term contracts agreed with fuel suppliers. These two fuel types contribute 47% to the total electricity production of the region and could be considered as relatively 'controllable' by a domestic country, i.e. input costs are locally determined.

The usage of the other three types of fuel in electricity production bears certain supply risks. One is associated with the supply price risk. For example, gas and oil contribute 30% to total electricity production. These two types of fuel bear "price risk" because none of the South East European countries has significant reserves of either oil or gas, while price is determined in world markets. Therefore, all countries in the region are price-takers and in a case of any supply/demand shock in the world oil market (usually gas price is tied to the price of oil), the countries will have to bear extra input costs or adjust their consumption accordingly. Thus, this dependency on oil and gas-based electricity leads to uncertainty in electricity prices for final consumers and feasibility investment projects in the region.

Another dimension of risk is a physical-supply risk associated mainly with the production of electricity by hydro electro stations in the regions. Hydropower contributes 23% to the total electricity production but is inherently dependent on hydrological conditions, particularly as the majority of hydro power plants are run of river rather than storage. In dry seasons rivers and even reservoirs become relatively empty, which constrains the ability to produce electricity. A high dependency on hydro power means that Albania and Bosnia are particularly exposed most to this type of risk. But equally, that they would have much to gain in terms of supply security from regional market integration, as discussed above.

Finally, we consider briefly environmental risk. There is significant uncertainty about the scope of future environmental laws and regulations that may have a significant impact on electricity generation within SEE and globally. While agreements reached at the 2007 Bali conference have been generally well received by environmental economists there remains considerable uncertaintly about future climate policy. which will raise the cost of investing in new generating capacity. At the time of writing, we do not have an agreement regarding what may come after the end of the Kyoto Protocol agreement in 2012, though we do have a roadmap to guide negotiations over the next two years. The problems of the utilization of nuclear energy and the disposal of nuclear waste remain unresolved. The heavy reliance in SEE on fossil fuel generation means that these types of environmental risks are a very real concern for governments, generators and potential investors in new generation capacity.

There is a real danger that public opinion and popular myth regarding price formation may motivate resistance to electricity market reform and undermine political commitment to, and crucially, investor confidence in the ECSEE project. Experience in the Nordic market provides evidence that at least domestic consumers prefer stable prices (von der Fehr et al. 2005). An important fact, which is specific to the SEE region, is that a high proportion of domestically supplied electricity is consumed by households rather than industries. Thus market liberalization is highly politicised. One of the major concerns that critics of the liberalization of electricity market express is that liberalization would lead to volatility in electricity prices and would hurt residential consumers and especially vulnerable groups of the population (Borenstein 2005). The fact that the residential consumption is more than 70% of the total final consumption in the Albanian economy and more than 50 % for Bosnia, Macedonia and Serbia makes it politically extremely difficult to liberalize the electricity market in these countries. Any supply/demand shocks would directly affect the population and especially vulnerable groups of population, which are a big proportion of population in such countries as Albania. This would increase pressure on national and local government to reverse reforms and continue to subsidize electricity for the general population.

DISCUSSION AND CONCLUSION

Capital investments, market fragmentation, vertical integration, and state ownership are the issues that most of the countries in South East Europe must resolve during the restructuring process. An efficient regional energy market would facilitate meeting peak demand in individual countries, improve the reliability of and stability of electricity supply across the region, encourage private investment and match the growing demand for electricity in the long-run. However, each type of fuel bears various risks for customers, energy companies and countries. Dependency on such types of fuel as hydro and thermal electricity could expose countries to physical supply shortages in a case of unfavorable natural or market conditions. Private investors would prefer transparency and predictability in regulatory and environmental policies when developing nuclear and thermal generation facilities rather than risk additional costs of complying with newly introduced stricter environmental laws. On the demand side, it is common to hear final consumers voicing concerns about price risk that they would bear after the liberalization of the electricity market. This fact could lead to an additional political pressure on politicians and regulators that could result in a halt or even reverse of reforms in the sector.

Carefully designed electricity market integration has the potential to address several of the key concerns expressed in contemporary energy policy. The Nordic Market suggests that moving from a set of vertically integrated national systems to a regional market is possible, and consumers in that region enjoy among the lowest (but cost-reflective) prices in the EU. But integrating the four systems has taken the best part of a decade to achieve, and was motivated by strategic interests of all the players. Levels of trust between the parties were high and the required trade-offs were judged to be acceptable.

By contrast, the motivation for integration in SEE appears to be on the one hand related to aspirations to membership of the EU, and on the other, a growing realisation that absent significant investment in generation and transmission capacity, consumers may have to accept regular supply shortages, as experienced in Albania in the last quarter of 2005.

While the potential gains from regionalisation are significant, and arguably critical to the continued economic development of SEE, so too are the institutional and political challenges posed by market integration. It is not clear how energy policy controlled at national level but with 'a regional dimension' will result in a coherent regional energy policy that reconciles the three objectives of EU energy policy, competitiveness, security of supply and sustainability.

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