Advisory

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Market analysis and priorities for future development of the Electricity market and infrastructure in Central-Eastern Europe under the North-South Energy Interconnections initiative

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1. Executive summary

In line with the European Union strategic goals set by the Lisbon European Council, the Commission is proposing a new strategy to develop an integrated European energy network which can offer a stable and reliable supply of energy to European citizens, while reducing the carbon footprint of the energy sector.

The Communication on infrastructure priorities[1], which was adopted on November 17th 2010, identified a range of priorities that must be implemented by 2020 to allow the EU to meet the energy and climate targets. The Communication put forward a new method of planning which build on the strengths of regional cooperation as a stepping stone towards the completion of the EU objectives.

In order to reach this aim, the Commission has launched a number of initiatives dealing with specific macro-regions within the European Union. One of these is focused on North-South Interconnections in Central-Eastern Europe, and in this area a High Level Group (HLG) has been set up in order to promote the required regional cooperation, implementation of energy infrastructure projects and improve market development and renewables integration. The countries of Austria, Bulgaria, Croatia, Czech Republic, Germany, Hungary, Poland, Romania and Slovakia and Slovenia together form the Study Area for this project.

This particular study refers to the Working Group (WG) of the North-South Interconnection Initiative, which shall support the High Level Group in delivering an Action Plan on the development of electricity interconnections and internal market actions by October 2011.

Section 2 provides an introduction to this report. This particular study refers to the Working Group (WG) of the North-South Interconnection Initiative, which aims to prepare an Action Plan on behalf of the High Level Group, which will identify and address obstacles to the realization of the connections in Central Eastern Europe.

Section 3 provides the results of our market analysis (Task 1). Data for 2010 is based primarily on information from the European Network of Transmission System Operators for Electricity (ENTSO-E); 2020 analysis is based on the actual 2010 data updated using growth rates from the PRIMES model for each dataset.

Overview of the current situation: 2010

Total electricity consumption in the study area in 2010 was 1.006 TWh, dominated by Germany, where total consumption in 2010 was 548 TWh (55% of total demand amongst the countries considered). The second market was Poland, where total annual demand was 143TWh (14% of total demand amongst the countries considered). Throughout the study area, the average sector split of electricity consumption is 82% for final energy demand (to customers), 11% for energy branch electricity usage[2], and 7% for transmission and distribution losses. Within final energy demand, industry is the largest single sector in nearly all countries, with the split between households and tertiary varying across the study area. All countries have peak demand in Winter (December - January). For adjacent and interconnected grid systems, differences in peak demand should be taken into account in grid planning – for example between Germany and Poland, Hungary and Romania – to determine where generation capacity requirements can be met through interconnection to plant in other markets, where this offers greater efficiency.

[1] Communication "Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network" COM(2010)0677

[2] Own consumption & pumping and Refineries & other uses.

The largest share of capacity (GW) in the study area was from conventional thermal power (146 GW, 54% of total capacity). Total capacity for renewable generation was 92GW (34% of total capacity), made up predominantly of hydro, wind and solar. Total nuclear capacity in the region was 32GW (12%). There is considerable variation by country with nuclear forming 18% to 27% of capacity in Slovakia, Slovenia, Hungary and Bulgaria. Austria has more than 60% hydro capacity, with Croatia, Romania, Slovakia and Slovenia also having at least 20% hydro. Wind is particularly significant in Germany (18%) and solar is circa 11% of capacity in both Germany and Czech Republic. In Poland, Hungary and Czech Republic, over 60% of capacity is from thermal plant. In terms of generation (GWh), total generation was 1.044TWh, equal to 104% of consumption within the study area. The share by plant type within the study are 61% from conventional thermal plant, 21% from nuclear and 18% renewable generation.

Generation load factor for the study area was 44% (based on total capacity and total generation). Slovenia's generation load factor is highest in the study area at 57% whereas the lowest overall generation load factor was in Austria (34%).

Generation capacity margins for countries in the study area ranges between 36% (Poland) and 120% (Austria) – however four out of the nine countries have generation margins between 35% and 55%. Where a low load factor is observed, for grid planning purposes it is equally, if not more, important to understand the extent to which the capacity is flexible and controllable thus available to be dispatched to meet market demand or grid requirements; or intermittent, requiring more responsive management mechanisms from both grid operators and market participants.

Market share is most concentrated in Croatia, Slovakia and Czech Republic, where more than 60% of the total national annual electricity production is generated by the largest electricity producing company. Eurostat data indicates that in Poland, Germany and Romania this figure is below 30%, although other data sources for Poland vary.

Considering interconnections within the study area, the region has approximately equal levels of import and export capacity (as measured by NTC) – however Germany, Austria, Slovakia, Hungary, Romania and Croatia all have more import capacity than export, while Slovenia, Poland and the Czech Republic have more export capacity. Only in Bulgaria is export capacity equal to import. The average gross interconnection capacity (import + export) is 80% of peak demand, however there is a significant degree of variation between countries.

The study area as a whole has a net positive energy balance in 2010, with net imports of -33,5 TWh in 2010 (within and on the borders of the study area), equivalent to 3% of total generation within the area – all countries except Hungary, Croatia, Austria and Slovakia (by a small margin) were net exporters. Whilst some countries such as Czech Republic and Bulgaria were net exporters in each month, in other cases, significant changes within year were observed in the pattern of net imports during the year when looking at monthly data.

Capacity utilisation at interconnection points within the study area varies significantly. The most heavily utilised interconnections are: from Germany to Poland; from Poland to Czech Republic; from Czech Republic to Germany; from Czech Republic to Austria; and from Slovakia to Hungary – each of these has more than 40% of hourly periods with over 50% capacity utilisation, arising largely from physical flows. Grid planning should take into account the seasonal patterns and maximum flows in order to ensure that sufficient capacity is provided, reflecting that imports and exports will be determined not only by the physical demand and supply balance of interconnected markets but also by relative market prices.

Loop flows, as demonstrated by the difference between physical and commercial interconnection flows within the study area for 2010, were highest from Germany to Poland (loop flows occurred in 92% of hourly periods) and from Poland to Czech Republic (in 95% of hourly periods).

The incidence of loop flows suggests that, within the study area, unscheduled power (loop) flows from Germany into Poland are transmitted through Poland into the Czech Republic and Slovakia, and onward into Austria and Hungary. There are also significant loop flows between Romania and Bulgaria. There are lower incidences of loop flows back into Germany, and from Austria into Slovenia and Hungary, as well as from Czech Republic into Slovakia. Assessment of these flows suggests that those originating in Germany are linked to the production of intermittent generation (wind and solar) and that these same patterns of flows are passed through from Poland into Czech Republic and Slovakia, and from the Czech Republic into Austria. Significant loop flows also exist from Slovakia to Hungary, and from Romania into Bulgaria, although these show less correlation with those originating in Germany. The Slovenian TSO (ELES) has indicated that high loop flows over the Slovenian power system are frequent.

Average spot and day-ahead market prices throughout the region were €44,25/MWh during 2010 – prices were highest in Poland at €49,0/MWh. Spot market prices were lowest in Romania, with an annual average price of just over €36,4/MWh, and also below the average in Czech Republic.

The impact of interconnection on market prices is visible from price correlation data, where the highest price correlations exist between Germany and Czech Republic, Germany and Poland as well as Poland and Czech Republic. These markets have significant interconnection capacity, although all three locations showed instances of congestion, suggesting that further price convergence could result from higher levels of market integration.

Forecast for 2020

Overall, consumption in the area is expected to increase from 1.006 TWh to 1.074 TWh in 2015 (an annual increase of 1,34%) and to 1.119 TWh in 2020 (an annual increase of 0,81%). Romania is the country with the largest expected demand growth in the period (an annual increase of 2,55% for the period 2010-2015 and of 2,11% for the period 2015-2020), followed by the Czech Republic, (with an annual increase of 2,16% for the period 2010-2015 and 1,72% for the period 2015-2020). The high growth rate in Slovakia and Romania is driven by high growth in GDP (4,28% and 3,71% per annum respectively). The growth rate in final energy demand is particularly high in the tertiary sector in both countries. Germany has the smallest expected demand growth rate within the countries considered, with an annual growth of 0,93% for the period 2010-2015 and an annual growth of 0,14% for the period 2015-2020. However in absolute terms, Germany (together with Poland) is the country with highest expected growth, of c. 30GWh. The relative overall increase in forecast consumption levels should be examined in further detail to support further grid planning, taking into account where changes in the structure of demand (for example replacement of industrial demand by growth in the tertiary sector), given the implications for changing patterns of demand e.g. increased seasonality, lower consumption load factor.

In total, 75,4GW of capacity are projected to be added to the system within the study area by 2020, representing a 28% increase from 2010. Additional capacity is predominantly from wind and solar sources (66,6GW) as well as some thermal capacity (8,6GW), offset by the closure of nuclear capacity (11,7GW). Net additions to capacity are most significant within Germany, where capacity is anticipated to grow by 36% by 2020. Croatia also expect significant capacity growth in % terms with an overall increase of 78%. Thermal generation is forecast to increase by 75%, with further significant additions of wind and solar capacity. The main capacity additions in other countries also come mainly from renewable sources, although there are also additions of nuclear capacity in Bulgaria (1GW) and Slovakia (1,3GW).

Across the study area, generation is projected to increase by 9% over the period to 2020, just below the growth rate in consumption, but significantly below the 28% increase in capacity. Significant increases in the share of generation from renewable are forecast to occur predominantly in Germany and Hungary (respectively: 36% and 24% share of generation in 2020), changing the characteristics of energy production and flows in the north-east and centre of the region as transmission networks are required to deliver in intermittent generation to demand centres, as well as to link to other locations and markets to source balancing flows.

Analysis undertaken by Cambridge Econometrics together with KEMA and Imperial College London[3] indicates that additional interconnection capacity of c. 5.000MW is required within the study region, primarily to enhance links from Hungary and from Czech Republic to surrounding countries. Conclusions from the European Wind Integration Study (EWIS) suggest that the current pattern of loop flows is likely to continue, and our observations on forecasts of generation from intermittent sources support this, with potential increases in the loop flows originating in Germany. It is anticipated that the study area will continue to have a positive energy balance by 2020, although net imports for the region as a whole are projected to increase from -37.600GWh in 2010 to -28.200GWh in 2020. PRIMES data suggests that in the period between 2010 and 2020, that average production costs will rise by 25% from €43,7 to €58,4, with little change in the relative costs between countries.

Section 4 addresses the integration possibilities existing within the study area (Task 2). Market integration is defined by the ENTSO-E Mission Statement as "the process of progressively harmonizing the rules of two or more markets", with the goal of creating a market where electricity can flow freely in response to price signals. The existing state of market integration is considered with respect to: Physical interconnection; congestion management; and market operation.

Current status of market integration

The smaller markets of Slovenia and Croatia are observed to have the highest provision of physical interconnection relative to peak demand, with connections in excess of 15% of peak demand on both their borders within the study area. Slovakia and Czech Republic, located at the centre of the study area, also have connections with NTC greater than 15% of peak demand on two of their borders, while Hungary and Austria have only one interconnection with such levels capacity.

Congestion management for all interconnectors within the study area is undertaken via market-based mechanisms based on capacity auctions, which in most of the study area are managed by the Central Auction Office. In other markets (Bulgaria, Croatia and Romania), there is at least bilateral co-operation between TSOs in the determination of available capacity. In all markets, with the exception of Bulgaria, capacity rights are available for periods of up to one year, allowing market participants to hedge their longer term positions.

Nearly all countries within the region are currently involved in market coupling on one of their borders, with the exception of Bulgaria, Romania and Croatia. Reports indicate that some of the existing market coupling arrangements may soon be extended to include other neighbouring markets – for example the coupling of Hungary and Poland to the existing arrangements between Czech Republic and Slovakia.

The Austria / Germany market area is the most mature and liquid within the study area, although the market in Romania also has relatively high liquidity, supported by the mandatory auctioning of volumes from state-owned producers. Balancing is typically undertaken by the TSO or via exchange platforms.

Integration possibilities

Analysis suggests, at an indicative level, that the market s of Romania, Bulgaria and Croatia have the lowest levels of integration when considered across the spectrum of physical interconnection, congestion management, market coupling and market operation. Market integration of both Bulgaria

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[3] Cambridge Econometrics, KEMA, Imperial College London, The Revision of the Trans-European Energy Network Policy (TEN-E): Final Report, October 2010

and Croatia might be improved against each of the criteria, with the exception of physical interconnection provision in Croatia, which is already high relative to peak demand.

Slovakia, Slovenia, Hungary and Poland have all made some progress towards market integration, although in each of these cases market operation could be improved through more liquid exchanges for electricity trading over a range of forward and shorter-term periods. The provision of physical interconnection capacity in Poland is low relative to peak demand, as evidenced by observations of grid congestion on several borders.

Austria, Germany and Czech Republic show progress against all of the indicators of market integration discussed here, although in all these countries there are relatively low levels of physical interconnection capacity as well as evidence of cross-border congestion.

In terms of integration indicators, possibilities for the develop of physical interconnection are addressed in further detail in Section 6. A model for congestion management is provided by the Central Auction Office, with the potential for further improvements from the implementation of flow-based model, which could be expected to enhance the efficiency of capacity allocation. The presence of a number of exchanges within the central and eastern part of the study area, each with relatively low liquidity, suggests that consolidation into fewer, or even a single, exchange platform, may generate more liquid market through the trading of products across a wider market area. Each of these measures is likely to be reinforcing, since each step towards market integration improves the competitiveness of energy markets thus provides commercial incentives for further integration.

Section 5 addresses the identification of bottlenecks and potential development options (Task 3). In practice, bottleneck identification will need to be pragmatic, depending to a significant extent upon expert judgement but carefully monitored to ensure consistency of criteria across the full assessment process. It will be driven by an analysis of historical data reflecting recent market conditions and has to be based on existing and readily available data sources. Juxtaposing the data available from the ENTSO-E transparency platform with the general list of indicators associated with bottleneck locations suggests that practicable indicators that can be seen as a primary basis for highlighting potential bottlenecks relative to NTC for each of cross-border physical flows, commercial flows and final cross-border delivery schedules respectively.

To implement this general approach, we have identified those interconnection points where utilisation of cross-border physical capacity lay between 50 and 99% in at least 15% of hourly periods during 2010. We have also examined those interconnections where the % of time periods when physical flows exceeded final cross border flows more than 30% of the time. We have further identified pairs of countries where market price or auction data patterns may be consistent with limited cross-border capacity. Combining these three indicators gives the following list of potential bottlenecks (where all three bottleneck indicators are met): Poland to Czech Republic, Czech Republic to Germany and Poland to Slovakia; in addition Austria to Slovenia, Czech Republic to Austria, Germany to Poland and Slovakia to Hungary present two out of the three bottleneck indicators.

In the case of flows from Poland to Slovakia, as well as Poland to Czech Republic, physical flows are greater than commercial flows in the majority of hourly periods, suggesting that congestion at these interconnection points is cause largely by loop flows, as the capacity utilisation on a purely commercial basis would be significantly lower. Between Czech Republic to Germany, congestion is causes largely by commercial flows which are higher than physical flows, suggesting that capacity is in fact utilised less than commercial arrangements would suggest.

Section 6 covers the assessment of current and planned projects (Task 4).

Prioritisation approach

Criteria for project prioritisation were selected on the basis of the EU energy sector objectives of market integration, security of supply and promotion of renewable resources. Indicators were defined on the basis of selecting, where possible, quantifiable measures which could be used to evaluate the extent to which each project met the defined criteria. The assessment process involved the use of a linear weighting and scoring model, sometimes referred to as a MADA (Multi-Attribute Decision Analysis) model, to evaluate the evidence provided against each of the indicators.

All Working Group participants were invited to submit a 'project fiche' for each of the projects which they wished to be considered for prioritisation. The purpose of the prioritisation exercise was to support the wider process of deciding which projects should be prioritised, through a review and assessment of individual proposals' relevant strengths, ensuring that each proposal is, as far as practicable, assessed in an identical manner to all the others. Our evaluation did not include any diligence on the project fiche responses which were assessed on the basis of the answers provided. The list of priority projects will continue to be reviewed, specifically in the light of more detailed market analysis (once this is available from ENTSO-E) and also on the basis of revised or additional project information, as and when this may become available.

Preliminary prioritisation outcomes

A total of 67 project fiches were initially submitted for assessment, including several project clusters, from which 9 interconnectors and 22 internal projects (within one Member State) were proposed as regional priorities. The remaining 27 projects are proposed for consideration as national priorities.

Figure 1: Summary of preliminary prioritisation outcomes

	Regional Priorities		**National Priorities**
	Interconnectors	Other	
Austria	1 (DE)	3	0
Bulgaria		1	3
Croatia		1	2
Czech Republic	1 (DE)	3	0
Germany	3 (PL x 2, CZ)	3	0
Hungary	2 (SK)	0	22
Poland		6	0
Romania		3	1
Slovakia	1 (HU)	0	0
Slovenia	1 (HU & HR)	2	0
Sub-total	*9 **	*22*	
TOTAL	**30**		**28**

* Since 2 projects are listed for several of the interconnected countries

In addition to performance against the selected prioritisation criteria, the impact of the prioritised projects was mapped against the findings of our market analysis. The table below summarises these issues, and lists the proposed regional priority projects which address those issues.

Conclusions of market analysis	Key issues adressed by priority projects
Current infrastructure heavily utilised: • Germany to Poland • Czech Republic to Germany • Czech Republic to Austria	Enhanced capacity at border locations: • Germany and Austria, Czech Republic, Poland • Slovenia and Croatia / Hungary • Slovakia and Hungary
Loop flows are a particular issue from • Germany to Poland; Poland to Czech Republic; Poland to Slovakia	Management of loop flows at border locations: • Germany and Poland • Germany and Czech Republic /
Significant increase in renewable generation capacity by 2020, located mainly in the north of the study area, and significant reduction in nuclear capacity Lower load factor and reduced "dispatchability" likely to increase the requirements for balancing networks – requirements for energy storage and, where possible, sharing of peaking capacity	Connection of generation capacity: Germany, Czech Republic , Romania, Slovakia, Slovenia Connection between wind capacity / flexible plant and pump storage: Austria, Romania
Extended distances likely to require increased long distance transmission capacity	Strengthening of internal network: Austria, Bulgaria, Croatia, Czech Republic, Germany (including management of reactive power), Romania, Slovenia, Poland

Section 7 covers the identification of implementation obstacles (Task 5). As part of the project assessment exercise (Task 4) project proponents were asked to identify the key obstacles facing their projects. The key risks affecting projects which have been identified as regional priorities are focused on development phase issues, which is not surprising given that the majority of projects under consideration are currently at the stage of pre-feasibility, feasibility or permitting.

The key implementation obstacles identified were:

Obstacles	Key issues
Financing	Scale of funding required for regional priority projects is significant – in Czech Republic, Germany and Slovenia the investment cost of regional priority projects alone is close to or in excess of 100% of existing non-current assets Difficulties in securing financing are likely to be faced by TSOs who are largely state-owned The current status of European (and indeed global) financial markets presents higher costs of financing than in recent years due to reduced

Obstacles	Key issues
	liquidity and the cost of more stringent banking regulations Certain projects may have specific technology risk, arising from the uses of innovative technologies or application of standard technologies in challenging environments Regulatory framework is key to funding
Regulatory framework	Competing regulatory priorities may arise from the various legal and policy frameworks within which regulatory authorities operate Certain projects, where the scale of investment is very significant relative to the existing RAB, may create a 'step change' in transmission tariffs which can be a barrier to regulatory approval Within current regulatory approaches it can be complex to provide evidence that specific investments will provide a measurable contribution to policy goals There is no defined approach for cross-border projects, meaning that regulatory approval for such projects can take place only within a policy framework designed to address internal projects although co-operation between regulators may occur at a policy or EU level, there is no framework for interaction between authorities in relation to approval of specific projects A lack of market alignment within the study area may constrain demand for access to interconnection capacity Once a project has been given regulatory approval, one of the key remaining risks for investors is changes to the regulatory regime, which may resulting in higher risks and lower returns.
Permitting and consents	Failure to respect priority corridors for infrastructure within local and national planning processes Lack of clarity, for example in the documentation, process, timetable, exemption criteria and, governing legislation. Complex and time-consuming documentation and reporting, e.g. EIA report and other requirements under the SEVESO regulatory framework. Sequential and multiple sequence steps required rather than parallel handling Lack of flexibility Lack of iterative procedures means that revised permitting applications are treated as though for a new project Multiplicity of permit procedures – including environmental, building and construction, electricity specific, land Acquisition of rights in or over land presents particular challenges Lack of resources and knowledge on the part of permitting authorities and, in some instances, project promoters, which may compound the challenges of achieving timely authorisations Duration of permit-granting procedures Stakeholder objection may be vociferous leading to further delays
TSO co-ordination	Lack of framework for bilateral co-ordination between TSOs on cross-border projects
Interdependence with other projects	Investment rationale is dependent on other projects, for example investments in generation capacity and / or consumption; and / or other infrastructure projects

Section 8 covers the definition of remedial actions (Task 6). In this section we have focused on remedial actions which are suitable for inclusion in the Action Plan (see Section 2) – that is measures which can be implemented by Member States within a defined timescales in order to address the issues identified in Section 7. Some of the issues raised in Section 7 may also be addressed via project specific measures, for example by the sharing of key project delivery and operation risks with third parties.

Remedial action	Issues addressed
Financing	
1. Provision of subordinate debt Key stakeholder/s: National government Timescales: medium term	Ability to access financing Cost of financing
2. Facilitate sharing of technical information Key stakeholder/s: National government Timescales: short term	Technology risk Ability to access financing Cost of financing
Regulatory framework	
1. Provide clarity over regulatory priorities regarding key infrastructure investments Key stakeholder/s: National government and Regulatory Authority Timescales: short term	Competing regulatory priorities Complex to provide evidence that the investment will provide a measurable contribution to policy goals Changes to the regulatory regime
2. Stable regulatory framework Key stakeholder/s: National government and Regulatory Authority Timescales: short and medium term	Changes to the regulatory regime Competing regulatory priorities
3. Flexible mechanisms for cost recovery and efficiency Key stakeholder/s: National government and Regulatory Authority Timescales: short term	Changes to the regulatory regime Competing regulatory priorities
4. Recognise separate regulatory treatment of key investments Key stakeholder/s: National government and Regulatory Authority Timescales: short term	Changes to the regulatory regime Step-change in transmission tariffs
5. Enhance co-ordination between authorities Key stakeholder/s: Regulatory Authority Timescales: short term	Lack of a defined approach for cross-border projects No framework for interaction between authorities
6. Demonstrate progress toward market integration Key stakeholder/s: Regulatory Authority Timescales: medium term	Lack of market alignment constrains demand for access to interconnection capacity
Permitting and consents	
1. Implement single local Authority Key stakeholder/s: National government Timescales: short term	Permitting process Multiple consents Costs Duration Resources
2. Minimise bureaucracy Key stakeholder/s: National government	Costs Duration

Remedial action	Issues addressed
Timescales: short term	Resources
3. Improve engagement at regional level Key stakeholder/s: National government Timescales: short term	Stakeholder interest Duration
4. Rationalise approvals for land rights Key stakeholder/s: National government Timescales: medium term	Acquisition of rights in land
5. Give more weight to Priority Corridors Key stakeholder/s: National government and regulatory authorities Timescales: short term	Priority Corridors Duration
6. Introduce an iterative process to manage upgrades, extensions and project design refinements Key stakeholder/s: National government and regulatory authorities Timescales: medium term	Stakeholder interest Iterative procedures Duration
7. Improve stakeholder engagement Key stakeholder/s: National government Timescales: short term	Stakeholder interest Duration
8. Coordination with taxation and other financial incentives Key stakeholder/s: National government Timescales: short term	Stakeholder interest Duration
9. Modelling – test case at regional level Key stakeholder/s: Regulatory authorities Timescales: short term	Permitting process Multiple consents High costs Duration Resources Stakeholder interest
10. Commission support and commitment Key stakeholder/s: Commission and national governments Timescales: ongoing	Permitting process Multiple consents High costs Duration Resources Stakeholder interest
TSO co-ordination	
1. Enhance bilateral co-ordination between TSOs in relation to priority and cross-border projects Key stakeholder/s: TSOs Timescales: short term	Lack of framework for bilateral co-ordination between TSOs on cross-border projects. Investment rationale is dependent on other projects
Additional measures are proposed for implementation on a project by project basis. Key stakeholder/s: National government, regulatory authorities and TSOs Timescales: short term	

Section 9 presents our conclusions against the project objectives which were to:

- identify potential future priorities based on market integration, security of supply and sustainability considerations
- analyze ongoing and planned electricity infrastructure projects in the region covered by the North-South initiative and assess to what extent they contribute to the objectives of the initiative
- identify the obstacles to market integration and implementation of infrastructure projects to support it

2. Introduction

In line with the European Union strategic goals set by the Lisbon European Council, the Commission is proposing a new strategy to develop an integrated European energy network which can offer a stable and reliable supply of energy to European citizens, while reducing the carbon footprint of the energy sector.

The Communication on Infrastructure Priorities[4], which was adopted on November 17th 2010, identified a range of priorities that must be implemented by 2020 to allow the EU to meet the energy and climate targets. The Communication put forward a new method of planning which build on the strengths of regional cooperation as a stepping stone towards the completion of the EU objectives. In the electricity sector four EU priority corridors are identified:

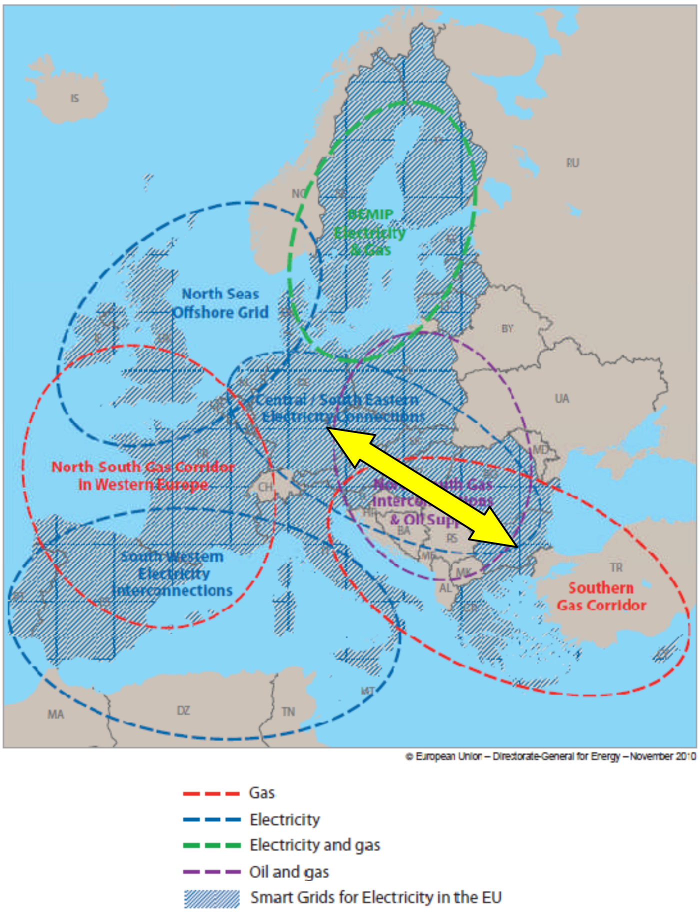
- An offshore grid in the Northern Seas and connection to Northern and Central Europe to transport power produced by offshore wind parks to consumers in big cities and to store power in the hydro electric power plants in the Alps and the Nordic countries.
- Interconnections in South Western Europe to transport power generated from wind, solar, hydro to the rest of the continent.
- **Connections in Central Eastern and South Eastern Europe –** strengthening of the regional network in North-South and East-West power flow directions, in order to assist market and renewables integration, including connections to storage capacities and integration of energy islands
- Integration of the Baltic Energy Market into the European market.

In order to reach this aim, the Commission has launched a number of initiatives dealing with specific macro-regions within the European Union, as shown in Figure 2. In its Communication (Nov 2010), the Commission highlighted the crucial importance of adequate, integrated and reliable energy networks for the achievement of EU policy goals and economic strategy. The goals outlined in this Communication need to be delivered through the development of energy infrastructure and provide a high level framework for this study:

- A properly functioning internal energy market
- Enhanced security of supply
- Integration of renewable energy resources
- Increased energy efficiency
- Consumer benefits from new technologies and intelligent energy use

[4] Communication "Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network" COM(2010)0677

Figure 2: European energy infrastructure priorities for electricity, gas and oil



Note: Central/South Eastern Electricity connections depicted with yellow arrow

Regulatory proposals laying down rules for the timely development and interoperability of trans-European energy networks were published by the Commission on the 19th of October 2011 under the Energy Infrastructure Package (EIP)[5], which aims to facilitate the implementation of trans-European priority corridors and areas for electricity and gas networks, as well as oil and carbon dioxide transport infrastructure.

The initiative focused on North-South Interconnections in Central-Eastern Europe has highlighted the need to set up a High Level Group in order to promote this required regional cooperation, implementation of energy infrastructure projects and improve market development and renewables integration.

As part of this approach a High Level Group for North-South Interconnections was set up with the aim of promoting the implementation of energy infrastructure projects and improving security of supply and market development in the region. The High Level Group of representatives comprising six Member States in Central-Eastern Europe (Bulgaria, the Czech Republic, Hungary, Poland, Romania and Slovakia; Croatia was invited to join the group as an observer) and the European Commission (chair) met for the first time on the 9th of February 2011 and agreed to deliver an Action Plan

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[5] Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL establishing the Connecting Europe Facility (COM(2011) 665) and Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC (COM(2011) 658 final)

encompassing the sectors of gas, electricity and oil by October 2011. The High Level Group also decided to invite Germany and Austria at its meeting in June, as well as Slovenia at its meeting in September to participate in the work of the High Level Group. Without prejudice to future extension of the High Level Group Austria, Germany and Slovenia participated in the work related to the electricity sector.

The countries of Austria, Bulgaria, Croatia, Czech Republic, Germany, Hungary, Poland, Romania and Slovakia and Slovenia together form the Study Area for this project. This particular study refers to the Working Group (WG) of the North-South Interconnection Initiative, which shall support the High Level Group in delivering an Action Plan on the development of electricity interconnections and internal market actions.

The objective of the North-South Interconnections Initiative is to strengthen regional cooperation in Central-Eastern Europe in the areas of development and integration of energy networks, diversification of routes and sources with a view to enhancing security of supply and promote market development.

The work should also contribute to the definition of criteria for project prioritization and selection as set out in the Infrastructure Communication. These criteria will allow the identification at EU level of 'Projects of European Interest'. Through the instrument of the so called ‘Projects of European Interest” the EU not only want to be able to identify the projects that should be considered more relevant, but also to identify the obstacles to market integration and implementation of infrastructure projects to support it.

We understand that the High Level Group of the North-South Interconnection initiative is the first group to undertake a prioritisation process in respect of the Energy Interconnections Priorities. Therefore the approach adopted sets an example for other priority corridors. We understand that the list of priority projects will be periodically reviewed taking into account changes in requirements.

The objective of this analysis is to support the High Level Group in delivering an Action Plan on the development of North-South and East-West electricity interconnections and internal market actions by October 2011 to strengthen the regional network in North-South and East-West power flow directions, in order to assist market and renewables integration, including connections to storage capacities and the integration of energy islands.

This report has been prepared by PricewaterhouseCoopers in collaboration with:

- Professor Alan Pearman, of The Centre for Decision Research at Leeds University Business School
- King & Spalding International LLP

Comments from the Working Group are also included, where stated within the document.

3. Task 1: Market analysis

3.1. Introduction and methodology

This report provides a revision of Sections 2 and 3 of the Stocktaking Document which has been produced by the Working Group on North-South Interconnections in Central Eastern Europe (draft 1, June 2011). Our analysis covers the study area reflecting participation in the Working Group: Austria, Bulgaria, Croatia, Czech Republic, Germany, Hungary, Poland, Romania, Slovakia and Slovenia.

This report is based predominantly on the Consultant's research and analysis of market data. Key data sources used in the preparation of this report are:

- Section 2: data for 2010 is based primarily on information from the European Network of Transmission System Operators for Electricity (ENTSO-E) (other sources are identified adjacent to the relevant figures or commentary)

- Section 3: 2020 analysis is based on the actual 2010 data updated using growth rates from the PRIMES model for each dataset (other sources are identified adjacent to the relevant figures or commentary)

- Alternative data for Slovakia has been provided by SEPS and for Czech Republic by CEPS – at the request of the Working Group members, this information has been used in place of ENTSO-E data for 2010 and in place of analysis based on PRIMESs for 2020

- Data for Croatia has been provided by HEP, since a full data set is not available from ENTSO-E and PRIMES

The PRIMES model is a modelling system that simulates a market equilibrium solution for energy supply and demand in the EU27 and its Member States. Its scenarios were derived by a consortium led by the National Technical University of Athens (E3MLab), supported by some more specialised models (e.g. GEM-E3 model that has been used for projections for the value added by branch of activity and PROMETHEUS model that has been deployed for projections of world energy prices). The scenarios are available for the EU and each of its 27 Member States simulating the energy balances for future years under current trends and policies as implemented in the Member States by April 2009.

For this study we have used outputs from the PRIMES Reference Scenario, which includes policies adopted between April 2009 and December 2009 and assumes that national targets under the Renewables directive 2009/28/EC and the GHG Effort sharing decision 2009/406/EC are achieved in 2020. This scenario was agreed with The Commission as the most appropriate source, since it includes the mandatory emission and energy targets set for 2020, and serves as a benchmark for policy scenarios with long term targets.

More details on the data used for the analysis are provided in the Appendix (Figure 43 and above) and referenced from the relevant text.

Note: in this report we use the convention of a comma (",") to denote the decimal mark e.g. 1,1 = one point one and a point (".") as a digit group separator e.g. 1.100 = one thousand one hundred.

3.2. Overview of the current situation: 2010

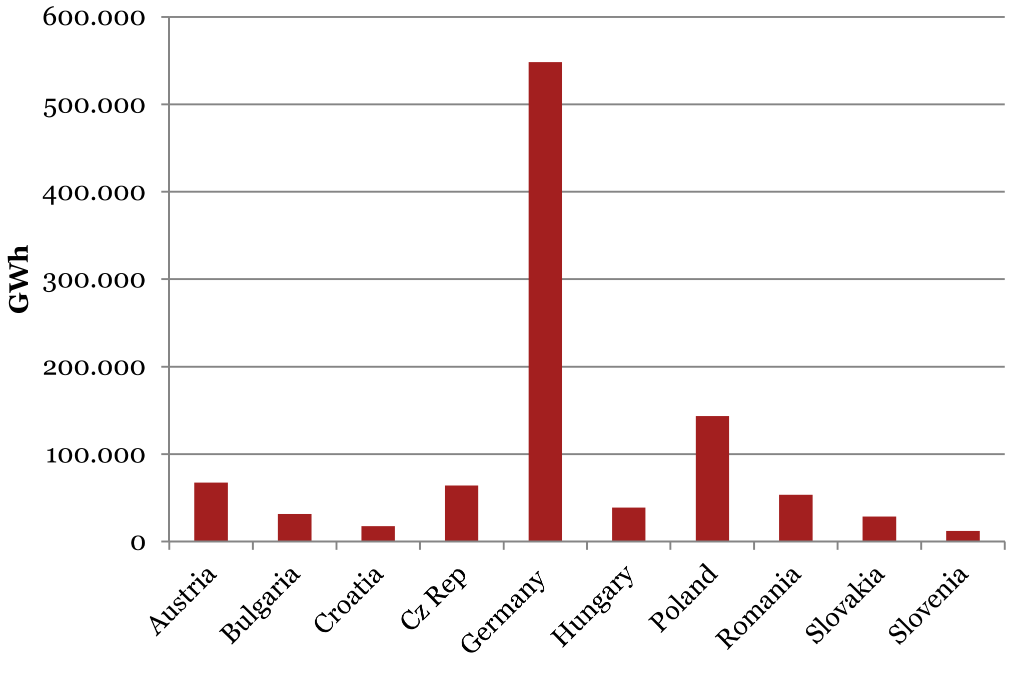
This section is based on observations from actual 2010 data as published by ENTSO-E[6]; however we note that as of 2011 some of the system characteristics have changed due to the decision by Germany to close nuclear plant. The impacts of this decision are reviewed in Section 3.9.2.

3.3. Consumption

3.3.1. Annual consumption levels

Total electricity consumption in the area in 2010 was 1.006 TWh, Figure 3 shows the annual consumption by country (for data table see Appendix, Figure 43). The largest market in terms of demand is Germany, where total consumption in 2010 was 548 TWh (55% of total demand amongst the countries considered).

Figure 3: Annual consumption 2010



Source: ENTSO-E[7]

Throughout the study area, the average sector split of electricity consumption is 82% for final energy demand (to customers), 11% for energy branch electricity usage[8], and 7% for transmission and distribution losses. Within final energy demand, industry is the largest single sector in nearly all countries, with the split between households and tertiary varying across the study area.

[6] With the exceptions explained in the introduction for Czech Republic , Slovakia and Croatia
[7] All following graphs are based on data sources explained in the introduction, except where otherwise stated
[8] Own consumption & pumping and Refineries & other uses.

Electricity consumption (%)	
Final energy demand	82%
Industry	44%
Households	27%
Tertiary	26%
Transport	3%
Energy branch	11%
Own consumption & pumping	64%
Refineries & other uses	36%
Transmission and distribution losses	7%

All consumption data (TWh) is actual 2010 data from ENTSO-E. In providing a further breakdown of this data by country, we have used the PRIMES model.

Germany, is the largest market in terms of demand with total consumption in 2010 of 548 TWh (56% of total demand amongst the countries considered). Total electricity consumption is made up of final energy demand (86%) as well as energy branch electricity consumption, which represents 9%, and transmission and distribution losses adding a further 5%. In terms of final energy demand, industrial consumption is 44% of total energy demand, with households and the tertiary sector consuming 28% and 26% respectively. The remaining 3% of energy demand is made up by transport. This consumption split is representative of the average within the study area.

The second largest market was Poland, where total annual demand was 143TWh (15% of total demand amongst the countries considered) – less than one third the size of the German market. The use of electricity by the energy sector (16%) and transmission losses (10%) is above average for the study area. In terms of final energy demand, industry is the largest sector, as is the case for all countries studied, however the share of consumption by the tertiary sector is the highest in the study area (33%).

Austria is the third largest market by consumption (67TWh[9]), and has very similar consumption characteristics to Germany in terms of the split of consumption between sectors.

Consumption in the Czech Republic was 64TWh, and also has a similar breakdown of final energy demand between sectors to that in Germany, however energy branch use (11%), as well as transmission and distribution losses (7%), are closer to the study area average.

Romania had total consumption of 57TWh, of which energy branch use and transmission and distribution losses are the highest in the study area, at 18% and 11% respectively. Within final energy demand, 60% is used by industry which is the highest share within the countries studied, while tertiary sector usage is the lowest, at 11%.

Hungary's total consumption of 39TWh is almost equally split between the main sectors of industry (28%), households (35%)[10] and tertiary (33%). Hungary is the only country within the study area where industry is not the highest consuming sector, and is consequently above average for the split of consumption in other areas.

Consumption in Bulgaria was 32TWh, with the highest level of transmission and distribution losses, of 13%. Domestic consumption is higher than average (34%) with a lower share of consumption in the industrial and tertiary sectors.

[9] Including consumption from pump storage, consumption to end users is 58TWh
[10] The Hungarian TSO Mavir reports a slightly lower share of 31% for households

Slovakia had total consumption of 29TWh, with the split between final energy demand, energy branch use and transmission and distribution losses close to the average for the study area. Within final energy demand, the share of both the tertiary sector (31%) and industry (47%) are above average, with a correspondingly lower share of consumption from the domestic sector (20%).

Croatia had total consumption of 18 TWh. Further breakdown was not available for 2010.

Slovenia is the smallest market in terms of electricity consumption: total consumption in 2010 was 12 TWh, less than half that of the next smallest market, Slovakia. Energy branch usage (7%) is lower than the average, with a correspondingly higher share of consumption from final energy demand. Within that category, the share of consumption from the industrial sector (55%) is among the highest in the study area, with a lower share from the tertiary sector (19%).

The split of energy consumption by sector can be summarised as follows:

- Austria, Germany and Slovenia have the lowest share of consumption from energy branch usage plus transmission and distribution losses (14%); Romania has the highest (29%)
- Industrial consumption as a percentage of final energy demand is highest in Romania (60%) and Slovakia (55%), and lowest in Hungary (28%)
- The share of household consumption is highest in Hungary (35%) and Bulgaria (34%) and lowest in Slovakia (20%)
- Consumption by the tertiary sector is highest in Hungary and Poland (both 33%) and lowest in Romania (11%)

Consumption by the transport sector is 4% or less in all countries, with the exception of Austria (6%)

The following sections assess consumption characteristics in more detail, providing further context for infrastructure requirements.

3.3.2. Peak demand and load shape

Data for 2010[11] shows that for all countries within the study area demand peaked during the winter – several countries show commonality on the timing of maximum peak demand, with the greatest number in mid December (week 51) and late January (week 5):

- Germany and Hungary - Week 48 (1 December)
- Croatia, Romania, Slovakia and Slovenia - Week 51 (mid-December)
- Austria, Bulgaria, Czech Republic and Poland - Week 5 (late-January)

Demand load factors (average hourly demand as a percentage of peak hourly demand) shows that the majority of countries have a load factor of between 70% and 75%: Austria and Germany are higher than this (80% and 78% respectively); only Bulgaria is lower (50%).

A more detailed analysis of load shapes (see Appendix, Figure 44 and Figure 45) shows that during 2010, seasonal demand shapes can be characterised as follows:

[11] ENTSO-E

- During summer, Austria and Croatia had the most variable demand during a sample 24-hr period (3rd Wednesday in July); whilst Slovakia and Slovenia have the flattest load shape

- During winter, demand in Austria is flatter, whilst Croatia and Slovenia have the most variable load shape (3rd Wednesday in January); Slovakia and the Czech Republic have the flattest load shape in winter

Differences in load shape between interconnected countries can provide an opportunity for increased system security and greater efficiency in both countries, since peaking capacity is required at different times and, where sufficient transmission capacity is available, can be utilised in both systems[12].

3.3.3. Conclusion

Total electricity consumption in the area in 2010 was 1,006 TWh, with over 55% coming from Germany. Industry is the highest consumer of final energy in all nearly all countries, along with average energy branch usage of 11% and losses (transmission and distribution) of 7%. Whilst industrial demand is relatively stable within the medium term i.e. during the course of a year, its longer term development is dependent on economic conditions which therefore need to be taken into account in grid planning, along with expectations for switching of demand between industrial and service (tertiary) sectors.

The majority of the study area has the highest levels of demand during the winter period, when temperatures are lowest creating heating demand, with some degree of similarity in the incidence of peak demand. For adjacent and interconnected grid systems, differences in peak demand should be taken into account in grid planning – for example between Germany and Poland, Hungary and Romania – to determine where generation capacity requirements can be met through interconnection to plant in other markets, where this offers greater efficiency.

3.4. Installed capacity and generation mix

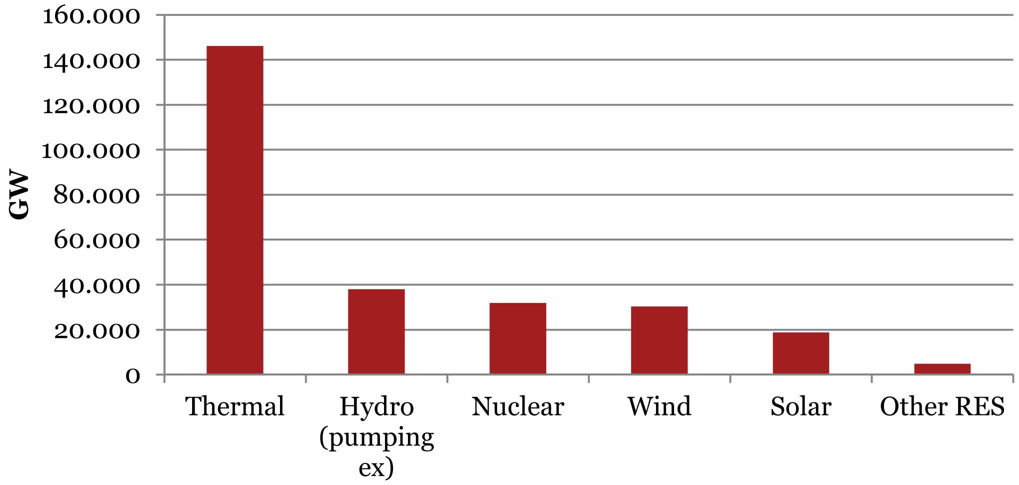
3.4.1. Capacity by plant type

Figure 5 below illustrates capacity in 2010 by plant type within the study area (see also Figure 46). The largest share of capacity in the study area was from conventional thermal power[13] (146 GW – 54% of total capacity). Total capacity for renewable generation was 92 GW (34% of total capacity). The majority of this was capacity for hydro (excluding pumped storage), which was 38 GW (14% of total capacity), followed by wind (30GW – 11% of total capacity), solar (19 GW – 7% of total capacity) and other renewables (5GW – 2% of total capacity). Total nuclear capacity in the region is 32GW (12%).

[12] Laboratoire d'analyse économique des réseaux et des systèmes énergétiques, Generation adequacy and transmission interconnection in regional electricity markets, 2008

[13] Thermal generation includes only conventional fossil fuel generation, whilst biomass is included in "other RES".

Figure 4: Capacity by plant type 2010 – study area total



The pattern of generation capacity can be characterised as follows:

- Nuclear capacity is present in Slovakia (27% of total generation), Slovenia (24%), Hungary (22%), Czech Republic (21%), Bulgaria (18%), Germany (14%) and Romania (8%).
- Hydro (excluding pumped storage) constitutes the majority of capacity in Austria (60%), but also has significant presence in terms of capacity in Croatia (49%), Romania (36% of total capacity), Slovakia (23%), Slovenia (31%) and Bulgaria (19%). Capacity for wind is particularly significant in Germany (18% of total capacity) and solar capacity has a significant presence in Germany and Czech Republic (11% and 10% of total generation respectively).
- Conventional thermal power has a significant share of total capacity in all countries, and constitutes the majority of capacity in Poland (93%), Hungary (71%), Czech Republic (62%), Bulgaria (58%) and Romania (54%).

Figure 5: Capacity by plant type 2010 (GW) – by country

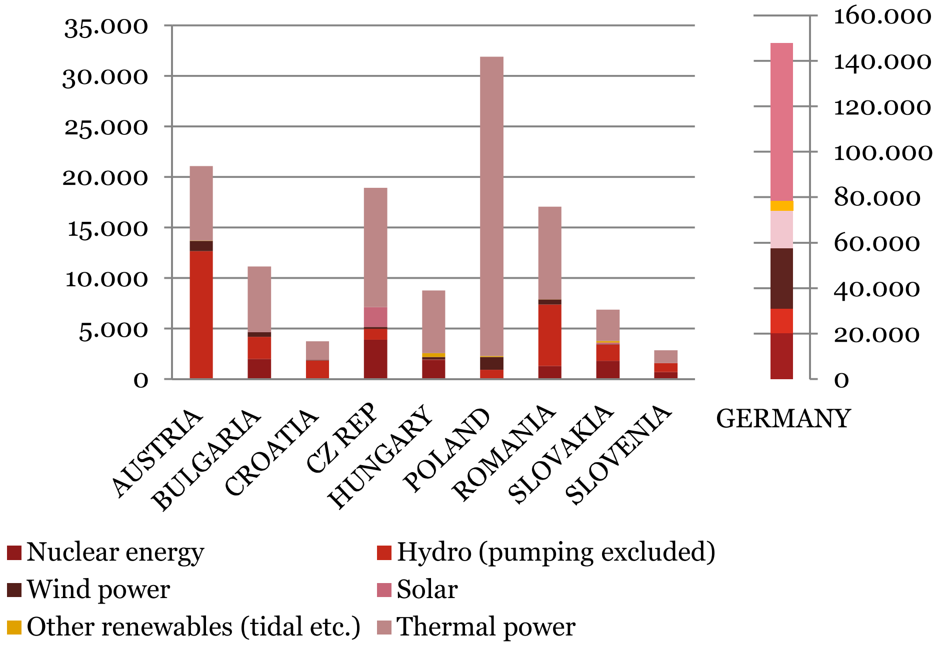
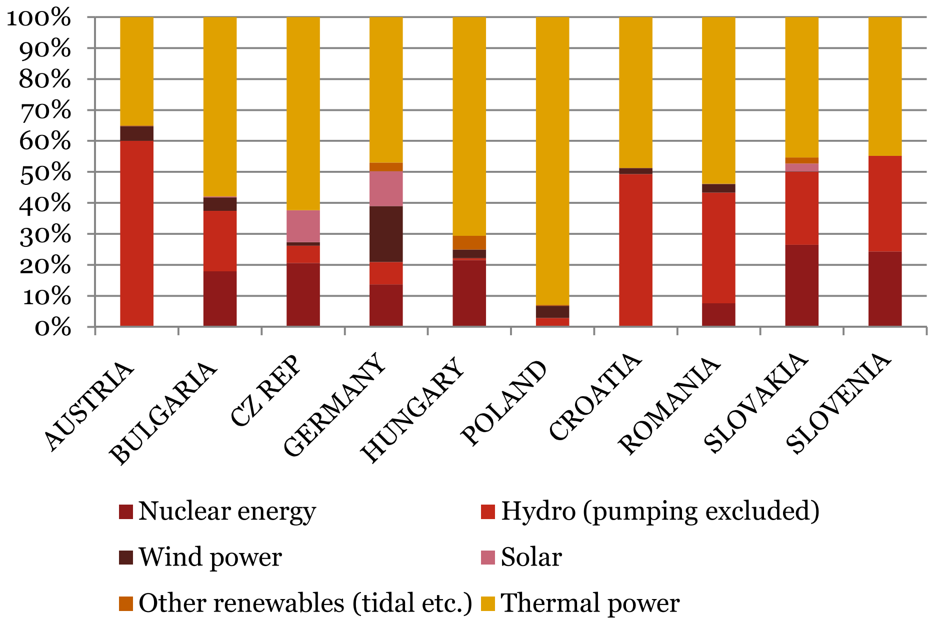


Figure 6: Capacity by plant type 2010 (%) – by country



Focus: nuclear sector – 2010

Seven countries within the study area currently have nuclear capacity, where it typically contributes at least one third of total power generation. Outside Germany, most of the nuclear capacity is located in the centre and south-east of the study area, with only Poland and Austria lacking commercial nuclear capacity. The majority of this capacity was constructed in the 1980s (circa 19,000MW), with around 2,500MW developed within each of the last two decades. Future plans for the nuclear sector are discussed in Section 3.9.

- Bulgaria has two nuclear reactors with a total generation capacity of 2.000MW. They generate 14.2 TWh, about 35% of Bulgarian electricity.

- Nuclear electricity generation in Czech Republic in 2010 was 26.4 TWh, around 33% of the total electricity production. 6 reactors are currently in operation with a generation capacity of 3.666 MW.

- Germany has the largest nuclear portfolio within the study area, with 17 units comprising 20.300MW of capacity and generating 133TWh in 2010. It also has some of the oldest plant, with 6 units dating from the 1970s. The impact of the recently approved German nuclear moratorium on the phase-out of German nuclear capacity is discussed in more detail in a subsequent section of this document.

- Nuclear electricity generation in Hungary in 2010 was 14.8 TWh, the 44% of the total electricity production. Four reactors are currently in force with a total generation capacity of 1.892 MW.

- Nuclear electricity generation in Romania in 2010 was 10.7 TWh, generating around 19% of the total electricity production. Romania has the newest nuclear capacity, with the Cernavodă plant commencing operation in 1996 and a second unit started up in 2007 bringing total generation capacity to 1.310 MW.

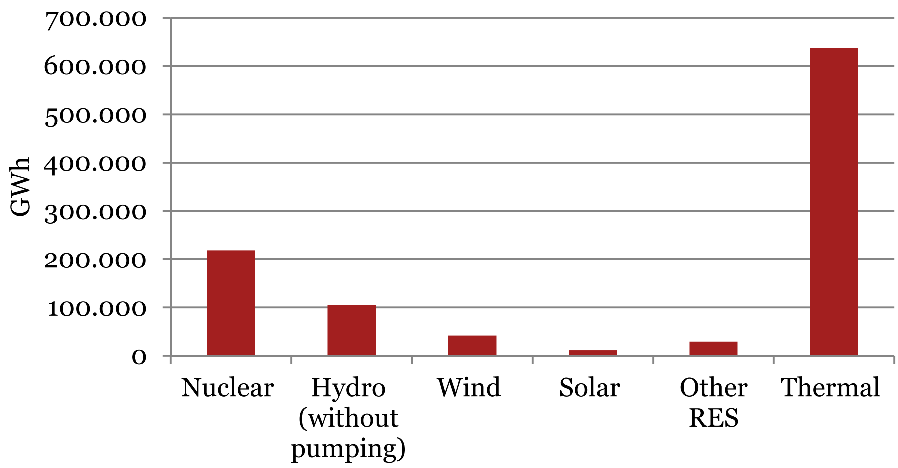
- Nuclear electricity generation in Slovakia in 2010 was 13.6 TWh, and with more than 50% of the total electricity production coming from nuclear, Slovakia has the highest reliance on this source of all countries studied. Currently 4 reactors are in operation with a total generation capacity of 1.820 MW.

- Nuclear electricity generation in Slovenia in 2010 was 5.4 TWh, roughly 37% of the total electricity production, from capacity of 696MW. Slovenia has one reactor jointly owned by Croatia. On 11 May 2011, Slovenia became member of the OECD Nuclear Energy Agency (NEA).

3.4.2. Generation by plant type

Figure 5, Figure 8 and Figure 9, below outline generation in 2010 by plant type within the study area (see also Appendix, Figure 47 and Figure 48). In 2010, total generation was 1.044TWh – equal to 104% of consumption within the study area. The largest share of generation within the study area in 2010 was from conventional thermal generation, with 637 TWh (61% of total generation in 2010), consistent with the significant share of capacity from this plant type (54%). The second largest share was from nuclear energy (218 TWh / 21% of total generation in 2010). Generation from renewable energy was 189 TWh (18% of total generation), compared to its 34% share of capacity. The largest share of renewable generation was from hydro (56% of total renewable). The differences between share of capacity and share of generation are examined in Section 3.4.3, where we have analysed generation load factor.

Figure 7: Total generation by plant type 2010 – study area total



However, generation characteristics vary significantly by country, as outlined in the charts below.

Figure 8: Generation 2010 by plant type (GWh) – by country

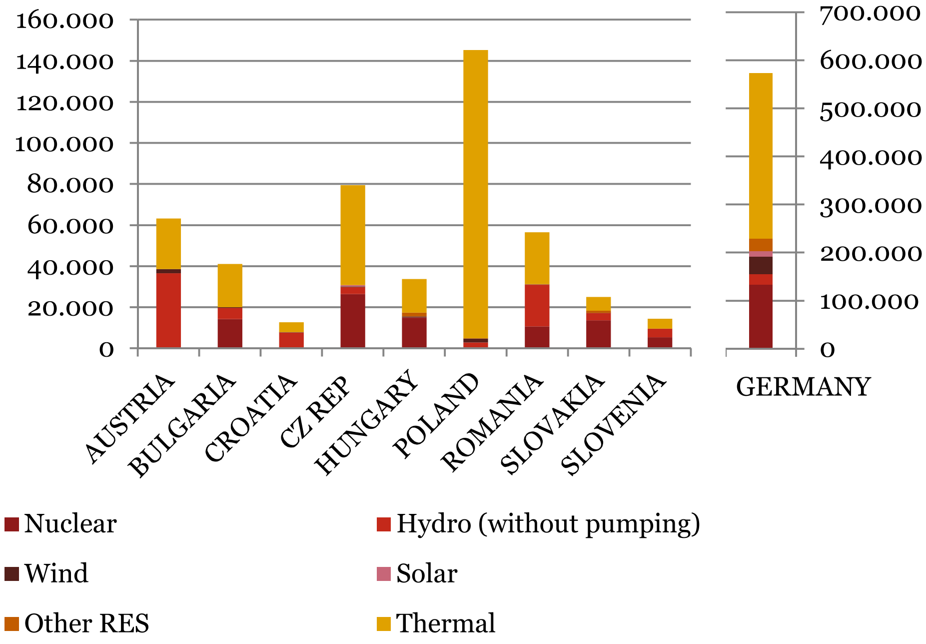
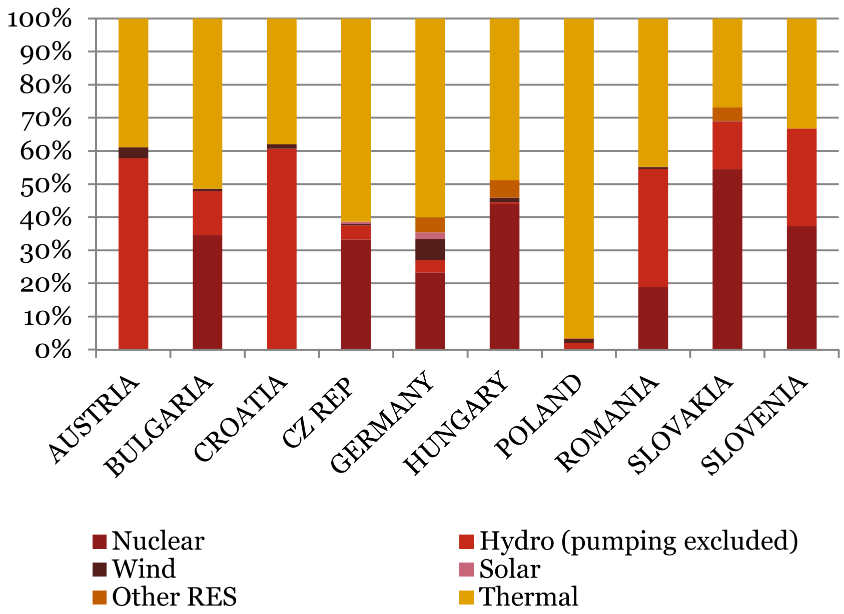


Figure 9: 2010 Generation by plant type (%) – by country



Looking in more detail at the generation mix by country:

- Total generation in Austria in 2010 was 63,2 TWh, the majority of which was from hydro generation(36,5 TWh – 57,7%). The remaining generation was from thermal (fossil fuels) sources (24,6 TWh - 39,0%) and from wind (2,1 TWh – 3,3%)[14]

- Bulgaria's total generation in 2010 was 41 TWh, the majority of which was from thermal sources (21,1 TWh - 51,4%). A significant share of generation was also from nuclear (14,2 TWh - 34,6%) and hydro (5,4 TWh - 13,3%) sources. Wind generation was less than 1% of total generation

- Czech Republic's total generation in 2010 was 79,4 TWh, the majority of which was thermal generation (48,7 TWh - 61,3%). Nuclear generation was 26,4 TWh - 33,3% of total generation. An additional 3,4 TWh – 4,2% of total generation was provided by hydro generation, whilst wind and solar generation were both less that 1% of total generation (0,3% - 0,6 TWh and 0,4% - 0,7% respectively)

- Total generation in Germany in 2010 was 573 TWh, the majority of which was thermal generation (344,3 TWh - 60,1%). Nuclear generation was 133,4 TWh (23,3%) and hydro generation was 21,7 TWh (3,8%). Germany also had a significant share of generation from renewable sources (36,7 TWh – 6,4% from wind generation, 10,9 TWh – 1,9% from solar generation, 26,3 TWh – 4,6% from other renewable).

- Total generation in Hungary in 2010 was 33,8 TWh. The majority of this generation was from thermal (16,5 TWh – 48,9%) and nuclear (14,8 TWh – 43,9%). Hydro generation was 0,2 TWh (0,5% of total generation), whilst wind generation was 0,5 TWh (1,5% of total generation). Generation from other RES (e.g. biomass) was 1,7 TWh (5,2% of total generation).

- Total generation in Poland in 2010 was 145,2 TWh. The vast majority of this was from thermal sources (140 TWh – 96,7% of total generation). Hydro generation was 2,8 TWh (2% of total generation), whilst wind generation was 1,8 TWh (1,2% of total generation) and other RES was 0,3 TWh (0,2% of total generation)

- Total generation in Romania in 2010 was 56,6 TWh, the majority of which was from thermal (25,3 TWh – 44,8% of total generation), hydro (20,2 TWh – 21,9% of total generation) and nuclear (10,6 TWh - 18,9% of total generation). Small amounts of generation were also provided by wind sources (0,2 TWh – 0,5% of total generation) and other RES (0,1 TWh – 0,2% of total generation)

- Total generation in Slovakia in 2010 was 24,9 TWh, the majority of which was from nuclear (13,6 TWh – 54,5% of total generation). A significant share of generation was also from thermal (6,7 TWh, or 26,8% of total generation) and from hydro (3,6 TWh or 14,4% of total generation). Generation from wind and solar sources was very limited (16 GWh and 20 GWh respectively), whilst some additional generation was driven by other renewable sources (1,0TWh – 4,1% of total generation)

- Total generation in Slovenia in 2010 was 14,4 TWh, of which 5,4 TWh was from nuclear generation (37,9%), 4,8 TWh was from thermal generation (33,2%) and 4,2 TWh was from hydro generation (29,5%)

[14] Wind generation data for Austria was not available from ENTSO-E and was therefore provided directly by APG

- Generation in Croatia was 12,7 TWh with the highest volume for hydro generation (7,7 TWh, 61% of total generation). The second largest share of generation was from thermal plant (4,8 TWh, 38% of total generation), with the remainder from wind (0,2 TWh, 1% of total generation) and a small amount of solar (less than 0,5%)

  Key points to highlight from this are:

- Slovakia and Hungary are the countries with the largest share of nuclear generation (54% and 44% respectively). Other countries within the study area with a positive share of nuclear generation include Slovenia (37%), Bulgaria (35%), Czech Republic (34%), Germany (23%), Romania (19%).

- Croatia, Austria, Slovenia and Slovakia have a significant share of hydro generation[15] (61%, 58%, 29% and 14%). HEP reported to the Working Group that hydro production in Croatia was largely driven by an exceptionally wet year (typically it is around 40-60%).

- Germany has the largest share of renewable generation (excluding hydro): wind generation was 6,4% of total generation in 2010; solar generation was 1,9% and there was a significant share of generation (4,6%) from other renewables.

- The vast majority of Poland's generation (97%) is from fossil fuels. The other countries with the majority of generation from fossil fuels are Czech Republic (61%), Germany (60%) and Bulgaria (51%).

3.4.3. Generation load factor

Load factor is a measure of the volume of energy generated by each unit of capacity, and hence of the variability of generation in country. Countries with higher levels of capacity from variable generation sources, such as renewable plant which is dependent on rainfall, wind or sun, will have a lower load factor than those with capacity from less variable sources.

ENTSO-E 10 Year Network Development Plan assumptions for the average load factors per plant type are compared with data for the study area in the table below:

Plant type	ENTSO-E TYNDP	Study area 2010 actual
Nuclear	78%	78%
Thermal		50%
Lignite	67%	
Coal	56%	
Gas	51%	
Renewable		23%
Hydro (excl pumped)	30%	
Off-shore wind	40%	
On-shore wind	20%	
Solar	7%	
Other (biomass, waste etc)	60%	

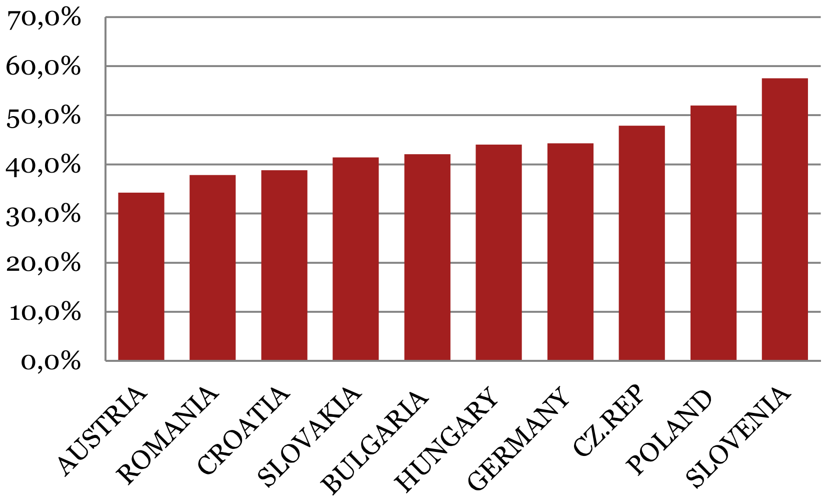
15 The data for hydro generation presented does not include pumped storage. A separate table including pumped storage generation data is included in the Appendix

Generation load factor for the study area was 44%. based on total capacity and total generation (see also Appendix, Figure 49). Slovenia's generation load factor (which is highest in the study area at 57%) arises from the high performance of its renewable plant (55% load factor – primarily hydro generation from lakes[16]), which comprises 30% of total capacity. The lowest overall generation load factor was in Austria (34%), due to large amount of hydro generation operating at an average load factor of 33% in 2010, which was significantly below historic levels. In addition the generation load factor from thermal plant (38%) was below the average for the region.

Generation load factor was also relatively low in Romania (38%), driven by a relatively high share of hydro generation operating at an average load factor of 38% in 2010 and by a generation load factor for thermal plant (31%) which was lower than average for the region.

Similarly, the lower load factor observed in Croatia (39%) was a result of low load factor from thermal plant (30%). Although the load factor for hydro was above average (48%), this capacity forms nearly 50% of the total and did not fully compensate for the lower output of thermal plant.

Figure 10: Generation load factor 2010



***Source**: PwC analysis of ENTSO-E data*

The low load factor within Austria arises partly due to the fact that the hydro plants operate based on the availability of wind generation and on market prices, however, this is not likely to generate particular balancing requirements, as these plants are typically dispatchable.

On the other hand, countries with a lower load factor arising from less predictable generation sources are likely to require balancing through local storage capabilities or interconnection with other areas which have different generation and / or climatic characteristics.

3.4.4. Generation capacity margin

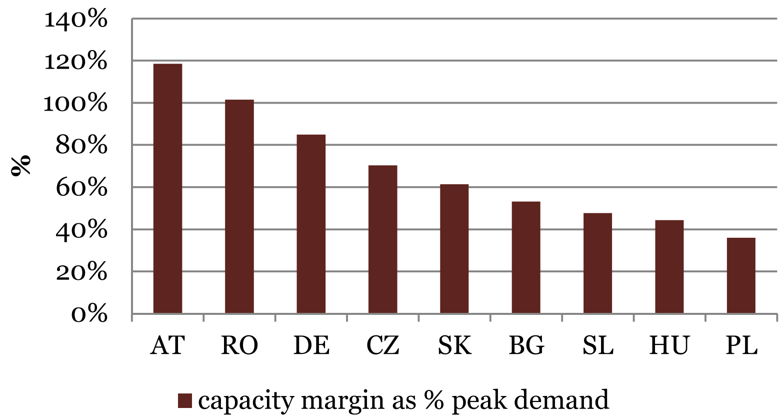
Generation capacity margins are the difference between installed capacity and peak demand, measured as a percentage of peak demand. These margins provide a simple and transparent indicator of generation adequacy, although other factors which should be taken into consideration include the

[16] Whilst PRIMES data (before 2010) shows that Slovenian hydro generation was mainly from lakes, the Slovenian TSO ELES has clarified that it was mainly driven from run of river, and that the high level of hydro generation was a result of particularly favourable hydrological conditions in 2010.

reliability of generation sources and the correlation of generation output with demand variations[17]. ENTSO-E use a measure of Remaining Capacity, which takes into account only Reliable Available Capacity[18].

Figure 12 below illustrates generation capacity margins for all countries in the study area, which ranges between 36% (Poland) and 119% (Austria) (see also Appendix, Figure 50). The variation in capacity margin observed here can be partly explained by the average generation load factor since, for countries within the study area, the two variables are observed to be inversely correlated – in 2010 Austria and Romania had the lowest generation load factors of the countries studied, whereas Czech Republic has one of the highest generation load factors. The lower the generation load factor, the less energy is generated by each unit of capacity, therefore countries with a low load factor need a higher capacity margin to generate sufficient energy.

Figure 11: Generation capacity margin



***Source**: PwC analysis of ENTSO-E data*
Note: Peak demand data was not available for Croatia

As stated, generation capacity margin is one simple metric for the assessment of generation adequacy, based on system inputs, however it should not be viewed in isolation since it is impacted by the relationship between flexibility and reliability of generation capacity, demand load factor and transmission interconnection capacity - as well as industry structures and pricing / tariff arrangements.

Another measure of generation adequacy, based on system outputs, is Loss of Load Probability, which is defined as the probability over some period of time that the power system will fail to provide uninterrupted service to customers. Research by the Laboratoire d'analyse économique des réseaux et des systèmes énergétiques has demonstrated that in continental systems there is a trade off between generation capacity and transmission interconnection capacity in order to reach a given level of loss of load probability (LOLP) of the power system[19]. This indicates that countries with a low generation capacity margin can improve generation adequacy (i.e. reduce LOLP) through investment in generation capacity and / or through investment in interconnection capacity.

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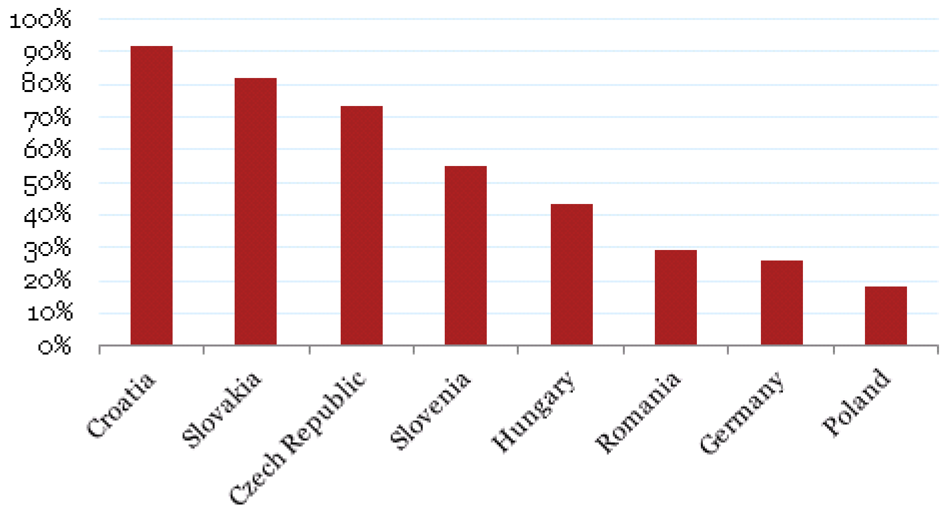
[17] Oxera, Margin for error? Security of supply in electricity, 2005
[18] ENTSO-E, Scenario Outlook and System Adequacy Forecast 2011 – 2025, 2010
[19] Laboratoire d'analyse économique des réseaux et des systèmes énergétiques, Generation adequacy and transmission interconnection in regional electricity markets, 2008

3.4.5. Generation market share

Market share is most concentrated in Croatia, Slovakia and Czech Republic, where in 2009 (latest data available) more than 60% of the total national annual electricity production is generated by the largest electricity producing company (see also Appendix, Figure 51). In Poland, Germany and Romania, in 2009, this figure was below 30%. Development of additional interconnection capacity is one way of strengthening competition through a more efficient internal market.

Figure 12: Market share of largest generator (2009)



Source: Eurostat
Note: no data is available for Austria or Bulgaria

Eurostat data indicates that the market share of the largest generator in Poland is 18%, making it the country with the lowest share of capacity by the single largest company. The Polish market is split into four vertically integrated power utilities. We note however that other sources suggest that the market share of the main company, PGE, is closer to 40%[20].

In Germany, where market share of the largest generator RWE is 26%, a wave of integration began in 2000, leading to the consolidation of six interconnected utilities into four major players: E.ON, RWE, EnBW and Vattenfall.

In the Romanian market the largest generator, Hidroelectrica, has 29% of capacity. The market consists of three state-owned power companies which manage hydro, thermal and nuclear plant respectively – hydro and thermal both make up at least 25% of the total capacity.

At the other end of the scale, Croatia has the largest share of capacity owned by a single company (92%), since the country's capacity is largely owned by one vertically integrated national utility, Hrvatska Elektroprivreda (HEP).

Generating capacity in Slovakia is largely held by Slovenske Elektrárne (SE) (82%), which was created from the former state power monopoly and was been partly privatised in 2006, when a 66% stake was sold to Enel.

[20] PGE's website states that the company's market share in generation is 40%
http://www.pgesa.pl/en/PGE/BusinessAreas/Pages/ConventionalPowerGeneration.aspx

In the Czech Republic the majority of generation capacity (74%) remains in the ownership of the mostly government owned national utility ČEZ.

Hungary and Slovenia rank in the middle of the table for market share of generating capacity with 43% and 55% respectively. The Hungarian market was re-structured in 1992 to create eight generating companies, the largest of which, Magyar Villamos Muvek (MVM), remains state-owned. In Slovenia the main company is state-owned Holding Slovenske Elektrarne (HSE) – however other sources state that its market share is closer to 65%[21].

3.4.6. Conclusion

The majority of capacity is from thermal plant (54%), offering a balance of flexibility and reliability. A significant share (34%) of capacity is renewable, comprised mainly of hydro and wind, with greater intermittency. Renewable capacity is centred in Germany, where nearly all of the wind (and solar) capacity is located, indicating that the intermittency of this generation needs to be absorbed by neighbouring countries and possibly others within the region. Nuclear capacity is also significant throughout much of the study area, with most of the capacity dating from 1980s.

Nuclear is more important in terms of share of generation, forming the largest source in both Slovakia and Slovenia, however thermal is the most important source in the majority of countries. Austria is the only country where the majority of generation comes from renewable sources, where the predominance of controllable hydro generation suggests the potential to balance intermittent sources from neighbouring Germany – highlighting the importance of effective transmission connections between the two countries and the relevant generation sources / demand centres.

Generation load factor provides an indication of the variability of generation capacity, and thus provides context for the level of security of supply. However where a low load factor is observed, for grid planning purposes it is equally, if not more, important to understand the extent to which the capacity is flexible and controllable thus available to be dispatched to meet market demand or grid requirements; or intermittent, requiring more responsive management mechanisms from both grid operators and market participants. In Austria for example, low load factor arises primarily from the flexibility of hydro plant, which can be actively managed. Whilst Germany has the highest levels of intermittent renewable energy, the generation load factor is currently balanced out by the higher than average load factor of thermal plant.

Generation adequacy is an indicator of security of supply, and one metric of this is generation capacity margin – the difference between installed capacity and peak demand. Looking at this measure alone suggests that Austria and Romania have the highest levels of generation capacity margin, whilst Czech Republic and Poland are at the other end of the scales, however more detailed grid planning should take into account more sophisticated measures, such as Reliable Available Capacity, which discounts the availability of intermittent capacity.

The Czech TSO has highlighted that accelerated phasing out of German nuclear power plant resulted from the nuclear moratorium and the subsequent accelerating pace of commissioning of intermittent sources in Germany are likely to have an impact on operational security and investment programs in the regional scale.

Generation market share provides some context for the degree of market competition, and data from Eurostat suggests that there is significant variation between the countries, with the highest levels of fragmentation in Germany and Romania, and the lowest levels in Croatia and Slovakia.

[21] HSE's 2010 annual report states that the company owns 1.849MW of generating capacity, equivalent to 65% of the national total 2.861MW.

3.5. Energy balances and exchanges

3.5.1. Interconnection capacity

For analysis purposes we have used data on Net Transfer Capacity (NTC), which indicates the amount of available transmission capacity in each direction of each interconnection line, after the TSO's calculated requirements for system reliability. The actual amount of capacity which remains available at any point is time (defined as Available Transmission Capacity, ATC) is based on Net Transfer Capacity minus the portion of capacity which has been allocated via transmission rights (Already Allocated Capacity, AAC) (see also page 61).

The region has approximately equal levels of import and export capacity – however Germany, Austria, Slovakia, Hungary, Romania and Croatia all have more import capacity than export, while Slovenia, Poland and the Czech Republic have more export capacity. Only in Bulgaria is export capacity equal to import.

There are many factors which determine interconnection capacity requirements, including power balances and relative market prices[22] - current levels of capacity utilisation and congestion illustrate where further capacity may be required (see Section 3.5.3).

The tables below show total import and export capacity for Winter 2010/11 and for Summer 2010 for the countries within the country area, as well as a breakdown of import and export capacity between individual countries.

ENTSO-E NTC: Winter 2010-11

	From:	DE	AT	SL	PL	CZ	SK	HU	RO	HR	BG
To:											
DE			2.000		1.100	2.300					
AT		2.200		900		1.000		800			
SL			900							1.000	
PL		1.200				800	500				
CZ		800	600		1.800		1.200				
SK					600	2.200		600			
HU			800				1.300		700	800	
RO								700			600
HR				1.000				1.200			
BG									600		

ENTSO-E NTC: Summer 2010

	From:	DE	AT	SL	PL	CZ	SK	HU	RO	HR	BG
To:											
DE			1.600		1.200	2.100					
AT		1.600		900		800		350			
SL			900							700	
PL		800				800	500				
CZ		800	600		1.900		1.100				
SK					600	2.100		500			
HU			500				1.150		500	500	
RO								600			400
HR				800				1.000			
BG									400		

Source: ENTSO-E

Looking in more detail at individual countries:

- Germany had more import capacity than export capacity both in Winter 2010/11 and in Summer 2010. This was largely driven by import capacity from the Czech Republic being

[22] ENTSO-E, Ten Year Network Development Plan 2010-2020, June 2010

significantly higher than export capacity, whilst in relation to interconnections with other countries (Austria and Poland) export capacity was slightly higher than import capacity

- Austria also had more import capacity than export capacity both in the winter and the summer periods, although in Summer 2010 there was only a marginal difference between import and export capacity. Import capacity was greater than export capacity to Germany and Czech Republic in the winter period, and to the Czech Republic only in the summer period. In the case of interconnections with Slovenia and Hungary, import capacity was equal to export capacity in the winter months. Export capacity to Hungary was greater than import capacity in the summer months.

- Slovenia had approximately equal levels of import capacity and export capacity, both in the summer and the winter period, with export capacity to Croatia only slightly higher than import capacity in the summer months

- Poland had significantly higher export capacity than import capacity both in summer and winter months. This difference was mainly driven by significantly higher export capacity to the Czech Republic, as well as higher export capacity to Germany in the summer months

- The Czech Republic had significantly higher export capacity than import capacity, both in summer and winter months. This is largely driven by exports being significantly higher than imports both in interconnections with Germany, Slovakia and, to a lesser extent, Austria, whilst exports to Poland were lower than imports both in summer and winter months

- Slovakia had lower export capacity than import capacity, largely driven by the difference between export and import capacity in the interconnection with the Czech Republic. Import capacity was also marginally higher than export capacity in interconnections with Poland. On the other hand, import capacity was higher than export capacity in interconnections with Hungary.

- Hungary had a slightly lower export capacity than import capacity, both in summer and winter months, largely driven by differences between import and export capacity in interconnections with the Czech Republic and, to a lesser extent, with Austria, whilst exports to Croatia were higher than imports

- Romania had approximately equal level of import capacity and export capacity, both in the summer and the winter period, with export capacity to Hungary only slightly higher than import capacity in the summer months

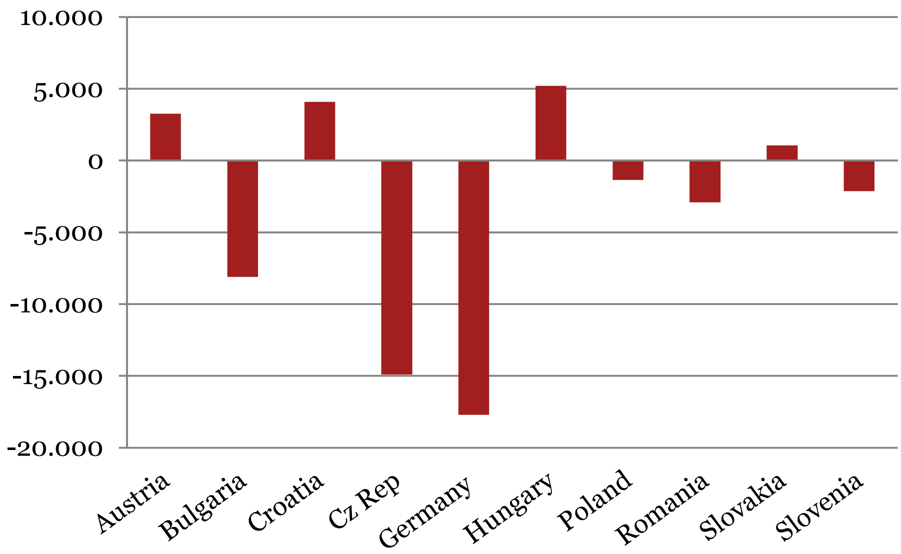
- Croatia had lower export capacity than import capacity, largely driven by lower export capacity to Hungary

- Bulgaria had equal levels of import and export capacity (both in the winter and summer months) with Romania, which was the only interconnection considered within the study area

3.5.2. Net imports

The study area as a whole has a net positive energy balance, with net imports of -33,5 TWh in 2010 (within and on the borders of the study area), equivalent to 3% of total generation within the area – all countries except Hungary, Croatia, Austria and Slovakia (by a small margin) were net exporters. Germany was the largest exporter by total volume, however both Bulgaria and Czech Republic exported volumes equivalent to c. 25% of their total domestic market (by consumption), compared to 3% for Germany.

Figure 13: Net imports 2010 (GWh)



In addition to energy transfers within the study area, electricity produced in Bulgaria is historically exported to the Balkan countries. In 2010, the electricity exported over the Bulgarian-Greek border accounted for 49% of the total exports[23], followed by through Serbia (30%), Macedonia (17%) and Romania (4%).

In most countries the balance of imports is matched by the provision of import / export capacity – however this is not the case for Germany, which has 40% more import capacity than export, however was primarily an exporter.

Whilst some countries such as Czech Republic and Bulgaria were net exporters in each month, in other cases, significant changes within year were observed in the pattern of net imports during the year when looking at monthly data. For example, Austria was a net exporter in the period January to April. It subsequently became a net importer up to September, whilst for the period October-December exports were higher than imports. Significant within year changes were also observed for Germany, which was mainly a net exporter but where imports were higher than exports in the months of June and August.

Below we provide a table outlining monthly net import data for each country within the study.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Austria	801	821	840	1202	-125	-714	-172	-459	-288	296	572	486	**3260**
Bulgaria	-316	-494	-487	-386	-353	-916	-1141	-1031	-738	-462	-873	-903	**-8100**
Poland	-163	-333	-157	51	146	-93	60	67	-182	-284	-240	-217	**-1345**
Romania	-95	17	20	-25	9	-157	-375	-401	-457	-544	-393	-515	**-2916**
Czech Republic	-1521	-1338	-1596	-1442	-726	-910	-1680	-938	-1260	-1463	-1101	-922	**-14897**
Germany	-3564	-3099	-2438	-2468	-738	1370	-23	1007	-649	-1600	-1979	-3526	**-17707**
Hungary	166	173	259	552	606	715	885	552	482	474	173	154	**5191**
Slovakia	133	214	66	-37	28	-120	284	-102	91	206	189	95	**1047**
Slovenia	-190	-97	-233	-196	-287	-237	-75	-207	-270	209	-260	-290	**-2133**

Source: ENTSO-E

[23] Bulgaria National Electricity Company (NEC), Annual Report 2010

3.5.3. Interconnection capacity utilisation

The Working Group have identified that the main electricity flows are initiated in the North Sea region and the north-eastern parts of Germany. Onshore wind power capacities and offshore development (starting with the recent first connections of commercial offshore wind farms to the onshore grids), together with new conventional power plants, concentrate in the northern and north-eastern parts of Germany; demand however rises mostly in southern Germany, increasing distances between generation and load centres or balancing equipment (e.g. pump storage). From Germany these flows are also reported to pass through all countries of the region – Poland, Czech Republic, Slovakia, Hungary, Austria, Croatia, Slovenia as well as through Ukraine (through so called “Burstyn island”, the part of Ukrainian power system synchronously connected to the ENTSO-E system) to the places of consumption in Southern Europe (e.g. Italy).

German Working Group members also highlighted that Germany is the main connection between Scandinavia and Middle Europe and also that neighbouring energy infrastructure has a considerable influence on the infrastructure in the region (for example, if the interconnectors DE-NL and DE-BE will be upgraded, this may have a considerable influence on flows within the northern part of the study region).

Demand for interconnection capacity is typically driven by the need to balance demand and supply portfolios in interconnected markets, by arbitrage opportunities (arising from differences in market price) and also by transit flows on a regional basis. Interconnector capacity utilisation is one measure of the level of this demand between two markets.

We have collected data from ENTSO-E for each of the interconnection points within the study region for 2010[24], including Cross-Border Commercial Schedules, Final Cross-Border Schedules (where available) and Cross Border Physical Flows. For each of these we have calculated the number of hourly periods during which capacity utilisation was less than 50%, between 50% and 99,9% and 100%.

Key finding of these calculations are presented in the table below; the most heavily utilised interconnections are Czech Republic to Austria and Germany to Poland and– each of these has more than 40% of hourly periods with over 50% capacity utilisation and more than 10% hourly periods at 100% capacity utilisation.

In addition Czech Republic to Germany, Poland to Czech Republic, and Slovakia to Hungary have more than 40% of hourly periods with over 50% capacity utilisation (but less than 10% of hourly periods at 100%).

No interconnections were identified with more than 5% of hourly periods at 100% capacity utilisation as well as less than 40% of periods with over 50% capacity utilisation.

From	To	% periods over 50% capacity	% periods at 100% capacity
More than 40% periods over 50% capacity AND More than 10% periods at 100% capacity:			
CZ	AT	46%	30%
DE	PL	45%	14%
More than 40% periods over 50% capacity:			
CZ	DE	56%	1%

[24] Note that interconnections with countries outside the study area have not been included as part of this analysis.

PL	CZ	41%	5%
SK	HU	44%	0%

The Austrian TSO APG has highlighted that the high levels of utilisation at the CZ to AT border arise primarily as the result of high loop flows, which are caused by congestion within Germany and capacity shortages between Germany to Austria at the tie line between the substation St. Peter und Isar.

Data for Croatia is not available from ENTSO-E, however HEP (Hrvatska Elektroprivreda) has commented via the Working Group that congestion appears on all Croatia borders in at least one direction (import from HU and Serbia, both directions with Slovenia and Bosnia-Herzegovina) and that additionally there are bottlenecks in Croatia internal grid which reduces possibilities for long-distance flows – particularly of hydro / wind production located in southern Croatia.

In most of the cases shown in above, 'physical flows' (based on ENTSO-E data for Cross Border Physical Flows) were higher than 'commercial flows' (based on ENTSO-E data for Final Cross-Border Schedules, where available, otherwise Cross-Border Commercial Schedules). Only for Poland to Czech Republic and Czech Republic to Germany were commercial flows higher than physical.

Utilisation of other interconnection points is listed in the Appendix (Figure 54: Capacity utilisation). In most of these cases (12 out of 1925), commercial flows are greater than physical flows.In the next section we explore the differences between physical and commercial flows in further detail.

3.5.4. Loop flows

Loop flows are defined as the difference between scheduled 'commercial' flows and actual physical flows. This difference arises when some portions of a scheduled power are distributed into other branches that are adjacently connected[26].

Using data from ENTSO-E for Cross-Border Commercial Schedules, Final Cross-Border Schedules (where available) and Cross Border Physical Flows for 2010, as described above, we have calculated for each interconnection point within the study area, the number of hourly periods during which physical flows were greater than commercial, and vice versa. In each case we have also calculated the physical flows as a percentage of commercial flows (for all periods where commercial flows were greater than physical; and for all periods where physical flows were greater than commercial.

Based on these calculations, we have identified below the interconnection points where there is a significant difference between physical and commercial flows, looking first at the number of hourly periods during which there was a difference between the two sets of flows, and secondly at the percentage difference.

From	To	% of period Physical > Final cross border	Physical as a percentage of Final cross border
In more than 50% of periods Physical > Final cross border flows (2010):			
DE	PL	92%	1.294%
PL	CZ	95%	683%
PL	SK	87%	946%
RO	BG	82%	378%

[25] The Bulgaria to Romania connection is omitted from this list since only physical data is available
[26] Choo, Nair, and Chakrabarti, Impacts of Loop Flow on Electricity Market Design, 2007

SK	HU	78%	188%
CZ	AT	75%	183%

The loop flows arise during more than 90% of hourly periods from Germany to Poland and from Poland to Czech Republic. In each case there is a significant difference between physical and commercial flows, in excess of 500%. These differences are shown in the graphs in Appendix I (Figure 58 to Figure 66). Other situations with high levels of loop flows arise between Poland and Slovakia, Romania and Bulgaria, Slovakia and Hungary and Czech Republic and Austria. Although this study includes only loop flows within the study area, the Slovenian TSO ELES have indicated that there are also significant loop flows arising at the SL-IT border.

Other borders where loop flows occur in at least 30% of hourly periods are from Austria into Hungary, Slovakia and Germany and from the Czech Republic into Germany and Slovakia. These differences are shown in the graphs in Appendix I (Figure 67 and Figure 68). In each of these cases, loop flows occur in between 30 and 49% of hourly periods, with volumes ranging between 125% and 261% of the final cross-border scheduled flows. However for the majority of the time (at least 50% of hourly periods) these interconnections have either physical flows lower than scheduled flows – particularly in the case of Czech Republic to Germany and to Slovakia (see) – or physical flows are the same as scheduled flows (which is usually the case for Austria to Hungary and to Germany). Flows between Austria and Slovenia are balanced between these three states with physical flows greater than scheduled in 39% of periods, physical flows equal to scheduled in 23% of periods, and physical flows less than scheduled in 38% of periods.

From	**To**	**% of period Physical > Final cross border**	**Physical as a percentage of Final cross border**
In more than 30% (and less than 50%) of periods Physical > Final cross border flows (2010):			
AT	HU	49%	261%
AT	SL	39%	206%
CZ	DE	31%	125%
CZ	SK	30%	137%
AT	DE	30%	227%

The map below illustrates how the highest incidence of loop flows, suggesting that unscheduled power flows from Germany into Poland are transmitted through Poland into the Czech Republic and Slovakia, and onward into Austria and Hungary. There are also significant loop flows between Romania and Bulgaria. As described above there are lower incidences of loop flows back into Germany, and from Austria into Slovenia and Hungary, as well as from Czech Republic into Slovakia.

Figure 14: Geographic representation of loop flows

Key: Physical flows > scheduled in more than 50% of hourly periods

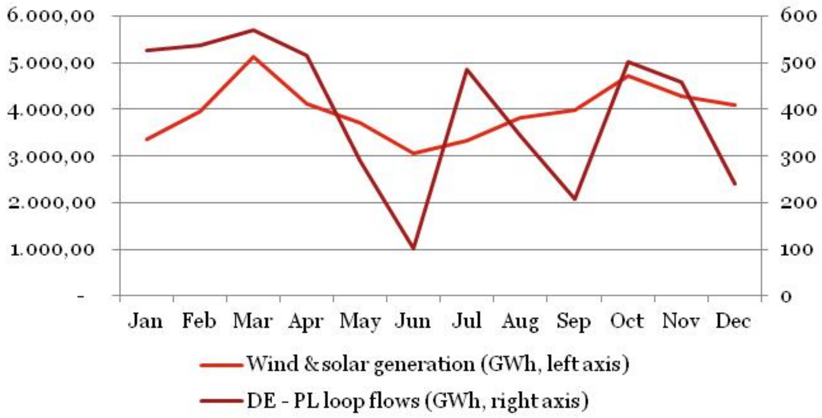
Physical flows > scheduled in between 30% and 49% of hourly periods

***Source**: PwC analysis of ENTSO-E data*

Looking at the major loop flows in further detail (where loop flows exist in >50% of hourly periods), it is apparent that the highest level of correlation in the incidence of loop flows are between those from Germany to Poland, and Poland to Czech Republic (84%), Poland to Slovakia (71%) and Czech Republic to Austria (70%). In addition to the loop flows we observed in the analysis above, the Slovenian TSO ELES has indicated that there are also significant loop flows over the Slovenian power system from Croatia (as well as Austria) and into Italy.

The seasonal pattern of these flows illustrates that the highest levels occur in February or March, July and October, with the lowest level of loop flows in June and August or September. This pattern of loop flows shows some similarity to the output of intermittent generation (wind and solar) in Germany, as illustrated in the graph below, based on monthly loop flows.

Figure 15: Comparison between monthly loop flows from Germany to Poland and intermittent generation in Germany (2010)



Correlations between loop flows are other interconnection points are below 50% – whilst loop flows are a common occurrence from Slovakia to Hungary and from Romania to Bulgaria, their patterns have less similarity with those at the borders described above. From Slovakia to Hungary, loop flows are highest between February and June and lowest from July to September, whilst from Romania to Bulgaria the peak months are August to October, with low levels of loop flows during the rest of the year.

More detailed analysis of loop flow volumes at the interconnection points with higher levels of correlation suggests that the power flows do not feed directly through to the neighbouring countries – explaining why the correlations are less than 100%. The sum of loop flows from Poland (to Czech Republic and Slovakia) is higher than the incoming volumes (from Germany), by 13% for the calendar year 2010. Similarly the loop flows from Slovakia (to Hungary) are higher than the incoming volumes from Poland, by 25%.

In addition, there are several locations where commercial flows exceed physical flows in the majority of hourly periods. The most notable of these are Slovakia to Czech Republic, and Romania to Hungary, where commercial flows are greater than physical flows in 88% and 73% of periods respectively. The other locations where this situation occurs in more than 50% of periods are listed below.

From	To	% of period Final cross border > Physical	Physical as a percentage of Final cross border
In more than 50 % of periods Final cross border > Physical flows (2010):			
SK	CZ	88%	3%
RO	HU	73%	60%
CZ	DE	68%	74%
CZ	SK	62%	55%
HU	AT	51%	34%

German Working Group members also highlighted that efforts are ongoing at a national level to manage loop flows, including consideration in network development plans and the new Grid Expansion Acceleration Act (Netzausbaubeschleunigungsgesetz, NABEG) – in addition it is anticipated that the North-South infrastructure projects (which have a national priority status in the EnLAG) will reduce adverse effects on neighbouring national grids.

3.5.5. Conclusion

Current levels of interconnection capacity vary significantly between countries, with the lowest levels in Germany and Poland (11% and 25%, as a percentage of peak demand) and the highest levels in Slovakia, Slovenia and Croatia (over 100%). Czech Republic has the highest overall level of interconnection capacity within the study region, along with other countries which are central to the region – Slovakia and Hungary, as well as Germany and Austria. Whilst these metrics suggest which countries have the highest degree of integration, other factors such as generation characteristics and borders outside the study region should be taken into account in grid planning.

The region has a net positive energy balance, with net exports of c. 4% of total generation, with both Bulgaria and Czech Republic exporting a significant share of their generation, and Germany the largest exporter by volume.

Grid planning should take into account the seasonal patterns and maximum flows in order to ensure that sufficient capacity is provided, reflecting that imports and exports will be determined not only by the physical demand and supply balance of interconnected markets but also by relative market prices. Where there are significant differences merit order (i.e. relative price of different plant types in each hourly period) of interconnected markets, there may be fluctuations between the export / import balance as different plant types are at the margin (i.e. are able to meet incremental demand at the lowest cost).

These dynamics are illustrated in the utilisation of interconnector capacity, which reflects the gross transfers in either direction within each hourly period. Looking at congestion in terms of the number of periods in which capacity was more than 50% and more than 100% utilised, suggests that the most congested interconnections points are from Czech Republic to Austria and from Germany to Poland. Lower levels of congestion are observed from Czech Republic to Germany from Poland to Czech Republic and from Slovakia to Hungary. None of these interconnections experienced 100% utilisation in a high number of periods (Czech Republic to Austria being the highest, utilised at full capacity in 30% of periods, followed by Germany to Poland at 14%), suggesting that although congestion does occur, the demand for capacity is served throughout most of the year. Nevertheless, in the majority of these cases, additions to capacity would improve the efficient functioning of the market; one exception which has been highlighted by the Austrian TSO APG is the border between Czech Republic and Austria, where the current congestion is likely to be relieved by investments in the internal German grid and at the German - Austrian border, which are anticipated to reduce loop flows through Czech Republic.

Loop flows cause problems for TSOs as they arise from unscheduled power flows and thus require responses from grid operators in order to maintain network stability. We found that within the study area these loop flows occur most frequently from Germany to Poland and from Poland to Czech Republic, where there are often significant differences (in excess of 500%) between scheduled and physical flows. Major loop flows (in more than 75% of periods) also exist on the border from Poland to Slovakia, and from Czech Republic to Austria. Further assessment of these flows suggests that those originating (within the study area) from Germany are linked to the production of intermittent generation (wind and solar) and that these same patterns of flows are passed through from Poland into Czech Republic and Slovakia, and from the Czech Republic into Austria. Significant loop flows also exist from Slovakia to Hungary, and from Romania into Bulgaria, although these show less correlation with those originating in Germany.

3.6. Market prices

Since prices give further information about the degree of market integration, we have considered spot market / day-ahead price data for Czech Republic (CZ), the Germany /Austria market area (DE – taken from the Austrian exchange EXAA), Hungary (HU), Poland (PL) and Slovenia (SL) – spot / day-ahead market price data is not publically available for Slovakia, Bulgaria or Croatia (see Section 4.2 for further description of the markets that exist in these locations).

According to plans of the Ministry of Economy and Energy, a full-functioning energy spot market should be established in Bulgaria by the end of 2011.

Analysis of spot and day-ahead price data – in terms of price levels and correlations – provides a tool for understanding the degree of integration between markets[27] and indicates the extent to which arbitrage occurs between locations.

3.6.1. Price levels

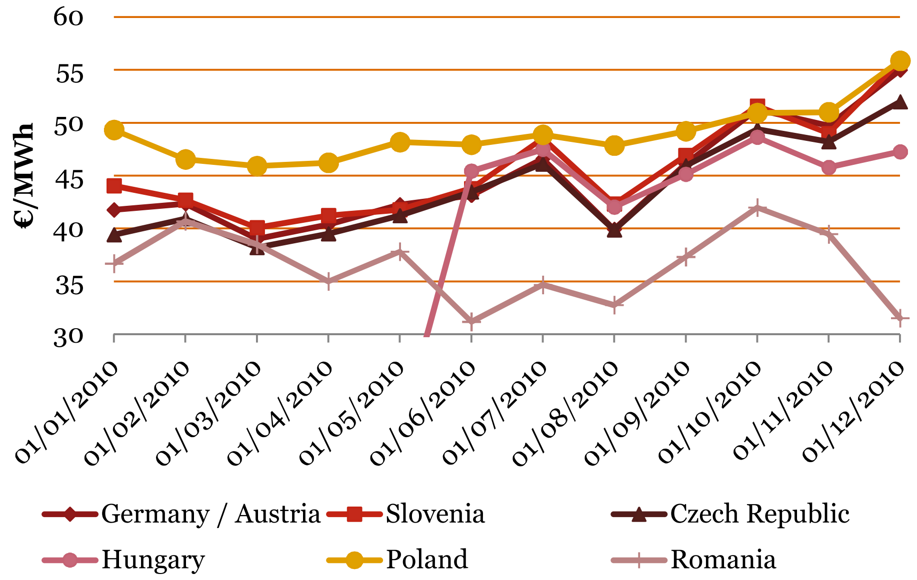
Average spot and day-ahead market prices throughout the region were €44,25/MWh during 2010 – prices were above average in Poland, which had an annual average spot price of €49,0/MWh. Prices were consistent with average price levels in the area in Hungary (€45,92) and Germany/Austria (€44,81). Spot market prices were lowest in Romania, with an annual average price of just over €36,4/MWh, and also below the average in Czech Republic. Further information on market price data is provided in Appendix 10.1.4 (Figure 72).

The greatest seasonal variation in short-term prices was apparent in Germany / Austria and Romania (excluding Hungary, where prices are only available for the second half of the year), with the least seasonal variation in Poland. All countries for which spot / day-ahead price data has been analysed have the highest prices in winter.

Figure 17 below illustrates monthly average spot / day-ahead prices in each of the markets where data is available.

[27] Oxford Institute for Energy Studies, Seeking the Single European Electricity Market, 2002

Figure 16: Spot market prices, 2010 (€/MWh)



Average prices in Czech Republic, Germany and Slovenia show a similar pattern, with Hungarian prices also following this trend following the opening of the EXAA Hungarian spot market in May. Although prices in Poland were higher for most of the year, in the last quarter Polish prices are more closely linked to those in Czech Republic and Germany. Prices in Romania show little relationship to those in other countries.

Prices in adjacent locations may be related due to arbitrage between markets and / or similarities in both demand patterns and generating costs. Market integration (e.g. through greater interconnection capacity) has been observed to contribute to price correlation between markets e.g. in NordPool[28]. Where prices in adjacent markets show very different patterns, it is likely that there is a lack of arbitrage opportunities – for example due to insufficient interconnection capacity or inefficient market operations. Examples of adjacent markets with significant differences in price which can be observed from the data above are Romania – Hungary..

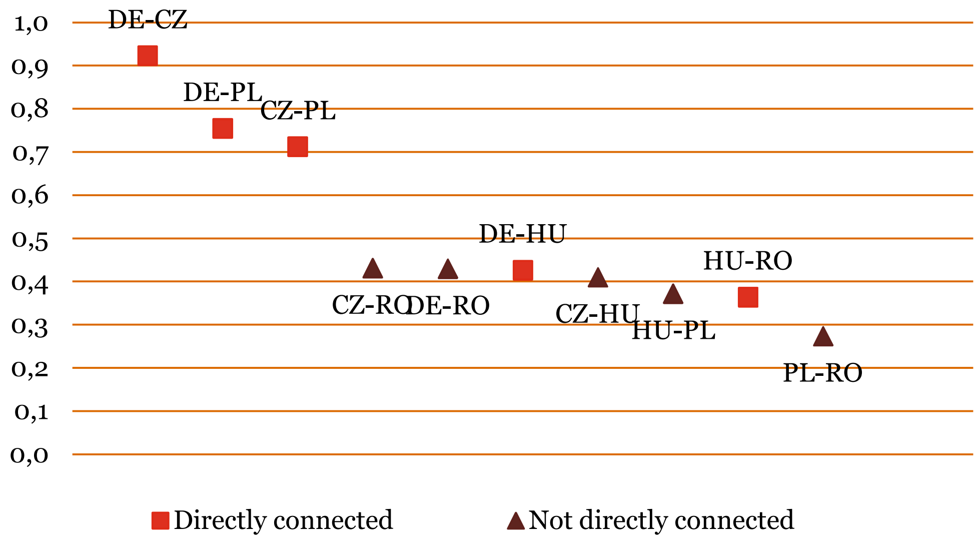
3.6.2. Price correlation

The price data illustrates a wide variation in levels of correlation ranging from 0,92 (Germany - Czech Republic) to 0,21 (Romania - Slovenia). Figure 17 below illustrates that markets which are not directly interconnected have, for the most part, a lower level of price correlation. This data is provided in table format in the Appendix (Figure 70).

We have looked at correlations in the available price data, using day-ahead prices or the daily average of spot market prices as available, hence the correlations below highlight more detailed price relationships than are apparent from the monthly average data. Data for Hungary is calculated only from May when spot market prices became available. Correlations with the Slovenian market have not been calculated as only monthly average data was available.

[28] Oxford Institute for Energy Studies, Seeking the Single European Electricity Market, 2002

Figure 17: Correlations: spot / day-ahead prices[29]



Source: market exchanges[30], PwC analysis

Three markets have a reasonably high degree of correlation (above 0,7), showing that prices tend to move up and down by similar values in each period. These markets are Germany / Austria, Czech Republic and Poland.

When comparing this data to published interconnection capacity (see 3.5.1), it is apparent that there is some relationship between interconnection capacity on a particular border point and the price correlation between the connected markets. However, the correlation between the Hungarian market and its interconnected markets of Germany/Austria and Romania is significantly lower than the correlations between other directly connected markets, potentially reflecting the relatively limited interconnection capacity between these markets.

3.6.3. Conclusion

Our review of spot market prices, for the markets in which these are available, showed that average prices were highest in Poland at €49,0/MWh. Spot market prices were lowest in Romania, with an annual average price of just over €36,4/MWh. In an efficient market the primary driver of market price should be the cost of production, however is likely to be influenced by a lack of competition – from within and outside the market e.g. where generation capacity is concentrated and / or there is a lack of interconnection to other markets.

Our analysis of Romania shows that the largest generator has a reasonably low market share, indicating the presence of competition, along with a high capacity margin, and lack of transmission congestion at border points. Germany and Austria also prices consistent with average levels, and share the characteristics of a relatively competitive generation market and high capacity margins, although there is some presence of congestion on the borders of these markets. These indicators provide some explanation of why prices in these markets are relatively low, however the Czech Republic has the second lowest prices despite relatively high levels of concentration in the generation market, and high incidences of congestion at border interconnections.

[29] Note that in the chart "DE" refers to the price area Germany/Austria
[30] See Appendix 10.1.4

The impact of interconnection on market prices is more clearly visible from price correlation data, where the highest price correlations exist between Germany and Czech Republic, Germany and Poland as well as Poland and Czech Republic. These markets have significant interconnection capacity, although all three locations showed instances of congestion, suggesting that further price convergence could result from higher levels of market integration.

3.7. Forecast for 2020

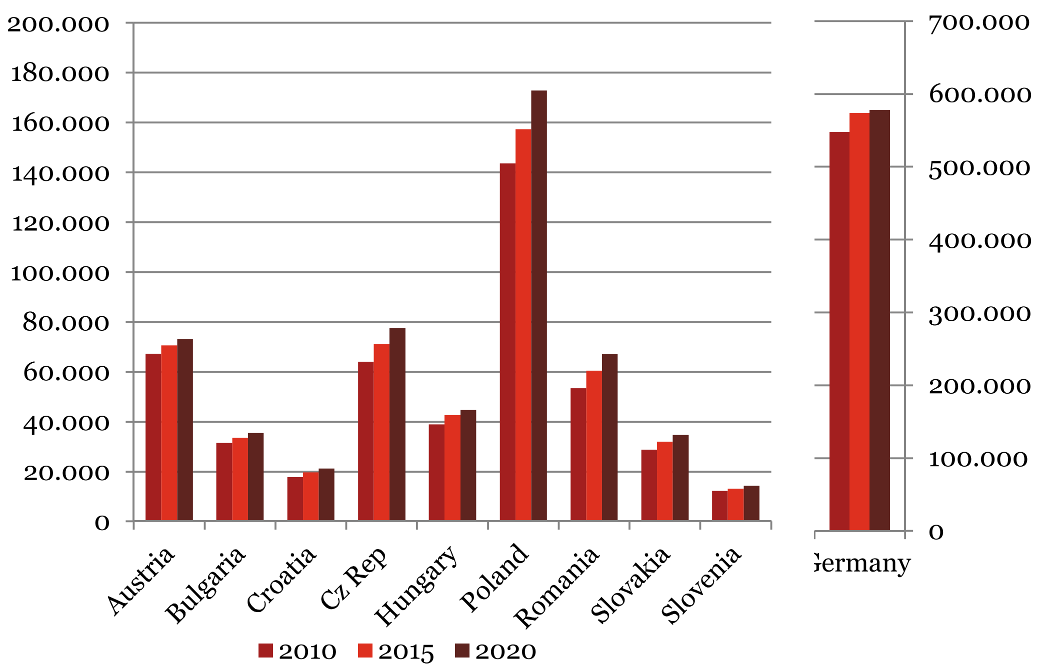
This section is based on 2010 actual data, as presented in Section 3.2, and the growth rates calculated by the PRIMES model, in order to provide a projection of the key datasets for the period to 2020. This data may not correspond to the latest national plans and policies – some TSOs have highlighted that there are discrepancies and where alternative data has been provided (by Czech Republic and Slovakia), we have revised our analysis to reflect this information. Nevertheless we have relied primarily upon the PRIMES growth rate data which has the advantage of being a single dataset with consistent inputs and assumptions, therefore forms a strong basis for this forward-looking part of the market analysis.

3.8. Consumption

3.8.1. Consumption

As shown in Figure 18, consumption[31] in the area is expected to increase by 11% between 2010 and 2020 (see also Appendix, Figure 71) – from 1.006 TWh to 1.075 TWh in 2015 (an annual increase of 1,34%) and to 1.119 TWh in 2020 (an annual increase of 0,81%). Romania is the country with the largest demand growth rate in the period (an annual increase of 2,55% for the period 2010-2015 and an annual increase of 2,11% for the period 2015-2020), followed by the Czech Republic (with an annual increase of 2,16% for the period 2010-2015 and1,72% for the period 2015-2020).

Figure 18: Demand by country (2010-15-20)

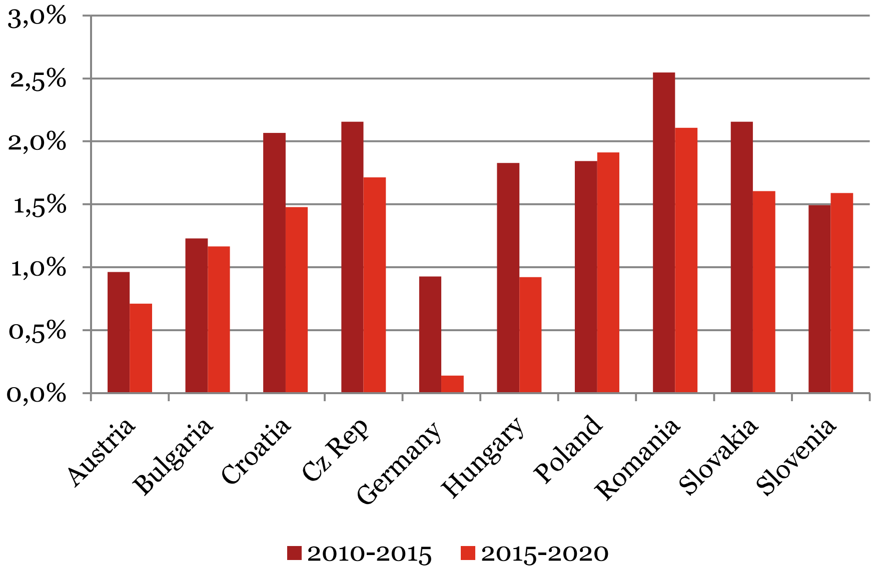


[31] Note that the dataset used to derived growth rates refers to Final Energy Demand, whilst the 2010 data used from ENTSO refers to electricity consumption. For more details, see Section 11.2

Source: ENTSO-E, PRIMES[32]

The high growth rate in Romania and the Czech Republic, as illustrated in Figure 19, is driven by relatively high growth in GDP (4,28% and 3,71% per annum respectively). The growth rate in final energy demand is relatively high in the tertiary sector in both countries (4,49% p.a. in Romania and 2,65% p.a. in the Czech Republic). Germany has the smallest expected demand growth rate within the countries considered (with an annual growth of 0,93% for the period 2010-2015 and an annual growth of 0,14% for the period 2015-2020), followed by Austria (with a growth rate of 0,96% p.a. for the period 2010-2015 and 0,71% p.a. for the period 2015-2020). Germany and Austria's comparatively lower growth rates are resulting from lower GDP growth (1,79% p.a. and 2,01% p.a. respectively for the period 2010-2020), leading to suppressed demand growth particularly in the industrial sector (with a growth rate of -0,07% p.a. in Germany and 0,93% p.a. in Austria against an average growth rate of 1,53% in the study area) and in the tertiary sector (with a growth rate of 0,94% p.a. in Germany and 0,51% p.a. in Austria against an average growth rate of 1,67% p.a. in the study area). However in absolute terms, Germany (together with Poland) is the country with highest expected growth, of c. 30GWh.

Figure 19: Demand by country - annual growth rates



Working Group members have commented that the main North-South energy flows in 2010 are driven by the transfer of energy generated in the northern part of the study area to consumption centres in southern Europe such as Italy. We note that in relation to Italy, PRIMES data suggests that Italian electricity imports will drop by 2,2% per year from 2010-2020. This is based on an assumption that 6,3GW of nuclear capacity will be added to the Italian system by 2020. Given the latest referendum results in that country[33], which rejected the proposal to include nuclear within the country's energy mix, it might therefore be considered realistic that levels of imports (GWh) experienced to date will continue, at least for the period 2010-2015.

[32] All following graphs are based on ENTSO-E 2010 data plus PRIMES growth rates, except where otherwise stated

[33] http://www.world-nuclear.org/info/inf101.html

3.8.2. Conclusion

Consumption in the area is expected to increase by 11% between 2010 and 2020 (from 1.006 TWh in 2010 to 1.119 TWh in 2020. The highest growth rates are expected in Romania (an annual increase of 2,6% for the period 2010-15 and an annual increase of 2,1% for the period 2015-2020, resulting from strong GDP growth projections, driving demand growth particularly in the tertiary sector.

The lowest growth rates are expected in Germany (an annual growth of 0,93% for the period 2010-2015 and an annual growth of 0,14% for the period 2015-2020, resulting from GDP projections which are below average for the study area and imply suppressed demand in the industrial and tertiary sectors.

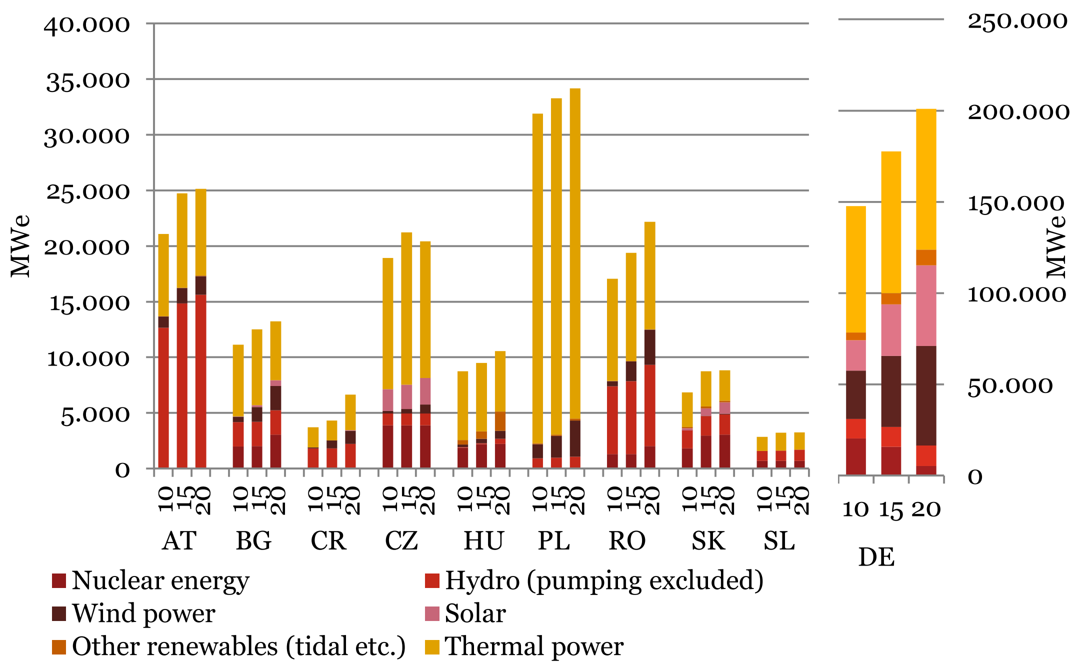
The relative overall increase in forecast consumption levels should be examined in further detail to support further grid planning, taking into account where changes in the structure of demand (for example replacement of industrial demand by growth in the tertiary sector), given the implications for changing patterns of demand e.g. increased seasonality, lower consumption load factor.

3.9. Installed capacity and generation mix

3.9.1. Capacity by plant type

In total, 75,4GW of capacity are projected to be added to the system within the study area by 2020, representing a 28% increase from 2010. Additional capacity is predominantly from wind and solar sources (66,6GW) as well as some thermal capacity (8,6GW), offset by the closure of nuclear capacity (11,7GW). Figure 20 illustrates this growth on a country by country basis (see also Appendix, Figure 73).

Figure 20: Installed capacity by plant type (MWe), 2010, 2015 and 2020



Net additions to capacity are most significant within Germany, where capacity is anticipated to grow by 36% by 2020. Most of this growth (60GW) comes from renewable capacity, with solar expected to grow by 27,5GW (over 150% over the 10 year period) plus an additional 28GW of wind capacity and

4,5GW of other renewables[34] (107% increase). There is also projected to be an increase of 8GW (11%) in thermal capacity. These increases are offset by a reduction of 15GW (75%) in nuclear capacity.

Croatia also expect significant capacity growth in % terms with an overall increase of 78%. Thermal generation is forecast to increase by 75%, with further significant additions of wind and solar capacity.

In Romania, overall capacity growth of 30% is projected by 2020, with 2,7GW wind capacity (600% increase), 1,2GW of hydro capacity (20% increase) and 0,7GW of nuclear capacity (55% increase).

In most other countries, capacity growth is between 7% and 25%[35] (between 1,5 and 4,0GW, except in Slovenia where the expected capacity increase in the period is 0,9GW). Poland has projected capacity growth of 7% to 2020, and the only significant addition to capacity is 2,0GW of wind (155% increase). However, it should be noted that for most countries these results are derived by applying PRIMES growth rates to the current ENTSO-E database. However, according to the PRIMES model, there would be an additional 1,5 GW of nuclear capacity installed by 2020 in Poland, not included in the graph above since nuclear capacity in 2010 is zero.

The main capacity additions in other countries also come mainly from renewable sources, although there are also additions of nuclear capacity in Bulgaria (1,0GW[36]) and thermal capacity in Croatia (1,3GW).

The Working Group have also noted that the addition of large pump storage capacity within Austria is likely to significantly increase power flows on interconnections from Germany to Austria and to Czech Republic, as large Austrian pump storage capacity is charged with the electricity produced from German renewable sources (both wind farms and photovoltaic power plants).

In addition the Working Group note that North-South flows in the Balkan region are expected to be intensified due to the RES sources concentrated in the Black sea coast region in Romania and Bulgaria, while linkage of the Turkish power system further augments flows in same direction.

3.9.2. Generation by plant type

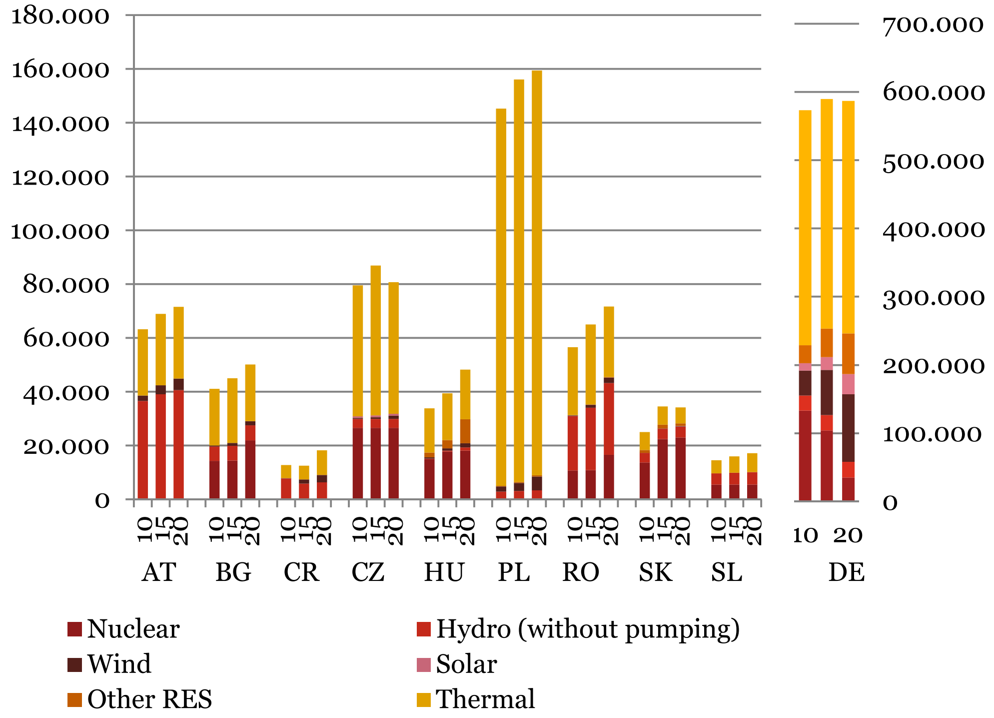
Across the study area, generation is projected to increase by 9% over the period to 2020, slightly below the growth rate in consumption (12%), but significantly below the 28% increase in capacity. These projections are illustrated in Figure 22 (see also Appendix, Figure 74).

[34] Note that the growth rate applied for "other renewable" was the overall growth rate for renewables in the Primes dataset, due to differences in the definition of categories between Primes and ENTSO-E. See Appendix II for more details

[35] The Hungarian TSO MAVIR has indicated that it expects different capacity (and generation) figures within the period than those derived from the PRIMES growth rates. In particular, it indicated that the projected increase in hydro capacity by 2020 and the projected increase in nuclear capacity by 2015 are higher than their own forecasts.

[36] Data from the National Electricity Company of Bulgaria states that planned commissioning of the Belene NPP will take place in 2017-2018, adding 2GW of nuclear capacity

Figure 21: Net Electricity generation by plant type (GWh), 2010, 2015 and 2020



As discussed in relation to capacity, there is a significant decrease in nuclear generation expected in the period to 2020 (a 37% reduction, primarily between 2015 and 2020), driven by the German nuclear phaseout.

Significant increases in capacity in Germany, Poland and Austria are reflected by only modest growth in generation (2%, 10% and 13% respectively), due to the high share of renewable capacity with low load factors. In Germany this is compounded by the closure of high load factor nuclear capacity.

Data provided by Croatia suggests that generation output will increase by 43%, with an increasing proportion of thermal generation, compared to overall capacity additions of over 70%.

There are significant increases in the share of generation from renewable sources (by 81% between 2010 and 2020). Generation is projected to increase in relation to wind (11% annual growth rate in the period 2010-2020) and solar (10% annual growth rate in the period 2010-20). These increases are limited to a few countries within the study area: most importantly Germany, where the share of generation from renewables is expected to double to 36% (largely from wind and other RES), Hungary, where it is forecast to triple to 24% (largely from other RES)[37]. In all other countries the share of generation from renewable is forecast to either decline (such as in Slovakia, where there is additional nuclear capacity) or remain close to 2010 levels.

This increase in intermittent generation, coupled with a decrease in nuclear baseload generation, is likely to increase requirements for balancing on a regional basis.

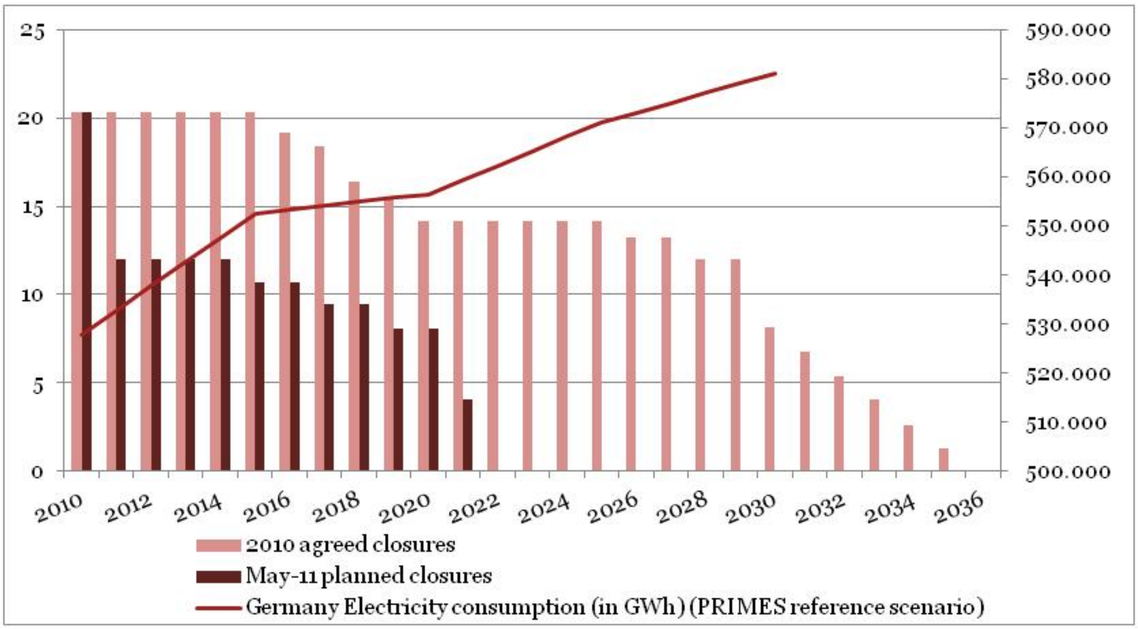
[37] The Hungarian TSO MAVIR considers that the renewable generation share of 24% derived by applying PRIMES growth rates is overestimated, and has highlighted that based on the NREAP submitted to the European Commission by the end of 2010, a RES share of 10,9% is expected in electricity generation by 2020.

Focus on: Impact of the German nuclear phase out on electricity generation

In March 2011, following the Fukushima incident, Germany announced the immediate shut down of eight nuclear power plants and the accelerated closure of the remaining nine in stages up to 2022. The nuclear moratorium implied the immediate shutdown of c/ 7000 MW of capacity (in addition to 1200 MW of capacity already on long term outages), which is equivalent to approximately 10% of total generation capacity. In 2010 nuclear production accounted for c/ 23% of total indigenous production in Germany.

As outlined by the chart below, German's nuclear shutdowns will be accelerated in the context of an annual increase of 0,5% in electricity consumption.

Figure 22: German nuclear capacity retirements and consumption projections



Source: World Nuclear Association, PRIMES reference scenario, EU

As outlined by the charts below, in the period immediately following the start of the nuclear moratorium, Germany has moved from being prevalently a net exporter of electricity to a net importer. When analysed on a country by country basis, it can be observed that Germany's imports from France have increased significantly since the start of the moratorium. In addition, Germany has become a net importer (marginally) from Denmark and Sweden and net exports from Poland, Netherlands and Switzerland have reduced significantly.

Figure 23: Germany net exports – physical flows

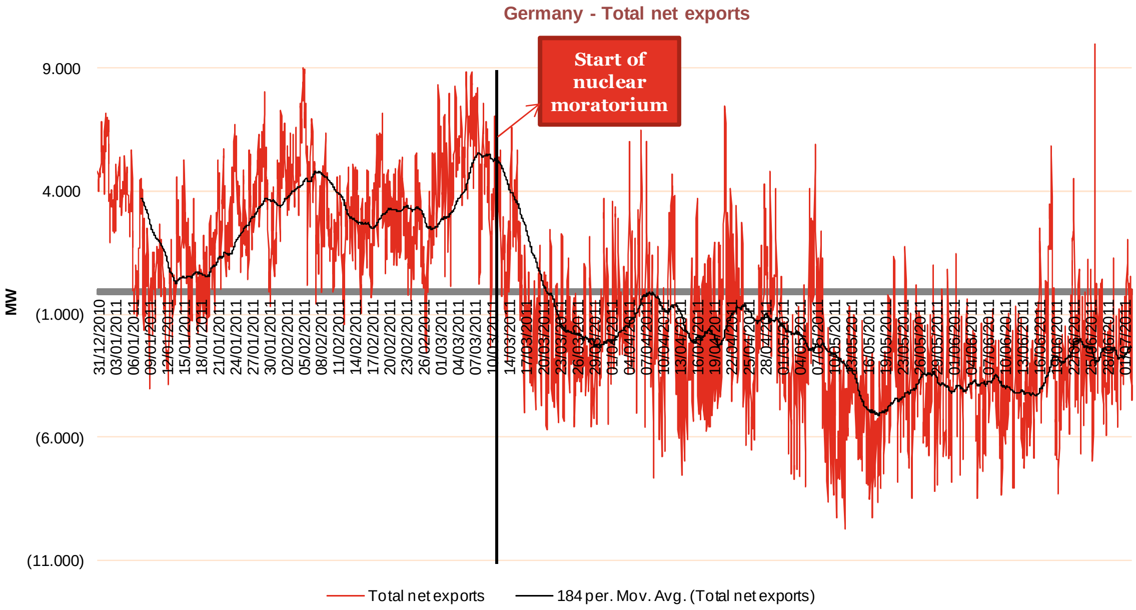
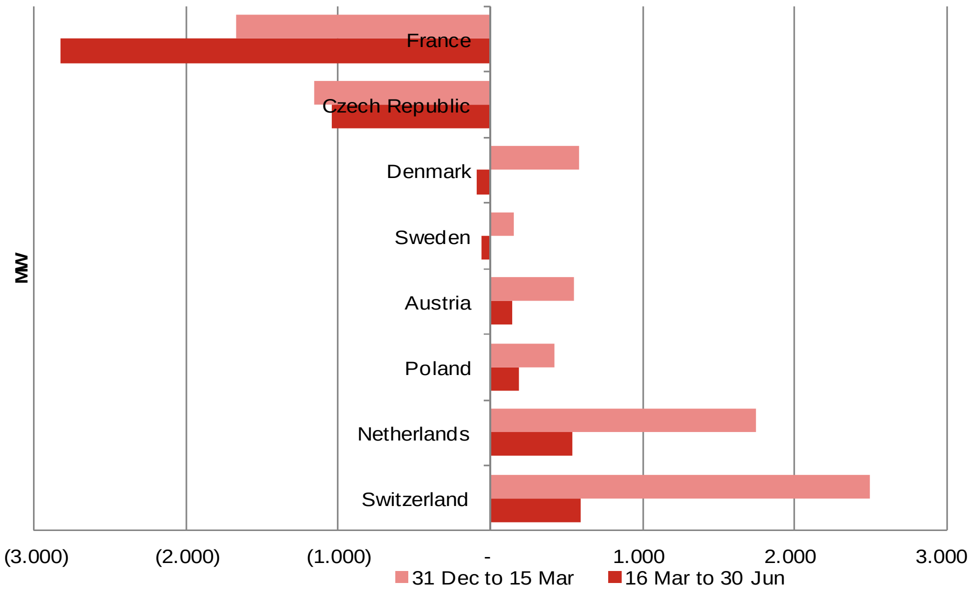


Figure 24: Germany average net exports – physical flows



Source: ENTSO-E

As outlined in a recent document by the German Federal Network Agency[38], some of the potential impacts of the German nuclear moratorium include:

[38] "Update of Bundeznetagentur report on the impact of nuclear power moratorium on the transmission networks and security of supply", 27 May 2011

- Security of supply: potential adverse effects on security of supply are more likely to become apparent during the winter season when PV generation drops and demand rises.

- Market distortions: under some circumstances, N-1 secure network operation could be at risk. In addition, there is a potential increase in requirements for security related interventions by TSOs (e.g. network switching, counteracting transactions and other interventions).

- Grid impact: potential impacts on the German grid include:

    - Increased stress on north-south / east-west flows – increased risk of cascading

    - Potential delays in network expansion, as some planned works cannot be carried out due to the increased network load

    - Potential delay in delivery of new investments, for which the need is heightened by nuclear closures e.g. EnLAG

    - Voltage maintenance (Rhine-Main; Rhine-Neckar; Hamburg) due to removal of reactive power supplies

Focus: nuclear sector – the next decade

Many countries within the study area have reappraised their nuclear policies during 2011, as a result of events in Japan. With the exception of Germany, as explained above, the majority have chosen to continue pushing ahead with nuclear investments.

- In Bulgaria, construction of the Belene nuclear power plant in northern part of the country (2.120MW) began in 2008, with a scheduled operation date of 2016/17*. The project was however halted in 2010 when the government announced a freeze on construction. The project currently appears embroiled in legal disputes and it is reported that a government decision on progress is unlikely to be made before elections in October. Additional units are proposed for the Kozloduy plant, with no scheduled start date for this project.

- The Czech Republic is planning construction of three further units to be operation by 2023 – 2025, as yet there is no decision concerning the outputs of these units. According to the International Energy Agency , the future expansion of nuclear capacity has been presented as one of the major pillars of the new Energy Strategy. Nuclear energy is anticipated to account about 47% of the power generation mix in 2050 (compared to 33% in 2010).

- In February 2011, the Hungarian Parliament has expressed support for building two new power reactors with each capacity of 1250-1700 MWe (from 2020 and 2025).

- Poland currently has no nuclear power plants although there are two research reactors. In 2011 the Government has passed a new law addressing the key challenges to new nuclear developments, to assist in the facilitation of a move away from coal fired generation. The first nuclear power plant authorised by the law is expected to be operational by 2020 and it will have a generating capacity of 3.000 MWe*. A second plant is expected to be completed by 2030 with the same capacity. The two plants are expected to generate 20 % of the country's electricity.

- Romania is planning to complete two more units at the Cernavodă Plant, each with capacity of 740 MW, by 2016 and 2017 *. In 2008 six international companies, together with the government-owned Nuclearelectrica, formed a consortium for the development of these units, however by January 2011 four of these had withdrawn, citing "economic and market uncertainties surrounding this project".

- Slovakia has two additional units at the Mochovce nuclear plants currently under construction, a total of 880MW, planned for completion in 2012 and 2013. In addition, other two reactors have been proposed for 2025 and beyond, in the east of the country

- In Slovenia, the Government is planning a further unit of 1.100 to 1600 MW. An application towards a second reactor at the Krsko nuclear power plant was submitted to the country's ministry of economy by GEN Energija in January 2010. Parliament is expected to decide on this in 2011.

Note that where the forecast nuclear developments described above are not fully reflected in the PRIMES data (as indicated by *), these have not been included in our analysis.

3.9.3. Conclusions

Generation capacity within the study area is projected to increase by 28% over the period to 2020, with significant increases in the share of capacity from renewable sources, predominantly wind and solar. The highest level of net capacity additions are expected in the Germany and Croatia, to meet projected demand growth in those countries.

In total these projections indicated that in the northern part of the study area – between the countries of Germany, Czech Republic and Poland – an additional 31GW of wind capacity and 28GW of solar capacity will be operational by 2020. Capacity from conventional sources (nuclear plus thermal) in these three countries is expected to reduce by 7GW due to the closure of German nuclear plant, offset by additional thermal plant in all three countries.

There are also expected to be additions of nuclear capacity in Bulgaria, although reports suggest that nuclear plant may also be operational by 2020 in Poland, Romania and Slovakia.

Significant increases in the share of generation from renewable are forecast to occur predominantly in Germany and Hungary (respectively: 36% and 24% share of generation in 2020), changing the characteristics of energy production and flows in the north-east and centre of the region as transmission networks are required to deliver in intermittent generation to demand centres, as well as to link to other locations and markets to source balancing flows.

3.10. Energy balances and exchanges

3.10.1. Interconnection capacity

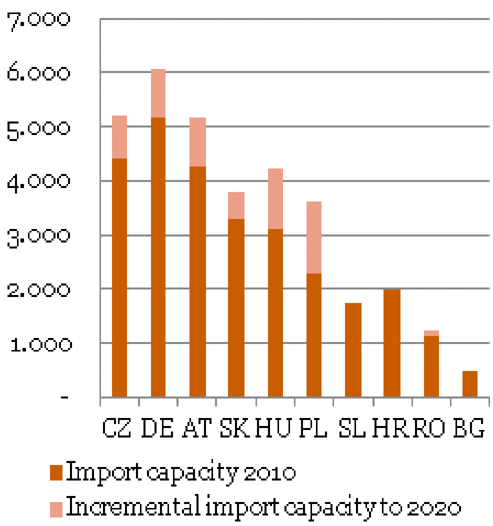
In 2010 The European Commission commissioned a study[39] which examined the requirements for investment in energy infrastructure. This analysis was undertaken by Cambridge Econometrics, using a modelling framework developed by KEMA and Imperial College London (ICL), including scenarios based on the PRIMES reference scenario (for 2020 and 2030). The modelling results provide snapshots of electricity transmission network investment requirements, additional generation investments and associated operational costs aligned with the respective time horizon. The study identifies the need for an additional 4.590MW of interconnection capacity within the study region.

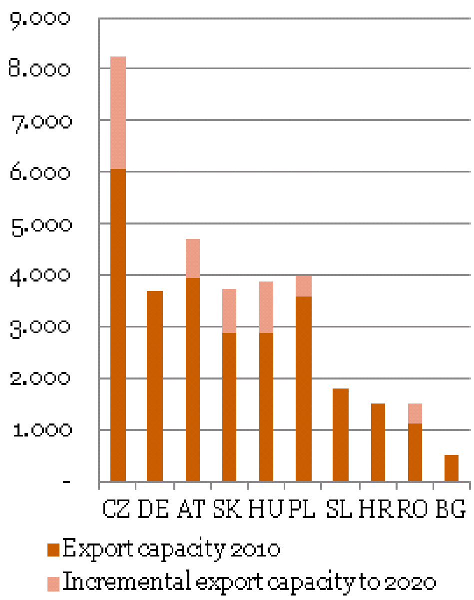
The results of this analysis are shown in Figure 26 and Figure 26 below, compared to the existing import and export capacity for each country within the study area (see also Appendix, Figure 75).

[39] Cambridge Econometrics, KEMA, Imperial College London, The Revision of the Trans-European Energy Network Policy (TEN-E): Final Report, October 2010

Figure 25: (left) Import capacity (MW)

Figure 26: (right) Export capacity (MW)





Source: 2010 capacities - ENTSO-E NTC capacity (Winter 2010-11); 2020 capacities KEMA / ICL study

The majority of incremental capacity requirements are at border points with Hungary (2.090MW) and Czech Republic (2.000MW), as detailed below

- Hungary – both export and import capacity
  - Export to: Slovakia 800MW, Austria 100MW, Romania 100MW
  - Import from: Slovakia 750MW, Austria -60MW[40], Romania 100MW
- Czech Republic – primarily export capacity
  - Export to: Germany 900MW, Austria 800MW, Slovakia -500MW[41]
  - Import from: Poland 200MW, Austria 800MW

Additional requirements identified are: Slovakia to Poland 300MW; Poland to Slovakia 200MW. No increases in capacity are foreseen for Slovenia or Bulgaria; Croatia is not included within the study.

Our observations on 2010 capacity utilisation (Section 3.5.3) showed high levels of usage on lines from Czech Republic to Austria and Germany, as well as from Poland to Czech Republic, consistent with KEMA / ICL's findings that additional capacity was required at these points. Interconnections in Hungary, were however utilised less than some others within the study region (e.g. Germany to Poland).

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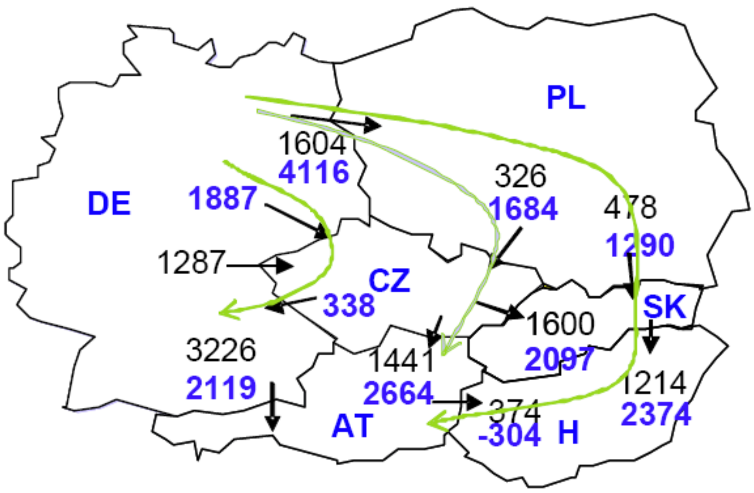
[40] KEMA / ICL assume 740MW capacity requirement for flows from Austria to Hungary; NTC for Winter 2010-11 was 800MW.
[41] KEMA / ICL assume 1.700MW capacity requirement for flows from Czech Republic to Slovakia; NTC for Winter 2010-11 was 2.200MW.

3.10.2. Loop flows

The European Wind Integration Study (EWIS)[42] undertook load flow modelling to indicate grid flows (both physical and scheduled) under a number of scenarios over a timeframe to 2015. The main findings of this analysis are that the European grid in 2015 will experience large flows over long distances from regions of high surplus power generation e.g. in the northern part of continental Europe, to the regions of high deficit in power generation, and that these flows will be mainly north to south. Part of the study considered the difference between scheduled and physical flows, and the results of the EWIS analysis for one of the considered scenarios (not specified in the EWIS report) is presented in Figure 27 below.

Figure 27 Difference between scheduled and physical power flows, large transit flows and minor loop flows



Key: 3226 Scheduled power flows (MW) **2119** Physical power flows (MW)

Transit and minor loop flow

Source*: European Wind Integration Study, Appendix 4.1 Risk Analysis*

This indicates a continuation of the current patterns of loop flows. It should be noted that the power flows forecast by EWIS are in excess of the capacity requirements identified by KEMA which have been referenced earlier in this report (Section 3.10.1).

3.10.3. Conclusions

The KEMA study has identified Hungary and Czech Republic as key locations where interconnection capacity requires expansion, in addition our analysis suggests that additional capacity may be required to support flows between Germany and Poland.

Conclusions from the EWIS study suggest that the current pattern of loop flows is likely to continue, and our observations on forecasts of generation from intermittent sources support this, with potential increases in the loop flows originating in Germany.

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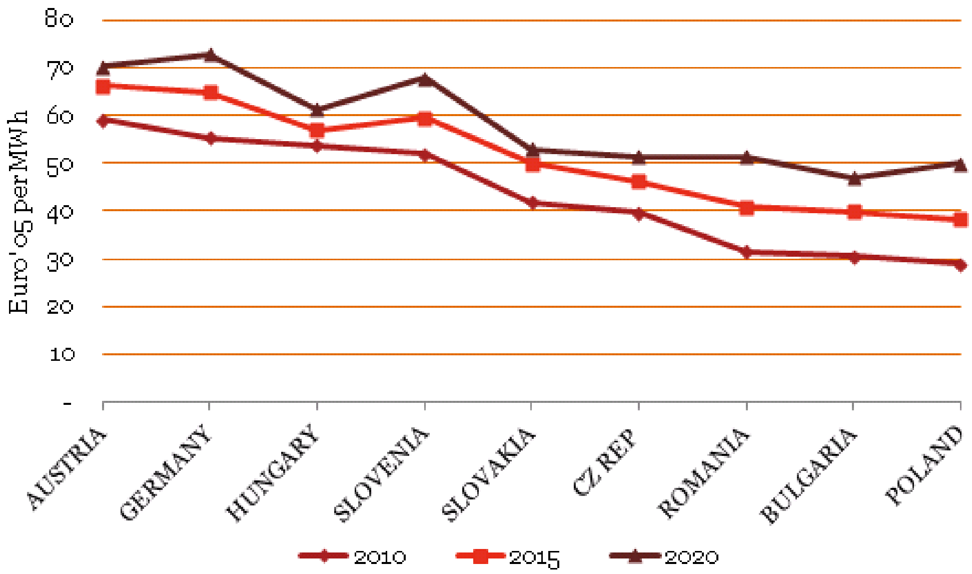
[42] European Wind Integration Study, 2010, undertaken by a consortium of European TSOs and supported by DG TREN.

3.11. Generation costs

Since forward market prices are not available beyond the next 12 to 24 months, and even then for only some markets, we have used PRIMES generation production cost data to illustrate potential changes in price among the countries of the study area (see also Appendix, Figure 76).

Figure 28: Average production costs in power generation (Euro '05 per MWh)



In 2010, this data suggests that production costs in Austria are nearly twice those in Poland, resulting largely from a difference in fixed costs (€11,7/MWh in Poland versus €34,3/MWh in Austria). This relationship is not altogether reflected in the market price data (see Section 3.6), particularly the high level of market prices in Slovenia which is not shown in production costs. The data below reflects an estimate of 2010 costs (produced by PRIMES in 2008), while actual market prices in each country will depend on factors such as fuel price out-turn as well as the relative efficiency of markets.

This data does suggest that in the period between 2010 and 2020, that average production costs will rise by 25% from €43,7 to €58,4, with little change in the relative costs between countries. The main exception to this trend are Hungary, where costs are projected to decrease from 23% above average in 2010 to close to the average cost in 2020. As stated above, there are a number of reasons why these cost changes may not be reflected in future market prices, however any change in the relative market price between interconnected countries is likely to lead to changes in the pattern of imports and exports, where there is sufficient capacity to allow arbitrage between markets.

4. Task 2: Integration possibilities

4.1. Introduction

Market integration is defined by the ENTSO-E Mission Statement as "the process of progressively harmonizing the rules of two or more markets", with the goal of creating a market where electricity can flow freely in response to price signals. The benefits of such a market are anticipated to include reduced prices, increased competition, greater market liquidity (which reduces risk) as well as reduced the need for back up generation, increased system security and facilitation of the integration of renewable energy sources[43].

Steps on the path to full market integration are considered by ENTSO-E to include the development of solutions which can harmonise forward markets, day-ahead markets and intra-day markets as well as solutions which allow congestion on networks to be effectively managed.

ACER have prepared a road map working toward the objective for a EU-single-price mechanism by 2013/14. It is anticipated that the first geographic component of this mechanism will be the Central Western European (CWE) market, to which other regional market couples or clusters will be added. As part of its 2011 five-year work plan, ACER has proposed that allocation rules within the CEE region shall be reviewed in comparison to the rules of the CWE market in order to identify any necessary adjustments to reach compatibility[44].

4.2. Existing integration

The current status of market integration varies throughout the study region. Market integration can be considered in terms of:

- Physical interconnection – we have considered physical interconnection as defined by NTC values, in comparison to peak demand in each of the countries, in order to understand the existing level of capacity relative to market size. This indicates the physical limit for the exchange of energy flows between countries.

- Congestion management – rules and process for allocation of cross-border transmission capacity, ideally with time horizons in line with forward energy markets. Development of a secondary market (exchange of capacity between market participants) allows more efficient (re-)allocation of capacity.

- Market operation – rules and processes for the trading and settlement of electricity within and between markets.

[43] ENTSO-E Mission Statement – Market integration and congestion management (https://www.entsoe.eu/market/market-integration-and-congestion-management/)
[44] Agency for the Cooperation of Energy Regulators (ACER), Central East Region Electricity Regional Initiative – Work Plan 2011-2014 (June 2011)

Key terms

Explicit auction: bidding for transmission capacity as a stand-alone product

Implicit auction: bidding for energy delivered at a market zone – the auction clearing process determines the most efficient amount and direction of physical power exchange to meet demand. Hence transmission capacity and energy are allocated together

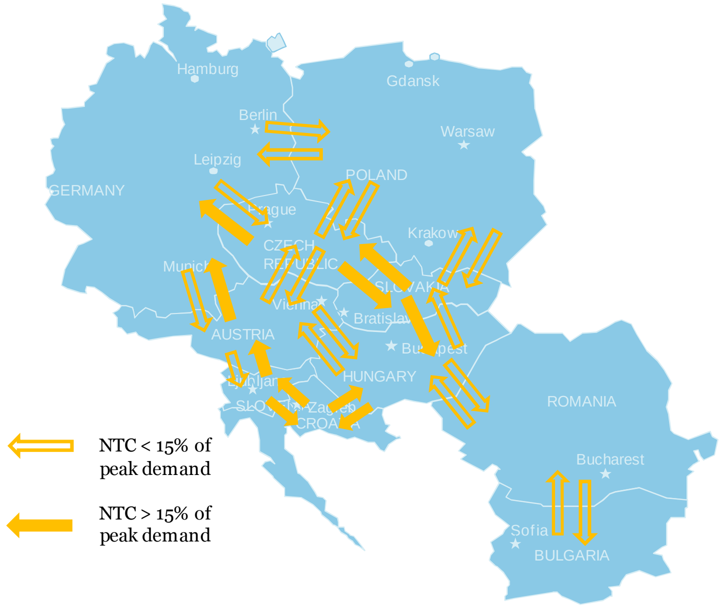
Capacity (NTC or ATC) based al location: determination of available transmission capacity based on TSO calculation of:

- Net Transfer Capacity (NTC) – calculated as Total Transfer Capacity minus the TSO's estimate of reliability margin; or
- Actual Transmission Capacity (ATC) – calculated as Net Transfer Capacity minus Already Allocated Capacity

Load flow based allocation: determination of available transmission capacity based co-ordinated estimation of regional power flows using power transfer distribution factors (PTDF matrix).

4.2.1. Physical interconnection

One observation on market integration can be made from the extent of physical interconnection between countries, based on the NTC values published by ENTSO-E. The map below shows the NTC value (average of the published summer and winter values) as a percentage of peak demand in the originating country, highlighting where NTC for a particular interconnection is greater than 15% of peak demand.



Note: this analysis reflects only the technical limits of NTC, commercial limits may vary

This suggests that the smaller markets of Slovenia and Croatia have the highest provision of physical interconnection relative to peak demand, with connections in excess of 15% of peak demand on both their borders within the study area. Slovakia and Czech Republic, located at the centre of the study area, also have connections with NTC greater than 15% of peak demand on two of their borders, while Hungary and Austria have only one interconnection with such levels capacity.

Physical interconnection (NTC) – by country

Extent of physical interconnection between each country and its neighbours within the study area, is indicated from high (4 cubes) to low (1 cube).

AT	BG	CZ	DE	HR	HU	PL	RO	SK	SL

4.2.2. Capacity allocation

Beyond physical interconnection capacity, a transparent and co-ordinated approach to capacity allocation is necessary in order for the efficient exchange of energy to take place between countries. Within the study area, capacity allocation takes place through congestion management and through market coupling measures. Each of these are considered below on a country by country basis.

4.2.2.1. Congestion management

Congestion management for all interconnectors within the study area is undertaken via market-based mechanisms based on capacity auctions, which in most of the study area are managed by the Central Auction Office. In other markets (Bulgaria, Croatia and Romania), there is at least bilateral co-operation between TSOs in the determination of available capacity. In all markets, with the exception of Bulgaria, capacity rights are available for periods of up to one year, allowing market participants to hedge their longer term positions.

Austria, Czech Republic, Germany, Hungary, Poland, Slovakia, Slovenia

The Central Allocation Office (CAO) was established in 2008 with the manage allocation and congestion management (CACM) for cross-border capacity in support of participating TSOs: APG (Austria), CEPS (Czech Republic), 50 hertz, Tennet (Germany), Mavir (Hungary), PSEO (Poland), SEPS (Slovakia) and Eles (Slovenia).

Since 2010 the CAO has been conducting yearly, monthly and daily explicit auctions for the participating countries and their external borders, based on the NTC capacity calculation method. The CAO is currently involved in the development of a flow-based model as a basis for the capacity calculation[45]. Such a flow-based model could be expected to enhance the efficiency of capacity allocation, indeed testing within the CWE market has demonstrated: higher proposed capacity offered to the market; improved Security of Supply concerning unusual market directions; improved cooperation, and therefore coordination between TSOs; and addresses transparency requirements[46]. However such flow-based models are technically complex and can therefore development and implementation requires long lead-times as well as significant resources.

Within this area Hungary and Slovenia also have bilateral auctions on their borders – respectively with Croatia, Romania, Slovakia and Ukraine; and with Austria, Croatia and Italy.

The Polish TSO, PSEO, recently announced the auction of its the Polish portion of interconnection capacity with Ukraine on a quarterly basis from Q4-11, marking the introduction of market-based principles for this interconnection.

On the other borders of Germany, capacity allocation is also carried out by the Capacity Allocation Service Company for the Central West European Electricity market (CASC-CWE), a service company which, on behalf of the relevant TSOs, implements and operates services related to the auctioning of power transmission capacity on the common borders of Belgium, France, Germany, Luxembourg and the Netherlands.

Bulgaria

ESO (the Electricity System Operator) acts as the Auction Operator for the allocation of capacity between Bulgaria and Macedonia (MEPSO), Serbia (EMS) and Turkey (TEIAS) on a daily and

[45] Agency for the Cooperation of Energy Regulators (ACER), Central East Region Electricity Regional Initiative – Work Plan 2011-2014 (June 2011)
[46] CWE Enhanced Flow-Based MC feasibility report, March 2011

monthly basis. Separate auctions of Commercial Transmission Rights (CTRs) are held on a monthly basis for capacity between Bulgaria and Greece and Romania.

Croatia

HEP-OPS carries out the following allocation procedures, after determining the available capacity in co-ordination with neighbouring TSOs:

- At the borders with Serbia and Bosnia and Herzegovina – yearly, monthly and daily unilateral auctions of Croatian part of ATC

- At the border with Slovenia in direction from Slovenia to Croatia – bilateral yearly, monthly and daily auctions of total ATC

- At the border with Hungary – bilateral yearly and monthly auctions of total ATC; MAVIR carries out daily auctions of total ATC.

Romania

Transelectrica holds monthly, daily and intra-day auctions are held for the allocation of capacity on interconnectors with Hungary, Serbia, Ukraine. Transelectrica coordinates the determination and publication of NTC values with the neighbouring countries TSOs.

Congestion management – by country

Extent of harmonisation of capacity allocation between each country and its neighbours, is indicated from high (4 cubes) to low (1 cube).

AT	BG	CZ	DE	HR	HU	PL	RO	SK	SL

4.2.2.2. Market coupling

Market coupling describes a situation where two or more market operators co-ordinate to manage cross-border power flow at the intersection of two market areas. This may consist of volume coupling, where only the calculation of volumes is centralised, or price coupling, where settlement of both price and volume is undertaken by a single auction office. TSOs must provide the auction office with available capacity and load flow information, in order to facilitate settlement calculations. The benefits of market coupling include greater efficiency in capacity allocation and in the arbitrage of energy prices between national markets[47].

Nearly all countries within the region are currently involved in market coupling on one of their borders, with the exception of Bulgaria, Romania and Croatia. Reports indicate that some of the existing market coupling arrangements may soon be extended to include other neighbouring markets – for example the coupling of Hungary and Poland to the existing arrangements between Czech Republic and Slovakia.

[47] Robert Schuman Centre for Advanced Studies, EUI Working Papers – The Achievement of the EU Electricity Internal Market through Market Coupling, Glachant, 2010

Germany / Austria

Germany and Austria are a single price zone, including the control areas of Amprion GmbH, Tennet TSO GmbH, 50Hertz Transmission GmbH, EnBW Transportnetze and Austrian Power Grid.

The Germany / Austria zone belongs to the CWE market which was introduced in January 2010 when the Germany / Austria market area and Denmark were integrated to the existing market coupling of France, Belgium and the Netherlands (the Trilateral Market Coupling). In January 2011 the NorNed interconnector was added, thus linking the day-ahead market of Norway to the CWE area.

To facilitate the CWE market, an entity known as the European Market Coupling Company (EMCC) calculates the optimal power flows on NorNed and on the two Interconnectors between Germany and Denmark, as well as on the Baltic Cable between Sweden and Germany, through a process known as Tight Volume Coupling – the relevant TSOs provide calculations of available interconnection capacity; exchanges in each of the market areas take bids; on the basis of this information EMCC calculates the optimal flow between the market areas. EMCC was established by NordPool Spot, EEX (which provides a platform for the Germany / Austria market) and three TSOs within the market area.

Czech Republic / Slovakia (Hungary, Poland)

The Czech and Slovak electricity markets have had a bilateral coupling in operation since September 2009. An implicit auction is used for the determination of flow direction and allocation of capacity between the two markets.

In February 2011 the Transmission System Operators of Czech Republic, Slovakia and Hungary (CEPS, SEPS, MAVIR) and the relevant Power Exchanges (OTE, OKTE, HUPX) began an integration process on the request from National Regulatory Authorities, with a goal to achieve market coupling by Q2 2012.

Hungary, the Czech Republic and Slovakia are committed to join European Price Coupling by the end of 2012.

Poland's largest energy exchange – PolPX – and Czech market operator OTE are also reported to be in talks about joining their power markets.

Bulgaria / Romania

It was reported in December 2010[48] that the Romanian energy regulatory agency ANRE and power exchange OPCOM are actively discussing market coupling with their Bulgarian counterparts.

Slovenia / Italy

In August 2010, a common regulatory framework was defined for co-ordination between GME (the Italian power exchange), BSP (the Slovenian power exchange), Terna (the Italian TSO), Eles (the Slovenian TSO) and Borzen (the Slovenian market operator), for activities related to the functioning of day-ahead markets. This consists of the simultaneous allocation of daily Physical Transmission Rights (PTRs) and clearing of energy bid-offers at the Slovenian-Italian border.

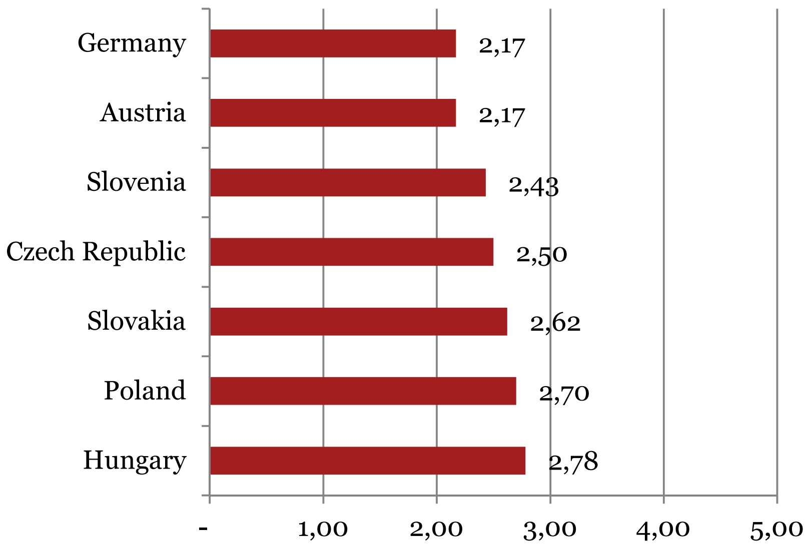
Poland / NordPool

In December 2010, the Polish exchange PolPX and NordPool announced the launch of price coupling between their respective spot markets, with an implicit auction for capacity on the 600MW SwePol Link.

[48] ICIS Heren, 1 December 2010

PwC's survey of traders in the CEE region[49] highlighted that market participants consider that there is particular urgency for further market coupling in Hungary and Poland.

Figure 29: Traders view of urgency to implement bilateral and multilateral market coupling (1 least urgent, 5 most urgent)



Source: PwC Trader Survey 2011

Market coupling – by country

Extent of market coupling between each country and its neighbours within the study area, is indicated from high (4 cubes) to low (1 cube).

4.2.3. Market operation

In addition to the physical elements of interconnection and allocation of capacity, for electricity markets to operate on a regional basis in an integrated and efficient manner, it is important for the market rules and processes to be co-ordinated, if not fully aligned.

One area where there is potential for greater harmonisation is the rules and process for trading of energy, which usually develop in the first instance in relation to spot or day ahead markets and later for futures contracts (monthly, annual contracts). Although several of the markets within the study area have a power exchange, offering a variety of contracts and providing price transparency, there are significant differences in liquidity, affecting the efficiency with which market participants can optimise their positions. In addition to power exchanges, market participants can engage in bilateral trading (over-the-counter, OTC), either directly or via a broker, however prices and volumes for such

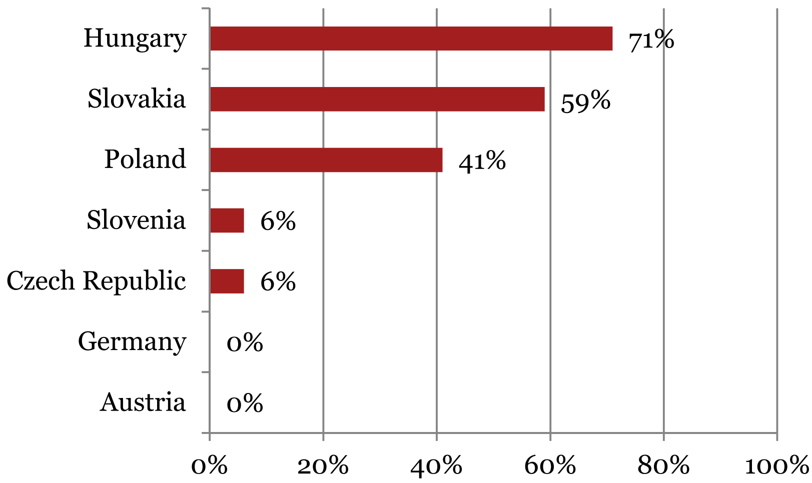
[49] PricewaterhouseCoopers International Limited, Impediments to Electricity Trading in Central and Eastern Europe (CEE) – Trader Survey 2011, including all countries within the study area with the exception of Bulgaria, Croatia and Romania

transactions usually remain confidential, leading to lower levels of market price transparency. Bilateral volumes are usually significantly higher than those which pass through market exchanges – for example in 2009, the German regulator reports that OTC volume traded on broker platforms was around twelve times higher than the volume traded on the EEX and EPEX spot markets for the Germany / Austria market area[50].

In addition to spot and forward trading of electricity, parties who have a physical market position i.e. generation capacity and / or demand offtake, will be required to access services such as balancing markets (balancing of demand and supply in real time) which are typically undertaken by the TSO or via exchange platforms. In addition generators may participate in the market for ancillary services (to provide stability for system conditions such as reactive power and frequency).

In a recent survey undertaken by PwC, traders identified a range of administrative and legal issues which differ between markets, and impact upon market participation. No issues were raised in Austria and Germany, while impediments were rated as most significant in the Hungarian market, due to high imbalance prices, penalties procedures and the scheduling IT system.

Figure 30: Traders view of markets with the most significant administrative and regulatory impediments

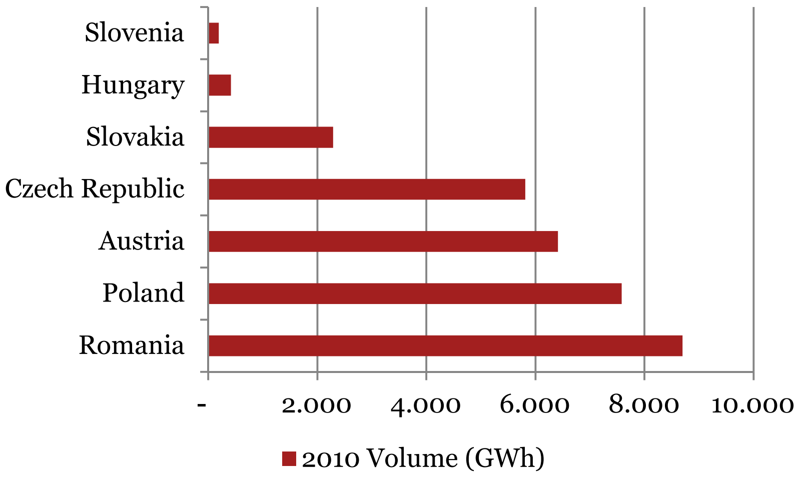


Source: PwC Trader Survey 2011

Liquidity is of key importance for parties who are intending to import or export power, since without transparent pricing signals there is greater uncertainty around the value of electricity in future periods, and reduced opportunities to manage a physical energy portfolio. The chart below illustrates liquidity on a number of exchanges within the study area:

[50] Bundesnetzagentur, Monitoring Report 2010

Figure 31: Market volumes, 2010 (GWh)



***Source**: PwC Trader Survey 2011; original and additional data from market operators*
Note: Analysis excludes Germany. Romanian market includes mandatory auctioning by state owned producers; Austrian market data covers only Energy Exchange Austria (EXAA) volumes, additional liquidity for the Austrian is provided by the European Energy Exchange (EEX).

The characteristics of market operation on a country-by-country basis are further explored in the following paragraphs.

Germany / Austria

Since Germany and Austria operate as a single market area, electricity spot products for the integrated market are offered by both EPEX Spot/EEX Derivatives (Germany) and EXAA (Austria). In addition EEX offers financial futures contracts. Following the Third Energy Package, Austria's three control areas are managed by Verbund APG, thus reducing the number of entities which market participants had to deal with for balancing services. There are four TSO control zones within Germany.

Bulgaria

All electricity trading is carried out on a bilateral basis as there is no electricity exchange – the regulator reported that in 2009, 24.5% of the internal consumption in the country is traded in the wholesale market at freely negotiated prices[51]. Market operation, including balancing markets, is carried out by the Electricity System Operator (ESO).

Croatia

In Croatia all electricity trading is undertaken on a bilateral basis, whilst settlement of the balancing market is managed Croatian Energy Market Operator (HROTE).

Czech Republic

The market exchange in Czech Republic is organised by the Electricity Market Operator (OTE), which merged with the Prague Energy Exchange (PXE) in 2009, and also operates the balancing market. Volumes traded on the combined markets in 2010 were equivalent to 8% of consumption. Additional

[51] State Energy and Water Regulatory Commission (SEWRC) Bulgaria, 2009 National Report to the European Commission

volumes are traded via bilateral contracts, which the regulator reports are generally for a one-year term[52].

Hungary

Since 2010 EXAA has been a platform for the exchange trading of spot contracts for the Hungarian market, although the volumes remain small (equivalent to approximately 1% of domestic consumption), with remaining volumes transacted on a bilateral basis. The majority of the production of domestic power plants is sold through 5-8-year agreements concluded with MVM, the former public utility wholesaler, who then sells these volumes on under 4- year framework agreements (VEASZs, long term electricity sales contracts) or through bilateral contracts or public capacity auctions – in 2009 the regulator reports that approximately 50% of volumes were sold through each of these methods[53].

Poland

In Poland, an electricity exchange is managed by Towarowa Giełda Energii S.A. , POLPX, which offers a continuous spot-market, as well as auctions for longer term contracts (quarter, annual). Market volumes remain low relative to domestic consumption (4%), although the overall size of the market (in GWh) is one of the largest in the study area. In 2008 the regulator required the termination of long-term PPAs, which should increase the ability of new entrants to access the market, although the following year it reported that the majority of power continues to be sold through bilateral contracts[54].

Romania

Romania has a Day-Ahead Market and Intra-Day Market organised by OPCOM, which in 2009 saw transactions equivalent to 13% of domestic consumption[55], including the mandatory auctioning of volumes from state-owned producers which supports liquidity. The majority of volumes are sold as bilateral contracts, on either a negotiated or regulated basis (in similar quantities) with additional volumes sold as centralised market contracts.

Slovakia

A trading exchange is offered by the Slovak Power Exchange (SPX) which also covers the markets of Hungary and Czech Republic, although data from the company (website) shows that volumes in these other markets are low – less than 200GWh per year, compared to 2,300GWh in Slovakia (equivalent to 7% of domestic consumption). Additional volumes are sold primarily through bilateral contracts.

Slovenia

In Slovenia there is an energy exchange operated by BSP SouthPool, which also offers contracts for delivery in Serbia, although liquidity remains low, equivalent to 1% of domestic consumption in 2010. Other volumes are sold via bilateral contracts, defined as ‘closed contracts’, which, along with contracts for import / export and balancing, the market operator (Borzen d. o. o.,) is mandated to record on a regulated market.

Market operation – by country

Extent of liquidity of electricity markets and transparency of market operation, is indicated from high (4 cubes) to low (1 cube).

[52] The Czech Republic’s National Report on the Electricity and Gas Industries for 2009
[53] Hungarian Energy Office, Annual report to the European Commission, August 2010
[54] The President of the Energy Regulatory Office in Poland, National Report to the European Commission, July 2010
[55] Romanian Energy Regulatory Authority, National Report 2009

AT	BG	CZ	DE	HR	HU	PL	RO	SK	SL

4.3. Integration possibilities

The analysis conducted above, at an indicative level, suggests that the market s of Romania, Bulgaria and Croatia have the lowest levels of integration when considered across the spectrum of physical interconnection, congestion management, market coupling and market operation. Market integration of both Bulgaria and Croatia might be improved against each of the criteria, with the exception of physical interconnection provision in Croatia, which is already high relative to peak demand. Romania has also made steps in the direction of market operation, with a relatively liquid short term market (supported by the mandatory auctioning of volumes from state-owned producers).

Slovakia, Slovenia, Hungary and Poland have all made some progress towards market integration, although in each of these cases market operation could be improved through more liquid exchanges for electricity trading over a range of forward and shorter-term periods. The provision of physical interconnection capacity in Poland is low relative to peak demand, as evidenced by observations of grid congestion on several borders (as discussed in Sections 3 and 5.2).

Austria, Germany and Czech Republic show progress against all of the indicators of market integration discussed here, although in all these countries there are relatively low levels of physical interconnection capacity as well as evidence of cross-border congestion (see Sections 3 and 5.2).

In terms of integration indicators, possibilities for the develop of physical interconnection are addressed in further detail in Section 6. A model for congestion management is provided by the Central Auction Office, with the potential for further improvements from the implementation of flow-based model, which could be expected to enhance the efficiency of capacity allocation. Within the study area the most sophisticated example of market coupling is observed in Germany / Austria as part of the CWE group, which other regional groupings are working towards coupling with, supported by co-ordination from ACER.

Prices in several of these markets are observed to be closely correlated with the German market (as discussed in Section 3), even where no physical interconnection exists, suggesting that market participants look to nearby liquid markets for price signals, even where there are no practical arbitrage opportunities. The presence of a number of exchanges within the central and eastern part of the study area, each with relatively low liquidity, suggests that consolidation into fewer, or even a single, exchange platform, may generate more liquid market through the trading of products across a wider market area. Since such exchanges operate as independent businesses, consolidation is likely to occur following the emerge of stronger players in a position to grow their market position through acquisitions.

Each of these measures is likely to be reinforcing, since each step towards market integration improves the competitiveness of energy markets thus provides commercial incentives for further integration.

5. Task 3: Bottlenecks and development options

5.1. Definition of bottlenecks

The term 'bottleneck' is deceptively easy to use and undoubtedly useful in describing to a broad audience the notion of some type of delay or obstruction in either service provision or a physical network such as a road or rail system or an electricity grid. At the broad, policy level, it is in common use in discussion of the present functioning of electricity transmission grids and their future development. Where it becomes more problematic is if a precise definition is required of what exactly is and is not a bottleneck and, more particularly, where bottlenecks might potentially occur in future. Thus there are two fundamental problems to be addressed, definition and forecasting. Addressing these issues also has to recognise that what is needed in the present context is timely and practicable support for policy decisions and not a deep and time-consuming philosophical exploration.

5.1.1. Defining a bottleneck – general principles

A good number of studies have explored the existence and alleviation of bottlenecks in electricity transmission networks. Examples include De Joode and Van Werven (2005)[56], Meeus et al.[57], KEMA Consulting (2003)[58], ENTSOE (2010)[59] and many others. They have used a range of indicators to seek to define what is, and what is not, a bottleneck. A bottleneck is not usually a blockage in the sense that all supply is cut off. It is a degradation in quality of service relative to some norm. What the norm is can often be a matter of judgement. What constitutes a degradation of service of sufficient severity to justify 'bottleneck' status is almost always a matter of judgement. There is no principled basis for drawing the boundary between bottleneck and no bottleneck. In any area of application, including transmission grids, the best that is likely to emerge is some kind of expert consensus about what profile of characteristics might reasonably permit a location on a grid to be regarded as a bottleneck.

For example, in KEMA Consulting (2003) where the objective was to national-interest transmission bottlenecks (power flow constraints) in the USA, the indicators encompassed locations that:

- Create congestion that significantly decrease reliability
- Restrict competition
- Enhance opportunities for suppliers to exploit market power
- Increase prices to consumers

[56] De Joode, J. and Van Werven, M. (2005) Optimal design of future electricity supply systems: an analysis of potential bottlenecks in NW-Europe, paper presented at the IAEE Annual European Energy Conference 2005, Bergen, Norway, 28-30 August 2005.

[57] Meeus, L., Purchala, K., Van Hertem, D. and Belmans, R. (2006) Regulated cross-border transmission investment in Europe. European Transactions on Electrical Power, vol. 16, p.591-601.

[58] KEMA Consulting (2003) *Analysis and Selection of Analytical Tools to Assess National-Interest Transmission Bottlenecks.*

[59] ENTSOE (2010) *Ten-Year Network Development Plan, 2010 – 2020.* ENTSOE, Brussels.

- Increase infrastructure vulnerabilities
- Increase the risk of blackouts

The assessment of bottlenecks thus requires assessing the reliability and economic impacts that they create, as well as those that would be avoided, if the bottlenecks were to be removed or reduced. This can be achieved in principle by a set of tools that identify the price of electricity in any specific location and assess the physical constraints or bottlenecks. The prices can be used in assessing the cost of a bottleneck to the consumer as one aspect of their overall economic impact. In any study of bottlenecks and of options to relieve them both of these elements - reliability and economic assessments - must be undertaken in order to evaluate the costs of bottlenecks and the benefits of relieving them. In data terms alone this is a daunting prospect.

5.1.2. Modelling and forecasting

In addition to the definitional and data problems of labelling a location a 'bottleneck', a further major issue is that policy decisions have to be made against the background of what future patterns of demand for energy are expected to be and in an environment where investments in transmission and generation infrastructure can take a substantial amount of time to complete and with some uncertainty about cost. A KEMA study[60] recognised the importance of the modelling and forecasting element of the overall task and it is clearly identified in the ENTSOE 2010 Ten Year Development Plan[61] and in Johnsson (2011)[62] as an issue that needs to be satisfactorily resolved, but where fully suitable techniques are not yet available. Thus, in addition to difficulties in unambiguously defining what a bottleneck is, there is the additional layer of complexity of not knowing with much accuracy what generation capacity will be available, exactly what transmission capacity will be available when and, overwhelmingly, what consumer demand patterns will be like, especially in the light of continuing efforts to influence public attitudes towards sustainability and the use of non-renewable resources.

5.1.3. Defining bottlenecks in practice

In practice, bottleneck identification will need to be pragmatic, depending to a significant extent upon expert judgement but carefully monitored to ensure consistency of criteria across the full assessment process. It will be driven by an analysis of historical data reflecting recent market conditions and has to be based on existing and readily available data sources. It should err on the side of inclusivity in that the intention is to draw up a list of possible bottleneck locations for which any concrete investment proposals would themselves be subject to much more rigorous appraisal. It has also been agreed that only cross-border flows will be considered when identifying bottlenecks.

The main data source available to us that encompasses most of the study area of concern (Croatia is not included) is the ENTSO-E 'Entsoe.Net' transparency platform. This provides information, among other things, on net transfer capacity (NTC) between countries and on cross-border physical and commercial flows and final cross-border delivery schedules. Juxtaposing the data available from the transparency platform with the general list of indicators associated with bottleneck locations outlined earlier suggests that practicable indicators that can be seen as a primary basis for highlighting potential bottlenecks relative to NTC for each of cross-border physical flows, commercial flows and final cross-border delivery schedules respectively.

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[60] KEMA Consulting (2003) Analysis and Selection of Analytical Tools to Assess National-Interest Transmission Bottlenecks.

[61] ENTSOE (2010) Ten-Year Network Development Plan, 2010 – 2020. ENTSOE, Brussels.

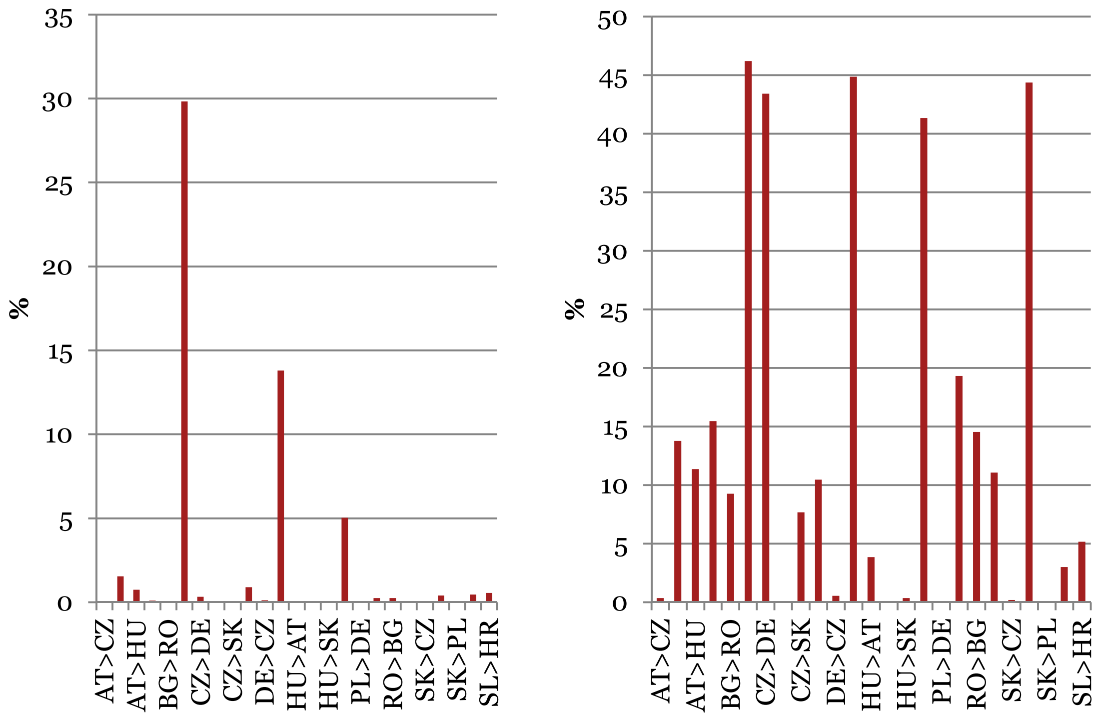
[62] Johnsson, F. (ed) (2011) Methods and Models used in the project Pathways to Sustainable European Energy Systems. Alliance for Global Sustainability, Chalmers University, Gothenberg, Sweden

5.2. Identification of bottlenecks

5.2.1. Cross-border physical flows

The Appendix (Figure 55 to Figure 68) provides graphs illustrating the relationship between NTC and each of the three flow measures on an hourly basis for the whole of 2010 for specific interconnection points. In order to allow a more straightforward comparison between border interconnections, we have further calculated on an hourly basis the proportion of time that each of the three flows exceeds NTC or lies within a 50 – 100% range of NTC. The results for Physical Flow are shown in Figure 32. The choice of the first (>NTC) threshold reflects evidence of some existing shortage of capacity. The choice of 50% as the figure to be the lower limit to underpin limit the second category is more subjective, but allows an indication of potential capacity problems to be made, given the possibility of growing demand for transmission. Checks were made on the robustness of the 50% limit to ensure that increasing or decreasing it by a small amount would not significantly alter the overall picture.

Figure 32: Percentage of hourly periods during which capacity utilisation was 100% (left) and between 50% and 99% (right)

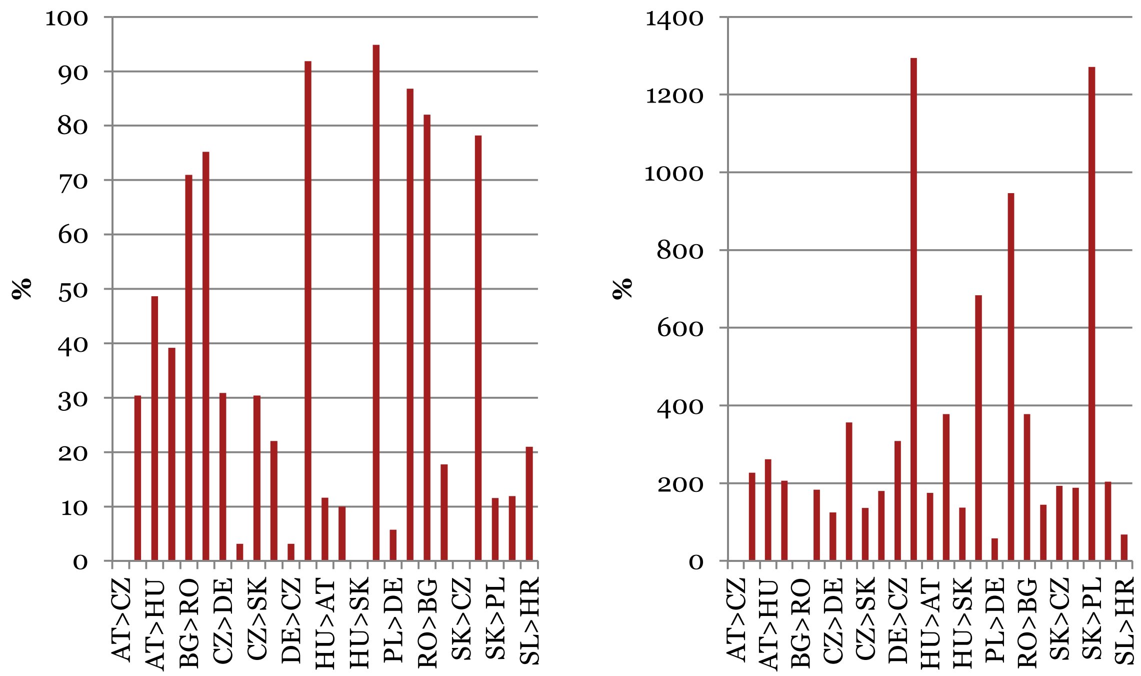


No specific assessments were made in relation to projected future demand levels since this lay outside the brief given for the overall assessment exercise.

5.2.2. Loop flows

Loop flows are defined as the difference between scheduled commercial flows and actual physical flows. They occur when elements of scheduled flows are distributed into other network branches. Figure 33 shows for each of the border crossings where data is available the % of hourly time periods when physical flows are greater than commercial, as well as physical flows as a % of commercial flows.

Figure 33: Percentage of hourly periods during which physical flows were greater than commercial (left) and physical flows as a percentage of commercial flows (right)



In addition to this direct evidence on cross-border and loop flows, a further, albeit less direct, perspective on the bottleneck question can be obtained by examination of various indicators deriving from market behaviour.

5.2.3. Price levels

Examination of records of spot market prices (see Section 3.6) revealed that average prices were highest in Poland and Slovenia, with lower prices being observed in Romania, Germany and Austria. In these locations we have also observed high capacity margins and a lower market share attributable to the largest generator.

5.2.4. Price correlation

Evidence on market price correlations during 2010, where available, (see Section 3.6.2). Higher price correlations were observed between Germany and Czech Republic, Germany and Poland and Poland and Czech Republic and relatively low ones elsewhere. There appears to be some relationship between interconnection capacity and price correlations.

5.2.5. Capacity auctions

Data on 2010 auction prices was obtained from the website of the Central Allocation Office (see Section 4.2.2). These provide evidence on the level of congestion revenues earned by TSOs for access to capacity on specific interconnection points, and thus indicate the relative level of demand experienced at each location.

For the TSOs for which data is available auction prices were assessed for 2010, both at an annual level and using monthly data. The highest prices were found, combining observation of annual and monthly data, between the following country pairs:

- Poland to Czech Republic
- Poland to Slovakia
- Poland to Germany
- Czech Republic to Germany
- Germany to Czech Republic

5.2.6. Conclusions

The ambiguity inherent in operationalising the concept of 'bottleneck', limited data availability and modelling capacity and the uncertainty about how precisely demand for electricity will develop across the states represented in the study all point to taking a multi-perspective approach to identifying borders where support for future investment in cross-border capacity might be justified. The aim has been to develop a set of indicators, common to all existing crossings, which can be used to filter out less likely possibilities. In this study we have based bottleneck identification primarily on existing physical flows and loop flows (as an indicator of the need to seek alternative pathways through the grid). This is then supplemented by a review of market price levels and correlations between prices across the states and auction price data, to check that no anomalous cases are incorrectly included or excluded.

To implement this general approach, we have identified those interconnection points where utilisation of cross-border physical capacity lay between 50 and 99% in at least 15% of hourly periods during 2010 (data presented in Figure 32). We have also examined those interconnections where the % of time periods when physical flows exceeded final cross border flows more than 30% of the time(data presented in Figure 34). Care was taken to use consistent thresholds where, as much as possible and for reasons of robustness of the outcome, there were few crossings which fell just below the threshold adopted. We have further identified pairs of countries where market price or auction data patterns may be consistent with limited cross-border capacity.

Combining these three indicators gives the following list of potential bottlenecks (highlighted in bold where all three bottleneck indicators are met): Poland to Czech Republic, Czech Republic to Germany and Poland to Slovakia. In addition Austria to Slovenia, Czech Republic to Austria, Germany to Poland and Slovakia to Hungary present two out of the three bottleneck indicators.

From	To	Capacity utilisation	Loop flows	Price data
AT	DE	-	✓	
AT	HU	-	✓	
AT	SL	✓	✓	
BG	RO	-	✓	
CZ	AT	✓	✓	
CZ	**DE**	✓	✓	✓
CZ	SK	-	-	
DE	AT	-	-	
DE	CZ	-	-	✓
DE	PL	✓	✓	
PL	**CZ**	✓	✓	✓
PL	DE	-	-	✓
PL	**SK**	✓	✓	✓

From	To	Capacity utilisation	Loop flows	Price data
RO	BG	-	✓	
RO	HU	-	-	
SK	HU	✓	✓	

In the case of flows from Poland to Slovakia, as well as Poland to Czech Republic, physical flows are greater than commercial flows in the majority of periods (87% and 95% respectively), and are on average 7 to 9 times higher than commercial flows within such periods. This suggests that congestion at these interconnection points is cause largely by loop flows, as the capacity utilisation on a purely commercial basis would be significantly lower.

As explored in Section 3, these loop flows are observed to originate, within the study area, from Germany, although this market is in turn connected to other areas with high levels of renewable energy generation which can generate loop flows.

Between Czech Republic to Germany, commercial flows are higher than physical flows during 67% of periods, during which physical flows are on average around 75% of commercial, suggesting that capacity is in fact utilised less than commercial arrangements would suggest.

Development options for the identified bottlenecks are assessed within Section6, under the assessment of current and planned projects.

6. Task 4: Assessment of current and planned projects

6.1. Definition of prioritisation criteria and indicators

In order to prepare a framework for the prioritisation of projects, we reviewed and commented upon the prioritisation criteria and indicators defined by the Commission (as part of the template for the project fiche). Indicators are used to assess the extent to which an individual project meets each of the defined criteria. These criteria and indicators form the assessment framework for the evaluation and assessment of projects. No 'de minimis' threshold is adopted in terms of whether information is relevant to the particular criteria or indicators.

The table below provides an extract from the project fiche template, in which the prioritisation criteria are outlined in bold (1-4), and indicators (a-c) are included below each of the criteria.

Figure 34: prioritisation criteria and indicators

1 **Priority level (where defined) in:**
- a) National energy policy (2020)
- b) TSO network development plans

2 **Capacity to connect renewable generation and transmit it to major consumption and / or storage centres**
- a) Will the Project facilitate the connection and transmission of renewable generation and / or storage?
- b) Does the project contribute to or facilitate energy efficiency?

3 **Increase of market integration and competition**
- a) Does the project increase market integration between member states?
- b) Does the project improve the competition in the internal energy market (beyond increased market integration)? e.g. connection for new market participants

4 **Contribution to security of electricity supply**
- a) Will the Project contibute to operational network security (i.e. continuous operation of the transmission network)?
- b) Will the Project contribute to balancing supply and demand (i.e. generation reserve capacity or demand management)?
- c) Will the project impact loop flows to / from neighbouring TSO areas?

Criteria were selected on the basis of the EU energy sector objectives of market integration, security of supply and promotion of renewable resources. Indicators were defined on the basis of selecting, where possible, quantifiable measures which could be used to evaluate the extent to which each project met the defined criteria – for example the MW of renewable generation to be connected (1a) or the MW of additional transfer capacity provided (2a). Where quantitative indicators were unlikely to be relevant or practical given the early development stage of most projects, a qualitative indicator was applied – for example in relation to the contribution to energy efficiency (1b) and the impact on loop flows (3c),

6.2. Prioritisation approach

All Working Group participants were invited to submit a 'project fiche' for each of the projects which they wished to be considered for prioritisation. In order to manage issues arising from separate but inter-dependent projects and rationalise the number of individual fiches submitted, a project' is defined as an investment which is:

- technically and financially independent and delivers the Project objectives on a stand-alone basis; or
- an economically indivisible series of tasks (actions and sub-actions) related to a specific technical function and with identifiable objectives.

An "indivisible series of tasks" might for example include a 'cluster' of actions and sub-actions which are located in the same area or along the same corridor and achieve a common measurable goal, in circumstances where none of the tasks can achieve the common goal on a standalone basis. The Project definition should include all investments which are critical to the delivery of the "identifiable objective", for example the provision of Over Head Line (OHL) plus sub-stations and essential grid reinforcements.

It should be noted that this approach did not specifically identify any 'merchant interconnectors' i.e. those which would expect to be granted exemption under EC Regulation 1228/2003 (Conditions for access to the network for cross-border exchanges in electricity), and thus derive their revenue (in whole or in part) from market-based revenues. Within the EU, such projects are an exception, and are often developed by parties other than the incumbent TSO. This makes it more difficult to identify them within the prioritisation process, as recognised by ENTSO-E within the 2010 Ten Year Development Plan[63] - which states that a process and criteria will be developed so as to provide proper inputs to the next release in a non-discriminatory manner. It is particularly important that such additions to the TYDP are also recognised within the on-going process for identification of priority projects, in order to identify where such projects may interface with TSO plans.

The purpose of the prioritisation exercise was to support the wider process of deciding which projects should be prioritised, through a review and assessment of individual proposals' relevant strengths, ensuring that each proposal is, as far as practicable, assessed in an identical manner to all the others. Our evaluation did not include any diligence on the project fiche responses which were assessed on the basis of the answers provided. The list of priority projects will continue to be reviewed, specifically in the light of more detailed market analysis (once this is available from ENTSO-E) and also on the basis of revised or additional project information, as and when this may become available.

In total, the number of responses finally included and assessed was as shown in Figure 35, although initially a larger number was put forward. Some of these were withdrawn, some merged to form clusters and some judged to be primarily relevant to other regions and the equivalent assessment exercises being conducted for those.

Figure 35: project fiche responses

Country	Number of projects
AT	5
BG	4
CZ	19
DE	20

[63] ENTSO-E (2010) Ten Year Development Plan

Country	Number of projects
HR	4
HU	27
PL	7
RO	3
SK	4
SL	3

The assessment process involved the use of a linear weighting and scoring model, sometimes referred to as a MADA (Multi-Attribute Decision Analysis) model (see, e.g., Dodgson *et al.*[64]). The choice of this relatively straightforward but robust approach reflects the fact that MADA has a good track record of delivering practicable decision support in similar infrastructure investment prioritisation exercises and that the assessment process is not the final arbiter of what will be undertaken, but simply a starting point for a fuller analysis.

Figure 36: Application of MADA approach

1. What is the context? What options are available? 2. Who are the decision makers and other key stakeholders? 3. What attributes may distinguish better from poorer options?	Preparation of project fiche
4. Assess expected performance of each option against each attribute	Project fiche responses
5. Assign weights to the attributes 6. Combine weights and scores 7. Identify a provisional ranking 8. Apply sensitivity testing	Assessment of project fiche responses

Of these eight steps, the first two were essentially determined by the process that led to the formation of the Working Group; step 3 was undertaken as described in 6.1. The remainder, steps 4 to 8 were implemented as follows, in order to rank the projects and therefore determine those which, on the basis of the project fiche information, make the greatest contribution to the prioritisation criteria.

Assess expected performance of each option against each attribute

Information from the project fiches was used to identify the expected performance of each project against the attributes (indicators). Where quantifiable indicators had been selected, a relative scoring system was defined on the basis of the quantified impact of a particular project in relation to the relevant range from all projects submitted – as described in Figure 37.

A key characteristic of this process is that to the maximum extent possible each project's fiche is treated in an identical way to all the others. In this way, each of the projects was assessed in terms of the nine sub- criteria.

[64] J. Dodgson, M. Spackman, A.D. Pearman and L.D Phillips, Multi-Criteria Analysis: a Manual, Department of the Environment, Transport and the Regions, London, pp.158, 2000. ISBN: 1 85112 454 3. Also at: http://www.odpm.gov.uk/stellent/groups/odpm_about/documents/ page/ odpm_about_608524. hcsp

Figure 37: assessment of performance against prioritisation indicators

12a) Priority in national energy policy	Yes/No	1/0	
12b) Priority in TSO development plan	Yes/No	1/0	
13a) Connection of renewable generation		0	if No
		1	if Yes and no quantification or MW figure in bottom third of range
		2	if Yes and MW figure in middle third
		3	if Yes and MW figure in top third of range
13b) Contribution to energy efficiency	Yes/No	1/0	
14a) Increase in market integration		0	if No
		1	if Yes and no quantification or MW figure in bottom third of range
		2	if Yes and MW figure in middle third
		3	if Yes and MW figure in top third of range
14b) Improvements to competition in internal market	Yes/No	1/0	
15a) Contribution to operational network security	Yes/No	1/0	
15b) Contribution to supply / demand balance		0	if No
		1	if Yes and no quantification or total MW figure in bottom half of range
		2	if Yes and total MW figure in top half
15c) Impact on reducing loop flows	Yes/No	1/0	

Assign weights to the attributes

In principle, each of the criteria (or attributes) may be of different significance to the overall decision and so can be given a different weight when the overall aggregation of weighted scores for each project, from which the final ranking of projects is derived, is computed. In this case, however, and in keeping with the wish for a relatively straightforward and robust assessment, it was decided in the first instance (see also step 8 of the process) to assign equal weight to each of the four top-level criteria and, within these, to give equal weight to each of the sub-criteria.

Combine weights and scores

Thus for each of the sub-criteria 12(a) through to 14(b) the minimum score possible was zero and the maximum was 3. For 15(a) through to 15 (c) the minimum was zero and the maximum 2. A theoretically "perfect" project would score 24 (although no project in fact achieved that level).

Identify a provisional ranking

Applying this process to all projects allowed a ranking of all projects to be put together, although, as will be discussed shortly, the ranking as such was of relatively little significance and the process is more appropriately seen as a way of starting to categorise projects into groups of relatively high, average, or lower relevance to the objectives of the Working Group.

Apply sensitivity testing

In any MADA exercise of this type, it is always appropriate to consider the robustness of the outcome of the project ranking to the input data on which the rankings clearly depend. Clearly with respect to the choice of criteria weights but to an extent also with the underlying project assessment data, there is a degree of judgement applied. It is important to understand whether changes in the basis of weighting or scoring would lead to radical changes in the outcomes, although experience from other applications is that the degree of sensitivity is often less than intuition might suggest, especially where the aim is to prioritise only a few projects from among a much larger set. The best projects are typically those that record strong performances "across the board" and for these projects re-arranging the weights between criteria will make little difference to their standing. So, indeed, it proved in this case, with the sensitivity testing that was undertaken indicating that significant changes in project ranking were not occurring.

As stated earlier, it was recognised from the outset that the MADA assessment could not capture all the information necessary to allow a full and fair categorisation of candidate projects. Thus, following the initial MADA work, and discussion with the Working Group and Commission, an additional 'overlay criteria' was applied – that all projects which demonstrated an impact in two or more countries within the study area should also be prioritised. This 'overlay' analysis was designed to take account of data- and modelling-induced anomalies including:

- There was no possibility to model the performance of the overall transmission system
- Hence potentially important interdependencies between projects were not necessarily explicitly accounted for
- There is inevitable uncertainty about *future* patterns of demand and supply
- Fiches were completed by different TSO teams under significant time pressure and so were not necessarily completed using identical conventions
- Projects were of diverse sizes and types.

The preliminary proposal of regional priority projects was discussed with the Working Group, allowing each country to comment on the projects proposed by others which impacted their own networks. From these discussions we note in particular that:

- the Polish projects GerPol Improvements are subject to further analysis to assess the cross-border benefits of the project, in particular for neighbouring countries
- the Vitkov – Mechlenreuth interconnector (proposed by CEPS) has not been assessed by 50 Hertz as its timescales are beyond 2020

6.3. Prioritisation outcomes

From the final project fiches which were submitted for assessment, including several project clusters, 9 interconnectors and 22 internal projects (within one Member State) were proposed as regional priorities. The remaining 27 projects are proposed for consideration as national priorities.

Figure 38: map of projects proposed as regional priorities

Map Id		Start point	End point
1	CZ	Cluster NW DE CZ	
7	CZ	Cluster West East Industry	
4	CZ	Cluster North South	
16	DE	Eisenhüttenstadt / Vierraden	Plewiska (PL) / Krajnik (PL)
17	DE	Cluster Connection of new power plants in 50HzT north, middle and south	
18	DE	Cluster North-South grid reinforcement in Eastern DE	
27	DE	50Hertz area (DE) – CEPS area (CZ)	
32	HR	Plomin	Melina
33	RO	Network strengthening in eastern part	
34	RO	Cluster Western border	
35	SK / HU	Reinforcement of the Slovak-Hungarian profile	
38	SL	SS Beričevo	SS Krško
39	SL	SS Cirkovce	SS Divača
40	SL	SS Cirkovce	Pince

Map Id		Start point	End point
41	AT	St Peter	Tauern
42	AT	Altheim (DE)	St Peter
43	AT	Ernsthofen	St Peter
44	AT	Duernrohr	Sarasdor
50	HU	substation of MAVIR ZRt. (HU)	Vel'ké Kapusany (SK)
51	DE	Wahle	Mecklar
52	DE	Altheim	St. Peter (AT)
53	BG	S/s Dobrudzha	S/s Burgas
56	CZ	Prosenice	Kletne
59	PL	GerPol Power Bridge	
60	PL	GerPol Improvements	
61	PL	Cluster Wind integration	
62	PL	Cluster Dob (Dobrzeń)	
63	PL	Cluster Koz (Kozienice)	
64	PL	Cluster Ost (Ostrołęka)	
65	RO	Tarnita	Gadalin, Mintia

Figure 39: Summary of preliminary prioritisation outcomes

	Regional Priorities		National Priorities
	Interconnectors	Other	
Austria	1 (DE)	3	0
Bulgaria		1	3
Croatia		1	2
Czech Republic	1 (DE)	3	0
Germany	3 (PL x 2, CZ)	3	0
Hungary	2 (SK)	0	22
Poland		6	0
Romania		3	1
Slovakia	1 (HU)	0	0
Slovenia	1 (HU & HR)	2	0
Sub-total	*9 **	*22*	
TOTAL	**30**		**28**

* Since 2 projects are listed for several of the interconnected countries

In addition to performance against the selected prioritisation criteria, the impact of the prioritised projects was mapped against the findings of our market analysis (Section 3, Task 1: Market analysis). The table below summarises these issues, including the map reference of each proposed regional priority project in brackets.

Conclusions of market analysis	Key issues adressed by priority projects
Current infrastructure heavily utilised: • Germany to Poland • Czech Republic to Germany • Czech Republic to Austria	Enhanced capacity at border locations: • Germany and Austria (42/52), Czech Republic (10, 27), Poland (16/59, 25) • Slovenia and Croatia / Hungary (40) • Slovakia and Hungary (50, 35/57, 36/58)
Loop flows are a particular issue from • Germany to Poland; Poland to Czech Republic; Poland to Slovakia	Management of loop flows at border locations: • Germany and Poland (60) • Germany and Czech Republic / Slovakia (16, 25)
Significant increase in renewable generation capacity by 2020, located mainly in the north of the study area, and significant reduction in	Connection of generation capacity: Germany (17, 51), Czech Republic (1-3, 8, 9, 7, 45, 54, 55), Romania (33), Slovakia (37), Slovenia (39)

Conclusions of market analysis	Key issues adressed by priority projects
nuclear capacity Lower load factor and reduced "dispatchability" likely to increase the requirements for balancing networks – requirements for energy storage and, where possible, sharing of peaking capacity	Connection between wind capacity / flexible plant and pump storage: Austria (41, 43), Romania (65)
Extended distances likely to require increased long distance transmission capacity	Strengthening of internal network: Austria (44), Bulgaria (53), Croatia (32), Czech Republic (1-3, 8, 9, 7, 45, 56), Germany (including management of reactive power) (18-26, 28-30, 46-49), Romania (34), Slovenia (38), Poland (60-64)

7. Task 5: Implementation obstacles

7.1. Introduction

Building on the initial risk assessment carried out in Task 4, this section outlines in further detail the obstacles to implementation which may affect the projects identified.

One of the core questions to be considered in relation to the feasibility assessment of large infrastructure projects is one of risk allocation, in terms of management and incentivisation of risks, cost efficiency and the appropriate corporate structure to optimise risk allocation. Typically several key parties are involved in the delivery of large electricity infrastructure projects, including the project proponent, the contractor, regulator and end consumer, as well as entities providing external financing. One of the critical development-stage issues for many such projects is therefore to determine the commercial (and ultimately legal) structure which will be adopted for delivery of the project. Risk allocation and risk management is indeed a key and overarching question when discussing obstacles to implementation and defining remedial actions, since the clear allocation of risks should provide clarity on which party will meet cost overruns and allow each to manage and mitigate their risks accordingly. For energy infrastructure projects the role of the regulator is particularly important, since where such projects are to become part of the Regulated Asset Base (RAB) the proponent will need to demonstrate that costs have been incurred on a "reasonable and prudent" basis in order to get regulatory approval for these costs to be socialised i.e. passed through to all end consumers via transmission tariffs.

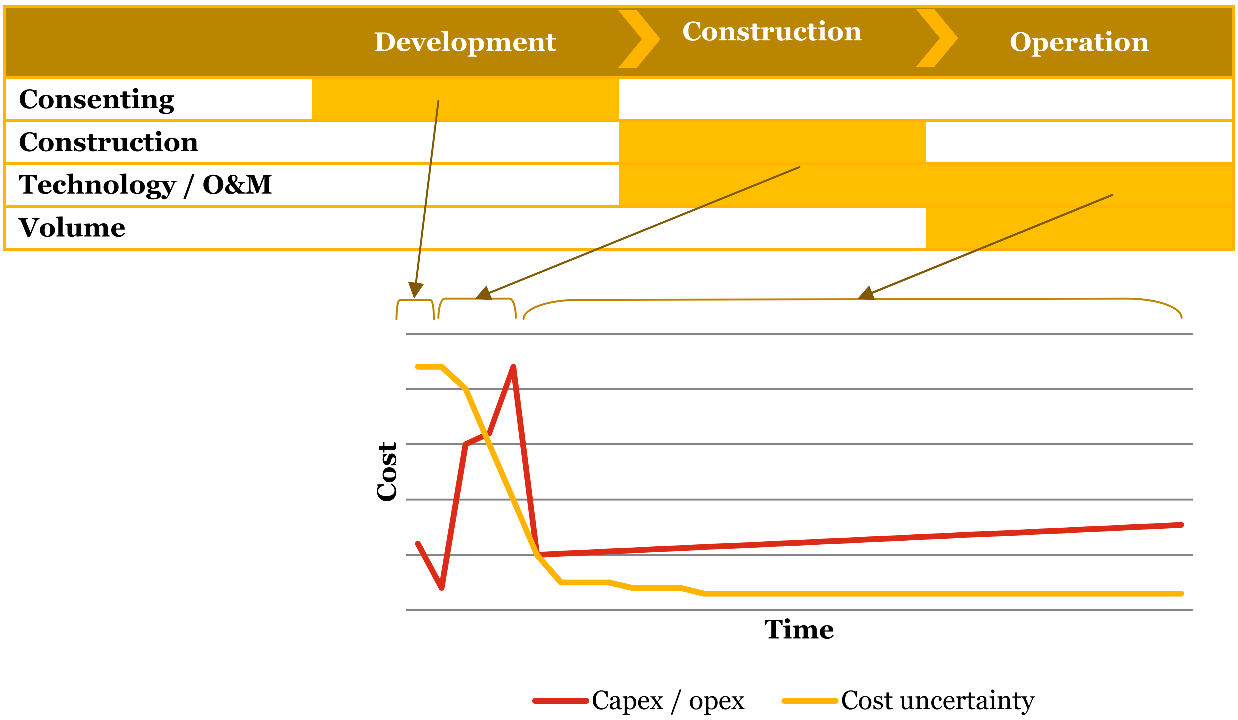
Figure 40: Overview of project feasibility assessment

Technical feasibility	Delivery feasibility	Economic feasibility	Regulatory feasibility
Technology (AC / DC) Construction time EPC cost O&M cost Distance Connection capacity Reinforcement requirements	Project structure Funding sources Risk allocation	Financial modelling Tariff scenarios • Auction tariff • Annual transmission fee Cost sensitivities	Consistency with current regulation Third party access requirements Derogation precedents

The definition of the preferred project structure is typically initiated sufficiently early in the project development that it can inform the development of a competitive contracting process, but also after the initial feasibility has been confirmed in order to reflect the proponent's understanding of technical and economic feasibility, as well as the risk appetite of relevant stakeholders.

Key features of energy infrastructure projects are that the majority of costs are incurred early in project lifecycle, as illustrated in Figure 41.

Figure 41: Overview of infrastructure project risk and cost profile



Early in the development phase, the technical feasibility will produce an initial project design and routing study, as well as estimates for connection and associated upgrades to the existing grid. Subsequently, the proponent will seek to estimate the most in further detail the likely costs of construction, for example through 'market soundings' with potential engineering, procurement and construction (EPC) contractors and with potential providers of finance. However throughout this stage the costs are subject to granting of the relevant permits and consents, as well as acquisition of the necessary land rights, which may introduce changes to the design and / or routing, with potentially significant cost impacts. Furthermore, cost estimates may be revised in the light of changing economic conditions: for example both EPC construction costs and costs of debt are subject to changes in the macro-economic environment; the availability of financing and its cost is also directly dependent on the allocation of project risk, specifically the scale of risk to be borne by the project proponent and providers of equity / debt.

Once financing and contracts for EPC (and operation and maintenance) have been put in place, as the project moves into the construction phase, many of the development phase risks may have been mitigated, however complex construction environments and the use of new technologies may also create uncertainty around the final costs during this phase.

During the operation phase, energy infrastructure projects are typically (although not always) operated as a regulated asset, thus the key remaining uncertainties are related to changes in the regulatory environment as well as operational costs. For projects reliant on 'merchant revenues' there is likely to be uncertainty in the operational phase around the level of demand and therefore project revenues – to the extent that capacity has not been contracted on a long-term basis (e.g. where Third Party Access exemptions have been granted).

In this Section 7, and also Section 8, we have focused primarily on the obstacles affecting regulated projects since all of the projects submitted as for assessment fell into this category – as discussed in Section 6.2 – however we note that merchant projects are likely to face the same if not greater obstacles than those discussed below. In the following sections we focus on the obstacles which may be addressed at a regional, national and local level, as well as issues which can be dealt with on a project-by-project basis.

On the 19th of October 2011 the European Commission published the Energy Infrastructure Package (EIP)[65], which aims to facilitate the implementation of trans-European priority corridors and areas for electricity and gas networks, as well as oil and carbon dioxide transport infrastructure. This includes legislative proposals to address the following issues, which are therefore not covered in detail in the remainder of this report:

- Permitting: Prioritisation of projects; large number of permits required; lack of binding time limits for procedures

- Regulation: Lack of sufficient incentives; unbalanced cost allocation

- Financing: funding gap – to be addressed through Connecting Europe Facility, including IFI-backed financial instruments and grants for studies

7.2. Obstacles identified

As part of the project assessment exercise (Task 4) project proponents were asked to identify the key obstacles facing their projects. The key risks affecting projects which have been identified as regional priorities are focused on development phase issues, which is not surprising given that the majority of projects under consideration are currently at the stage of pre-feasibility, feasibility or permitting. Funding is seen as a major implementation issue for slightly fewer projects however it is clear that funding is also an over-arching issue, since issues with the regulatory framework, for example, are also likely to jeopardise project funding.

7.2.1. Financing

The total capital cost estimates for projects identified as regional priorities is close to €7,5 billion. In all of the countries within the study area, with the exception of Germany, the TSOs are 100% publically owed, with the state as the ultimate owner. Within Germany, of the two TSOs involved in the Working Group, TenneT TSO GmbH is ultimately held by the Dutch state, while 50Hertz Transmission GmbH is owned by Eurogrid GmbH, a company which is partly held by an infrastructure fund and partly by the Belgian company Elia System Operator NV/SA (itself 50% state owned). This picture highlights the degree to which the cost of financing will depend upon the states' own credit rating, since any borrowing at a corporate level will depend on the sovereign rating.

Figure 42: Standard & Poors sovereign ratings (as at 30 September 2011)

Austria	AAA	Hungary	BBB-
Bulgaria	BBB	Poland	A-
Croatia	BBB-	Romania	BB+
Czech Republic	AA-	Slovenia	AA

[65] Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL establishing the Connecting Europe Facility (COM(2011) 665) and Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC (COM(2011) 658 final)

Germany	AAA	Slovakia	A+

Over the past 15-20 years infrastructure projects worldwide have frequently been financed through non-recourse project financing, a lending approach which relies on the revenue stream of financed projects to meet debt repayments, and, in the event of default, allows the lender to take control of the operating asset. This approach is particularly well suited to infrastructure projects in all sectors due to the ability to match the term of financing to the period of contracted revenues (typically 10-20 years) thereby maximising the debt capacity of the project. Project financing of projects in excess of €100 million (but also for smaller projects) is typically carried out by a club of banks, in order to cap the exposure of each party to a single project and also in order to share the costs of due diligence – this threshold would apply to at least one regional priority projects in most of countries within the study area.

In the current financial market, banks are reducing their long-term lending commitments as a result of the Basel III regulations which require banks to increase their capital allocation and also to maintain a Net Stable Funding Ratio (ratio of stable funding such as customer deposits to long term loans). The effect of these regulations is to increase the cost of non-recourse financing relative to funding from capital markets (e.g. shares, bonds). As the liquidity of debt financing reduces, banks have also been seen to focus their resources on clients with whom they have existing relationships – those with a track record of successful project delivery and operation. TSOs seeking financing on a non-recourse basis are therefore likely to experience **difficulties in securing financing** and, where projects do meet the banks' criteria, **higher costs than in recent years**.

Bond financing might provide a feasible alternative for some projects, although this market has also contracted in recent years, and is typically liquid only for projects with a rating of 'A' or above, a threshold met by only 4 of the countries within the study area. Bonds rated below this level would be unlikely to attract interest from investors such as insurance and pension funds, who are major investors in the infrastructure sector in other parts of Europe. Until 2008 bond issuances could be insured with a 'monoline wrap', whereby a third party insurer would underwrite the repayment of both interest and capital, thus increasing the rating of the bond issuance. However the sub-prime crisis in the US and ensuing 'credit crunch' has seen many such insurers downgraded and others withdrawing from the monoline market.

The security of project revenues also will have a significant impact on the costs of funding. The key issue here is regulatory framework – as explored in the following section – and where the majority of costs are passed through to consumers via regulated transmission tariffs, the key risk for financing will be the credit rating of the customers. In most cases transmission revenues are collected via energy retail / supply companies, the number of counterparties and associated credit risks are therefore usually, but not always, minimal.

In addition some projects may face revenue uncertainties associated with **technology risk**, in cases where delivery or operation of the project relies upon new or innovative technologies. A note from the Commission also notes that innovative technologies involving higher risks and/or uncertainties, such as offshore grid investments using direct current technologies, large-scale electricity storage or smart grids projects, may face difficulties in securing financing[66]. In these cases project funders will need to be comfortable that these technologies are capable of delivering the necessary services, and will wish to undertake due diligence – the costs of which will be reflected in funding costs – in order to understand the associated risks.

[66] Commission Staff Working Paper - Energy infrastructure investment needs and financing requirements, June 2011

7.2.2. Regulatory framework

Since all of the projects fiches have been submitted by TSOs acting as project proponents, we would expect the majority of the priority projects to be developed within the Regulated Asset Base (RAB) of the relevant companies, on which they will earn a regulated rate of return. The proponents will therefore seek regulatory approval for the majority of investment and operational costs, which will be passed through to tariff customers, with the remainder to be managed by the proponent and other parties.

The Energy Infrastructure Package addresses the issue of insufficient regulatory incentives, which was specifically mentioned as an obstacle on a number of project fiches – for example it was stated that for one project in Germany the regulatory assumption on load is too optimistic; that cost benchmarks are inaccurate; and that there is a lack of simple guidelines for compensation. In addition, as observed in Section 3, infrastructure requirements which are expected for the study area will be increasingly focused on the transit of power across two or more Member States. Although such investments may take place within one country, the benefits may be realised in another – and furthermore such benefits may vary under different market scenarios. In such cases the current regulatory approaches may result in an imbalance between allocation of costs and realisation of benefits, with the result that the full benefits are not recognised by national regulatory authorities. We understand that this issue of cost allocation is also covered by the Energy Infrastructure Package.

Emerging from the fiche responses and experiences of other projects in the region is the broader issue that regulatory polices arise from various legal and policy frameworks – European, national and local – which in some cases create **competing regulatory priorities**. In particular, there may be pressure on regulators to minimise price increases in addition to policy measures aimed at increased integration of renewable and greater market integration – both of which need to recognise and incentivise greater investment from TSOs. This issue has the effect of impacting the timescales for regulatory decision making, as well as reducing the transparency of the decision process, making it more difficult for project proponents to plan for and manage the regulatory process. One member of the Working Group has highlighted that these issues exist also at a European level – for example the relationship between EU environmental legislation and EU rules on Trans-European Networks is “not clarified”, leading to varying interpretation and implementation at a national level.

For the majority of grid investments, even large capex expenditures have a relatively small impact on consumer tariffs, once the cost is amortised over the life of the project. However in cases where the scale of investment is very significant relative to the existing RAB the resulting **‘step change’ in transmission tariffs** can prove to be a further barrier to regulatory approval.

TSOs are frequently assessed on reliability, using measures such as Loss of Load Probability, however in many cases – as discussed in Section 6 – the investments being considered as regional priorities are not only based on a security of supply rationale, but are required in order to meet other policy objectives such as integration of renewable and increased market integration. Whilst there are established practises to determine the extent to which a particular project will improve system reliability, it can be more **complex to provide evidence that the investment will provide a measurable contribution to policy goals** such as reduction of consumer prices (e.g. through more efficient use of grid or connection of generation capacity which reduces overall system costs) or market integration, in particular where these benefits will accrue over time.

Many of the projects of regional interest are cross-border projects, where investment will be made by two TSOs, for the construction of new lines and upgrades to existing infrastructure within their own control areas, as well as the potential for some joint investments. In such cases it has been observed that there is a **lack of a defined approach for cross-border projects**, meaning that regulatory approval for such projects can take place only within a policy framework designed to address internal projects. Furthermore such projects require interaction between regulatory authorities, and although co-operation between regulators may occur at a policy or EU level, there is **no framework for**

interaction between authorities in relation to approval of specific projects. This lack of co-ordination results in a lack of alignment on:

- treatment of costs e.g. rate of return, approach to cost estimation / benchmarking etc;
- regulatory derogations and exemptions e.g. Third Party Access; and
- timescales for project review and approval.

This lack of alignment means in practise that projects crossing national boundaries may need to meet different regulatory hurdles in the respective jurisdictions, which is not always possible within the framework of a joint project.

Existing cross border interconnectors within the study area receive some revenue from capacity auctions, which allow third parties (other than the relevant TSOs) to purchase capacity which is not required for system stability (i.e. total capacity net of Transfer Reliability Margin) or already allocated to other parties. These auctions provide TSOs with an important revenue source which is used to meet the costs of making such capacity available. Part of the commercial feasibility analysis for a new interconnection project will be to forecast the expected congestion revenues i.e. revenues from capacity auctions, however this forecast is highly dependent on demand, generation and pricing assumptions for the relevant markets, as well as the extent to which market integration facilitates short- and long-term cross border trading. In their project fiche responses, several TSOs raised the issue that a **lack of market alignment constrains demand for access to interconnection capacity**. The effect of this is that even where market fundamentals (demand / supply balance) indicate that there is a requirement for investment in cross-border infrastructure, forecast congestion revenues may be limited. Since such revenues are usually netted off from the costs to be socialised, lower congestion revenues will increase the proportion of costs to be reflected in transmission tariffs. Particular examples provided by TSOs where a lack of market alignment impacts investment were balancing markets and ancillary services, both important factors for market integration, as explored within Section 4.

Once a project has been given regulatory approval, one of the key remaining risks for investors is **changes to the regulatory regime**, resulting in higher risks and lower returns. The typical regulatory period is circa five years, after which the TSOs costs are re-assessed in order to determine the efficient costs of service. Where the regulator believes, for example on the basis of cost benchmarking, that the TSO could provide its licensed services more efficiently, its allowed revenue maybe reduced. Conversely, where the TSO has demonstrated a need for new investments, the cost of these may be included within the regulated asset base (RAB) to be remunerated through the allowed revenues. Alternatively, where regulation includes performance-based measures, for example service quality measured through loss of load probability, TSOs may be penalised for failing to meet the target levels.

7.2.3. Permitting and consents

A significant obstacle to the development of European electricity infrastructure is the cumbersome, lengthy and multiple permit and consent procedures. The realisation of purely national projects encounters substantial permit hurdles. This problem is exacerbated in the case of regional or cross-border projects, where the processes may be duplicated and the stakeholder issues more complex. The project fiche responses included general issues related to the duration of the permitting and consenting processes and their cost implications, evidence which is supported by the Commission's findings that efforts associated with the permitting procedures could exceed 10% of total project costs[67].

Our review has highlighted many obstacles to timely, efficient and predictable implementation of projects arising from permitting and related procedures. Many of the obstacles identified echo similar themes to those identified by the Commission in its own consultations. We comment on these below and provide illustrative examples from Member State experience. The examples are provided as symptomatic of the wider thematic issues highlighted.

We note that there are differences in the scale and nature of the obstacles encountered in the Member States within the Study Area and that some Member States have made recent advances in seeking to streamline their procedures. However, our review has highlighted that even where steps are proposed or being implemented to expedite and simplify permitting procedures, this is an topic on which there is scope for further improvements and greater consistency.

Many of the issues identified on the project fiches are already addressed by the proposed Energy Infrastructure Package, hence will not be covered in detail in this section: Missing prioritization of projects; lack of binding time limits for issuing approvals – particularly environmental permissions; large number of permissions from different authorities required and many steps in the permitting process, without the possibility to progress different permissions in parallel.

One of the issues which has been reported to occur early during the development phase is a **failure to respect priority corridors for infrastructure** within local and national planning processes. Individual TSOs often identify "priority corridors" for spatial planning purposes within the relevant Member State, to indicate areas of land which are likely to be required for the delivery of key infrastructure projects. The experience in several countries has however been that these corridors are not respected within local planning processes – when applications are submitted by TSOs for planning consents within the relevant corridors, which may have been defined some years previously, construction has taken place in the intervening period thus rendering the corridor unsuitable for the intended infrastructure development.

The permitting processes are reported to suffer from a number of challenges:

- **Lack of clarity**, for example in the documentation, process, timetable, exemption criteria and, governing legislation. Furthermore some parties found the permitting process to be lacking in transparency.

- **Complex and time-consuming documentation and reporting**, e.g. EIA report[68] and other requirements under the SEVESO[69] regulatory framework.

- **Sequential and multiple sequence steps required** rather than parallel handling, e.g. in Bulgaria, a building permit is issued after a written request from the developer. The project must be first approved by the chief architect of the municipality (a design permit) before the permit can be issued.

- **Lack of flexibility**, e.g. Bulgaria has fixed time limits for building permits - the permit loses legal effect if construction is not commenced within three years of entry into effect or is not completed within five years of entry into effect.

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[67] Commission Staff Working Paper - Energy infrastructure investment needs and financing requirements, June 2011

[68] The EIA process is an assessment of the possible positive or negative impact that a proposed project may have on the environment, together consisting of the natural, social and economic aspects. It ensures environmental issues are raised at the beginning of the project and that all concerns are addressed as a project gains momentum through to implementation.

[69] The Seveso Directive is the main piece of EU legislation that deals specifically with the control of on-shore major accident hazards involving dangerous substances.

- Where the permit granting process identifies issues with a project the proponent will be required to revise the necessary project elements before re-submitting a permit application – examples indicated on the project fiches were the requirement to include underground cabling, or to change the design in order to reduce noise in particular locations. Such design changes may have a significant impact on project costs (particularly in the case of underground cables) but in addition a **lack of iterative procedures** means that revised permitting applications are treated as though for a new project, with all of the elements re-assessed even where there are no changes from the earlier application, and with corresponding timescales impacts.

From the point of view of project proponents, the **high cost** of obtaining permits for a particular project presents a financial disincentive. In addition, TSOs reported a **lack of resources and knowledge** on the part of permitting authorities and, in some instances, project promoters, which may compound the challenges of achieving timely authorisations.

The **duration of permit-granting procedures** creates a further obstacle. The Commission's findings report that the time between the start of the process until the final commissioning of a power line takes frequently more than ten years, and the commissioning of a project which faces substantial public opposition can even take longer[70]. Procedures may be subject to unpredictable delays creating uncertainty for project delivery owing to the lack of fixed and binding time limits for issuing approvals. Members of the Working Group stated that permitting procedures in Germany have taken up to 10 years, although the Act to Accelerate Expansion of the Grid (NABEG) provides measures to reduce such issues, including a 'one-stop-shop' at national level and streamlining of planning and permitting procedures. In Slovenia the permitting process is reported to take an average of 6,5 years, although measures have been taken at a national level to address this issue.

Stakeholder objection may be vociferous leading to further delays, particularly via the appeals process. This issue is compounded where cross-border or national projects may be perceived to be lacking in local benefit – particularly where local authorities have a role in the permitting process, leading to local interests (such as environmental impact) being prioritised over national interests (such as security of supply). However, when seeking to streamline procedures it needs to be recognised that there may be potential negative public reaction to any shortening of the permitting processes.

Promoters face a **multiplicity of permit procedures** in chiefly the following areas:

- Building & Construction – e.g. in Austria there are 3 main stages: (i) declaration on the construction site (Bauplatzerklärung); (ii) building permit pre-construction commencement (Baubewilligung); and (iii) operating permit upon completion of construction (Benützungsbewilligung)
- Environmental – e.g. EU, national and local procedures; forestry permissions etc
- Electricity- and network- specific
- Land - see below

In addition, in many countries there are different permitting procedures at a local and national level – for example in Germany, permitting procedures are in the competence of the Bundesländer (federal states) therefore projects which cross Länder boundaries face multiple processes and potentially varying interpretations of the procedures. 'Local' may also include issues at a communal level (for example in relation to spatial planning), below the jurisdiction of federal states.

The **acquisition of rights in or over land presents particular challenges**. These include:

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[70] Commission Staff Working Paper - Energy infrastructure investment needs and financing requirements, June 2011

- Identification of relevant land owners, whether private, state or municipal-owned
- Engagement with land owners either by the local authority or directly by the promoter; and objections by owners and local residents
- Land appropriation process, e.g. compulsory purchase
- Different nature of rights in land, ranging from acquisition of a legal freehold interest to access, wayleaves or planning permission
- Variation between (and also within) Member States in the role and responsibilities of authorities at local and national level
- Wider financial implications of the acquisition of rights in land for the relevant land owners which may lead to delay and complications in the permitting process. For example, it was identified that in one Member State at least the construction of infrastructure on land previously used for non-commercial purposes could change the tax treatment of the relevant land.

7.2.4. TSO co-ordination

An additional issue raised by the process of selecting projects of regional interest, and by project fiche responses, was the **lack of framework for bilateral co-ordination between TSOs on cross-border projects**. Whilst TSOs may have individually identified a need for requirement in adjoining parts of their respective networks, a lack of close co-operation between the relevant parties in the initial development phase of the project can lead to a lack of alignment on definition of the proposed investment and duplication of effort, resulting in delays to the decision-making process.

In highlighting this area we distinguish the activities of ENTSO-E in promoting regional engagement in the electricity sector. The specific concern highlighted in our review is the lack of a formalised or generally accepted framework for direct engagement between TSOs on specific projects. That said, it was drawn to our attention that ad hoc cooperation exists on specific projects in some cases.

7.2.5. Interdependence with other projects

For many infrastructure projects, the **investment rationale is dependent on other projects**, for example on:

- Investments in generation capacity and / or consumption – where the project objective is to link new generation capacity or load into the existing grid; and / or
- Other infrastructure projects – where the project objective is to facilitate additions or upgrades to other parts of the grid.

These developments are in turn dependent on largely external factors such as:

- Rate of macro economic growth
- Investment decisions of third parties, such as independent generators, TSOs in neighbouring areas and national energy policy
- Delivery risk of specific projects, which may be significant for example in relation to the development of nuclear generation capacity and offshore wind

As outlined in Section 3, the electricity grid within the study area is likely to become more frequently used for both balancing flows and long-distance transport of energy, with greater volatility introduced by a higher share of generation from renewable. In this environment there is likely to be higher levels of interdependency between projects, particularly in countries which have particularly high levels of renewable generation and those which experience high levels of transit flows and those.

Figure 41 highlighted how the majority of costs for infrastructure projects are incurred during the development and construction phases, thus if expected market developments (and therefore demand) do not occur as expected, infrastructure projects are at risk of becoming obsolete, or a ‘stranded asset’. For regulated assets, where TSO costs are socialised across the consumer base, this risk is passed to end consumers, however the regulatory approval process for such investments requires TSOs to demonstrate that their feasibility studies have taken such risks into account.

8. Task 6: Remedial actions

In this section we have focused on remedial actions which are suitable for inclusion in the Action Plan (see Section 2) – that is measures which can be implemented by Member States within a defined timescales in order to address the issues identified in Section 7. We have also addressed, at a very high level, measures that may be adopted on a project-by-project basis in order to facilitate development.

For each action we have identified the 'key stakeholders' i.e. the party or parties with the authority and competence for implementation, as well as an indication of whether the action should be delivered in the short or medium term, based on both the ease of implementation and the priority accorded to the action.

8.1. Issues for Action Plan

8.1.1. Financing

As discussed in section 7.2.1, one of the key issues for financing is the sheer scale of funding required for regional priority projects, which will be required in the context of other on-going investments and reducing liquidity in debt markets. Whilst the Energy Infrastructure Package includes the Connecting Europe Facility, specifically targeting energy projects in the period from 2014 to 2020, as well as provision for financial instruments (equity/debt incl. project bonds in cooperation with IFIs) and grants for studies and works, there are additional measures that can be taken at a Member State level in order to support the financing of key projects. These measures can only be effective in close alignment with the proposed measures regarding regulatory frameworks, since the efficient allocation of risk between tariff customers and other parties is one of the key issues to be addressed before the project funding strategy can be finalised. Additional measures which can be adopted on a project-by-project basis are addressed below.

Remedial action	Issues addressed (see Section 7)
1. **Provision of subordinate debt** State-backed lending agencies can act as catalysts for private investment by co-ordinating the provision of subordinate debt, such as mezzanine facilities or insurance-like products, which reduce the risk for other lenders and therefore the cost of financing. While such mechanisms must be delivered within rules on State Aid, examples of this approach include the Green Development Bank (UK) being developed to support investments in the low carbon economy, as well as the KfW / BMU (Germany) programme for offshore wind energy. Such loans may be relatively short term, terminating for example during the early years of operation, since once transmission projects are operational the risks are significantly lower (see Section 7.1) and financing can therefore be more accessible and lower in cost. Key stakeholder/s: National government Timescales: medium term	Ability to access financing Cost of financing
2. **Facilitate sharing of technical information** Authorities at a national, regional or EU-wide basis, can facilitate due diligence by investors through sharing studies and evidence on the reliability of new transmission technologies.	Technology risk Ability to access financing Cost of financing

Remedial action	Issues addressed (see Section 7)
A similar approach has been implemented successfully by the UK's Crown Estates, for example – in order to facilitate investment in offshore wind, Crown Estates invested in wind speed studies, seabed surveys, bird surveys, etc. which were made available to all potential investors. Key stakeholder/s: National government Timescales: short term	

8.1.2. Regulatory framework

As discussed in Section 7.2.2, the key issues in relation to regulation are the requirement for a regulatory framework which incentivises TSOs to invest in priority infrastructure projects by providing a fair and stable return on investment (reflecting the timescales for recovery of capital costs which are frequently in excess of 20 years), whilst delivering value for users of the network. The regulatory approach should include a transparent decision-making process in which the criteria and timescales can be understood by project proponents in order that regulatory risks can be adequately evaluated as part of the project feasibility. In developing the regulatory framework and mechanisms discussed below, Authorities should recognise that transmission projects for modernisation, reconstruction and expansion which are integrated on a regional level can contribute to a wide range of policy objectives.

The remedies proposed here are also likely to address funding issues (availability and cost of financing) by de-risking project revenues.

Remedial action	Issues addressed (see Section 7)
1. **Provide clarity over regulatory priorities regarding key infrastructure investments** In order to provide clear investment signals regulatory authorities should, within the parameters of national energy policy, clearly state their objectives with regard to investment in key infrastructure projects. These objectives should be evident within the regulatory approval process for new TSO investments. This approach should aim to clarify how the requirement for infrastructure investment will be balanced with other regulatory objectives such as consumer welfare and increased integration of renewable generation. Direction for these objectives should be given at a policy level to demonstrate that they will be applied in a consistent and sustained manner. Key stakeholder/s: National government and Regulatory Authority Timescales: short term	Competing regulatory priorities Complex to provide evidence that the investment will provide a measurable contribution to policy goals Changes to the regulatory regime
2. **Stable regulatory framework** Regulatory authorities should seek to provide stable signals to incentivise long-term investment in transmission infrastructure, recognising that the time period for recovery of large-scale investments may be are frequently up to or in excess of 20 years. A track record of regulatory stability creates less risk for investors (both equity and debt) in assessing their long-term returns and therefore	Changes to the regulatory regime Competing regulatory priorities

Remedial action	Issues addressed (see Section 7)
reduces both risk and the cost of investment. The approach to defining such stability should be considered together with the actions discussed in 3 and 4 below, in order to ensure that the Authority retains the ability to deliver value for network users. Key stakeholder/s: National government and Regulatory Authority Timescales: short and medium term	
3. **Flexible mechanisms for cost recovery and efficiency** Within a framework of regulatory stability, large-scale infrastructure investments require mechanisms which can be used to (a) incentivise cost efficiency; and (b) recognise that that certain risks lie outside the TSOs' control and may therefore be underwritten by tariff customers e.g. material change provisions. Examples of such mechanisms include award / claw-back mechanisms in relation to out-turn costs against the agreed budget, which have the effect of allocating a stated portion of over-spend (e.g. additional costs associated with contract delivery) and under-spend (e.g. from greater efficiency) between the TSO and tariff customers. In addition, provisions for 'Material Adverse Change' allow project proponents to request a reconsideration of rate of return if costs outside of their control have escalated e.g. risk-free rates, routing changes caused by permitting process etc. Key stakeholder/s: National government and Regulatory Authority Timescales: short term	Changes to the regulatory regime Competing regulatory priorities
4. **Recognise separate regulatory treatment of key investments** Investments which are very significant relative to the existing asset base present a rationale for treatment by regulators on a stand-alone basis i.e. separately from other assets within the RAB. This approach also has the benefit that the regulatory review period for such investments can be extended in order to deliver greater regulatory stability, without compromising the ability for regulators to incentivise cost-efficiency and performance in relation to other, less risky, assets. Examples of where this approach has been applied include the East-West Interconnector (Republic of Ireland). Separate treatment of such assets also allows the regulator to recognise where some revenue 'smoothing' may need to be introduced in order to avoid a step change in tariffs – for example by allowing introduction of pre-funding of some costs through tariff revenues during the project construction phase. Examples of this approach exist for large infrastructure investments in all sectors (see for example 'Terminal 5 pre-funding', CAA (UK) 2001). Where alternative delivery structures (as described in Section 8.2) can be used to mitigate project risk for consumers, these should be recognised and facilitated by regulatory authorities. Key stakeholder/s: National government and Regulatory Authority Timescales: short term	Changes to the regulatory regime Step-change in transmission tariffs
5. **Enhance co-ordination between authorities** Development and implementation of regulatory priorities for key infrastructure investments (as described above) should be co-	Lack of a defined approach for cross-border projects

Remedial action	Issues addressed (see Section 7)
ordinated between national regulatory authorities. This should be undertaken through an existing forum, such as ACER, in order to ensure that co-ordination is sustained. The goal of such co-ordination should be to define the process for regulatory approval of cross-border infrastructure, as well as to determine how assessment metrics may be aligned for the consistent treatment of relevant cross-border projects. Key stakeholder/s: Regulatory Authority Timescales: short term	No framework for interaction between authorities
6. **Demonstrate progress toward market integration** Market integration proposals have been made by ACER for the CEE region, addressing capacity allocation; market coupling; intraday markets; and Electricity Balancing Markets Integration (EBMI). The alignment with and implementation of such proposals at a national level will also facilitate infrastructure projects by creating a greater demand for trading on a cross-border basis. Key stakeholder/s: Regulatory Authority Timescales: medium term	Lack of market alignment constrains demand for access to interconnection capacity

8.1.3. Permitting and consents

The Commission's Energy Infrastructure Package identifies, amongst other matters, measures which will include streamlining of permitting procedures at EU-wide level. In order to frame the context of our recommendations below we make the following observations on the relationship between the Energy Infrastructure Package and our recommendations:

- Our review and recommendations do not intend to duplicate the Energy Infrastructure Package but are rather focused on measures which may be taken at Member State or regional level to seek to alleviate obstacles in the area of permitting and consents. At the same time, we note that the Energy Infrastructure Package can only be effective if it operates in combination with measures at the individual Member State (and potentially regional) level and that localised initiatives will need to be supported at the EU level. In other words, EU-wide and individual Member State measures cannot be viewed in isolation.

- In the debate up to the Energy Infrastructure Package, some commentators called for the creation of an EU wide or 'umbrella authority' to act as the overarching arbitrator in areas of doubt and assist coordination and consistency in conjunction with the Member States. Notwithstanding the limited scope of our review at the national and regional level, we see potential benefits in such a body in supporting efforts at the local level and in seeking to reconcile local, regional and, ultimately, EU interests in appropriate cases.

- In view of the different legal systems pertaining to the Member States, our recommendations cannot be overly prescriptive as to the detail in which certain proposals (e.g. acceleration in time limits) might be implemented. The recommendations seek to identify areas for improvements leaving it to individual Member States to decide how to reflect the spirit and purpose of the recommendation at national level and consistent with national legal substantive and procedural rights.

- Where obstacles have been identified as arising from supra-national legislation (e.g. in the environmental sector), it is noted that improvements would need to be 'top down' (i.e. led or promoted by initiatives at EU level rather than national) at least as a starting point.

- The recommendations focus on improvements for the permitting procedures in relation to projects of regional interest which is the scope of our study. However, we note that some of the difficulties identified are much more endemic in the legal and regulatory system (e.g. delays and complexity in permitting). Therefore, we can see that many of our recommendations below have validity for other projects and that Member States may want to consider how improvements could be extended more generally in light of the experience in this area.

- Against the background of negative public response to many proposed infrastructure projects, any 'streamlining' of permit procedures needs to be balanced against the legal rights of those affected, hence transparency and stakeholder engagement should be considered as over-riding principles in the implementation of the actions described below. Principles of consistency, non-discrimination, transparency and public participation need to be respected, whilst facilitating timely and consistent authorisation of priority projects.

The following are among mutually reinforcing actions which could be considered:

Remedial action	Issues addressed (see Section 7)
1. Implement single local Authority One single authority at Member State level to act as a single coordinator of permitting and planning procedures. The authority would be focused on co-ordinating the relevant procedures at a local and national level to ensure that regional priority projects are recognised as such at all levels of the permitting process. In addition the authority should be able to provide project proponents with information to clarify the permitting procedures and approval process, and assist with disputes. Key stakeholder/s: National government Timescales: short term	Permitting process Multiple consents High costs Duration Resources
2. Minimise bureaucracy Local Authority should be permitted to delegate certain routine application procedures to project managers by mutual consent. The emphasis should be on reducing time limits, which was the most significant concern expressed in our review. Key stakeholder/s: National government Timescales: short term	Costs Duration Resources
3. Improve engagement at regional level Where infrastructure transits more than one Member State the Local Authorities in each Member State should engage on issues affecting their national interests and on regional and European interests; escalation to EU Umbrella Authority in the event of disagreement or with the consent of two or more Local Authorities. Such engagement should also assess alignment between national implementation of EU measures, and address any inconsistencies which may delay or prevent the development of priority projects. Key stakeholder/s: National government Timescales: short term	Stakeholder interest Duration

Remedial action	Issues addressed (see Section 7)
4. **Rationalise approvals for land rights** To rationalise planning approval procedures at national level, the Local Authority should undertake a review of national and regional/ local procedures to seek to identify whether there is scope for a reduction in bureaucracy and increased simplicity at the national and regional/ local level Key stakeholder/s: National government Timescales: medium term	Acquisition of rights in land
5. **Give more weight to Priority Corridors** Priority Corridors should be respected in national permitting and planning procedures. Priority corridors may be based on the requirements for projects identified as regional priorities, or alternatively, those included within the ENTSO-E TYDP, and ensure that the land within a specified corridor (e.g. 140m of planned / existing OHL) is kept free of new development for a selected period of time. This prioritisation should be respected during the permitting process through to Commercial Operation Date. Key stakeholder/s: National government and regulatory authorities Timescales: short term	Priority Corridors Duration
6. **Introduce iterative process to manage upgrades, extensions and Project Design Refinements** The permitting process should allow for upgrades, extensions and project design refinements to be treated as an amended application with only relevant parts of the process to be repeated. The same process may be applied to projects which deliver upgrades to existing lines, with a flexible process focused on assessing only those components of the project which are materially different to the existing infrastructure. Conditions can be attached to a permit to mitigate any impact of the development in terms of noise, access, etc. Key stakeholder/s: National government and regulatory authorities Timescales: medium term	Stakeholder interest Iterative procedures Duration
7. **Improve stakeholder engagement** Local, national and regional authorities to promote engagement between investors, regulators, promoters, affected local community, and raise awareness of benefits of projects with stakeholders at Member State level. A co-ordinated communication campaign should be used to raise awareness of the necessity for infrastructure investment and the contribution that such projects make across a range of policy goals, and thus their contribution to the public interest. Increased transparency of processes and benefits will also enhance stakeholder engagement, and in such respects the single local Authority (see 1 above) will be well placed to ensure that procedures are transparent to stakeholders as well as project proponents. The Working Group reported a positive experience of involvement from European co-ordinators for priority projects – the selection of locally respected individuals for such roles can also raise public awareness and engagement. Ensure there are measures in place for voicing legitimate concerns at	Stakeholder interest Duration

Remedial action	Issues addressed (see Section 7)
national level with assistance of EU Umbrella Authority where needed. Key stakeholder/s: National government Timescales: short term	
8. **Coordination with taxation and other financial incentives** Seek to align taxation and other financial regulation, incentives and subsidies so that this supports infrastructure development and does not otherwise disadvantage the financial or other interests of relevant stakeholder or landowners. Key stakeholder/s: National government Timescales: short term	Stakeholder interest Duration
9. **Modelling** Develop a test case at regional level to seek to identify areas for specific improvements in the permitting procedures at the national and regional level. Insights from such an exercise may be used to develop best practices and support specific changes at the national and regional level. Key stakeholder/s: Regulatory authorities Timescales: short term	Permitting process Multiple consents High costs Duration Resources Stakeholder interest
10. **Commission support and commitment** Commission to commit to support initiatives at national level to expedite and streamline permitting procedures and promote any EU-wide initiatives which may be necessary to support such. Key stakeholder/s: Commission and national governments Timescales: ongoing	Permitting process Multiple consents High costs Duration Resources Stakeholder interest

8.1.4. TSO co-ordination

Whilst the North-South Interconnections Working Group has facilitated interaction between TSOs in relation to key issues within the region, this process should be continued through the appropriate forums in order to ensure that as existing project plans progress, and new ones are developed, these are jointly considered by the impacted TSOs.

Remedial action	Issues addressed (see Section 7)
1. **Enhance bilateral co-ordination between TSOs in relation to priority and cross-border projects** TSO co-ordination is particularly important in relation to: • Definition of the project scope and objectives – consistency of approach and assumptions • Requirements and priorities for investment appraisal – coherent and compatible methodologies and thresholds • Implementation and monitoring of the projects – via risk identification and allocation to / mitigation by the party best able to manage defined risks. ENTSO-E is the key existing forum for such co-ordination, and its role in drafting the Ten Year Development Plan positions it centrally	Lack of framework for co-ordination between TSOs on cross-border projects. Investment rationale is dependent on other projects

within the on-going process of project prioritisation.
Key stakeholder/s: TSOs
Timescales: short term

This action will also mitigate some of the issues associated with inter-dependencies between projects, where other TSOs can provide further information and / or control over the relevant interfaces.

8.2. Other measures

Some of the issues raised in Section 7 may also be addressed via project specific measures, for example by the sharing of key project delivery and operation risks with third parties. These measures would be implemented by the project proponent i.e. for the projects proposed as regional priorities, the TSO, however there is likely to be a requirement for both shareholders (in most cases national government) as well as regulatory authorities to understand and buy-in to the selected approach.

The key approaches to risk sharing and mitigation typically include:

- Involvement of third party equity – for example through a joint venture, or public-private partnership. In addition to the input of equity funding, such measures allow the project to benefit from the skills and experience of parties who would typically bring a track record in delivery of relevant project types, thereby enhancing the availability, and reducing the cost, of further financing. On the other hand, the inclusion of third parties may entail a reduction in the proponent's legal control over the asset, however this can be managed through shareholder agreements and approach to corporate governance.
- Third party debt – inclusion of debt financing reduces the overall project funding costs, since debt returns are typically lower than those required for equity. In addition non-recourse debt funding (where available, as discussed in Section 7.2.1) sets a cap on the overall losses which can be incurred in relation to a project, since in the event of default the lender has a claim on ownership of the asset. Nevertheless, this reduction in financing costs requires a significant investment of resources during the development process since lenders will expect many of the delivery and operation risks to be identified and mitigated before entering into non-recourse arrangements.
- Procurement of construction and associated services – this approach can be tailored to transfer risks to the contractor, for example transfer of responsibility for project design (e.g. through a turnkey Engineering Procurement Contract, or EPC approach) or maintenance (e.g. through the Design, Build and Maintain contracting approach). The incremental costs and availability of such risk transfer will depend on the depth of the contracting market and therefore varies throughout the economic cycle.
- Insurance – commonly used to underwrite risks associated with, at a minimum, construction ('Contractors All Risks' insurance) and third party liability.

The appropriateness of each of these approaches should be considered in the light of the project-specific risks as well as the market environment within which the investment is to be undertaken.

Key stakeholder/s: National government, regulatory authorities and TSOs
Timescales: short term

8.3. Conclusions

The table below outlines the proposed remedial actions grouped by the key stakeholders and timescales for implementation.

	Short term	Medium term
National Government	• Facilitate sharing of technical	• Provision of subordinate debt

	information • Implement single local Authority • Minimise bureaucracy • Improve engagement at regional level • Improve stakeholder engagement	• Rationalise approvals for land rights
National Government + Regulatory Authority	• Provide clarity over regulatory priorities regarding key infrastructure investments • Recognise separate regulatory treatment of key investments • Give more weight to Priority Corridors	• Introduce iterative process to manage Project Design Refinements
Regulatory Authority	• Enhance co-ordination between authorities	• Demonstrate progress toward market integration
TSO	• Enhance co-ordination between TSOs in relation to priority and cross-border projects • Project-specific measures	

9. Conclusions

The objective of the study was to:

- identify potential future priorities based on market integration, security of supply and sustainability considerations,
- analyze ongoing and planned electricity infrastructure projects in the region covered by the North-South initiative and assess to what extent they contribute to the objectives of the initiative,
- identify the obstacles to market integration and implementation of infrastructure projects to support it.

We have therefore presented our conclusions against each of these issues.

Potential future priorities

It is apparent that the current infrastructure provision is heavily utilised in some specific locations - in particular Germany to Poland, Poland to Czech Republic and Czech Republic to Austria. These interconnection points are those which have the highest level of loop flows, where physical flows substantially exceed planned commercial flows.

Throughout the study area the main change in the period 2010 to 2020 will be a significant increase in renewable generation capacity, located primarily in the north of the study area, and a closure of nuclear capacity.

The lower load factor and lower 'dispatchability' of this renewable generation is likely to increase the requirements for balancing networks on a national and regional basis – largely on a short-term (daily, monthly, seasonal) basis in response to changing weather patterns and resulting peaks or troughs in renewable generation. The variability of such flows means that the amount and the direction of flows will not be stable, but it will change more frequently from north-south and east-west direction to south-north and west-east direction and vice versa.

At the same time, the distances between the location of this new renewable generation and centres of consumption to the south of the study area will require electricity to be transported longer distances, with the capability to meet structural generation shortages in markets outside the study area. Such North-South transit capacities should taking into account the grid development in neighbouring areas, specifically for the connection of new generation around the Northern Seas and the Baltic Sea. The Working Group have highlighted that, given the impact of the current interconnection insufficiencies on the neighbouring grids, and especially in Eastern Europe, a coordinated regional approach is vital to solve this issue.

These requirements should be taken into account in the prioritisation of infrastructure projects which shall be selected on the basis of their contribution to: the connection of renewable generation; enhancing market integration and competition; and increasing security of supply.

Analyze ongoing and planned electricity infrastructure projects

Criteria were selected on the basis of the EU energy sector objectives of market integration, security of supply and promotion of renewable resources. Indicators were defined for each of the criteria, on the basis of, where possible, quantifiable measures which could be used to evaluate the extent to which each project met the defined criteria.

The outcome of this process was a list of 31 projects which address the prioritisation criteria, including 11 interconnector projects and 20 internal projects. These address the issues identified within the market analysis as follows.

Conclusions of market analysis	Key issues adressed by priority projects
Current infrastructure heavily utilised: • Germany to Poland • Czech Republic to Germany • Czech Republic to Austria	Enhanced capacity at border locations: • Germany and Austria, Czech Republic, Poland • Slovenia and Croatia / Hungary • Slovakia and Hungary
Loop flows are a particular issue from • Germany to Poland; Poland to Czech Republic; Poland to Slovakia	Management of loop flows at border locations: • Germany and Poland • Germany and Czech Republic /
Significant increase in renewable generation capacity by 2020, located mainly in the north of the study area, and significant reduction in nuclear capacity Lower load factor and reduced "dispatchability" likely to increase the requirements for balancing networks – requirements for energy storage and, where possible, sharing of peaking capacity	Connection of generation capacity: Germany, Czech Republic , Romania, Slovakia, Slovenia Connection between wind capacity / flexible plant and pump storage: Austria
Extended distances likely to require increased long distance transmission capacity	Strengthening of internal network: Austria, Bulgaria, Croatia, Czech Republic, Germany (including management of reactive power), Romania, Slovenia

Obstacles to market integration and implementation of infrastructure projects

Information provided by TSOs, via project fiches, suggests that the most significant issues facing priority projects are permitting and consenting issues, as well as issues with the regulatory framework, both of which affect projects with a total value of just below €3,5 bn, or 57% of the total regional priority projects by value. Funding is seen as a major implementation issue for slightly fewer projects, recognized for only 35% of the priority projects by value – however it is clear that funding is also an over-arching issue, since issues with the regulatory framework, for example, are also likely to jeopardise project funding.

Financing issues arise largely from market failures which are outside the direct control of stakeholders within the High Level Group, for example the current crisis in financial markets, however there are actions which can be undertaken in order to mitigate the effect of the market environment on priority projects. The majority of issues identified are those which can be addressed through the Action Plan, focusing on measures to simplify and accelerate procedures for permitting and consents, as well as those to enhance co-operation and alignment between regulatory authorities. The Working Group has proved valuable as a forum for TSOs to interact and co-ordinate some of their planning – such co-operation should continue, for example through regional groupings within ENTSO-E. Additional actions to manage and mitigate implementation risk can be taken on a project-by-project basis, and TSOs should be encouraged to explore delivery approaches which have been successfully implemented elsewhere for similar projects.

10. Appendix I: data

10.1. 2010 data

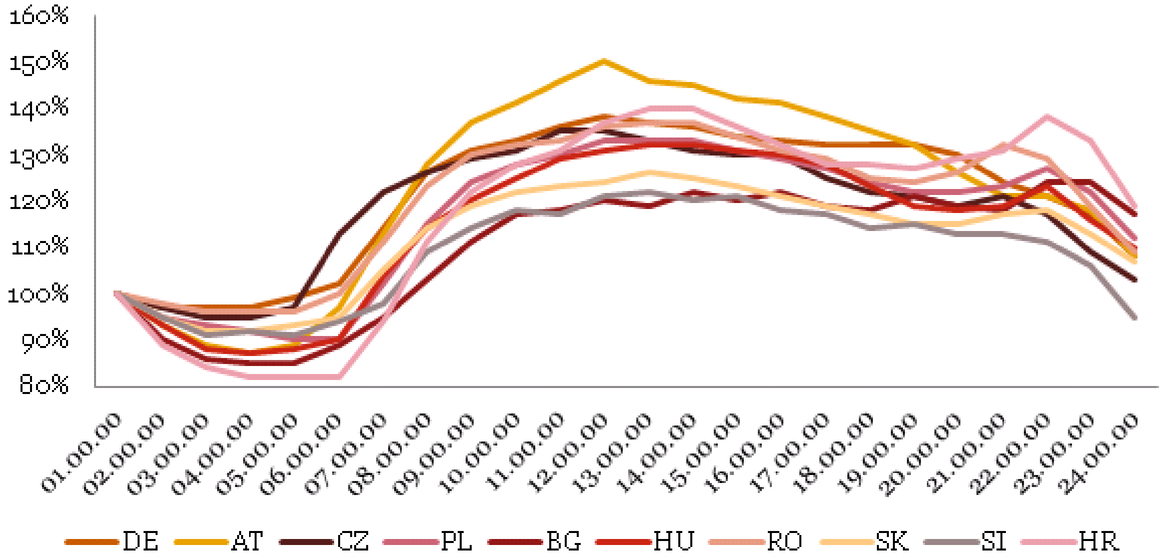
10.1.1. Consumption

Figure 43: consumption by country 2010 – GWh

	Austria	Bulgaria	Croatia	Czech Republic	Germany	Hungary	Poland	Romania	Slovakia	Slovenia	TOTAL
ENTSO-E 2010[71]	67.32	31.53	17,784	64.015	548.219	38.976	143.564	53.362	28.761	12.248	985.881
PRIMES Electricity consumption (%)											
Final energy demand	86%	74%	N/A	81%	86%	78%	74%	71%	82%	86%	82%
Industry	42%	40%	N/A	43%	44%	28%	40%	60%	47%	55%	44%
Households	26%	34%	N/A	26%	28%	35%	23%	25%	20%	23%	27%
Tertiary	25%	24%	N/A	26%	25%	33%	33%	11%	31%	19%	26%
Transport	6%	2%	N/A	4%	3%	3%	3%	4%	2%	2%	3%
Energy branch	9%	12%	N/A	11%	9%	13%	16%	18%	11%	7%	11%
Trans / dist losses	5%	13%	N/A	7%	5%	9%	10%	11%	6%	6%	7%

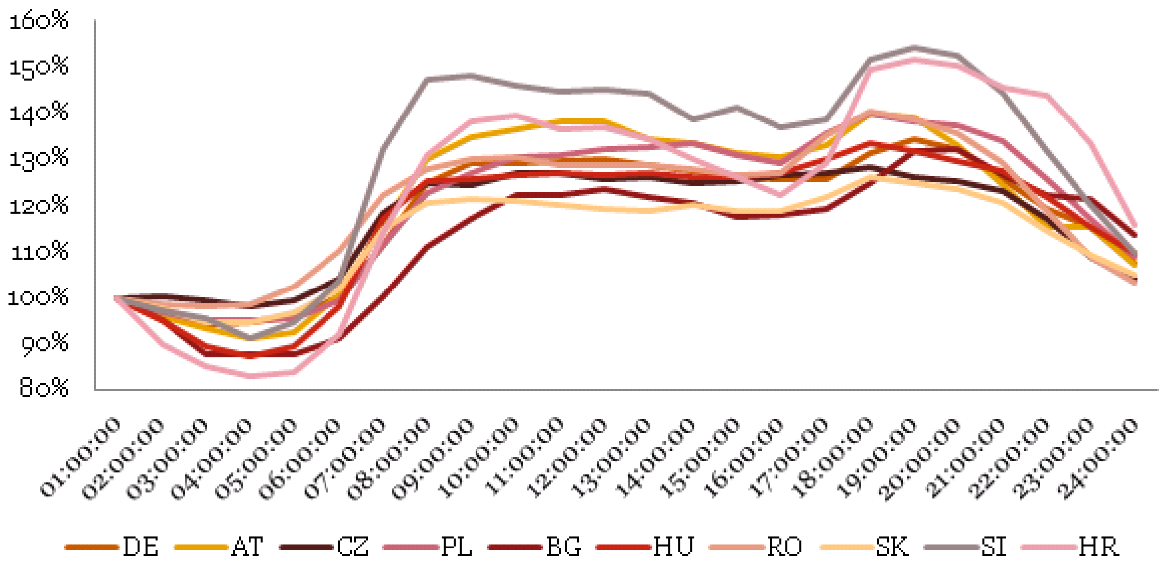
[71] The 2010 consumption data for the Slovakia has been updated with data provided by the Slovakian TSO

Figure 44: Average Levelised hourly load values – 3rd Wednesday July)



Source: ENTSOE

Figure 45: Average Levellised hourly load values – 3rd Wednesday January)



Source: ENTSOE

10.1.2. Installed capacity and generation mix

Figure 46: Installed capacity by plant type 2010 – MWe

Installed capacity by plant 2010 (MWe)	**AT**	**BG**	**HR**	**CZ**	**DE**	**HU**	**PL**	**RO**	**SK**	**SL**
Nuclear energy	0	2.000	0	3.900	20.300	1.892	0	1.300	1.820	696
Hydro (pumping excluded)	12.665	2.170	1.835	1.056	10.700	50	918	6.087	1.612	883
Wind power	1.002	488	73	217	26.600	240	1.274	479	7	0
Solar	0	25	1	1.959	16.600	0	0	0	183	0
Other renewables (tidal etc.)	29	0	0	0	4.200	390	92	22	130	0
Thermal power	7.389	6.451	1.814	11.794	69.300	6.181	29.612	9.166	3.112	1.282

Source: ENTSOE

Figure 47: Total generation by plant type 2010 – GWh

Nuclear	218.464
Hydro (pumping excluded)	105.716
Wind	42.202
Solar	11.487
Other RES	29.418
Thermal	637.055
Total generation	**1.044.342**

Source: ENTSOE

Figure 48: Generation by plant type 2010 – GWh

	AT	**BG**	**HR**	**CZ**	**DE**	**HU**	**PL**	**RO**	**SK**	**SL**
Nuclear	0	14.181	0	26.441	133.373	14.830	0	10.686	13.576	5.377
Hydro (pumping excluded)	36.496	5.431	7.681	3.374	21.698	181	2.839	20.174	3.593	4.249
Wind	2078	331	164	334	36.665	503	1.821	290	16	0
Solar	0	0	3	590	10.874	0	0	0	20	0
Other RES	0	0	0	-5	26.262	1.764	260	112	1025	0
Thermal	24.638	21.084	4.808	48.705	344.278	16.503	140.270	25.284	6691	4.794
TOTAL	**63.312**	**41.027**	**12.656**	**79.439**	**573.150**	**33.781**	**145.190**	**56.546**	**24.921**	**14.420**

Source: ENTSOE

Figure 49: Generation load factor 2010

	2010
AUSTRIA	34,2%
BULGARIA	42,1%
CROATIA	38,8%
CZ.REP	47,9%
GERMANY	44,3%
HUNGARY	44,1%
POLAND	52,0%
ROMANIA	37,9%
SLOVAKIA	41,4%
SLOVENIA	57,5%

Source: ENTSOE data; PwC analysis

Figure 50: Generation capacity margin 2010

Country	capacity margin as % peak demand
AT	119%
RO	101%
DE	85%
CZ	81%
SK	57%
BG	53%
SL	48%
HU	44%
PL	36%

Source: ENTSOE data; PwC analysis

Figure 51: Market share of largest generator (2009)

Austria	:
Bulgaria	:
Croatia	92%
Czech Republic	74%
Germany	26%
Hungary	43%
Poland	18%
Romania	29%
Slovakia	82%
Slovenia	55%

Source: Eurostat

10.1.3. Energy balances and exchanges

Figure 52: Interconnection capacity (NTC) - Winter 10/11

ENTSO-E NTC: Winter 2010-11											
	From:	DE	AT	SL	PL	CZ	SK	HU	RO	HR	BG
To:											
DE			2.000		1.100	2.300					
AT		2.200		900		1.000		800			
SL			900							1.000	
PL		1.200				800	500				
CZ		800	600		1.800		1.200				
SK					600	2.200		600			
HU			800				1.300		700	800	
RO								700			600
HR				1.000				1.200			
BG									600		

Source: ENTSOE

Figure 53: Net imports 2010 - (GWh)

Austria	3.260
Bulgaria	-8.100
Cz Rep	-14.897
Germany	-17.707
Hungary	5.191
Poland	-1.345
Romania	-2.916
Slovakia	1.047
Slovenia	-2.133

Source: ENTSOE

Figure 54: Capacity utilisation

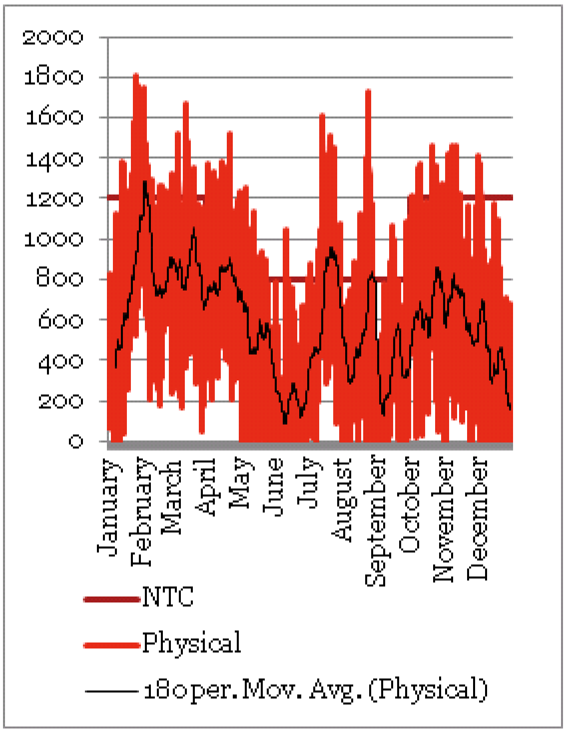
From	To	% periods over 50% capacity	% periods at 100% capacity
More than 20% periods over 50% capacity			
RO	HU	33%	1%
SK	CZ	24%	1%
AT	SL	22%	1%
Less than 20% periods over 50% capacity:			
DE	AT	19%	5%
PL	SK	19%	0%
AT	CZ	15%	1%
CZ	SK	15%	0%

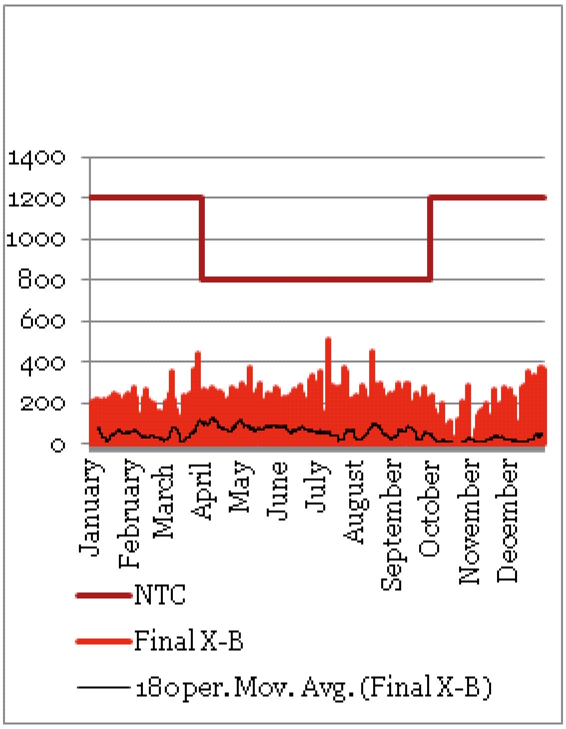
From	To	% periods over 50% capacity	% periods at 100% capacity
RO	BG	15%	0%
AT	DE	14%	2%
HU	SK	13%	3%
AT	HU	11%	1%
SL	HR	10%	2%
HU	AT	10%	1%
BG	RO	9%	0%
SL	AT	6%	0%
PL	DE	1%	0%
DE	CZ	0%	0%
CZ	PL	0%	0%
SK	PL	0%	0%
HU	RO	0%	0%

Source: ENTSOE; PwC analysis

Figure 55: (left) Germany to Poland Cross-Border Physical Flow

Figure 56: (right) Germany to Poland Final Cross-Border

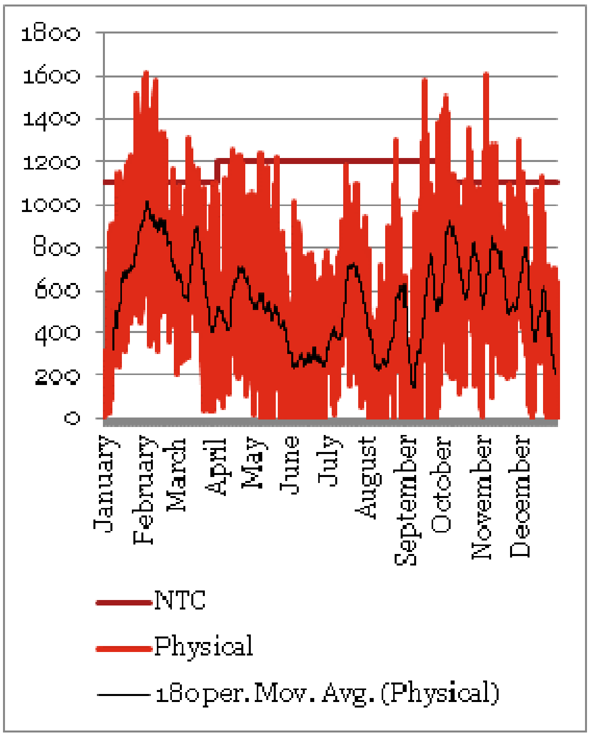




Source: ENTSOE; PwC analysis

Figure 57: (left) Poland to Czech Republic Cross-Border Physical Flow

Figure 58 (right) Poland to Czech Republic Final Cross-Border



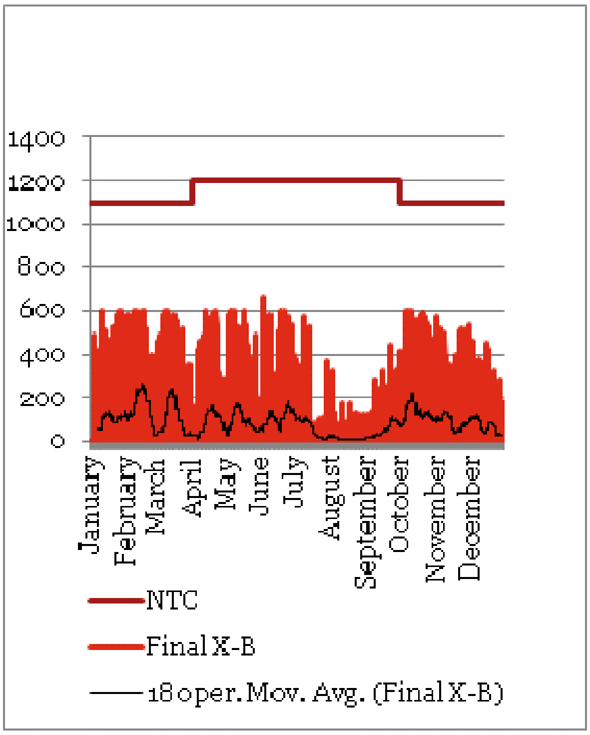
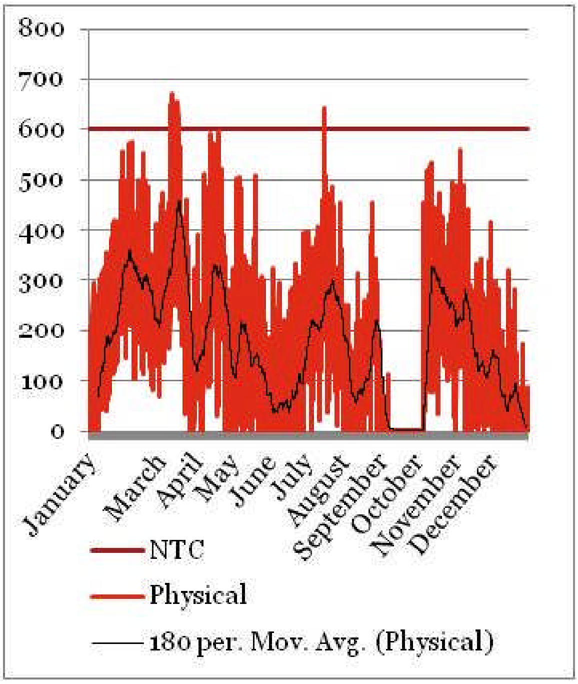


Figure 59: (left) Poland to Slovakia Cross-Border Physical Flow

Figure 60 (right) Poland to Slovakia Final Cross-Border



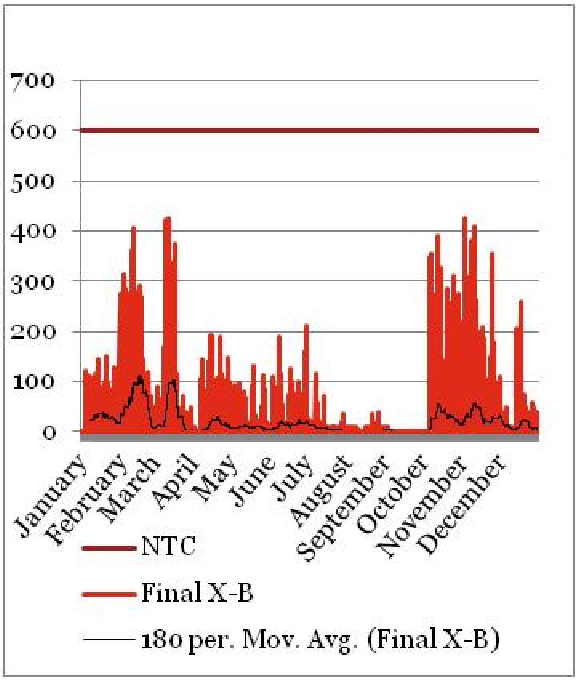
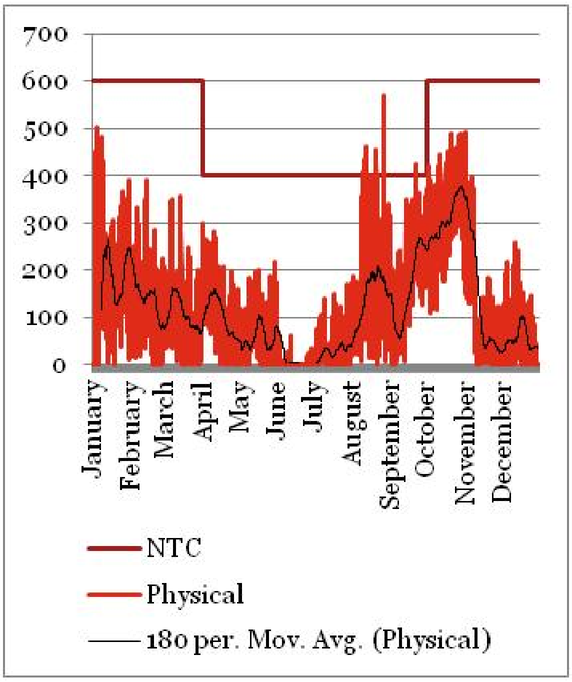
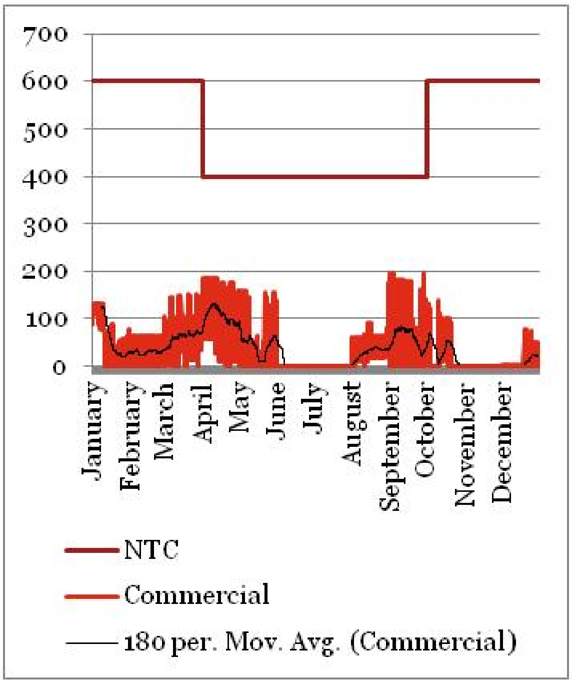


Figure 61: (left) Romania to Bulgaria Cross-Border Physical Flow

Figure 62 (right) Romania to Bulgaria Cross-Border Commercial Flow[72]

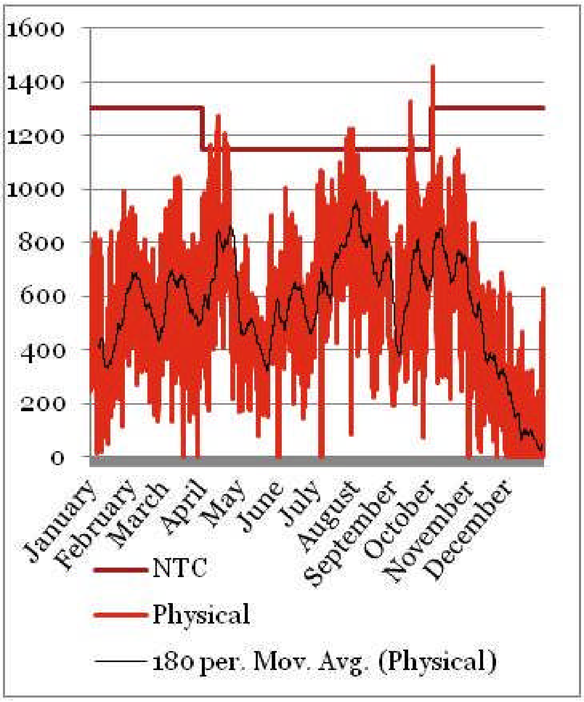


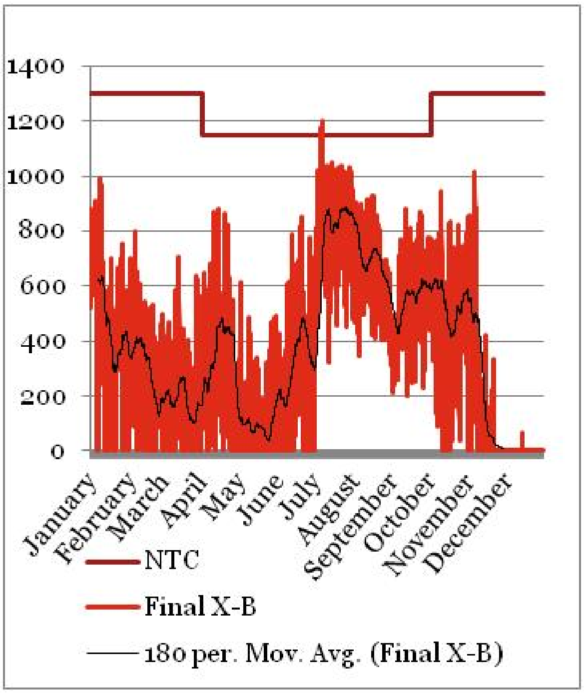


Source: ENTSOE; PwC analysis

Figure 63: (left) Slovakia to Hungary Cross-Border Physical Flow

Figure 64 (right) Slovakia to Hungary Final Cross-Border

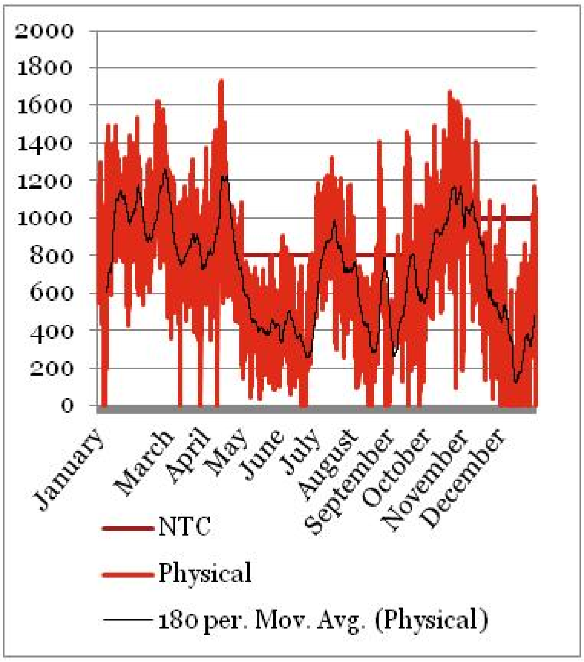


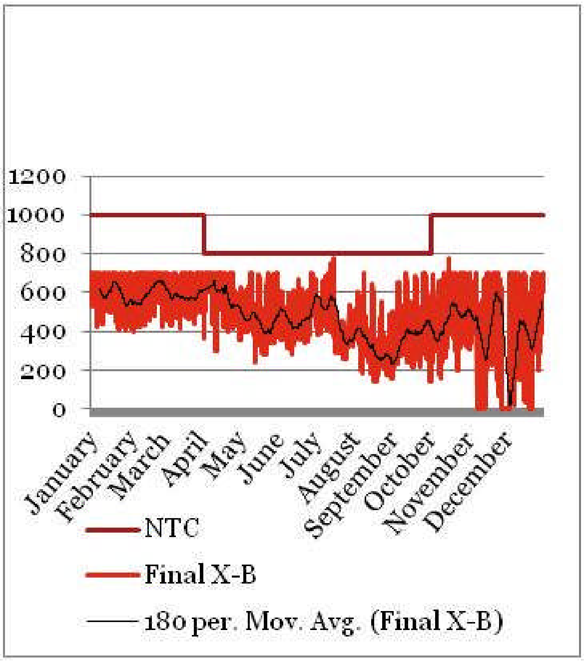


[72] Final Cross Border schedules not available

Figure 65: (left) Czech Republic to Austria Cross-Border Physical Flow

Figure 66 (right) Czech Republic to Austria Final Cross-Border

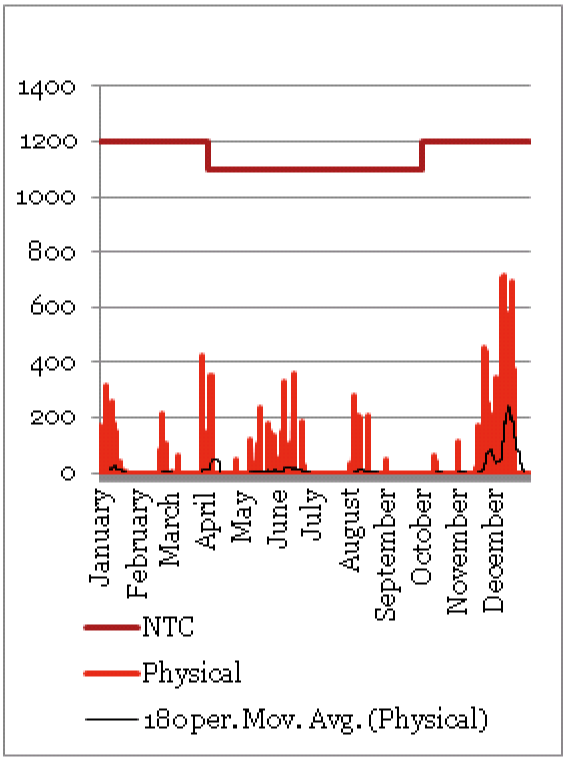


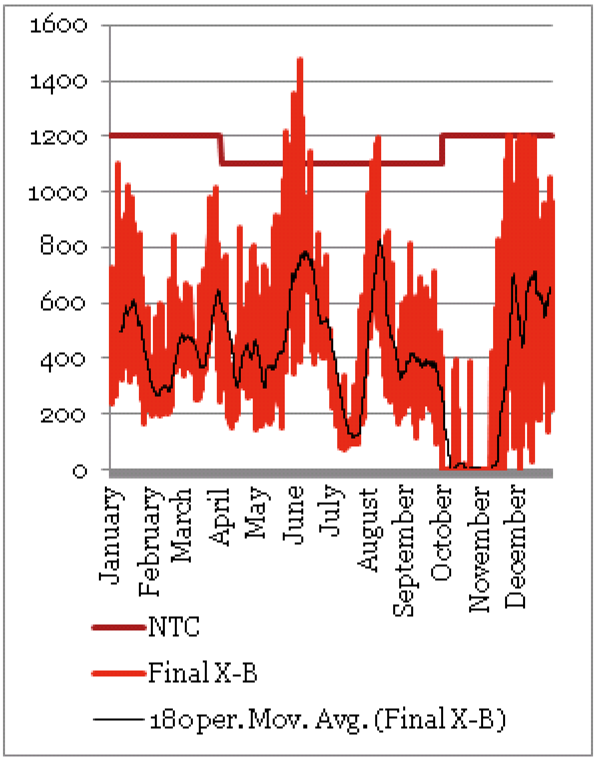


Source: ENTSOE; PwC analysis

Figure 67: (left) Slovakia to Czech Republic Cross-Border Physical Flow

Figure 68: (right) Slovakia to Czech Republic Final Cross-Border





Source: ENTSOE; PwC analysis

10.1.4. Market prices

Spot day ahead prices sourced from:

- Germany / Austria: Spot prices delivery area Austria / Germany, European Energy Exchange A.G.
- Slovenia: Slovenian TSO ELES
- Czech Republic: Annual market report, Day Ahead Market index, OTE, a.s.
- Hungary: Spot Market Energy HU, bEXAbase (01-24), Energy Exchange Austria
- Poland: Day Ahead Market, IRDN index, Polish Power Exchange (PLN/MWh); converted to EUR/MWh based on daily forex rates from European Central Bank (via La Camera di Commercio di Milano)
- Romania: ROPEX Day Ahead Market, Baseload, Opcom SA

Figure 69: Average monthly spot / day-ahead market prices (€/MWh)

		month	hours	Germany / Austria	Slovenia	Czech Republic	Hungary	Poland	Romania
01/01/2010	31/01/2010	1	744	41,76	44,03	39,42	0,00	49,32	36,68
01/02/2010	28/02/2010	2	672	42,34	42,69	40,93	0,00	46,53	40,69
01/03/2010	31/03/2010	3	744	39,01	40,07	38,21	0,00	45,90	38,49
01/04/2010	30/04/2010	4	720	40,38	41,23	39,50	0,00	46,22	35,01
01/05/2010	31/05/2010	5	744	42,25	41,78	41,21	20,42	48,16	37,82
01/06/2010	30/06/2010	6	720	43,14	43,78	43,45	45,43	47,93	31,18
01/07/2010	31/07/2010	7	744	46,61	48,51	46,10	47,48	48,86	34,68
01/08/2010	31/08/2010	8	744	39,93	42,31	39,87	42,03	47,85	32,77
01/09/2010	30/09/2010	9	720	46,11	46,91	45,94	45,13	49,19	37,31
01/10/2010	31/10/2010	10	744	51,25	51,58	49,40	48,63	50,92	41,98
01/11/2010	30/11/2010	11	720	49,70	48,98	48,21	45,77	51,00	39,47
01/12/2010	31/12/2010	12	744	54,98	55,83	51,98	47,25	55,85	31,53
	AVERAGE			44,79	45,64	43,68	45,96	48,98	36,47

Figure 70: Market price correlation, 2010 data

	BG	CZ	HR	DE/AU	HU	PL	RO	SK
BG								
CZ								
HR								
DE/AU		0,92						
HU		0,41		0,43				
PL		0,71		0,75	0,37			
RO		0,43		0,43	0,36	0,27		
SK								

higher than		0,6
between 0,3 and 0,59		0,3
lower than		0,3

10.2. 2020 data

10.2.1. Consumption

Figure 71: Demand by country and growth rates (2010-15-20)

	2010	2015	2020
Austria	67.324	70.627	73.174
Bulgaria	31.537	33.523	35.525
Croatia	17.784	19.700	21.200
Cz Rep	64.015	71.218	77.540
Germany	548.219	574.068	578.092
Hungary	38.976	42.670	44.672
Poland	143.564	157.291	172.918
Romania	53.362	60.512	67.163
Slovakia	28.761	32.000	34.650
Slovenia	12.248	13.191	14.272
TOTAL	**1.005.790**	**1.074.801**	**1.119.205**

FINAL ENERGY DEMAND (GWh)	2010-2015	2015-2020
Austria	0,96%	0,71%
Bulgaria	1,23%	1,17%
Croatia	2,07%	1,48%
Cz Rep	2,16%	1,72%
Germany	0,93%	0,14%
Hungary	1,83%	0,92%
Poland	1,84%	1,91%
Romania	2,55%	2,11%
Slovakia	2,16%	1,60%
Slovenia	1,49%	1,59%

Source: ENTSO-E (2010); PRIMES

Figure 72 Electricity consumption, population, GDP and energy intensity indicators (Source: PRIMES data)[73]

AUSTRIA	2000	2005	2010	2015	2020
Electricity consumption (in GWh)	58486	65627	66770	70342	72909
Final energy demand	51363	56180	57300	60111	62278
Industry	20813	24038	24275	25639	26629
Households	13647	14659	15126	15991	16723
Tertiary	13599	14392	14428	14837	15181
Transport	3304,4	3090,4	3471,1	3643,9	3745,1
Energy branch	3932	6015	5943	6548	6821
Own consumption & pumping	2077,6	4123,3	4155,7	4730,5	5021,7
Refineries & other uses	1854,7	1891,7	1786,8	1817,9	1799,6
Transmission and distribution losses	3191	3432	3528	3682	3810
Population (Million)	8,002	8,207	8,405	8,57	8,723
GDP (in 000 MEuro'05)	225	244,5	254,5	281,9	310,4
Energy intensity indicators (2000=100)					
Industry (Energy on Value added)	100	100,8	96,58	86,4	79,45
Residential (Energy on Private Income)	100	102,5	103,3	97,56	88,15
Tertiary (Energy on Value added)	100	106	102,7	97,98	89,86
Transport (Energy on GDP)	100	121,6	118,2	110,1	99,81

BULGARIA	2000	2005	2010	2015	2020
Electricity consumption (in GWh)	36020	36384	35509	36827	38208
Final energy demand	24128	25673	26327	27985	29656
Industry	8582,5	9836,2	10645	12238	13481
Households	9856,2	9044,4	8977,9	9194,7	9662,9
Tertiary	5236,1	6379,9	6271,3	6097	5968,2
Transport	452,92	412,93	432,8	455,51	544,46
Energy branch	5550	5830	4438	4259	4129
Own consumption & pumping	4432	4797	3383,7	3166,4	3044,8
Refineries & other uses	1118	1033	1054,3	1093	1084,4
Transmission and distribution losses	6289	4882	4744	4583	4423
Population (Million)	8,191	7,761	7,564	7,382	7,188
GDP (in 000 MEuro'05)	16,91	21,88	25,75	30,45	34,65
Energy intensity indicators (2000=100)					
Industry (Energy on Value added)	100	72,06	61,87	52,1	44,77
Residential (Energy on Private Income)	100	74,19	63,21	57,47	56,23
Tertiary (Energy on Value added)	100	93,93	84,87	72,55	66,04
Transport (Energy on GDP)	100	110,2	95,39	89,97	84,36

[73] Data for 2010 in this table is PRIMES forecast data, and not actual data

CZECH REPUBLIC	2000	2005	2010	2015	2020
Electricity consumption (in GWh)	62883	69285	77288	85675	92841
Final energy demand	49342	55236	64015	71218	77540
Industry	18941	23141	24885	27662	29390
Households	13820	14716	15223	16592	18146
Tertiary	14277	15243	15105	17340	19630
Transport	2304,6	2135,6	2309	2399,7	2508,5
Energy branch	8585	9022	8117	8712	8951
Own consumption & pumping	5801	6749,8	5922,9	6524,3	6786,4
Refineries & other uses	2784,5	2272,6	2193,7	2187,7	2164,4
Transmission and distribution losses	4955	5026	5156	5745	6350
Population (Million)	10,28	10,22	10,39	10,5	10,54
GDP (in 000 MEuro'05)	83,39	100,2	114,3	134,8	154,2
Energy intensity indicators (2000=100)					
Industry (Energy on Value added)	100	73,83	61,61	56,3	50,6
Residential (Energy on Private Income)	100	97,24	90,19	79,51	71,7
Tertiary (Energy on Value added)	100	80,75	73,41	62,76	55,55

GERMANY	2000	2005	2010	2015	2020
Electricity consumption (in GWh)	6E+05	6E+05	6E+05	6E+05	6E+05
Final energy demand	482516	517411	527731	552614	556487
Industry	221886	232062	232237	234316	230721
Households	128884	141774	148496	157627	164920
Tertiary	115839	127377	129663	142550	142414
Transport	15907	16197	17335	18121	18432
Energy branch	56410	61755	57103	52075	49421
Own consumption & pumping	41343	43705	40736	36120	33644
Refineries & other uses	15067	18050	16367	15955	15776
Transmission and distribution losses	32818	29323	30319	32609	33680
Population (Million)	82,16	82,5	82,14	81,86	81,47
GDP (in 000 MEuro'05)	2177	2243	2282	2511	2724
Energy intensity indicators (2000=100)					
Industry (Energy on Value added)	100	89,52	83,09	77,84	72,44
Residential (Energy on Private Income)	100	107,4	110,1	98,98	87,8
Tertiary (Energy on Value added)	100	98,16	95,26	85,77	75,17
Transport (Energy on GDP)	100	91,14	90,47	83,61	76,45

HUNGARY	2000	2005	2010	2015	2020
Electricity consumption (in GWh)	38624	41974	42297	45878	47983
Final energy demand	29436	32330	32990	36117	37811
Industry	8797,4	9269,3	9346,2	9844,7	10355
Households	9790,2	11113	11505	12602	14119
Tertiary	9833,2	10852	11018	12571	12202
Transport	1014,8	1095,8	1121,3	1098,9	1134,9
Energy branch	4349	5704	5290	5404	5699
Own consumption & pumping	3151,8	2828,5	2087,9	2020,8	2287,2
Refineries & other uses	1197,4	2875,5	3202,3	3383,2	3411,7
Transmission and distribution losses	4839	3940	4017	4358	4473
Population (Million)	10,22	10,1	10,02	9,964	9,893
GDP (in 000 MEuro'05)	72,01	88,68	87,61	101,1	114,8
Energy intensity indicators (2000=100)					
Industry (Energy on Value added)	100	79,03	81,46	76	69,59
Residential (Energy on Private Income)	100	89,59	93,77	80,66	70,56
Tertiary (Energy on Value added)	100	85,98	86,8	76,06	65,42
Transport (Energy on GDP)	100	104,4	123,8	121,4	111,9

POLAND	2000	2005	2010	2015	2020
Electricity consumption (in GWh)	1E+05	1E+05	2E+05	2E+05	2E+05
Final energy demand	98304	1E+05	1E+05	1E+05	1E+05
Industry	40446	41310	45675	48766	51623
Households	21030	25059	27000	29522	32877
Tertiary	32500	35040	38560	43539	49716
Transport	4328,2	3569,4	3971,1	4395	4544,5
Energy branch	24241	24609	25117	25648	27800
Own consumption & pumping	13747	13962	14601	15046	17379
Refineries & other uses	10494	10646	10516	10602	10420
Transmission and distribution losses	14231	14560	15520	16416	17365
Population (Million)	38,65	38,17	38,09	38,07	37,96
GDP (in 000 MEuro'05)	210	244,4	298,1	353,9	406,1
Energy intensity indicators (2000=100)					
Industry (Energy on Value added)	100	67,18	56,28	49,83	44,78
Residential (Energy on Private Income)	100	90,95	79,4	69,62	60,83
Tertiary (Energy on Value added)	100	98	88,87	79,51	71,02
Transport (Energy on GDP)	100	112,8	128,1	126,5	115,2

ROMANIA	2000	2005	2010	2015	2020
Electricity consumption (in GWh)	51229	56500	57481	63890	69204
Final energy demand	33906	38804	40870	46346	51440
Industry	19905	23680	24397	26641	29510
Households	7650,6	9232,3	10309	11949	12703
Tertiary	4518,2	4330,2	4535,7	5952,8	7037,8
Transport	1831,7	1561,7	1628,1	1802,7	2188,8
Energy branch	10695	11617	10571	10897	10983
Own consumption & pumping	3335,4	3930,3	3791,7	3949,1	3898
Refineries & other uses	7359,7	7686,6	6779,2	6947,6	7084,5
Transmission and distribution losses	6628	5843	6040	6648	6782
Population (Million)	22,46	21,66	21,33	21,1	20,83
GDP (in 000 MEuro'05)	60,43	79,8	93,83	115,4	135
Energy intensity indicators (2000=100)					
Industry (Energy on Value added)	100	81,38	71,12	61,06	54,04
Residential (Energy on Private Income)	100	58,93	48,76	41,4	36,29
Tertiary (Energy on Value added)	100	121,7	110,4	99,61	85,49
Transport (Energy on GDP)	100	94,12	95,73	94,64	90,05

SLOVAK REPUBLIC	2000	2005	2010	2015	2020
Electricity consumption (in GWh)	27735	28082	34045,	37747	40656
Final energy demand	22006	22846	28761	32000	34650
Industry	9739,2	11032	11621	13487	15016
Households	5418	4700,2	4883,2	5629,5	6188,3
Tertiary	5883,9	6541,8	7631,1	9437,4	10962
Transport	964,83	571,9	592,21	613,27	667,56
Energy branch	3902	3548	3414	3509	3486
Own consumption & pumping	3419,6	2223,5	1972,5	1938,2	1886
Refineries & other uses	482,67	1324,9	1441,6	1571,2	1600,2
Transmission and distribution losses	1827	1687	1870	2237	2520
Population (Million)	5,399	5,385	5,407	5,427	5,432
GDP (in 000 MEuro'05)	30,28	38,49	48,18	61,03	73,29
Energy intensity indicators (2000=100)					
Industry (Energy on Value added)	100	69,11	50,36	41,77	34,82
Residential (Energy on Private Income)	100	77,64	70,28	58,76	51,27
Tertiary (Energy on Value added)	100	61,38	56,86	50,41	44,54
Transport (Energy on GDP)	100	96,83	96,6	87,93	76,14

SLOVENIA	2000	2005	2010	2015	2020
Electricity consumption (in GWh)	12301	14790	15511	16731	18069
Final energy demand	10519	12740	13412	14444	15628
Industry	5528	7170,7	7440,4	8450,7	9086,7
Households	2600,5	2950,5	3132,6	3312	3730,1
Tertiary	2125,6	2420,6	2596,3	2418,7	2508,5
Transport	264,95	197,96	242,55	262,48	302,87
Energy branch	970,8	1097	1097	1261	1335
Own consumption & pumping	851,49	989,29	961,75	1119,8	1193,5
Refineries & other uses	119,34	107,51	135,49	141,32	141,38
Transmission and distribution losses	810,9	953,8	1002	1026	1106
Population (Million)	1,988	1,998	2,034	2,053	2,058
GDP (in 000 MEuro'05)	23,99	28,71	32,72	38,39	44,01
Energy intensity indicators (2000=100)					
Industry (Energy on Value added)	100	92,4	82,76	76,99	71,54
Residential (Energy on Private Income)	100	92,23	85,19	80,77	74,04
Tertiary (Energy on Value added)	100	82,44	72,56	63,36	54,66
Transport (Energy on GDP)	100	93,96	110,7	115,2	108,8

10.2.2. Installed capacity and generation mix

Figure 73: Installed capacity by plant type (2010-15-20) (Source; ENTSO-E 2010; PRIMES)

Installed capacity by plant 2010 - 2020 (MWe)	**AUSTRIA**		
	10	**15**	**20**
Nuclear energy	0	0	0
Hydro (pumping excluded)	12.665	14.838	15.607
Wind power	1.002	1.370	1.691
Solar	0	0	0
Other renewables	29	35	38
Thermal power	7.389	8.497	7.800
TOTAL	**21.085**	**24.740**	**25.136**

Installed capacity by plant 2010 - 2020 (MWe)	BULGARIA		
	10	15	20
Nuclear energy	2.000	2.027	3.045
Hydro (pumping excluded)	2.170	2.196	2.211
Wind power	488	1.303	2.168
Solar	25	187	534
Other renewables	0	0	0
Thermal power	6.451	6.812	5.282
TOTAL	11.134	12.524	13.240

10.2.2.1. Installed capacity by plant 2010 - 2020 (MWe)	CZ REP		
	10	15	20
Nuclear energy	3.900	3.900	3.900
Hydro (pumping excluded)	1.056	1.056	1.056
Wind power	217	400	800
Solar	1.959	2.200	2.400
Other renewables (tidal etc.)	0	0	0
Thermal power	11.794	13.665	12.265
TOTAL	18.926	21.221	20.421

Installed capacity by plant 2010 - 2020 (MWe)	GERMANY		
	10	15	20
Nuclear energy	20.300	15.735	5.295
Hydro (pumping excluded)	10.700	10.861	11.157
Wind power	26.600	39.025	54.621
Solar	16.600	28.183	44.105
Other renewables	4.200	6.165	8.709
Thermal power	69.300	77.760	77.064
TOTAL	147.700	177.729	200.950

Installed capacity by plant 2010 - 2020 (MWe)	HUNGARY		
	10	15	20
Nuclear energy	1.892	2.205	2.219
Hydro (pumping excluded)	50	65	464
Wind power	240	410	725
Solar	0	0	0
Other renewables	390	672	1.731
Thermal power	6.181	6.133	5.425
TOTAL	8.753	9.487	10.565

Installed capacity by plant 2010 - 2020 (MWe)	POLAND		
	10	15	20
Nuclear energy	0	0	0
Hydro (pumping excluded)	918	994	1.075
Wind power	1.274	1.955	3.250
Solar	0	0	0
Other renewables	92	117	159
Thermal power	29.612	30.186	29.682
TOTAL	31.896	33.252	34.166

Installed capacity by plant 2010 - 2020 (MWe)	ROMANIA		
	10	15	20
Nuclear energy	1.300	1.311	2.021
Hydro (pumping excluded)	6.087	6.536	7.314
Wind power	479	1.803	3.146
Solar	0	0	0
Other renewables	22	26	31
Thermal power	9.166	9.717	9.666
TOTAL	17.054	19.393	22.178

Installed capacity by plant 2010 - 2020 (MWe)	SLOVAKIA		
	10	15	20
Nuclear energy	1.820	2.986	3.072
Hydro (pumping excluded)	1.612	1.732	1.812
Wind power	7	34	41
Solar	183	674	1.037

Other renewables (tidal etc.)	130	170	133
Thermal power	3.112	3.168	2.728
TOTAL	**6.864**	**8.764**	**8.823**

Installed capacity by plant 2010 - 2020 (MWe)	**SLOVENIA**		
	10	**15**	**20**
Nuclear energy	696	696	696
Hydro (pumping excluded)	883	921	1.006
Wind power	0	70	340
Solar	0	0	0
Other renewables (tidal etc.)	0	0	0
Thermal power	1.282	1.616	1.572
TOTAL	**2.681**	**3.303**	**3.614**

Figure 74: Net electricity generation by plant type (GWh) (2010-15-20) (Source: ENTSO-E (2010), PRIMES)[74]

Net Electricity generation by plant type (in GWh)	**AUSTRIA**		
	2010	**2015**	**2020**
Nuclear	0	0	0
Hydro (pumping excluded)	36.496	38.955	40.488
Wind	2.078	3.346	4.295
Solar	0	0	0
Other RES	0	0	0
Thermal	24.638	26.636	26.752
TOTAL	**63.212**	**68.937**	**71.535**

Net Electricity generation by plant type (in GWh)	**CROATIA**		
	2010	**2015**	**2020**
Nuclear	0	0	0
Hydro (pumping excluded)	7.681	5.796	6.289
Wind	164	1.555	2.680
Solar	3	15	81
Other RES	0	0	0
Thermal	4.808	5.060	9.055
TOTAL	**12.666**	**12.440**	**18.124**

[74] Data on wind generation in Austria is not available from ENTSO-E

Net Electricity generation by plant type (in GWh)	BULGARIA		
Nuclear	14.181	14.372	21.883
Hydro (pumping excluded)	5.431	5.499	5.570
Wind	331	970	1.582
Solar	0	0	0
Other renewables	0	0	0
Thermal	21.084	24.056	21.031
TOTAL	**41.027**	**44.896**	**50.066**

10.2.2.2. Net Electricity generation by plant type (in GWh)	**CROATIA**		
	2010	**2015**	**2020**
Nuclear	0	0	0
Hydro (pumping excluded)	7.681	5.796	6.289
Wind	164	1.555	2.680
Solar	3	15	81
Other RES	0	0	0
Thermal	4.808	5.060	9.055
TOTAL	**12.666**	**12.440**	**18.124**

Net Electricity generation by plant type (in GWh)	**CZ REP**		
	2010	**2015**	**2020**
Nuclear	26.441	26.441	26.441
Hydro (pumping excluded)	3.374	3.374	3.374
Wind	334	616	1.231
Solar	590	663	723
Other RES	-5	-6	-7
Thermal	48.705	55.768	48.919
TOTAL	**79.439**	**86.856**	**80.681**

Net Electricity generation by plant type (in GWh)	**GERMANY**		
Nuclear	133.373	103.954	35.081
Hydro (pumping excluded)	21.698	22.562	23.033
Wind	36.665	66.414	99.025
Solar	10.874	18.465	29.529
Other renewables	26.262	41.852	59.481
Thermal	344.278	336.568	340.505
TOTAL	**573.150**	**589.816**	**586.653**

Net Electricity generation by plant type (in GWh)	**HUNGARY**		
Nuclear	14.830	17.739	17.994
Hydro (pumping excluded)	181	296	1.281
Wind	503	871	1.541
Solar	0	0	0
Other renewables	1.764	3.108	8.898
Thermal	16.503	17.393	18.466
TOTAL	**33.781**	**39.406**	**48.182**

Net Electricity generation by plant type (in GWh)	**POLAND**		
Nuclear	0	0	0
Hydro (pumping excluded)	2.839	2.984	3.221
Wind	1.821	3.055	5.209
Solar	0	0	0
Other renewables	260	324	435
Thermal	140.270	149.626	150.519
TOTAL	**145.190**	**155.990**	**159.384**

Net Electricity generation by plant type (in GWh)	**ROMANIA**		
Nuclear	10.686	10.780	16.472
Hydro (pumping excluded)	20.174	23.224	26.748
Wind	290	1.099	2.017
Solar	0	0	0
Other renewables	112	136	163
Thermal	25.284	29.708	26.225
TOTAL	**56.546**	**64.946**	**71.625**

Net Electricity generation by plant type (in GWh)	**SLOVAKIA**		
	2010	**2015**	**2020**
Nuclear	13.576	22.274	22.915
Hydro (pumping excluded)	3.593	3.860	4.039
Wind	16	80	95
Solar	20	74	114
Other RES	1.025	1.344	1.047
Thermal	6.691	6.811	5.865
TOTAL	**24.921**	**34.443**	**34.075**

Net Electricity generation by plant type (in GWh)	**SLOVENIA**		
	2010	**2015**	**2020**
Nuclear	5.377	5.377	5.377
Hydro (pumping excluded)	4.249	4.446	4.687
Wind	0	128	622
Solar	0	0	0
Other RES	0	0	0
Thermal	4.794	6.035	6.978
TOTAL	**14.420**	**15.986**	**17.664**

10.2.3. Energy balances and exchanges

Figure 75: KEMA / ICL interconnection capacity (2020)

KEMA / ICL study does not include Croatia.

	From:	DE	AT	SL	PL	CZ	SK	HU	RO	HR	BG
To:											
DE			-		-	900					
AT		-		-		800		100			
SL			-							-	
PL		-				-	300				
CZ		-	800		200		- 200				
SK					200	- 500		800			
HU			- 60				750		400	-	
RO								100			-
HR				-				-			
BG									-		

10.2.4. Generation costs

Figure 76: Average production costs in power generation (Euro '05 per MWh)

Source: PRIMES model

Average production costs in power generation	2010	2015	2020
AUSTRIA	59	66	70
GERMANY	55	65	73
HUNGARY	54	57	61
SLOVENIA	52	60	68
SLOVAKIA	42	50	53
CZ REP	40	46	51
ROMANIA	32	41	51
BULGARIA	31	40	47
POLAND	29	38	50

11. Appendix II: Comparison between Primes and ENTSO-E data

The tables below compare the annual consumption, generation and capacity forecast data for 2010 included in the Primes database with the data from ENTSOE that has been used for the purposes of the stocktaking document.

11.1. Assumptions

GDP – Since the PRIMES model was produced in 2009 it would be reasonable to assume that GDP forecasts for the short/medium term (2015) would have reduced, with a resulting impact on consumption and therefore also generation, within the study area. The consumption data provided here for 2015 and 2020 may therefore be viewed as a “high scenario”

Renewables – in several countries (Austria, Germany, Hungary, Poland) the 2010 installed capacity of renewables was 20-25% higher (Hungary 60%) than the PRIMES 2010 data. In these cases it is likely that the growth rates for renewable capacity would be lower than forecast, since some of the capacity investments have been brought forward, e.g. due to market incentive mechanisms. For this reason we would consider the data for renewable capacity for 2015 and 2020 as a “high scenario”.

11.2. Consumption

Annual consumption 2010 (GWh)	PRIMES	ENTSOE	Change	% Change
Austria	66.770	67.324	554	0,83%
Bulgaria	35.509	31.537	-3.972	-11,19%
Cz Rep	70.794	64.015	-6.779	-9,58%
Germany	615.153	548.219	-66.934	-10,88%
Hungary	42.297	38.976	-3.321	-7,85%
Poland	155.843	143.564	-12.279	-7,88%
Romania	57.481	53.362	-4.119	-7,17%
Slovakia[75]	30.012	26.636	-3.376	-11,25%
Slovenia	15.511	12.248	-3.263	-21,04%
Total consumption 2010	**1.089.370**	**985.881**	**-103.489**	**-9,50%**

The ENTSOE actual data for consumption in 2010 for the area under consideration is c/ 103GW (9,5%) lower than the Primes data (which was used to calculate the growth rates up to 2020).

There are some differences in the definition of consumption used by the two sources, as the dataset used from Primes is for “Final Energy Demand”, which excludes Energy Branch consumption (i.e. own consumption and pumping) and transmission and distribution losses. Instead ENTSO-E define consumption as “net electricity consumption including network losses without consumption for

[75] Note that for Slovakia data provided by the national TSO has been used for the purposes of the analysis included in this document

pumped storage". This would suggest that if network losses were excluded from the ENTSO-E consumption data, the values would be more than 10% lower than the Primes consumption projections for 2010.

11.3. Capacity

Capacity 2010 (MW) [76]	PRIMES	ENTSOE	Change	% Change
Austria	16.863	21.085	4.222	25,04%
Bulgaria	9.634	11.134	1.500	15,57%
Cz Rep	14.760	17.791	3.031	20,53%
Germany	141.003	147.700	6.697	4,75%
Hungary	9.385	8.753	-632	-6,74%
Poland	32.481	31.896	-585	-1,80%
Romania	20.396	17.054	-3.342	-16,39%
Slovakia	6.628	7.055	427	6,45%
Slovenia	3.284	2.861	-423	-12,89%
Total Capacity 2010	**254.434**	**265.329**	**10.895**	**4,28%**

ENTSO-E outturn capacity in 2010 was 4% higher than the forecast capacity in the Primes data. Significant changes were observed in Austria, were capacity was 25% higher than the forecast capacity from Primes (largely driven by higher capacity for hydro in the ENTSOE data). For Czech Republic, actual ENTSOE capacity for 2010 was 21% higher than Primes capacity, largely driven by higher capacity for solar and fossil fuels/thermal power. 2010 capacity for Romania and Slovenia was lower than estimated in the Primes data. This was driven in both cases by a reduction in thermal power.

11.4. Generation

Generation 2010 (GWh)[77]	PRIMES	ENTSOE	Change	% Change
Austria	59.914	61.134	1.220	2,04%
Bulgaria	36.459	41.027	4.568	12,53%
Cz Rep	74.615	78.851	4.236	5,68%
Germany	593.568	573.150	-20.418	-3,44%
Hungary	35.608	33.781	-1.827	-5,13%
Poland	148.627	145.190	-3.437	-2,31%
Romania	57.668	56.546	-1.122	-1,95%
Slovakia	30.026	25.193	-4.833	-16,10%
Slovenia	15.230	14.420	-810	-5,32%
Total Generation 2010	**1.051.714**	**1.029.292**	**-22.422**	**-2,13%**

Overall, Generation in 2010 as outlined in the ENTSO-E data was broadly in line with the Primes forecast, with a difference of 22 TWh (c. 2%) between the two datasets. The most significant difference was observed in Slovakia, where the ENTSOE data for generation in 2010 was 16% lower than the PRIMES estimate. This was largely driven by a significant difference in the estimate for

[76] Note that the TSOs of Czech Republic and Slovakia have provided updated capacity data, which has been used for the purposes of this document
[77] Note that the TSOs of Czech Republic, Slovakia and Austria have provided updated generation data, which has been used for the purposes of this document

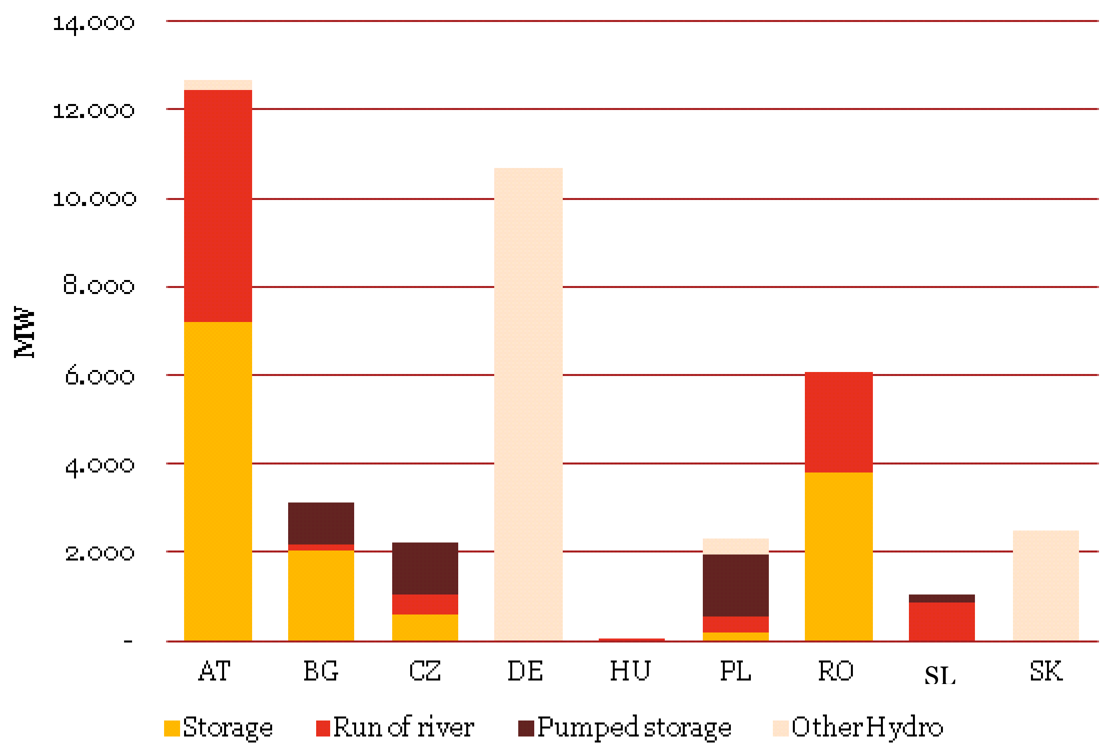
thermal generation (with an estimate of 12 TWh in the PRIMES dataset vs an observation of 5,6 TWh in ENTSO-E) which was only partially offset by higher estimates of generation for nuclear and renewable generation. A small part of this difference may be driven by different categorisation of thermal power, since the data used in reference to thermal power from ENTSOE referred only to generation from fossil fuels, while thermal generation within PRIMES data included elements such as biomass, fuel cells and geothermal heat. However, these elements constitute only a small part of overall thermal generation, therefore a significant difference between the two datasets remains.

In the case of Bulgaria, the ENTSOE actual data on generation was 12,5% higher than the Primes 2010 forecast. This was largely driven by increases in generation from thermal power and hydro, which were only partially offset by the reduction in wind generation.

11.5. Hydro

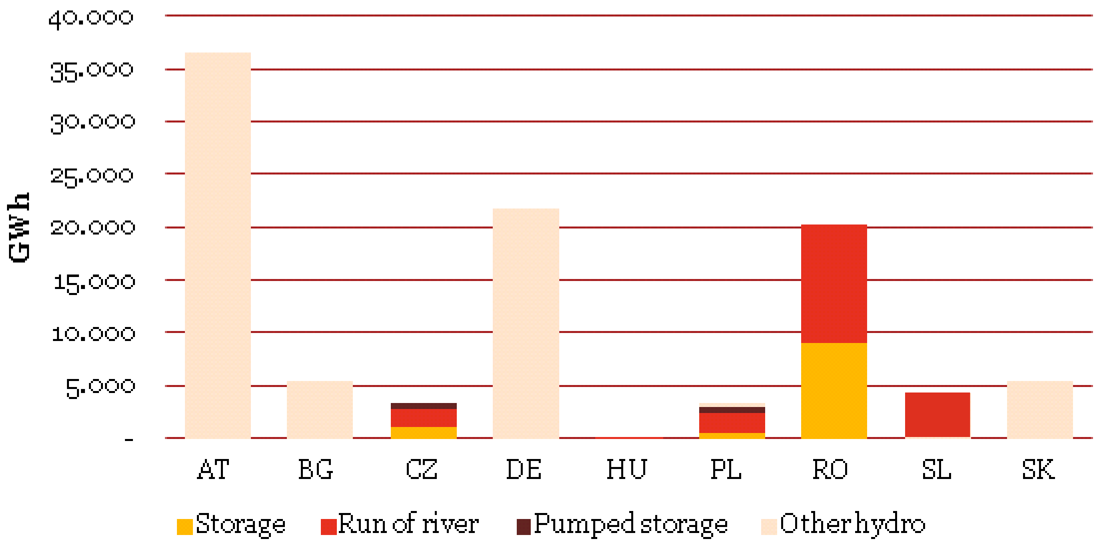
The charts below outline in more detail the components of hydro generation and capacity for the countries considered in 2010, based on ENTSO-E data. This provides a full picture of hydro, as, in relation to capacity and generation from hydro analysed in this document, when available we have excluded pumped storage, in order to ensure consistency with the Primes approach.

Figure 77: Hydro net generating capacity 2010 (MW)



Source: ENTSO-E

Figure 78: Hydro generation by country 2010 (GWh)



Source: ENTSO-E

Note: In relation to both charts, “other hydro” has been calculated as the difference between total hydro and the individual components as specified in ENTSO-E data. In addition, when a breakdown for hydro capacity or generation was not provided, the data was labelled as “other hydro”

12. Appendix III –Assessment outcomes: projects of regional interest

A short description of each of the proposed regional priority projects is provided below – based information drawn directly from the project fiches submitted by TSOs. The TSO's own project identifier is shown in square brackets.

Austria:

- Enhancement of interconnection (Austria-Germany), including new 400 kV double circuit OHL St. Peter (Austria) - Isar (Germany), installation of the 4th circuit Isar - Ottenhofen and 400 kV switchgears in Altheim, Simbach and St. Peter, as well as 3 transformers – strengthens the connection between Austria and Germany and therefore has a positive impact on the interaction between RES production and pumped storages in both countries [AT St Peter (AT) - Isar (DE)_HK]
- Upgrade of existing OHL St.Peter- Ernsthofen (Austria) – an important step to achieve the 380kV-ring structure which will be the backbone of the Austrian transmission grid; strengthens west-east connection in Austria and increases transport capacity of surplus wind generation towards pump storage plant [AT St Peter-Ernsthofen_gu]
- New double circuit OHL St.Peter-Tauern, (380-kV-Salzburgleitung line) including new substations, dismounting of 220kV and 110kV-lines and extensive entrainment of 110kV-lines – improves security of supply on regional and national level, enables integration of planned hydro pumped storage plants and Combined Cycle Power Plants [AT St Peter-Tauern_HK]
- Additional two 380kV-circuits on existing towers to strengthen the north-south connection around Vienna as well as for the integration of wind power plants in the east of Austria [AT Duernrohr-Sarasdorf_gu]

Bulgaria:

- New OHL from substation Dobrudja to substation Bourgas – increases transfer capacity in the region, enhances the security of supply in maintenance schemes and favours RES integration [BG project Bourgas – Dobrudja]

Croatia:

- New double circuit OHL connecting new 400 kV switchyard (new 500 MW unit in existing TPP Plomin, with new transformer 400/220 kV, 400 MVA) and existing substation 400/220/110 kV Meline – facilitates conventional generation integration and increase the security of supply [OHL 400 kV TPP Plomin-Melina]

Czech Republic:

- New double circuit OHL interconnector Vitkov-Mechlenreuth (Germany); new double circuit OHL Vernerov-Vitkov; new double circuit OHL Prestice-Vitkov; strengthen OHL Kocin-Prestice; new double circuit OHL Kocin-Mirovka; strengthen OHL Mirovka-Cebin; new OHL between substation Mirovka and line V413 new substation Vitkov; new substation Vernerov – to accommodate crossborder flows in north-south direction and connect wind farms directly to CEPS grid in this region; potential to connect storage hydro power plant Sumny Dul (in

preparation)
[Cluster North South[78]: Vit; VIT_MECH; PRE_VIT; KOC_PRE; KOC_MIR; MIR_CEB; MIR_V413; VER_VIT; VER]

- Network strengthening in western and central area: strengthen OHL Babylon-Vyskov; strengthen OHL Babylon-Bezdecin; new OHL Vyskov-Reporyje; strengthen OHL Hradec-Reporyje; strengthening of OHL Vyskov-Cechy Stred –reduces infrastructure vulnerability and ensures security of supply; secures sufficient transmission capacity for energy sources connections in the region [Cluster NW DE CZ: BAB_VYS; BAB_BEZ; VYS_REP; HRA_REP; VYS_CST]
- Strengthening of OHL Tynec-Krasikov and OHL Cechy Stred-Chodov– to secure sufficient transmission capacity for energy sources connections in the region and reduce infrastructure vulnerability [Cluster West East Industry: TYN_KRA; CST-CHD]
- Strengthening of substation Kocin to develop sufficient transmission capacity for energy sources connections in the region – increases market competition, reduces infrastructure vulnerability, secures reliable grid operation and security of supply. [CZ KOC]
- Strengthening of substation Mirovka to develop sufficient transmission capacity for energy sources connections in the region – increases market competition, reduces infrastructure vulnerability, secures reliable grid operation and security of supply. [CZ MIR]
- Strengthening of OHL Prosenice-Kletne – reduces infrastructure vulnerability, secures reliable grid operation and security of supply, secures sufficient transmission capacity for energy sources connections in the region. [CZ PRN-KLT]

Germany:

- Interconnector (Germany-Poland): 3rd 400kV double circuit OHL interconnection between Poland (Plewiska) and Germany (Eisenhüttenstadt) with reinforcement of the Polish internal grid; upgrade of existing line Krajnik (PSE Operator)-Vierraden (50Hertz Transmission) – improves security of supply, increases power exchange capacity between PL and DE, supports RES integration. Expected to decrease the loop flow from DE to PL and to CZ/SK [DE-50 Cluster 136]
  [DE 380-kV-interconnector Eisenhüttenstadt-Plewiska; DE 380-kV-interconnector Vierraden-Krajnik]
- Increase of interconnection capacity between CEPS and 50Hertz Transmission: (currently under consideration)either a new 400kV tie-line (OHL on new route) or a reinforcement of the existing 400kV tie-line Hradec (CEPS) – Röhrsdorf (50Hertz Transmission 50 km). Should be considered to avoid overloading of neighbouring grids esp. in high wind situations – expected to maintain / improve security of supply, support RES integration and CCE Market development
  [DE 380-kV-enhancement of interconnector to CEPS]
- New 400 kV double OHL Isar (Germany) - St. Peter (Austria) including 4 circuit Isar - Ottenhofen and 400 kV switchgears Altheim, Simbach and St. Peter and 3 transformer – strengthens connection between Austria and Germany and therefore has a positive impact on the interaction between RES production and pumped storages in both countries [DE project fiche Isar-St Peter]
- Grid enhancement – supports RES and conventional generation integration in Germany, security of supply and market development; avoids loop flows through neighbouring grids [DE-50 Cluster 50]

[78] This cross-border interconnection is currently under consideration.

- New 380kV double-circuit OHL between the substations Vieselbach-Altenfeld-Redwitz combined with upgrade between Redwitz and Grafenrheinfeld (partly already commissioned)
  [DE 380-kV-connection Halle(Saale)-Schweinfurt (Südwestkuppelleitung)]
- New 380kV double-circuit OHL from the Northern part of the 50Hertz Transmission control area to the South-Western part of the 50HzT control area with considered further extension to South-Western part of Germany [DE 380-kV-grid enhancement and structural change Lubmin-Wolmirstedt]
- Southern Uckermark – new 380kV double-circuit OHL Neuenhagen-Vierraden-Bertikow as prerequisite for the planned upgrading of the existing 220kV double-circuit interconnection Krajnik (PL) – Vierraden (DE)
  [DE 380-kV-grid enhancement Southern Uckermark (Uckermarkleitung)]
- South-east – upgrade of several existing double-circuit 380kV OHLs [DE 380-kV-grid enhancement South-East]
- Western Pommerania-Northern Uckermark – construction of new 380kV double-circuit OHLs and decommissioning of existing old 220kV double-circuit OHLs
  [DE 380-kV-grid enhancement Western Pommerania-Northern Uckermark]
- South-west – construction of 2 x new double-circuit OHL; 3 x upgrading of existing double-circuit OHL
  [DE 380-kV-South-Western grid enhancement]
- Northern Berlin – construction of new 380kV double-circuit OHL between the substations Wustermark-Neuenhagen [DE 380-kV-grid enhancement Northern Berlin]
- Saxony – upgrade of the existing -circuit 220 kV to 380kV OHL; construction of new 380kV double-circuit OHLs; double connection/loop in for substations [DE 380-kV-grid enhancement Saxony (South-Western)]
- Förderstedt – construction of new OHL, double connection / loop in for Förderstedt and reinforcement of existing switchgear [DE 380-kV-South West grid enhancement Förderstedt]
- South and west – construction of new 380kV substation in Southern Magdeburg area and decommissioning of existing old 220kV equipment; construction of new 380kV double-circuit OHL and double connection/loop in for Förderstedt; reinforcement of existing switchgear; upgrading of the existing double-circuit 380kV OHL; construction of new 380kV double-circuit OHL [DE 380-kV-grid enhancement Southern and Western area of Magdeburg]
- Construction of new reactive power compensation devices in two stages (mid-term and long-term) – supports RES in North-Eastern Germany, maintains security of supply and supports market development; enables long distance transport of RES by keeping up the voltage limits under heavy grid conditions [DE reactive power compensation devices]
- Construction and extension of new 380kV/110kV substations – supports RES integration in Germany and maintains of security of supply [DE 380-kV-substations long term; DE 380-kV-substations mid and short term]
- Offshore wind farm connection project (by AC-cables on transmission voltage level or by clustering with DC connections) – supports RES integration in German part of the Baltic sea [DE OWP Region East; DE OWP Region West.]

- Construction of new substations / lines / extension / reinforcement of devices for integration of planned and/or newly build power plants in northern, central and eastern part of 50HzT control area. Support of conventional generation integration maintaining of security of supply and support of market development, grid access for new market participants [DE connection of new powerplants in 50HzT north, middle and south]
- New 380-kV-OHL between Lower Saxony and Hessen in Germany including two new substations and three transformers – necessary to ensure the transportation of the increasing RES generation in northern Germany (onshore and offshore) and increasing transits from Scandinavia to the Alp region (AT, CH, IT) [DE project fiche Wahle-Mecklar]

Hungary:

- New OHL between North-east Hungary (HU) and Vel'ké Kapusany (SK) – enhances operational network security, market integration and / or competition [HU 53]

Poland:

- Third connection between Germany and Poland, new 2x400 kV OHL together with other necessary investment in the area – increases market integration between member states (additional NTC of 1500 import and 500 MW export on PL-DE/SK/CZ synchronous profile); allows wind integration planned to be installed in Poland and Germany; and improves network security [G-P Power]
- Installation of PSTs on two existing lines on PL/DE border together with necessary investments – expected to decrease loop flows between Germany to Poland, Poland to Czech Republic and Poland to Slovakia; expected to increase security of supply in the region due to enhanced control of power flow ; enhances RES integration in Poland and northern Germany [G-P Improve]
- New AC substation in Northern Poland x4, connected by splitting and extending of existing 400kV line and new 800kV and 400kVOHL interconnection lines; Construction of a new 400kV OHL x 3; new AC 400kV switchgear in existing substation and upgrade of substations - facilitates two corridors in the north-south direction that will be utilized for evacuation of power from existing (in Germany) and planned (Germany and Poland) off-shore wind farms; increase of cross border (existing Poland – Sweden DC connection) capabilities; facilitates the connection of 5000 MW of RES generation (wind) and 2900 MW of conventional generation; contributes to increase of security of supply. [Wind Integration]
- Set of high voltage investments allowing connection of new conventional generation for the supply of Wrocław agglomeration area including new 400kV OHL double circuit line; upgrade and extension of 400 kV switchgear in substation Dobrzeń – allows export of energy to Czech Republic; facilitate evacuation of new RES (150 MW wind farm); contributes to enhancement in maintaining security of supply for the Wrocław agglomeration area (strengthening the internal network), as well as lower Silesian region bordering with Czech Republic [Power DBN]
- Set of high voltage investments allowing connection of new conventional generation for the supply of Warsaw agglomeration area including new 400kV OHL double circuit line; upgrade and extension of 400 kV switchgear for the connection of new line; replacement of conductors on existing 2x220 kV OHL – facilitates connection of planned conventional unit (1000 MW) in Kozienice which is anticipated to export power to the Baltic states; has positive impact on energy efficiency; strengthens internal network and improving security of supply for Warsaw agglomeration area [Power Koz]
- New 400kV double circuit OHL line to replace existing 220kV line – faciliates planned conventional unit (1000 MW) in Ostrołęka power planned which is anticipated to export power to the Baltic states; allows evacuation of RES (wind) generation from the area of northern Poland; contributes to increase of the safety and reliability of network operation; ; has positive

impact on energy efficiency; contributes to increase of the safety and reliability of network operation
[Power OST]

Romania:

- Network reinforcement – increases grid capacity to transfer power between Romania and other SE European countries; allows load balancing of Moldova area; facilitates connection of planned nuclear (Cernavoda) and conventional generation; allows integration of wind generation and better control of loop flows through Bulgaria caused by wind generation connected in the area [RO_East_RES]
  - connection of 400 kV OHLs Isaccea (RO) - Varna (BG) and Isaccea (RO) - Dobrudja (BG) in substation Medgidia S (RO);
  - new 400 kV double circuit OHL (1 circuit equiped) Gutinas-Smardan
  - new 400 kV OHL Cernavoda-Stalpu double circuit
  - upgrade to 400 kV of the existing single circuit and new 400 kV substations
  - new 400 KV double circuit OHL (1 circuit equiped) Medgidia S – Constanta N
  - new 400 KV OHL Gădălin – Suceava
  - upgrade of 220 kV axis Stejaru-Gheorghieni-Fantanele – necessary for RES integration in the region
- Network reinforcement – increases NTC and favours RES integration in the region; alleviates loop flows through Bulgaria and Hungary [RO-Western_Border]
  - New 400 kV overhead line Portile de Fier - Resita s.c., new / extended / rehabilitated substations
  - Upgrade of the 220 kV d.c. line Resita-Timisoara-Sacalaz and new / extended substations
- Connection of storage: new 400 kV substation Tarnita, where the pumped storage hydro power plant shall be connected (1000MW); new 400 kV OHL Tarnita - Cluj Gadalin ; new 400 kV OHL Tarnita – Mintia – supplies reserve/balancing services for Romania and possibly for neighboring countries (Hungary, Serbia); supports integration of important amounts of wind generation in Romania and neighboring countries and of intended nuclear units in Romania [RO_Tarnita Storage].

Slovenia:

- Double circuit 400 kV OHL Cirkovce-Pince (Heviz/Žerjavinec) presents new interconnection line with Hungary and Croatia
  [SL electricity ELES_CIR-PIN]
- Double circuit 400 kV OHL Beričevo-Krško and internal 400 kV transmission loop – increases level of safe and reliable operation, reduces losses, increases transmission capacity between eastern and western areas (especially Italy) and facilitates market integration
  [SL electricity ELES_BER-KK]
- Upgrade of internal 220 kV network to 400 kV voltage level (Divača-Kleče-Beričevo-Podlog-Cirkovce) represents the reconstruction and upgrading of infrastructure and increased transmission capacity of 1.330 MW – integration of on- and off-shore wind, security of supply and market integration in central and SE Europe
  [SL electricity ELES_Prehod]

Slovakia / Hungary (joint submission):

- Reinforcement of the Slovak-Hungarian profile establishing two interconnections and associated internal developments including:
  - double line between Gabčíkovo substation in Slovakia and Gönyű substation on Hungarian side and
  - connection of the two existing substations Rimavská Sobota and Sajóivánka with a single line.
  - new internal lines on the Slovak territory: new double line between substations Gabčíkovo and Veľký Ďur with equipment; and new single line between Veľký Ďur and Levice substations
  - new equipments on the Hungarian territory: Győr substation, adding the third 400/120 kV 250 MVA transformer; and Sajóivánka substation, adding the second 400/120 kV 250 MVA transformer and two tertiary shunt reactors.

  Provides benefits for the two countries and region in terms of improved security of supply, increased NTC to facilitate transits of power flows in N-S direction, removal of bottleneck in the continental central-east region and enhanced (n-1) reliability criterion.
  [SK / HU Reinforcement of the Slovak-Hungarian profile]

pwc