Multiple Framework Service Contract

TREN/R1/350-2008 lot 2

Market analysis and priorities for future development of the gas market and infrastructure in Central-Eastern Europe under the North-South Energy Interconnections initiative (Lot 2)

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ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
AHP	Analytic Hierarchy Process
CBA	Cost-Benefit Analysis
CCGT	Combined Cycle Gas Turbine
CEE	Central-Eastern Europe
CEER	Council of European Energy Regulators
CHP	Combined Heat and Power
DG ENER	Directorate-General for Energy of the European Commission
DHPs	District Heating Plants
EC	European Commission
EIB	European Investment Bank
EIP	Energy Infrastructure Package
ENTSO	European Network of TSOs
ENTSOe	European Network of TSOs for electricity
ENTSOg	European Network of TSOs for gas
EU	European Union
EWG	(The North-South Interconnections) Electricity Working Group
FID	Final Investment Decision
GDP	Gross Domestic Product
GWG	(The North-South Interconnections) Gas Working Group
H-H	Households
HHI	Herfindahl-Hirschman Index
IAP	Ionian-Adriatic Pipeline
IEM	Internal Energy Market
IFIs	International Financial Institutions
IGB	Interconnector Greece-Bulgaria
IMF	International Monetary Fund
ITB	Interconnector Turkey-Bulgaria
LGTT	Loan Guarantee Instrument for Trans-European Transport Network projects
LNG	Liquefied Natural Gas
MCA	Multi-Criteria Analysis
PPP	Public-Private Partnership
RES	Renewable Energy Sources
TEN	Trans-European Networks
TEN-E	Trans-European Energy Networks
TEN-T	Trans-European Transport Networks
ToR	Terms of Reference
TPP	Thermal Power Plant
TSOs	Transmission System Operators
TYNDP	Ten-Year Netowrk Development Plan (produced by ENSTOg)

EXECUTIVE SUMMARY

1. INTRODUCTION

1.1 Project objectives

1.1.1 Background to the commissioning of the present study

In November 2010, the European Commission (EC) adopted the "Energy Infrastructure Package" (EIP), which is intended to form a new blueprint for the strategic planning of key energy infrastructure at a supranational level within Europe and in its 'neighbourhood'. The EIP seeks to coordinate, facilitate and optimise the development of networks in support of the "Energy Policy for Europe", and is also seen as a mechanism for overcoming identified impediments to the financing and implementation of infrastructure projects. More specifically, the EIP sets out a new method for planning and developing infrastructure projects entailing the following steps:

- The specification of a limited number of European priorities, which must be implemented by 2020 to meet the EU's long term policy objectives and for which European action is warranted;
- The identification of specific "projects of European interest" necessary to implement these priorities, using a transparent and agreed methodology; and
- The adoption and employment of new tools for implementing the projects, such as improved regional cooperation, more streamlined and efficient permit procedures, and innovative financial instruments.

Consistent with the foregoing, the EIP identifies certain priority corridors, which in the case of gas includes linking the Baltic, Black, Adriatic and Aegean Seas. The development of north-south interconnections in Central-Eastern and South-Eastern Europe forms an important element of this corridor. Moreover, the EC commissioned a "High Level Group" based on the cooperation of the countries in Central-Eastern Europe (CEE) with the mandate to devise an action plan for the development of interconnections in gas, electricity and oil by the end of 2011.

The High Level Group on north-south interconnections, which is chaired by the EC, includes Bulgaria, the Czech Republic, Hungary, Poland, Romania and Slovakia as members, and Croatia as an observer. Since commencing this study, Austria, Germany and Slovenia have also become members of this group. The High Level Group in turn established a "working group on natural gas" (GWG) consisting of representatives of the relevant ministries, regulatory authorities and transmission system operators (TSOs) in the participating countries. [1]

[1] With the exception of Austria and Germany, which only participate in the electricity working group (and not to the GWG).

The purpose of the present assignment (which was chiefly carried out during the June - October 2011 period) was to assist the EC in guiding the deliberations of the GWG through the preparation of a study that:

- Analyses planned gas infrastructure projects (interconnections, storage facilities and LNG regasification terminals) in the region covered by the north-south initiative and assesses the degree to which they contribute to the objectives of the EIP initiative;
- Specifies potential future priority projects based on security of supply and market integration considerations; and
- Identifies the obstacles to implementing these priorities.

1.1.2 Our understanding of the study objectives and issues

A key objective for the present study was to **translate the principles enunciated in the EIP into a methodology and framework for selecting priority projects** among the total planned infrastructure options, given expected future developments in demand, supply and transit. In this context, the following elements were viewed as important and to a large degree dictated the approach applied for screening potential infrastructure projects:

- **Satisfaction of future demand** – before examining other considerations, it was firstly necessary to identify the infrastructure expansions (if any) required to meet demand within the region of study and for each country, and to simultaneously ensure that required transit flows (to meet demand in adjacent regions) are not jeopardised;
- **Promotion of security and continuity of supply** – even if market demand under 'normal' conditions (including expected seasonal fluctuations) is met, infrastructure options that guarantee gas supply under all reasonable conditions (including extreme weather) notwithstanding the failure of another major system component must be identified;
- **Promotion of market integration and competition** – the screening and prioritisation of projects must also consider their impact on competition. An important factor in this context (and also for security of supply) will be the impact that planned projects have on the **diversification of gas supplies**, especially if they provide a physical connection to gas sources that are currently absent in the relevant CEE markets.

The transformation of the above infrastructure assessment elements into quantifiable and independent sets of criteria and sub-criteria, as well as the definition of their relevant importance were topics of considerable discussion and consultation with the Commission and the GWG.

2. SCOPE OF WORK

The study was structured around five discrete but inter-dependent tasks as follows:

- **Regional market analysis (Task 1)** - the purpose of this task was to determine the demand or import requirements of the specified CEE countries and the region as a whole for the period to 2020/2030, and also the required transit flows to meet demand in downstream markets.
- **Identification of planned infrastructure options (Task 2)** - the purpose of this task was primarily to document all the relevant gas infrastructure development projects, including investments in (cross-border) interconnections, reverse flow projects, storage facilities and LNG terminals. This list of projects was incorporated in the assessment and modelling work in the next task to identify those projects that are needed to overcome constraints or bottlenecks in the system, or more generally which satisfy the selection/prioritisation criteria that were adopted for evaluating the projects.
- **Assessment of planned gas infrastructure projects (Task 3)** - the purpose of this task was to assess the currently planned gas infrastructure projects and determine a priority listing of the projects in accordance with EIP principles. A project was generally considered a high priority if it satisfied a number of requirements - it should help meet 'indigenous' demand and facilitate the transit of required gas volumes to neighbouring markets, and/or provide greater security or continuity of supply, and/or promote regional market integration.
- **Identification and assessment of implementation obstacles (Task 4)** - having determined the priority infrastructure projects, the purpose of this task was to identify and assess any barriers to their timely realisation. The obstacles examined as part of this task fell within the following three categories: procedural / permitting, regulatory and financial.
- **Specification of actions to overcome identified obstacles (Task 5)** - the final project task entailed the preparation of a set of recommendations to address the obstacles and potential project implementation difficulties identified in the previous task.

3. DESCRIPTION OF KEY METHODOLOGICAL MATTERS

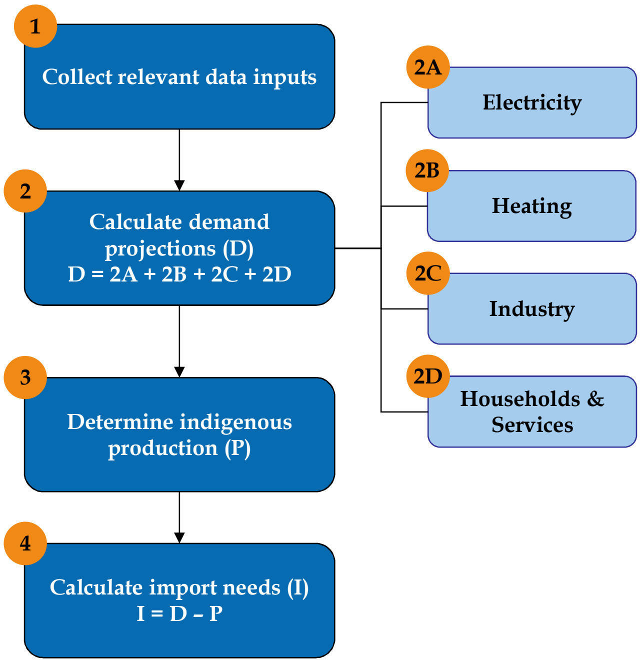
The key methodological issues that needed to be addressed during the study were the derivation of forecasts for gas demand and transit volumes, and the approach to assessing and prioritising the proposed infrastructure projects.

3.1.2 Calculation of demand in the CEE countries

Overall framework

Our demand projections entailed a 'bottom-up' approach, which attempted to build up the forecasts on the basis of demand estimates for each significant gas consuming sector – electricity, heating, industry, and households and services. The overall framework is depicted in Figure E1 below.

Figure E1: Broad framework for determining the gas demand and import requirements of the CEE countries



As part of step 1, we scoured the various available data sources, with a view to minimising data requests and using common sources for each of the relevant countries to the extent that this was possible. We also issued a short questionnaire to the GWG members (see Annex 10), and received responses from Bulgaria, the Czech Republic, Hungary and Poland.

Our main data sources for the demand projections are Eurostat (for historical data), ENTSOe and the answers to questionnaires (wherever received) for planned power generation plants, and the IMF for GDP forecasts.

In step 2, we calculated our demand forecasts employing the approach described below for each of the respective main gas consuming sectors. In order to determine the import needs of the CEE region (step 4), one also needs to deduct indigenous production. For this purpose, we used the production forecasts to 2020 developed by the GWG, with appropriate assumptions for the post-2020 period.

Electricity sector

For the short-run period (defined to be up to 2017), we examined the gas-fired power plant projects that are currently being built or planned, and determined the equivalent gas demand deriving from their operation with different load factors. For the longer term, we calculated high-level electricity consumption forecasts and on the basis of assumed peak load factors determined generation capacity requirements and determined whether further capacity additions of gas-fired generation are likely to be needed.

Heating sector

Gas demand forecasts for the heating sector were calculated in three main steps. Initially, estimates were derived for heat output (consumption plus losses) – we generally assumed that heat output will remain constant at current levels as slight increases in consumption are expected to be counterbalanced by efficiency improvements within the heat distribution systems. Having estimated future heat output for each country, the next step entailed the determination of the portion of heat production that will be met by gas-only district heating plants (DHPs). In the final step, the assumed heat output was converted to equivalent gas demand by applying the historical efficiency factors for gas DHPs in each of the countries.

Industry sector

The methodology used to calculate the gas consumption forecasts for industry in the CEE region (excepting Croatia) was the following:

- For every gas consuming industry sector we ran regressions to establish the relationship between industrial output for each sector and GDP growth rates.
- On the basis of the above derived equations and forecasts of GDP growth rates we developed projections of future industrial output or production.
- In order to determine the equivalent gas demand associated with the forecasted industrial output, we assumed gas intensity factors for each sector that are equal to the average of the three-year period 2005-2008.
- To arrive at the final gas consumption figures we also applied efficiency factors to take into account the possibilities and likelihood of further efficiencies that can be achieved in industrial processes.
- Finally, with the exception of Poland (which did not experience economic recession and industrial production seems to have held up), we assumed that there will be an element of demand destruction in all other countries.

In the case of Croatia, we did not have data for industrial production and were therefore unable to apply the above methodology. Hence, we assumed instead that consumption in industry would return to pre-crisis (2008) levels by 2014, consistent with predictions for GDP growth, and that gas consumption would increase thereafter at an annual rate of 2%.

Households and services

For all countries except Bulgaria (where gas use in the residential sector is limited) and Hungary, we applied benchmark annual growth rates for household consumption of 0.8%, 0.5% and 0.2% for the maximum, base and minimum scenario, respectively. These low growth rates reflect the fact that most markets are mature and that with future energy savings, there is expected to be limited demand growth. Given the feedback we received, in the case of Hungary we have assumed that under the maximum scenario consumption will remain at current levels, while under the other two scenarios household consumption will *decrease* annually by 2% and 3% for the first 10 years and remain constant thereafter. The approach used for Bulgaria was different, as gas use is currently very limited, although there are plans for developing gas distribution networks. We therefore employ assumptions about the rate of gasification and customer penetration in the newly gasified regions.

Having calculated household consumption, we then derived consumption for the services sector by assumption. Specifically, we assumed that consumption in the commercial sector as a proportion of total demand for the household/services sector would remain constant at historical levels.

3.1.3 Calculation of gas volumes to be transited through the CEE region

In addition to the demand and import requirements of the CEE countries, it is also important to ensure that there is sufficient infrastructure capacity in the region to support the continued transit of gas to downstream markets. The relevant countries and the assumptions we used for each regarding the required transit flows through the CEE region are presented in Table E1 below.

Table E1: Assumed transit flow requirements for each downstream market

Country	Share/volume of import needs transited through the CEE region	Comments
Bosnia and Herzegovina **FYR of Macedonia** **Serbia**	100%	All these countries will be supplied either through existing routes or the Southern corridor (whether through IGB, ITB, IAP or Nabucco) most of which necessitate transit through the region*
Greece **Austria** **Netherlands** **Switzerland** **Turkey**	80% of the current contract volumes for supply of Russian gas for the base case; +/- 10% for the min. and max. scenarios, respectively	All of these markets are characterised by diversified supply sources and entry points. We therefore assume that for reasons of diversification and security of supply they will not seek to increase the absolute volumes of gas sourced from Russia and transited through the CEE region. In the case of Turkey, we only use the contract for supplies through the Trans-Balkan route (which runs through Romania and Bulgaria).
Lithuania	80% of the PL-LT interconnection maximum capacity; +/- 10% for the min. and max. scenarios, respectively	We assume that: (i) the PL-LT interconnection will be constructed and operational from 2017, and (ii) its maximum capacity will be 3 bcm
Italy **France** **Germany**	80% of the current contract volumes and, after these expire, of the expected volumes in future contracts+ for the base case; +/- 10% for the min. and max. scenarios, respectively	In the case of France and Germany we assume 50% of their Russian imports will come through Nord Stream from 2013, thus, correspondingly reducing transit flows through the CEE region. Furthermore, in the case of Germany we assume that 50% of the transit requirements pass through the Yamal pipeline#.

* We note that an exception to this is IAP, which would supply BiH without requiring transit in the CEE region. When the IAP pipeline is assessed/added to the gas flow model we deduct 0.5 bcm from the transit needed for BiH. We also assume that there will not be a direct interconnection between Greece and FYROM.

+ The evolution of Russian contracts for these countries was provided by Booz&Co.

This distinction for the Yamal pipeline is made because we only take into consideration its off-takes to the Polish market when examining the CEE gas system.

3.1.4 Peak demand

To identify potential bottlenecks in the CEE system caused by daily peaks, we derived projections for the daily peak demand of both the CEE countries and the downstream markets. Calculation of the peak demand for the CEE countries was based on our annual demand projections (base scenario) and the estimations of ENTSOg, published in the Ten-Year Network Development Plan 2011 – 2020. More particularly, for the period 2011-2020, we apply a peak load factor (specific for each country and year) to our annual projections; the peak load factor is derived by taking the ENTSOg annual demand projections and dividing them by the ENTSOg "high daily demand" (1-in-20 conditions). For the period 2021-2030, we use the average peak load factor of the 2011-2020 period for each country.

In the case of the downstream markets, we assume that they will not experience a simultaneous peak demand day with the CEE countries. Rather, the daily gas requirements of downstream markets are calculated by determining the historical (2006-2010) average daily winter demand (October through to March), which is then adjusted for the assumed transit volumes/coverage through the CEE region.

3.2 Project assessment

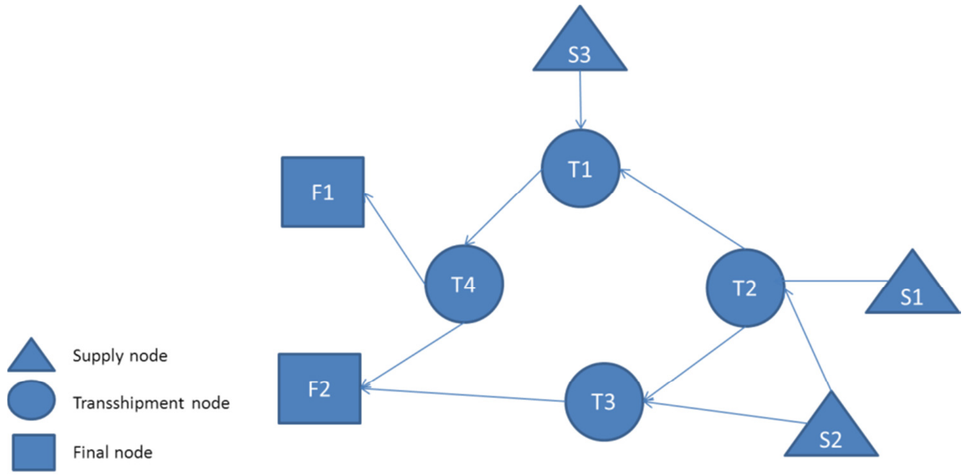
The two key tools for assessing the proposed infrastructure projects are the gas flow simulation model and the multi-criteria analysis.

3.2.1 Gas flow simulation model

For the purposes of both identifying infrastructure groups that cover CEE gas import requirements and selecting infrastructure groups that help meet the security of supply infrastructure standard (of Regulation 994/2010), a model was developed that simulates the gas flows in the CEE region. As demonstrated in Figure E2, the flow network model incorporates the following basic features:

- Supply sources (including LNG terminals) are represented as supply nodes, without any 'predecessors';
- The CEE markets are represented as 'trans-shipment' nodes. Gas into each trans-shipment node comes from imports (supply nodes and neighbouring trans-shipment nodes), while gas out of the node goes to indigenous demand (net of production, where relevant) and transit volumes. Local storage facilities are only taken into consideration when examining daily demand, and in that case are treated as additional production equivalent to the daily maximum withdrawal rate of the given storage facility;
- Some markets outside the CEE region, which also transit gas from the supply sources to the final destination markets, are also represented as trans-shipment nodes and treated like the CEE markets;
- Downstream markets that do not transit gas further from the supply sources are represented as final nodes without any successors; and
- The total required gas flows between any two trans-shipment nodes are represented as arcs, connecting the two relevant nodes. Each arc is limited by the maximum technical capacity of the respective interconnection(s).

Figure E2: Diagrammatic representation of the gas flow network model



3.2.2 Multi-criteria analysis

Multi-criteria analysis (MCA) techniques were employed for the appraisal of the infrastructure options. The box below describes the methodological approach and its key features. Following this, we present the selection criteria together with their scores and weights, which were developed in consultation with the GWG.

Box 1: Project appraisal and evaluation methodology – Multi-criteria analysis

Description	▪ Establishes preferences between options by reference to an explicit set of objectives that the "decision making body" has identified and for which it has established measurable criteria ▪ All MCA approaches require the exercise of judgement by the decision-making team in establishing objectives and criteria, estimating relative importance weights and judging the contribution of each option to each performance criterion
Key features	▪ A standard feature of MCA is a decision criteria tree which is a hierarchical representation of the criteria and sub-criteria to be used and facilitates the evaluation of the options ▪ MCA techniques commonly apply numerical analysis to the criteria tree in two stages: ➢ *Weighting*: numerical weights are assigned to define for each criterion (and sub-criterion) the relative valuation of the significance of each – any numbers can be used for the weights so long as their ratios consistently represent the ratios of the valuation of the differences in preferences between the top and bottom scores ➢ *Scoring*: the expected performance or consequence of each option is assigned a numerical score on a scale (which may be qualitative or quantitative) indicating the level of preference or achievement of the criterion

Type of MCA proposed	▪ A linear additive evaluation model was applied, as models of this type have a well-established record of providing robust support to decision-makers ▪ The linear model shows how an option's values on the various criteria can be combined into one overall value ▪ This is done by multiplying the value score for each criterion by the weight of that criterion, and then adding all those weighted scores together
Procedure for deriving criteria weights	▪ The "Analytic Hierarchy Process" (AHP) was employed to derive the weights for each criterion and sub-criterion ▪ AHP is based on pairwise comparisons of the relative importance of any one particular criterion relative to another criterion ▪ As per common practice with AHP, a 9-point scale was employed to express the intensity of the preference of one criterion relative to another (1 = equal importance, 3 = moderate importance relative to the other, 5 = strong or essential importance, 7 = very strong or demonstrated importance, 9 = extreme importance)

Consistent with the priorities and principles of the Energy Infrastructure Package, we proposed three broad criteria categories, namely "Physical availability (of gas)", "Diversification of Supply" and "Promotion of the Internal Energy Market (IEM)". The sub-criteria that we proposed and were agreed for each criterion category together with the scoring system are presented in the table below.

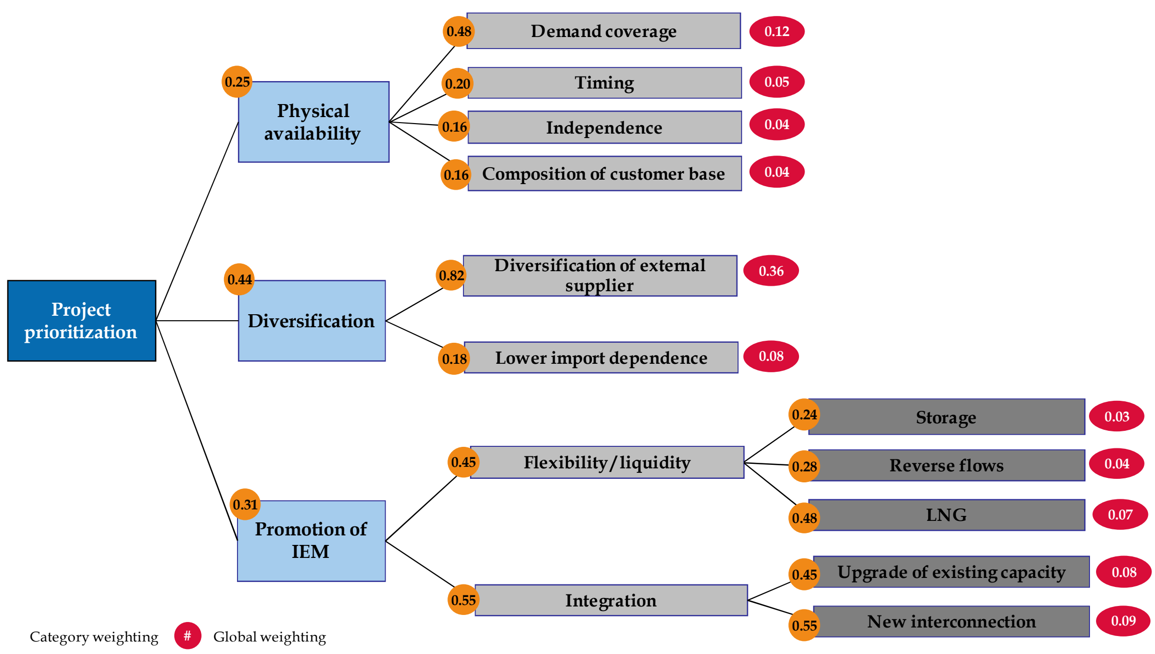
Table E2: Proposed sub-criteria and scoring

Criteria	Scoring / Rating
Physical Availability	
Demand coverage	{Capacity to cover peak demand: 4, Capacity to cover peak demand without industry: 3, Capacity to partially cover peak demand without industry: 2, is not required for security of supply: 0} (Applicable to examination of N-1 rule)
Timing	{2011-2013: 4, 2014-2016: 3, 2017-2019: 2, Post-2020: 1}
Independence	{Stand-alone: 4, dependent: 0}
Composition of customer base	(Distribution + heating demand) / total demand in the year of project commissioning
Diversification	
Diversification of external supply	{New supplier + new source + new route (off-take directly in the country): 4, New supplier + new source + new route (off-take in neighboring country): 3, Existing supplier + new route + new or existing source: 1}

Lower import dependence		Capacity (only of infrastructure that provides access to gas produced internally in the EU or to trading hubs, i.e. to EU gas) / Total import needs in the year of project commissioning
Promotion of IEM		
Flexibility / liquidity	**Storage**	Storage capacity / Peak demand in the year of project commissioning
	Reverse flows	Reverse flow capacity / Peak demand in the year of project commissioning
	LNG	{Yes: 4, No: 0}
Integration	**Upgrade of existing capacity**	Interconnection capacity / Market size in the year of project commissioning
	New interconnection	Interconnection capacity / Market size in the year of project commissioning (not applicable to countries that are already connected)

The final step required the attachment of weights to each sub-criterion to arrive at a decision tree. As mentioned above, to derive the weights we used the AHP technique. The final scoring system is depicted in the decision criteria tree of Figure E3.

Figure E3: Decision criteria tree

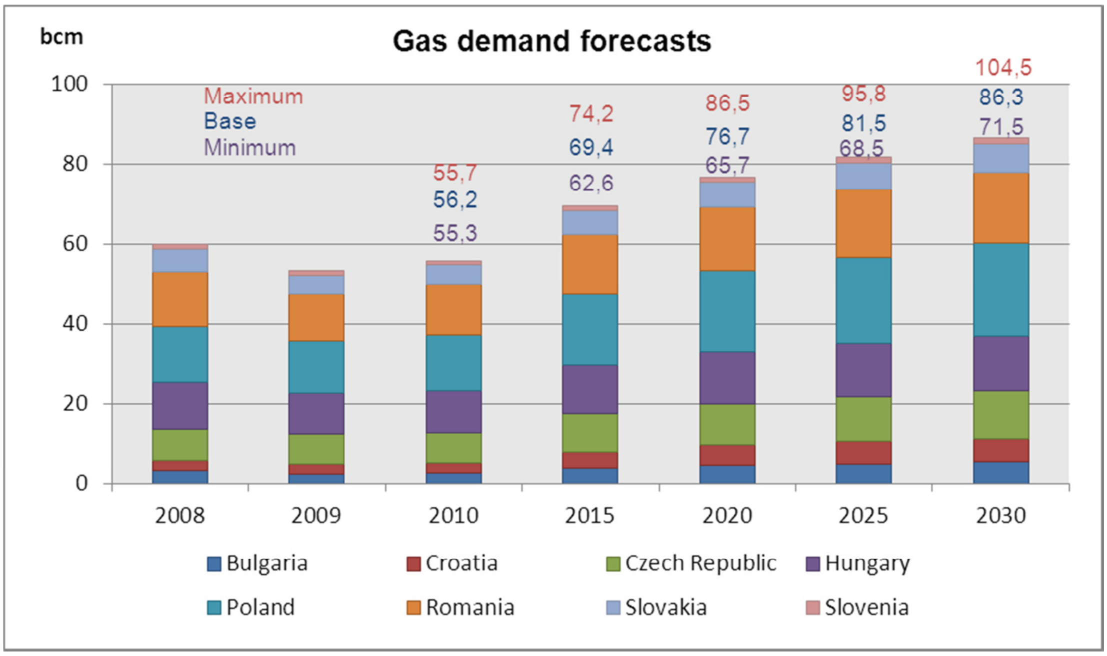


4. PROJECT RESULTS

4.1 Results of the demand, transit & supply analysis

According to our estimates the incremental annual **demand** in the region compared to 2009 volumes under the base scenario is approximately 23 bcm to 33 bcm by 2020 and 2030, respectively. This represents an average annual growth rate over the entire period (i.e. to 2030) of 2.3%. Under the base scenario total demand reaches 86 bcm, but could go as high as approximately 100 bcm (under the maximum scenario) or as low as about 70 bcm (low scenario).

Figure E4: Demand projections for CEE countries, by country



The **peak daily demand** figures used in our analysis are summarized in the table below.

Table E3: Peak demand estimates

Peak demand (severe weather), mcm/day				
Country	**2015**	**2020**	**2025**	**2030**
Bulgaria	18.4	18.4	18.4	18.4
Croatia	15.9	18.0	20.7	21.7
Czech Republic	75.2	82.3	82.3	82.3
Hungary	77.3	88.9	95.2	97.7
Poland	82.3	106.1	112.6	119.8
Romania	118.2	124.8	133.2	140.6
Slovakia	39.1	41.0	42.8	44.9
Slovenia	5.7	6.3	7.0	7.5

The **transit flows** through the CEE region to the downstream markets, which were used in our analysis, both for annual and daily demand, are presented in the figures below.

Figure E5: Required annual transit flows to downstream markets (2020, base case scenario)

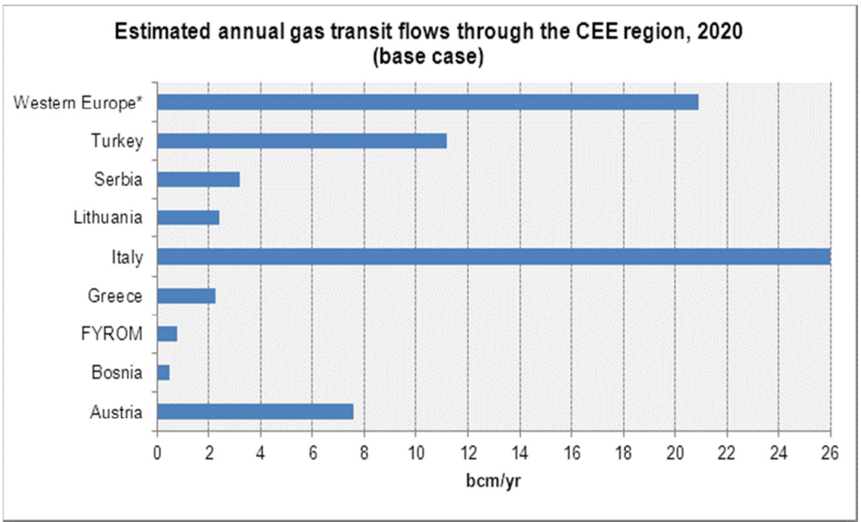
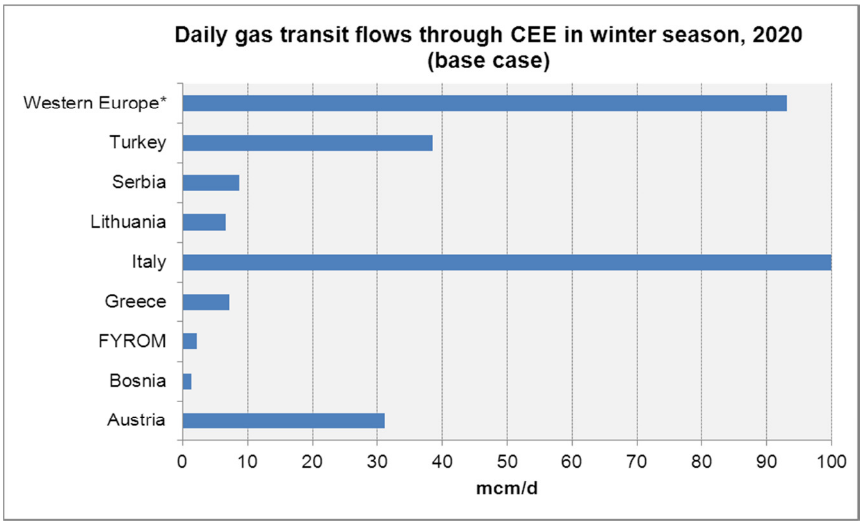


Figure E6: Required daily transit flows to downstream markets in the winter season (2020, base case scenario)



As it is difficult to draw definitive conclusions about the likely **future supply sources** for the CEE's/Europe's incremental import needs in general and for the two major transit options of Nabucco and South Stream in particular, we adopted a set of scenarios for the purposes of the gas flow analysis. These are shown in the table below.

Table E4: Supply scenarios

	Pipelines	Timing (year)	Volumes (bcm)
Base case	Nabucco	2017/ 2020	15 / 31
'Complementary routes'	South Stream	2017	50 (northern branch), 13 (southern branch)
	Nabucco	2017/ 2020	15 / 31
'Competitive routes'	South Stream	2017	50 (northern branch), 13 (southern branch)

We note that in each scenario there will also be the existing supply routes from the EU/Norway and Russia. For the former, we assumed that volumes will remain at historical levels of approximately 7 bcm (this seems a reasonable assumption, given the expected depletion of gas fields and reduced production within the EU and Norway). Supply from Russia through existing routes was also assumed to be at historical levels in the beginning, but once alternative supplies/routes become available as shown in the table above, these volumes were deducted from the existing Russian routes.

Finally, for each supply scenario above, we ran an additional scenario (six scenarios in total) that included the possibility of shale gas production in Poland. For this purpose we assumed that production commences in 2020 at 5 bcm and increases to a maximum 10 bcm in 2022, which is maintained through to 2030.

4.2 Results of the flow model

Simulations of the flow model were conducted for (i) annual demand, (ii) daily peak demand under severe weather, and (iii) the "N – 1" rule (for all customers and excluding industrial customers).

- **Annual demand**: for this case, application of the model demonstrated that, regardless of the examined supply scenario, there are no occurring bottleneck issues in the CEE markets, despite the increase of demand. The reason is the development of transcontinental infrastructure in the region, i.e. Nord Stream, Nabucco and / or South Stream, that reduce demand and transit needs;
- **Daily peak demand under severe weather**: As in the case of annual demand coverage, the implementation of the transcontinental projects will release capacity in the existing system, thus facilitating gas flows to cover daily peak demand, even under severe weather. Bottlenecks only appear in the SK-AT and the AT-DE interconnections up to 2013, before the commissioning of Nord Stream,, due to the large gas volumes that need to be transited to downstream markets;

- **"N – 1" rule**: the analysis for most countries, after assuming the disruption of the largest infrastructure, demonstrated that the remaining infrastructure is not sufficient to cover both demand and transit needs, thus leading to bottlenecks and requirements for flow reversal. As a result, for security of supply reasons new infrastructure must be constructed to facilitate supply of the markets under these extreme conditions. The results of the flow simulations with the planned infrastructure are presented in the table over the page.

The key conclusions that can be drawn from the gas flow model analysis are the following:

- The **CEE region is characterized by significant gas infrastructure** and can therefore **meet projected annual and peak demand under all reasonable scenarios**;
- **Supply problems present themselves in the event of outage of the main supply infrastructure**, i.e. under the N-1 rule;
- **Most of the projects being promoted partially or fully contribute to meeting demand under extreme conditions**;
- The projects best suited to meeting demand under the N-1 rule depend on the specific circumstances of each country;
- In the absence of new infrastructure development, **the countries most likely to have security of supply problems are Bulgaria, Croatia, Romania and Slovenia**.

Table: Demand coverage using the planned infrastructure

Country	Project	"N – 1" rule for all customers			"N – 1" rule without industrial customers		
		Base	Competitive	Complementary	Base	Competitive	Complementary
BULGARIA	ITB	✓	✓	✓	✓	✓	✓
	IGB	✓	✓	✓	✓	✓	✓
	Varna CNG	✗	✗	✗	✗	✗	✓
	Chiren UGS	✗	✗	✗	✗	✗	✓
	BG ← RS	✗	✗	✗	✗	✗	✗
	BG ← RO (new)	✗	✗	✗	✗	✗	✗
CZECH REPUBLIC	AT → CZ	If the SK-CZ pipeline is out, CZ can cover its demand through the use of storage and reverse flow in the DE-CZ line. As a result, the AT – CZ pipeline and the upgrade of the CZ – PL interconnection, are not required to cover the gas needs of the Czech Republic.					
	CZ ← PL upgrade						
CROATIA	Adria LNG	✓	✓	✓	✓	✓	✓
	LNG RV	✗	✗	✗	✓	✓	✓
	IAP	✗	✗	✗	✓	✓	✓
	Benicanci UGS	✗	✗	✗	✓	✓	✓
HUNGARY*#	HU ← HR (rev. flow)	✓	✓	N/A	N/A	N/A	N/A
	HU ← SI	✗	✗	N/A	N/A	N/A	N/A
	HU ← SK	✓	✓	N/A	N/A	N/A	N/A
	HU ← RO (rev. flow)	✗	✗	N/A	N/A	N/A	N/A
POLAND#	PL → SK	✓	✓	✓	N/A	N/A	N/A
	Baltic Pipe	✓	✓	✓	N/A	N/A	N/A

	CZ → PL upgrade	✓	✓	✓	N/A	N/A	N/A
	LNG upgrade	✓	✓	✓	N/A	N/A	N/A
ROMANIA	Constanta LNG	✗	✗	✗	✓	✓	✓
	BG → RO (new)	✗	✗	✗	✗	✗	✗
	RO ← BG (rev. flow)	✗	✗	✗	✓	✓	✓
SLOVAKIA	PL → SK	Regardless of the scenario, Slovakia can cover its demand through reverse flows in the CZ – DE and SK – CZ pipelines. However, although peak demand can be covered with reverse flows from the west, the interconnections PK – SK and HU – SK can facilitate direct connection to the UA – PL and UA – HU pipelines, respectively.					
	HU → SK						
SLOVENIA#	HR → SI	✓	✓	✓	N/A	N/A	N/A
	HU → SI	✗	✓	✓	N/A	N/A	N/A

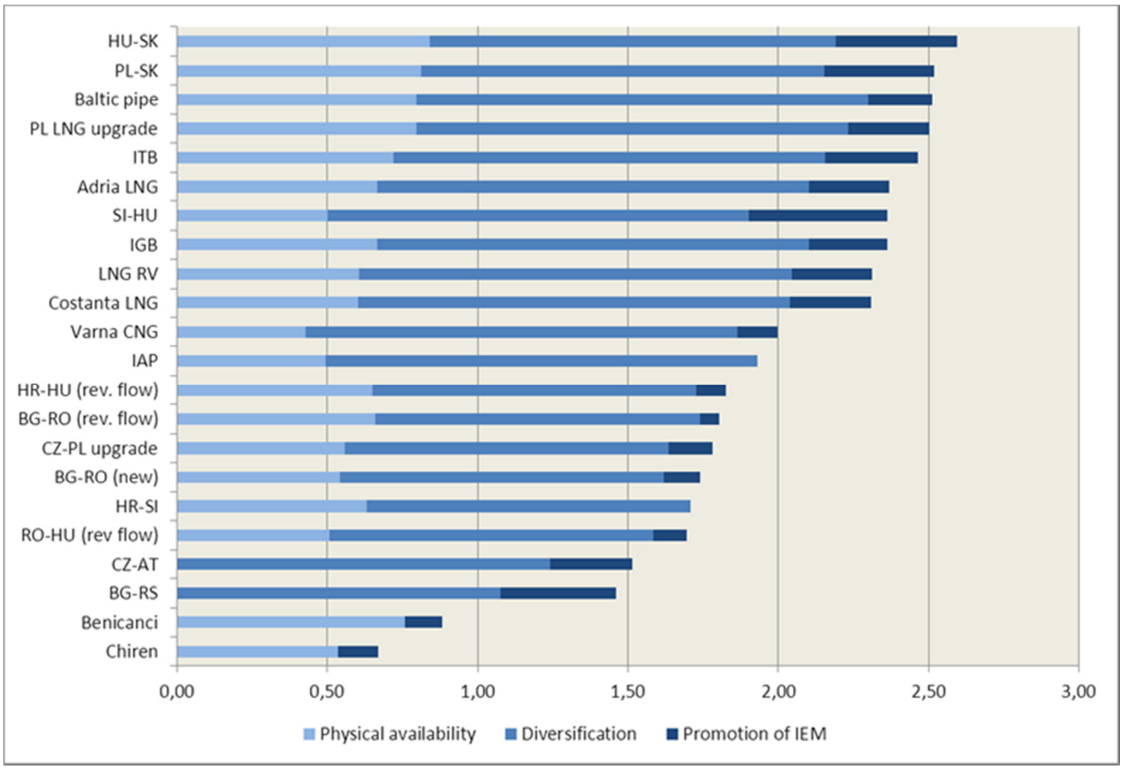
* In the case of Hungary and the N-1 demand case, the complementary supply scenario (which entails the construction and operation of both the Nabucco and South Stream pipelines) is not examined, as no bottlenecks appear in this case – this is why the relevant column is marked with "N/A". In other words, direct supply from Nabucco and South Stream is adequate to cover Hungarian import demand under the complementary supply scenario.

We note that in the case of Hungary, Poland and Slovenia, if we assume that industrial customers are not supplied then peak demand is covered without the implementation of any new project. As a result, the planned infrastructure is not examined under this demand case and the relevant columns are marked "N/A".

4.3 Results of the project assessment

To estimate the rating of each project against the criteria and sub-criteria, we apply the rating system described earlier under the MCA section. The overall results in the ranking are shown in the figure below.

Figure E7: Ranking of projects (overall)



The key conclusions that can be drawn from the project assessment are the following:

- The **HU-SK and PL-SK interconnections are ranked highest** because they score highly on all three key criteria of physical availability, diversification and promotion of IEM;
- Given the importance placed on diversification of supply, **new supply projects** – LNG (Adria, RV, Constanta) and southern corridor projects (ITB, IGB, IAP, Varna CNG) – **generally rank highly**;
- Many of the above projects may be competing (both in destination and source markets) and therefore more detailed feasibility and cost-benefit analyses are required to assess their relative merits;
- Most **cross-border pipeline projects are middle ranking** because they score well on one or two but not all criteria;
- **Storage and reverse flow projects rank highly for physical availability but have low overall scores** as they contribute little to diversification.

The above analysis is highly dependent on the assumptions made in the supply scenarios in regards to the implementation of the large trans-continental pipelines in South Eastern Europe. It is advisable to update the analysis after the future development of the Southern Gas Corridor is clearer, especially following the decision (expected in the first quarter of 2012) on which infrastructure projects will be supplied from Shah-Deniz II.

Finally, we wish to emphasise that the production of this report was a joint effort and resulted from extensive consultation and rigorous debate with all working group members (and observers) through formal meetings and via electronic communication. We have tried to the extent possible to accommodate all views and sought at all times to maintain maximum transparency regarding our data sources, assumptions and methodological approach. In this regard, we note that we have also addressed all formal comments received on the interim and draft final reports that were issued (for more information, we refer you to Annexes 11 and 15).

5. ASSESSMENT OF IMPLEMENTATION OBSTACLES

5.1 Legal and regulatory obstacles

The main legal and regulatory barriers that may be hindering investments in gas infrastructure projects are broadly outlined below.

5.1.1 Delays due to lengthy and complex consultation and permit granting procedures

Specific permitting problems in the region include:

- Problems related to land owners; **negotiations on compensation for land or finding the owner** can cause problems and significant delays in the process.
- **Projects are not prioritized** in most of the countries; therefore, there is no special or streamlined treatment of these. There is no differentiation in the permitting procedure between a greenfield project and an upgrade project (or even a simple reconstruction of an existing facility).
- In some of the countries, **many permits from different authorities are required**. There are many steps and several parallel procedures in the permitting process.
- There is a **lack of binding time limits** for procedures in some of the countries.

5.1.2 Difficulties relating to the existing regulatory framework

Key obstacles in the regulatory area include:

- The **absence** (in many, but not all, countries) **of a stable and predictable regulatory environment**, especially tariff setting methodology for infrastructure projects, which is one of the key requirements to support the realisation of investments.
- **Tariffs do not provide sufficient incentives (i.e. sufficient rates of return)** for companies in some countries which may delay or even block projects.
- **Measures obstructing or prohibiting the flow of gas** (especially for export) exist in some countries which obstructs trade and the incentive for constructing and operating cross-border infrastructure. The **lack of access to gas storage capacities on a regional level** has the same effect.
- **Regulated prices covering too wide a scope of users and/or regulated prices well below potential market prices** (i.e. prices that are not cost-reflective) do not incentivize investments and energy efficiency, and are potentially discriminatory.

5.1.3 Insufficient framework for regional cooperation

Strong regional co-operation is required to identify, implement and monitor all necessary investments which are needed to reach the 20-20-20 EU targets. In this regard, the Gas Security of Supply regulation has stimulated increased cooperation in the region, e.g. Visegrad Group or the CEE Gas Regional Investment Plan (GRIP) under preparation by the Transmission System Operators of the relevant countries (Austria, Bulgaria, Croatia, Czech Republic, Germany, Hungary, Poland, Romania and Slovakia). Nevertheless, the following are also needed:

- **Greater cooperation between regulators** on the different regulatory regimes for cross-border investments;
- There should be **a Gas Regional Initiative that comprises North-South participating countries in one group**; and
- There is potential for **cooperation of the North-South group with relevant neighbouring countries** and, especially, with the Energy Community and SE European countries.

5.2 Potential remedies for legal and regulatory obstacles

To overcome the legal and regulatory barriers identified above, the following broad recommendations are proposed.

5.2.1 Procedural remedies

The measures below, which build upon experience and structures already employed in some countries could be considered by the GWG members:

- Establishment of a list of strategic infrastructure projects and the prioritisation of these projects at a national level;
- Development of a standardised permitting procedure with binding time durations;
- Adoption of a 'one stop shop' mechanism at a national level for the priority projects;
- Integration of spatial planning and land/easement matters into the permitting procedure;
- Standardisation of the permit application documents;
- Limitation of legal recourse and appeals to a single level of jurisdiction; and
- Promotion of effective stakeholder consultation.

5.2.2 Regulatory remedies and enhanced regional cooperation

There are two particular issues, which we believe ought to be given consideration in this context:

- **The permission (by regulatory bodies) of sufficient rates of return on the new infrastructure** – many of the projects that are being promoted under the North-South interconnection initiative are necessary for reasons of security or diversification of supply and may not be justifiable on purely commercial grounds. In this sense, they differ from national gas transmission systems which generally face lower systematic risks and therefore should arguably be permitted higher regulated returns as compensation for the added risk (of under-utilisation).
- **Examination by regulators of consumers' willingness to pay for supply security** – this is an area which we believe has not been given sufficient consideration and could be a matter for investigation by national regulatory authorities and ACER. That is, given that many of the projects are justified on the grounds of security of supply, regulators should assess the value that consumers place on interruptions avoided with a view to determining the 'security insurance premium' that could potentially be levied on customers so as to internalise the cost of energy security (as opposed to relying on public funding of the relevant investments).

5.3 Innovative financial instruments for natural gas infrastructure projects

The EC has estimated that investments of approximately EUR 200 billion will be required for energy transmission networks, in the period 2014-2020 in order to meet the EU's 2020 targets. However, it is expected that only about 50% of the required investments for transmission networks will be taken up by the market by 2020. This leaves a gap of about EUR 100 billion. Approximately EUR 40 billion of this gap according to the EC is caused by delays in obtaining the necessary environmental and construction permits. The remaining shortfall of approximately EUR 60 billion is due to difficult access to finance and lack of adequate risk mitigating instruments, especially for projects with positive externalities and wider European benefits, but no sufficient commercial justification. This is particularly the case with regard to multi-country, cross-border connections.

In order to overcome this funding gap, the Commission has proposed the creation of a **Connecting Europe Facility.** The EC has emphasised the need to maximise the impact of European financial intervention by playing a catalytic role in mobilising, pooling and leveraging public and private financial resources, through alternative infrastructure instruments. In this context, beyond the traditional support forms (grants, interest rate subsidies), the following options could be examined:

- equity participation and support to infrastructure funds;
- loan guarantees;
- public-private partnerships;
- leveraging loan finance from IFIs; and
- targeted facilities for project bonds.

All these mechanisms have already been employed for other types of infrastructure (particularly transport) and can have similar application in the gas / energy sector.

1. INTRODUCTION

1.1 Project objectives

1.1.1 Background to the commissioning of the present study

In November 2010, the European Commission (EC) adopted the "Energy Infrastructure Package" (EIP), which is intended to form a new blueprint for the strategic planning of key energy infrastructure at a supranational level within Europe and in its 'neighbourhood'. The EIP seeks to coordinate, facilitate and optimise the development of networks in support of the "Energy Policy for Europe", and is also seen as a mechanism for overcoming identified impediments to the financing and implementation of infrastructure projects (especially those transcending national borders). More specifically, the new infrastructure policy seeks to assist the development of integrated EU infrastructures and markets with a view to, *inter alia*:

- Facilitating competition in the European Union's (EU's) single energy market, with resulting benefits for customers and the competitiveness of the EU economy;
- Improving security of supply and minimising the cost of supply disruptions (of the type experienced, for example, in January 2009 as a result of the Russian-Ukrainian gas dispute); and
- Promoting sustainability by enabling the integration of more renewable energy sources consistent with the relevant targets set in the Energy Policy.

Many of the policy and legal measures adopted by the EU since the adoption of the new Energy Policy in 2007 have similarly been geared toward the achievement of these objectives. Indeed, the most recent relevant EU directives and regulations that are collectively referred to as the "third (internal energy market) package" introduces a number of measures intended to facilitate coordinated and efficient network planning and investment, including:

- The requirement that transmission system operators (TSOs) prepare a regional and European 10-year network development plan biennially, in the framework of the European Network of TSOs (ENTSO);
- The establishment of rules of cooperation for national regulatory authorities on cross-border investments through the Agency for the Cooperation of Energy Regulators (ACER); and
- An obligation on national energy regulators to take into account the impact of their decisions on the EU internal market as a whole.

Notwithstanding the introduction of the above measures, the EC considers that there continue to remain obstacles preventing the realisation of the necessary infrastructure investments. These barriers include:

- The uncertainty surrounding future market developments (regarding, for example, import and production infrastructure in upstream markets in countries outside the EU);
- The national focus of tariff-setting and the lack of sufficient cost allocation principles between jurisdictions to take into account cross-border benefits;
- The difficulty of funding and recovering from users the cost of projects that are characterised by non-pecuniary positive externalities (such as the provision of secure supplies in the case of low probability-high impact events); and
- The lack of a coherent methodology (in the TEN-E framework) for identifying complementary and 'additive' projects that fill infrastructure gaps.

Consequently, the EIP sets out a new method for planning and developing infrastructure projects entailing the following steps:

- The specification of a limited number of European priorities, which must be implemented by 2020 to meet the EU's long term policy objectives and for which European action is warranted;
- The identification of specific "projects of European interest" necessary to implement these priorities, using a transparent and agreed methodology; and
- The adoption and employment of new tools for implementing the projects, such as improved regional cooperation, more streamlined and efficient permit procedures, and innovative financial instruments.

Consistent with the foregoing, the EIP identifies certain priority corridors, which in the case of gas includes linking the Baltic, Black, Adriatic and Aegean Seas. The development of north-south interconnections in Central-Eastern and South-Eastern Europe forms an important element of this corridor. Moreover, the EC has commissioned a "High Level Group" based on the cooperation of the countries in Central-Eastern Europe (CEE)[2] with the mandate to devise an action plan for the development of interconnections in gas, electricity and oil by the end of 2011.

[2] These countries are otherwise known as "Visegrad+" comprising the Visegrad Four - Poland, the Czech Republic, Slovakia, and Hungary - plus Bulgaria and Romania.

Beyond the definition of criteria for project prioritisation and selection consistent with the principles of the EIP, the High Level Group is tasked with identifying obstacles to the implementation of the priority projects and defining measures for overcoming them, specifying possible financial sources and mechanisms, and delineating the steps required to ensure the realisation of the projects.

The High Level Group on north-south interconnections, which is chaired by the EC, includes Bulgaria, the Czech Republic, Hungary, Poland, Romania and Slovakia as members, and Croatia as an observer. Since commencing this study, Austria, Germany and Slovenia have also become members of this group. The High Level Group in turn established a "working group on natural gas" (GWG) consisting of representatives of the relevant ministries, regulatory authorities and TSOs in the participating countries. [3]

The **purpose** of the present assignment (which was carried out during the June - October 2011 period), in accordance with the issued project terms of reference (ToR), was to assist the EC in guiding the deliberations of the GWG through the preparation of a study that:

- Analyses planned gas infrastructure projects (interconnections, storage facilities and LNG regasification terminals) in the region covered by the north-south initiative and assesses the degree to which they contribute to the objectives of the EIP initiative;
- Specifies potential future priority projects based on security of supply, market integration and sustainability considerations; and
- Identifies the obstacles to implementing these priorities.

1.1.2 Our understanding of the study objectives and issues

In line with the general directions given in the EIP and the specific objectives of the present study, the focus of this assignment was on the following two critical parameters[4]:

- The specification of (a limited number of) concrete projects that are consistent with the EIP principles, which in turn required the **formulation of clear selection or project prioritisation criteria**; and

[3] With the exception of Austria and Germany, which only participate in the electricity working group (and not the GWG).

[4] These of course are not the only parameters that are significant for the more effective development of integrated networks in the EU. For example, as the EC has highlighted, another important element entails the formulation of principles for allocating infrastructure investment costs between interconnected networks. This, however, was considered to be outside the scope of the present study.

- The development of proposals for overcoming any obstacles to the actual and/or timely implementation of the identified priority projects, which must be specified (by the GWG) in the form of a clear Action Plan.

Regarding the first point, we note that the EIP introduces a new top-down approach to identifying infrastructure gaps and provides high-level principles that should guide the prioritisation and selection of project proposals.

On the other hand, the pre-existing TEN-E framework was based on a bottom-up approach with no clear guidelines for discriminating between projects (some of which were competing and/or mutually exclusive). The 10-year network development plans prepared so far by ENTSOg also lack sufficient clarity regarding the categorisation and/or prioritisation of projects, notwithstanding the attempt made to examine whether peak flow requirements are met in each market.[5]

Consequently, a key objective for the present study was to **translate the principles enunciated in the EIP into a methodology and framework for selecting priority projects** among the total planned infrastructure options, given expected future developments in demand, supply and transit.

In this context, the following elements were viewed as important and to a large degree dictated the approach applied for screening potential infrastructure projects:

- **Satisfaction of future demand** – before examining other considerations, it was firstly necessary to identify the infrastructure expansions (if any) required to meet demand within the region of study and for each country, and to simultaneously ensure that required transit flows (to meet demand in adjacent regions) are not jeopardised. We note in this respect that six of the 8 countries forming the geographical scope of the study (*viz*. Bulgaria, the Czech Republic, Hungary, Poland, Romania and Slovakia) are significant transit countries;
- **Promotion of security and continuity of supply** – even if market demand under 'normal' conditions (including expected seasonal fluctuations) is met, infrastructure options that guarantee gas supply under all reasonable conditions (including extreme weather) notwithstanding the failure of another major system component must be identified;

[5] We nevertheless note as the Polish delegation has commented that "[the 10-year network development plans] TYNDP is not intended to prioritize projects nor to examine supply/demand issues on national basis but on the European level. The role of TYNDP is to provide, from the perspective of TSOs, a pan-European view of potential gas transmission infrastructure developments during the subsequent 10 years."

- **Promotion of market integration and competition** – the screening and prioritisation of projects must also consider their impact on competition. An important factor in this context (and also for security of supply) will be the impact that planned projects have on the **diversification of gas supplies**, especially if they provide a physical connection to gas sources that are currently absent in the relevant CEE markets. Also, when assessing the current and foreseeable state of competition it is important to consider all relevant markets. The relevant markets are likely to be those for transmission capacity and wholesale gas supply. However, other related markets could also be affected and should be considered, especially markets in which gas is or will be a major input (e.g. gas-fired electricity generation).

Although cost is considered an important element for the assessment of gas infrastructure, it is not taken into consideration in this study. However, we wish to emphasise that in our view the assessment of costs and benefits from a social perspective must be undertaken before affording priority status to any of the projects. Moreover, only projects with a demonstrated positive benefit-cost ratio should proceed, as otherwise the costs outweigh the benefits and resources are best allocated to other activities/projects with a positive economic rate of return. In this respect, we understand that cost-benefit analysis according to an agreed methodology will form a precondition for the selection of projects as "Projects of Common Interest".

In addition, the issue of sustainability, although included in the criteria of the EIP, is not evaluated in the assessment of the proposed projects, as any individual project of itself is not considered to affect the promotion of sustainable energy to a significant degree. However, we note that the extent to which the gas infrastructure projects promote the substitutability of gas for other fossil fuels with greater greenhouse gas emissions, the projects (all other things equal) contribute to the EU's sustainability objectives.

The transformation of the above infrastructure assessment elements into quantifiable and independent sets of criteria and sub-criteria, as well as the definition of their relevant importance were topics of considerable discussion and consultation with the Commission and the GWG. The results of this analysis are presented later in this report.

1.2 The structure and scope of the report

The purpose of this report is to describe the tasks that were undertaken (both in terms of scope and approach) throughout the study period, and to present the findings of all elements of the study, including the regional market/demand analysis, the project assessment and the evaluation of implementation obstacles.

For the preparation of the report, we have necessarily taken into account the ToR that we were issued and the proposal we had put forward (and on the basis of which we were selected). However, we have modified our approach and the scope as required, on the basis of the comments received at the kick-off meeting held with DG ENER on 20 June 2011, the 6th, 7th and 8th GWG meetings held respectively on 8 July 2011, 13 September 2011 and 12 October 2011, as well as the High Level Group Meetings of 16 September 2011 and 28 October 2011. A large number of comments were also received via e-mail from the various country delegations in the intervening periods.

The remainder of this report is structured as follows:

- Section 2 sets out the scope of the study and the specific tasks/activities that were undertaken;
- Section 3 describes the methodological approach that was adopted for key facets of the study;
- Section 4 contains the results of the regional market analysis and project assessment; and
- Section 5 delineates the barriers to project implementation and suggests possible remedies.

There is also a set of appendices, which contains more detailed information (particularly with respect to the assumptions and results of the regional market analysis and the project assessment methodology and results).

2. SCOPE OF WORK

In accordance with the ToR issued to the Consultant, the study was structured around five discrete but inter-dependent tasks. This section sets out the broad scope for each of these five tasks.

2.1 Regional market analysis (Task 1)

The purpose of this task was to determine the demand or import requirements of the specified CEE countries and the region as a whole for the period to 2020/2030, and also the required transit flows to meet demand in downstream markets.[6] The sum of these two parameters (i.e. gas import requirements for 'indigenous' demand plus transit flows) determines the minimum capacity/infrastructure requirements for each relevant country (under 'normal' market and operating conditions).

For the purposes of the analysis, it was initially intended that we rely on the 2009 update of the "Energy Trends to 2030", which employs the PRIMES modelling framework and adopts the following two scenarios:

- Baseline scenario – this assumes that no new policies are implemented and therefore the targets set in the EU energy policy are not met; and
- Reference scenario – under this scenario the binding targets for a 20% renewables share in final energy consumption and a 20% reduction in greenhouse gas emissions in 2020 compared to 1990 are assumed to be achieved.

Using the above projections was meant to ensure consistency with other analysis undertaken by DG ENER (including in the electricity working group (EWG)) and also uniformity of approach between (most of the CEE) countries. However, following consultation with the GWG and the Commission, it was generally felt that the above projections should not be relied upon given the significant and unprecedented changes and decreases in demand across all European gas markets during 2008-2010 as a result of the financial crisis and ensuing economic recession, and which have yet to be incorporated in the PRIMES model update. Another important factor potentially affecting the validity of the projections and the estimated transit flows in the region was the recent German decision to shut down all nuclear reactors by 2022.

[6] In our study proposal, we had stipulated that the time horizon for the analysis should extend to 2020 to coincide with the focus of the EIP and the 2020 objectives of the EU Energy Policy, and also because there would be greater certainty attached to the forecasted numbers. The GWG, however, has subsequently requested that we extend the forecasts to 2030.

In the context of preparing the "Stocktake Document", the GWG had produced demand forecasts for each of the countries and the region as a whole (with the exception of Slovenia, which had only just recently joined). The Consultant was neither able to ascertain the assumptions underpinning these projections, nor was it clear that a common methodology had been employed to derive the forecasts for each country. Accordingly, at the 6th GWG meeting (which was the first attended by the Consultant), it was suggested that we produce some demand estimates, which could be cross-checked with the projections in the Stocktake Document.

The GWG agreed that the Consultant undertake this work, as it was considered important to base the assessment of infrastructure options on robust demand estimates (subject, of course, to time and data limitations). The methodology employed by the Consultant to produce demand forecasts is presented in section 3 of this report. It should be noted that this work represented a significant change to the initially envisaged scope of work and was the main focus of the first half of the study period up to the beginning of September.

Finally, we clarify that for the purposes of determining import requirements, projections of domestic production (where relevant) also needed to be taken into account.

2.2 Identification of planned infrastructure options (Task 2)

This task largely required fact finding, in that it entailed the detailed documentation of both existing and planned infrastructure (interconnections, storage facilities and LNG terminals) and covered matters such as technical and contractual capacity (for existing infrastructure), and status, sponsors and timing (for new infrastructure).

The purpose of this task was primarily to document all the relevant gas infrastructure development projects, including investments in (cross-border) interconnections, reverse flow projects, storage facilities and LNG terminals.

This list of projects was incorporated in the assessment and modelling work in the next task to identify those projects that are needed to overcome constraints or bottlenecks in the system, or more generally which satisfy the selection/prioritisation criteria that were adopted for evaluating the projects.

In the case of bottlenecks, it was important to ascertain the timing and magnitude of the constraints, as these provide the rationale and determine the required timing for the implementation of new infrastructure. This lends further credence to the importance of ensuring greater certainty about the likely level of future gas demand (as part of the first task). Equally important was the need to have accurate and realistic data regarding the timing of planned infrastructure projects.

The Consultant notes in this regard that the GWG undertook considerable work in preparing the list of future projects. Furthermore, DG ENER had issued a template project fiche (which was reviewed by the Consultant) and was circulated to GWG members. The project fiche was intended to provide comprehensive data regarding the technical, financial and ownership features of the projects, as well as their intended timing and perceived benefits and problems or risks. The completed project fiches and the demand/supply projections represent the bulk of data inputs that were required by the Consultant to undertake the requisite analysis.

2.3 Assessment of planned gas infrastructure projects (Task 3)

The purpose of this task was to assess the currently planned gas infrastructure projects and determine a priority listing of the projects in accordance with EIP principles. As mentioned above, a project was generally considered a high priority if it satisfied a number of requirements - it should help meet 'indigenous' demand and facilitate the transit of required gas volumes to neighbouring markets, and/or provide greater security or continuity of supply, and/or promote regional market integration.

The Consultant applied a three-step process to assess the planned gas infrastructure projects in the CEE region, with respect to their necessity in meeting demand (within and outside the region), and their contribution to ensuring security of supply and market integration, and meeting the other principles and criteria of the EIP.

Step 1: Contribution of proposed infrastructure to covering gas import requirements

Our purpose was to identify potential future bottlenecks in the CEE gas transmission system, which would result in unmet gas demand in both the CEE and downstream markets, and to examine the contribution of the planned new and upgraded interconnections and LNG terminals (defined in Task 2) in resolving these bottlenecks. Our calculations were made on an annual and peak daily (under severe weather conditions) basis for the period 2010 – 2030. Storage facilities were considered only in the case of peak daily demand, as they were considered to be flexibility mechanisms that are used to manage seasonal flows within a year.

Step 2: Selection of infrastructure groups that enhance security of supply

In our view and understanding, a major driver of the EIP, particularly as it applies to gas and the CEE region, is to enhance security and diversity of supply. Moreover, and very importantly, the recent adoption of the security of supply regulation[7] establishes an "infrastructure standard" as follows:

> "Member States or, where a Member State so provides, the Competent Authority shall ensure that the necessary measures are taken so that by 3 December 2014 at the latest, in the event of a disruption of the single largest gas infrastructure, the capacity of the remaining infrastructure, determined according to the N – 1 formula as provided in point 2 of Annex I, is able, without prejudice to paragraph 2 of this Article, to satisfy total gas demand of the calculated area during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years." (Article 6.1).

The importance of security of supply was further reinforced by the GWG members at the 6th GWG meeting, where there was general support for the inclusion of supply security as one of the project selection criteria.

Accordingly, in this step we examined which of the planned infrastructure projects fulfil the 'N – 1 formula' of the security of supply regulation for the period 2010 – 2030. In this step, storage facilities were also taken into consideration. The 'N-1 formula' was examined for two demand scenarios – in the first, we assumed that total national daily peak demands under extreme weather conditions had to be covered, while in the second scenario only that part of daily peak demand that excludes consumption by industrial customers had to be accommodated. The latter case was examined because several of the proposed projects failed to completely fulfil the 'N-1 formula', although they are large capacity projects and can contribute significantly to meeting part of peak gas needs. In addition, it is reasonable to assume that efficient security of supply arrangements would entail a differentiated treatment between customers, whereby customers who can cost-effectively maintain fuel-switching capabilities need not be protected against supply disruptions. These customers are likely to be industrial (as opposed to residential or smaller commercial) customers.

For the purposes of undertaking the analysis of the abovementioned steps, the Consultant developed a model that simulates the gas flows in the CEE region, as described in the methodological section of this report.

[7] Regulation 994/2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC.

Step 3: Prioritisation of the infrastructure groups

In the first two steps, the contribution of the proposed infrastructure projects in covering demand, facilitating gas transit and improving security of supply in the CEE region was examined. However, in addition to these factors, the prioritisation among the various infrastructure projects also took into account additional criteria such as the promotion of market integration and diversification of gas supply.

As mentioned above, the definition of the precise criteria and sub-criteria used in this step, as well as the methodology that was applied for ranking projects (e.g. through the specification of weight coefficients) was the subject of consultation and agreement with the Commission and the GWG.

2.4 Identification and assessment of implementation obstacles (Task 4)

Having determined the priority infrastructure projects, the purpose of this task is to identify and assess any barriers to their timely realisation. The assessment of such barriers should guide the Commission in establishing whether there is a case for some action or support and, if so, in which form. The obstacles examined as part of this task fell within the following three categories:

- **Financial and commercial** – the financial and commercial viability of a project could be affected by the risk profile of the project (due to, say, volume risk arising from the unavailability of upstream supply or reduced downstream demand, price and market risk, technical and operational risks, etc.), the lack of sufficient debt finance (owing to the liquidity problems still confronting the banking sector) or a prohibitive cost of capital (as interest rates rise in response, for example, to anticipated surging demand for capital in emerging economies), or the inability to recover the full cost of infrastructure development given the large externalities associated with the infrastructure (e.g. a pipeline needed for security of supply but with low utilisation under normal market conditions);
- **Legal and regulatory** – arguably many of the potential legal and regulatory obstacles to developing cross-border pipelines and other similar infrastructure have largely been addressed through the 'third package'. However, Member States have until March 2012 to fully implement the package, while there may be some problems or obstacles arising in implementing the required laws, rules and procedures, such as, inadequate consideration by regulators of the benefits accruing to end-users in another country/jurisdiction, the specification of low regulated rates of return (which in turn impact on the commercial viability of the projects), etc.

- **Procedural** – these issues generally relate to permitting and administrative delays associated with obtaining the necessary approvals or authorisations across more than one jurisdictional boundary and also protests on the part of citizens. These issues are generally not as significant in the gas sector (with the exception perhaps of LNG terminals), as they are in the case of electricity and renewable energy sources.

In order to assess the above obstacles, the Consultant reviewed the consultation undertaken by the Commission in the context of preparing the infrastructure communication. Moreover, the GWG members were encouraged by DG ENER during working group meetings to present their views on the nature and extent of the identified obstacles, although comments in this regard (compared to other elements of the study) were not very forthcoming.

In this context, it is important to note that during the course of the study the Commission prepared and released an "Energy Infrastructure Legislative Proposal", which addresses (at a high level) many of the above factors.

2.5 Specification of actions to overcome identified obstacles (Task 5)

The final project task entailed the preparation of a set of recommendations to address the obstacles and potential project implementation difficulties identified in the previous task. The nature of the recommendations is guided by the type of obstacles identified.

As part of this task, the Consultant also explored **alternatives to bank lending for funding the identified projects**, given that this is a significant issue that had been highlighted by the Commission and receives special attention in the EIP.

3. DESCRIPTION OF KEY METHODOLOGICAL MATTERS

The key methodological issues that needed to be addressed during the study (under the expanded scope with respect to the regional market analysis) were the derivation of forecasts for gas demand and transit volumes, and the approach to assessing and prioritising the proposed infrastructure projects. This section presents the methodology adopted for both these elements of the study.

3.1 Demand forecasts

3.1.1 General considerations

Changes in natural gas demand are driven by many factors, including macroeconomic variables (domestic and foreign economic activity, industry structure, etc.), energy prices (both for gas and for alternative fuels and energy sources, such as residual and distillate fuel oil, coal and electricity), changing technology, weather, regulatory and market structures governing energy use and markets, environmental regulations, demographic changes (e.g. the size of households), and many others. To accurately capture the effects of these factors would require extensive data collection and sophisticated modelling, which was not possible within the (data, time and resource) constraints of the present study.

In addition to the above, it is very difficult to assess the impact on gas markets and consumption in Europe and the CEE region during the period 2008-2010 and the likely developments as economies recover from the recent crisis. This is particularly so as the data available in the public domain is contradictory at best and incomplete or unavailable at worst.

Consequently, to derive the demand forecasts we attempted to employ a pragmatic approach that has regard to data limitations, but also one which necessarily requires the use of professional judgement in many instances. For this reason, the results presented in this report should not be viewed as precise forecasts or estimates of any future level of demand. Rather, they should be considered as indicators of broad trends and ranges of likely outcomes that stem from the particular assumptions we have made. These assumptions are explicitly presented in section 4 and the appendices to this report and their reasonableness was tested with the GWG members, who have better knowledge of their respective markets and country circumstances.[8]

[8] After issuing a draft interim report on September 12th 2011, we received comments from most of the countries. For details, please refer to Annex 11.

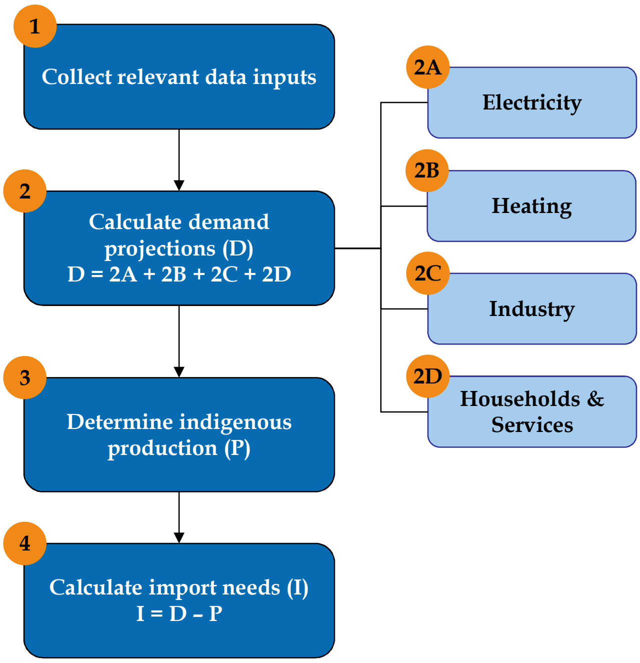
Given the uncertainty surrounding the demand outlook, we employ three different scenarios (minimum, base, maximum) and validate our results vis-à-vis the forecasts already prepared by the GWG. Further cross-checking was performed against the PRIMES updated figures and, for the case of the electricity sector, with the estimates of the EWG.

3.1.2 *Calculation of demand in the CEE countries*

Overall framework

Our demand projections entail a 'bottom-up' approach, which attempts to build up the forecasts on the basis of demand estimates for each significant gas consuming sector – electricity, heating, industry, and households and services. The overall framework is depicted in Figure 1 below.

Figure 1: Broad framework for determining the gas demand and import requirements of the CEE countries



As part of step 1, we scoured the various available data sources, with a view to minimising data requests and using common sources for each of the relevant countries to the extent that this was possible. We also issued a short questionnaire to the GWG members (see Annex 10), and received responses from Bulgaria, the Czech Republic, Hungary and Poland.

Our main data sources for the demand projections are Eurostat (for historical data), ENTSOe and the answers to questionnaires (wherever received) for planned power generation plants, and the IMF for GDP forecasts.

In step 2, we calculate our demand forecasts employing the approach described below for each of the respective main gas consuming sectors. In order to determine the import needs of the CEE region (step 4), one also needs to deduct indigenous production. For this purpose, we used the production forecasts developed by the GWG and which are reproduced below in Table 1. The GWG forecasts extended to 2020; in order to derive estimates for the entire outlook period to 2030, we assumed the following:

- Production in Bulgaria and Slovakia is zero in the post-2020 period;
- Croatian, Hungarian and Romanian production is assumed to continue declining at the same average annual rate to that for the period to 2020; and
- Production in Poland and the Czech Republic stabilises at 4 bcm and 0.11 bcm for the post-2020 period, respectively.

Table 1: Projected production from conventional sources in the CEE region, bcm/year

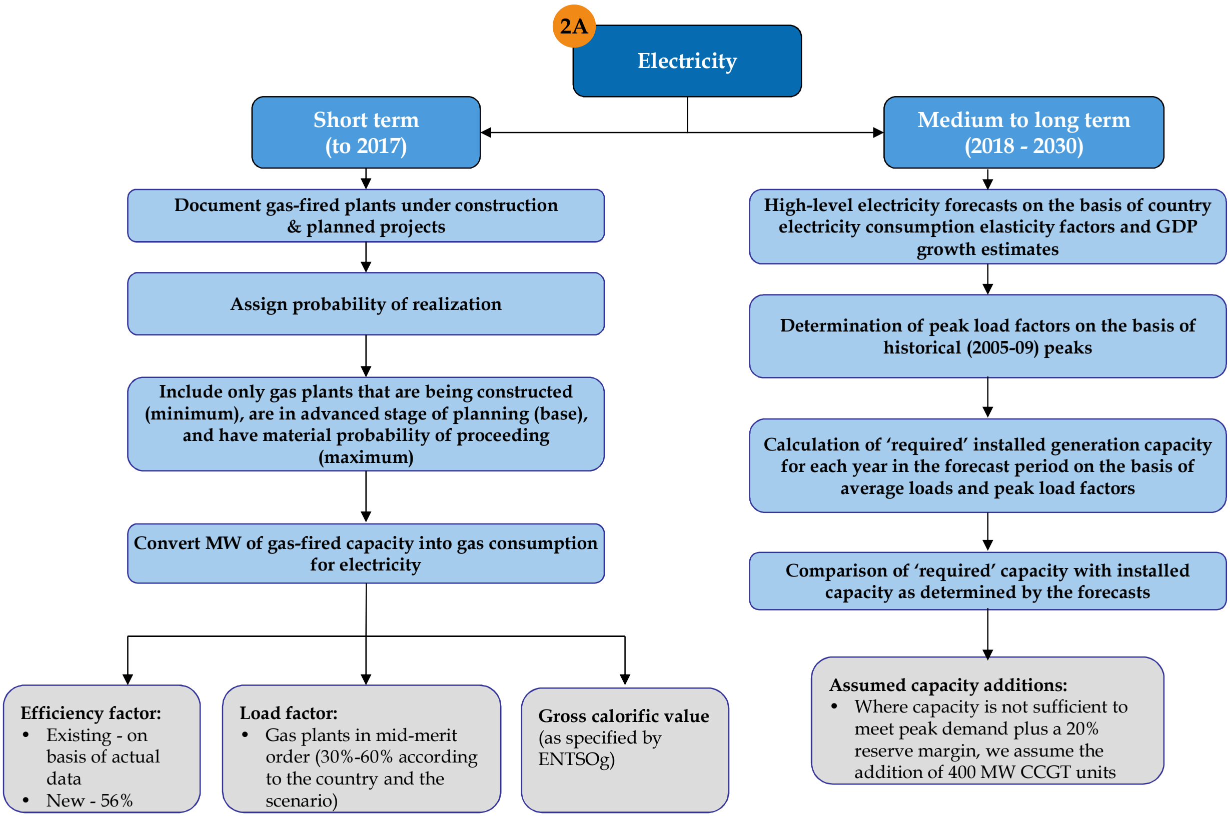
Year	Bulgaria	Croatia	Czech Republic	Hungary	Poland	Romania	Slovakia	Total
2010	0.07	2.30	0.20	2.50	4.30	10.40	0.09	**19.86**
2011	0.46	2.26	0.15	2.57	4.30	10.62	0.16	**20.53**
2012	0.46	2.21	0.14	2.29	4.30	10.33	0.16	**19.89**
2013	0.42	2.30	0.15	2.18	4.30	10.04	0.16	**19.55**
2014	0.38	2.20	0.18	2.14	4.30	9.78	0.16	**19.12**
2015	0.34	2.20	0.22	2.18	4.35	9.52	0.16	**18.96**
2016	0.30	2.10	0.14	2.18	4.35	9.37	0.16	**18.60**
2017	0.27	2.00	0.13	2.10	4.30	9.22	0.16	**18.18**
2018	0.25	1.90	0.13	1.78	4.20	9.05	0.16	**17.47**
2019	0.22	1.90	0.13	1.55	4.00	7.57	0.00	**15.37**
2020	0.20	1.80	0.12	1.50	4.00	7.38	0.00	**15.01**
2021	0.00	1.76	0.11	1.43	4.00	7.13	0.00	**14.32**
2022	0.00	1.71	0.11	1.36	4.00	6.89	0.00	**13.96**
2023	0.00	1.67	0.11	1.29	4.00	6.66	0.00	**13.62**
2024	0.00	1.63	0.11	1.23	4.00	6.43	0.00	**13.29**
2025	0.00	1.59	0.11	1.17	4.00	6.22	0.00	**12.98**
2026	0.00	1.55	0.11	1.11	4.00	6.01	0.00	**12.67**
2027	0.00	1.52	0.11	1.05	4.00	5.81	0.00	**12.38**
2028	0.00	1.48	0.11	1.00	4.00	5.61	0.00	**12.09**
2029	0.00	1.44	0.11	0.95	4.00	5.42	0.00	**11.82**
2030	0.00	1.41	0.11	0.90	4.00	5.24	0.00	**11.55**

Electricity sector

Consistent with our earlier general observations, we have adopted a practical methodology to examining gas demand for electricity generation. For the short-run period (defined to be up to 2017), we examine the gas-fired power plant projects that are currently being built or planned, and determine the equivalent gas demand deriving from their operation with different load factors. For the longer term, we calculate high-level electricity consumption forecasts and on the basis of assumed peak load factors determine generation capacity requirements and determine whether further capacity additions of gas-fired generation are likely to be needed.

The approach in our view is easily understandable and verifiable and, therefore, GWG members were requested to indicate whether on the basis of their specific knowledge of their country's circumstances some of the assumptions ought to be modified. The approach to deriving the gas demand forecasts for the electricity sector is depicted diagrammatically in Figure 2, and is further detailed below.

Figure 2: Methodology for determining gas demand in the electricity sector



The calculation of the short-term forecasts entails the following steps and considerations:

- We assume that it generally takes five to six years from the time that a project concept for a gas-fired power plant is developed up to the point that it commences operation at maximum capacity (hence, the short-term forecast horizon to 2017). This period generally assumes that consent and permitting procedures take 1-2 years, construction 2-3 years and that a further year is needed before maximum capacity is reached.[9]
- We have attempted to document the gas-fired thermal power plants (TPPs) that are currently being planned or constructed – if the above time frame is correct, it would be very difficult for any plant that is not currently planned to be fully operational by 2017.

[9] Lead times, especially for construction, vary from one project to another, depending on a number of factors such as the size of the plant, the construction site or the need for new connections with the transmission network. Nevertheless, we believe that our time frame is fairly representative.

- For each of the plants, we have assigned a (percentage) probability of it being realized. This acknowledges that plans can differ to reality, as experience has shown that not all plants that are planned are also built. However, without the ability (within the constraints of the present assignment) to speak to industry specialists in each of the countries, we have relied on our own judgement and press reports for assigning the probabilities.
- We have adopted three scenarios of gas demand – a minimum, base and maximum scenario. In the minimum scenario, in addition to the plants currently in operation, we include only those plants that are presently under construction; in the base scenario we also add plants that are at an advanced stage of planning; in the maximum scenario we further add the plants that are judged to have a material probability (>40%) of being constructed. The current installed capacities of TPPs and the planned gas-fired TPPs together with their assumed commissioning dates and the scenarios in which they have been included are presented in annexes 2-9 for each of the CEE countries.
- In order to determine gas demand from the plants assigned to each scenario, one must apply efficiency and load factors. For all new plants in all countries we assume an efficiency factor of 56%, which is consistent with the factors applying to newly-constructed combined cycle gas turbines (CCGTs). The efficiency factors we use for existing plants are those that are consistent with historical averages for each country (see annexes 2-9).[10]
- The final step in the approach is to assign load factors to the relevant plants. We note that we have not assigned load factors to individual plants, but to gas-fired generation capacity as a whole. Actual load factors depend on a number of parameters, including the merit order of operation, the nature of gas contracts, and gas and electricity prices. As the gas demand forecasts are highly sensitive to the assumed load factors, we have adopted a range of load factors differentiated by scenario (for details see annexes 2 to 9), and which take into account the following:
    - Existing load factors, which are assumed to be maintained for the period to 2012;
    - The fact that gas plants generally operate in the range of 20-75% load factor;

[10] We note that higher efficiency factors imply lower gas demand as the same level of electricity can be generated with less fuel.

- The second phase of the EU Emissions Trading Scheme from 2013, which we believe will improve the competiveness of gas-fired plants vis-à-vis other fossil-fuelled plants;
- The expectation that gas-fired TPPs are likely to be in the mid-merit order for most of the CEE countries; and
- The implementation of targets for generation from renewable energy sources (RES) – we generally believe that the impact on gas-fired generation will be positive for a couple of reasons. First, increased penetration of RES will require more back-up generation to which gas TPPs are particularly suited and, second, we believe that the RES targets set for 2020 will not be fully realised, thus increasing the load factors of gas plants (from as early as 2017).

While the above approach is reasonable for assessing gas demand from the electricity sector over the short term, it is not appropriate for longer term forecasts. To generate the longer term gas demand projections for electricity, we employ a somewhat crude approach, consisting of the following steps:

- Firstly, we develop high-level electricity forecasts on the basis of country electricity consumption elasticity factors (see annexes 2 to 9) and GDP growth estimates;
- Secondly, we determine peak load factors on the basis of peak consumption for each country over the 2005-2009 period (see annexes 2 to 9);
- Thirdly, we calculate the required installed generation capacity for each year in the forecast period on the basis of average loads (consumption/8,760 hours) and the peak load factors; and
- We then compare the 'required' capacity with the installed capacity (which we set equal to existing capacity plus the capacity of the new plants that are expected to enter the system less the capacity of plants that are planned for decommissioning). Where capacity is not sufficient to meet peak demand plus a 20% reserve margin, we generally assume the addition of 400 MW CCGT units (provided, of course, such increments of capacity are needed). On the basis of our analysis, it appears that most countries have sufficient capacity for the outlook period, especially under the base case (for details, please see annexes 2 to 9).[11]

[11] We note that our findings and assumptions appear to be consistent with the system adequacy forecasts of ENTSOe for 2011-2025.

Heating sector

Gas demand forecasts for the heating sector were calculated in three main steps. As for the other sectors, key assumptions underpinning the analysis can be found in the report's annexes.

Initially, estimates are derived for heat output (consumption plus losses) – we generally assume that heat output will remain constant at current levels as slight increases in consumption are expected to be counterbalanced by efficiency improvements within the heat distribution systems. More specifically, for Croatia, the Czech Republic, Poland and Slovenia we assume a zero growth rate under the base case, and an annual growth/reduction rate of +1%/-1% for the maximum/minimum scenario.

We have used different assumptions for Hungary, Romania and Slovakia where available data suggests that there is likely to be a reduction in heat output. In the case of Hungary, heat demand is expected to follow the decreasing trend of the recent past, which is explained by the increase of electricity, gas and biomass in the household / services sector as well as the implementation of energy efficiency measures. Similarly, in Romania the performance of the district heating systems tends to be very poor - partly because of insufficient insulation of pipes and excessive corrosion, and also due to an inability to meet peak heat demand – which has therefore resulted in increasing substitution away from this energy source. Coupled with the gradual elimination of subsidies in the sector and the promotion of energy efficiency, we expect heat output to fall significantly. Finally, in the case of Slovakia efficiency improvements are expected to result in decreasing heat output in future. The specific assumptions used for all countries' predicted heat output can be found in the annexes to this report.

Having estimated future heat output for each country, the next step entails the determination of the portion of heat production that will be met by gas-only district heating plants (DHPs). This is calculated by estimating the heat output expected from CHPs and non-gas DHPs, with the balance representing the heat output of the gas-only DHPs.[12] For the purposes of calculating the heat output of CHPs and non-gas DHPs, we assume the following:

- The output of existing CHPs remains constant at current levels;
- Non-gas DHP output production changes in accordance with recent trend rates; and

[12] Heat output from gas-fired CHPs must be deducted from the calculations, as gas consumption of CHPs is considered in the projections for the electricity sector.

- New CHPs (primarily biomass-fuelled plants) are assumed to have a load factor of 75% from their year of commissioning.

In the final step, the assumed heat output is converted to equivalent gas demand by applying the historical efficiency factors for gas DHPs in each of the countries.

Industry sector

Industrial consumption of natural gas is very important in the CEE region and is likely to be a pivotal element in the future development of gas consumption. The industrial sector, however, is diverse in the region and difficult to evaluate. This is particularly so as industry in CEE is continuing to undergo significant structural changes. Moreover, industrial demand is influenced by many competing factors, including economic growth, technological advancement, competition in national and world markets, the ease of using and the price of alternative fuels, and many other considerations.

Once again, it has not been possible within the scope and timing of the present project to comprehensively analyse the likely future development of gas demand in industry. However, as with the other main consuming sectors, we have adopted an approach that is clearly verifiable; the assumptions of our analysis were therefore subject to review and validation by the GWG members.[13] The methodology used to calculate the gas consumption forecasts for industry in the CEE region (excepting Croatia) is the following:

- For every gas consuming industry sector we ran regressions to establish the relationship between industrial output for each sector and GDP growth rates. The regression used data for 1995-2008 and the resulting relationships were found to be largely significant (i.e. they had a high coefficient of determination or R^2). In the country annexes (2 to 9) we present the equations and R^2 for the main gas consuming sectors that account for approximately 80% of gas consumption.
- On the basis of the above derived equations and forecasts of GDP growth rates we developed projections of future industrial output or production. We employ the IMF's GDP forecast growth rates out to 2016 for all scenarios. For the post-2016 period we assume real GDP growth of 3%, 2% and 1.5% for the maximum, base and minimum scenarios, respectively.

[13] We acknowledge that a major weakness of the analysis is that it does not take into account the influence of prices and the potential for substitution possibilities (particularly over the long run). However, we lacked sufficient pricing information for each main industrial sector in the various CEE countries to determine reasonable econometric relationships to take prices into consideration.

- In order to determine the equivalent gas demand associated with the forecasted industrial output, we assume gas intensity factors for each sector (see country annexes) that are equal to the average of the three-year period 2005-2008.
- To arrive at the final gas consumption figures we also apply efficiency factors to take into account the possibilities and likelihood of further efficiencies that can be achieved in industrial processes. According to the International Energy Agency and other parties and organisations, it is generally estimated that savings in the order of 10% of primary energy consumption can be achieved by industry employing best practice commercial processes and equipment that are known and available today. Accordingly, for each country we have assumed that these efficiencies will be achieved over the initial five-year period – to convert the primary energy saving to a gas efficiency factor we apply a weight coefficient determined by the ratio of current gas consumption to total primary energy consumption for each industry sub-sector. For the remaining period, we assume annual gas savings of 0.5%, 1% and 1.5% for the maximum, base and minimum scenarios, respectively.
- Finally, with the exception of Poland (which did not experience economic recession and industrial production seems to have held up), we assume that there will be an element of demand destruction in all other countries. This is because, industrial production declined sharply in 2008-2009 and although it started to grow again in the latter part of 2009, it was still very much below pre-crisis levels. Moreover, there have also been signs of apparent slower growth rates since mid-2010 (following the end of fiscal stimulus in many countries). Although it is difficult to predict the direct impact on natural gas demand since some fuels will have been affected more than others, it seems prudent to us that our forecasts take into account an element of demand destruction. For this purpose, we assume demand destruction equivalent to 5% of 2008 industrial gas consumption, with the exception of Bulgaria and the Czech Republic. For the former, we use a figure of 350 million cubic metres, which was provided to us by the Bulgarian representatives in response to the issued questionnaire. In the case of the Czech Republic, where we understand industrial output was particularly hard hit and is rising only slowly, we assume demand destruction equivalent to 10% of 2008 consumption.

In the case of Croatia, we did not have data for industrial production and were therefore unable to apply the above methodology. Hence, we assumed instead that consumption in industry would return to pre-crisis (2008) levels by 2014, consistent with predictions for GDP growth, and that gas consumption would increase thereafter at an annual rate of 2%.

Households and services

Gas demand growth in the residential and services sectors is related primarily to population growth and the costs of using gas versus other fuels for space heating and similar applications. Residential and commercial demand also reflects demographic shifts, penetration of gas-based technologies, growth in floor space, and levels of efficiency of gas burning appliances. Weather, measured in terms of heating degree-days, has an important short-term impact on both residential and commercial gas consumption. In the absence of any data that captures the effects of the abovementioned parameters, we have used some simplifying assumptions for deriving our demand estimates for these two sectors.

For all countries except Bulgaria (where gas use in the residential sector is limited) we apply benchmark annual growth rates for household consumption of 0.8%, 0.5% and 0.2% for the maximum, base and minimum scenario, respectively. These low growth rates reflect the fact that most markets are mature and that with future energy savings, there is expected to be limited demand growth.

In the case of Hungary, we have assumed that under the maximum scenario consumption will remain at current levels, while under the other two scenarios household consumption will *decrease* annually by 2% and 3% for the first 10 years and remain constant thereafter. These rates have been adopted following the feedback received from the Hungarian representatives stating that 15%-25% energy savings are possible in this sector.

We note that before applying the above annual growth/reduction rates to residential/commercial consumption in 2009, we have normalised the latter to average temperatures. This is because both the 2008/09 and 2009/10 winters were colder than average and this would have acted to raise observed demand for 2009 in this sector.

Having calculated household consumption, we then derive consumption for the services sector by assumption. Specifically, we assume that consumption in the commercial sector as a proportion of total demand for the household/services sector will remain constant at historical levels (please refer to the annexes for the proportions employed in each country).

The approach used for Bulgaria was different, as gas use is currently very limited (only 2% of households are gas consumers), while gas distribution licences have been issued just for 49% of municipalities. However, as one of the Government's strategic targets is the development of gas distribution, for the purposes of the forecasts we assume the following:

- The gasified percentage of the population in the licensed regions is considered to grow 15%. In the maximum scenario, a higher growth rate (20%) is assumed, while in the minimum scenario only limited development (5%) of the country's gasification is assumed.
- The unlicensed regions are considered to receive licences for gas distribution in 2019 (maximum scenario), 2020 (base scenario) or 2021 (minimum scenario).
- The newly licensed regions are expected to have a significant number of connections in their initial years, thus an annual increase of 40% - 80% (depending on the scenario) in connections is assumed.
- For all regions, we assume average household consumption to be 1,080 cubic metres (as provided to us by the Bulgarian representatives).
- Gas demand in the services sector is calculated on the assumption that it represents 30% of the total demand in the household / services sector.

3.1.3 Calculation of gas volumes to be transited through the CEE region

As discussed in earlier parts of this report, in addition to the demand and import requirements of the CEE countries, it is also important to ensure that there is sufficient infrastructure capacity in the region to support the continued transit of gas to downstream markets. In order to determine the required transit flows, one must answer the following two questions:

- Which are the relevant downstream countries/markets that are supplied with gas transited through the CEE region? and
- What volumes of gas and/or proportion of these countries' import requirements will be transited in future through the gas network system of the CEE region?

The relevant countries and the assumptions we propose to use for each regarding the required transit flows through the CEE region are presented in Table 2 below.

Table 2: Assumed transit flow requirements for each downstream market

Country	Share/volume of import needs transited through the CEE region	Comments
Bosnia and Herzegovina **FYR of Macedonia** **Serbia**	100%	All these countries will be supplied either through existing routes or the Southern corridor (whether through IGB, ITB, IAP or Nabucco) most of which necessitate transit through the region*
Greece **Austria** **Netherlands** **Switzerland** **Turkey**	80% of the current contract volumes for supply of Russian gas for the base case; +/- 10% for the min. and max. scenarios, respectively	All of these markets are characterised by diversified supply sources and entry points. We therefore assume that for reasons of diversification and security of supply they will not seek to increase the absolute volumes of gas sourced from Russia and transited through the CEE region. In the case of Turkey, we only use the contract for supplies through the Trans-Balkan route (which runs through Romania and Bulgaria).
Lithuania	80% of the PL-LT interconnection maximum capacity; +/- 10% for the min. and max. scenarios, respectively	We assume that: (i) the PL-LT interconnection will be constructed and operational from 2017, and (ii) its maximum capacity will be 3 bcm
Italy **France** **Germany**	80% of the current contract volumes and, after these expire, of the expected volumes in future contracts+ for the base case; +/- 10% for the min. and max. scenarios, respectively	In the case of France and Germany we assume 50% of their Russian imports will come through Nord Stream from 2013, thus, correspondingly reducing transit flows through the CEE region. Furthermore, in the case of Germany we assume that 50% of the transit requirements pass through the Yamal pipeline#.

* We note that an exception to this is IAP, which would supply BiH without requiring transit in the CEE region. When the IAP pipeline is assessed/added to the gas flow model we deduct 0.5 bcm from the transit needed for BiH. We also assume that there will not be a direct interconnection between Greece and FYROM.

+ The evolution of Russian contracts for these countries was provided by Booz&Co.

This distinction for the Yamal pipeline is made because it is considered as a dedicated transit pipeline that does not affect the CEE gas system; only its off-takes to the Polish market are used when examining the CEE gas system.

3.1.4 Peak demand

To identify potential bottlenecks in the CEE system caused by daily peaks, we derived projections for the daily peak demand of both the CEE countries and the downstream markets.

Calculation of the peak demand for the CEE countries was based on our annual demand projections (base scenario) and the estimations of ENTSOg, published in the Ten-Year Network Development Plan 2011 – 2020.[14] More particularly, for the period 2011-2020, we apply a peak load factor (specific for each country and year) to our annual projections; the peak load factor is derived by taking the ENTSOg annual demand projections and dividing them by the ENTSOg "high daily demand" (1-in-20 conditions). For the period 2021-2030, we use the average peak load factor of the 2011-2020 period for each country.

In the case of the downstream markets, we assume that they will not experience a simultaneous peak demand day with the CEE countries. Rather, the daily gas requirements of downstream markets are calculated by determining the historical (2006-2010) average daily winter demand (October through to March), which is then adjusted for the assumed transit volumes/coverage through the CEE region.

As explained earlier, for the purposes of assessing the fulfilment of the 'N-1 formula', apart from the daily peak demand under extreme weather conditions, we also examined peak demand excluding industrial customers. In this case, we applied the historic share of non-industrial consumption in total gas demand for the period 2006 – 2010 to our projections of daily peak demand.

Finally, in order to derive the import needs of each country, estimations for daily production in the CEE countries were also required. For this purpose, we used average annual production volumes increased by 25%, on the assumption that production is ramped up during the winter months and especially under peak demand conditions. As explained elsewhere, we also assume that storage facilities (where relevant) also operate at maximum flow rates, which are presented in the table below.

Table 3: Gas storage maximum flow rates

Maximum flow rates, mcm/day	
Bulgaria	3.3
Czech Republic	55.5
Hungary	79
Poland	26 upgraded to 49 in 2014
Romania	23.8 upgraded to 29.8 in 2015
Slovakia	37.4

[14] ENTSOg estimations were not used as stand-alone data as the corresponding annual consumption of the countries differed from our projections and they did not cover the post-2020 period.

3.2 Project assessment

The two key tools for assessing the proposed infrastructure projects are the gas flow simulation model and the multi-criteria analysis. Our approach to each is described in the respective sections that follow.

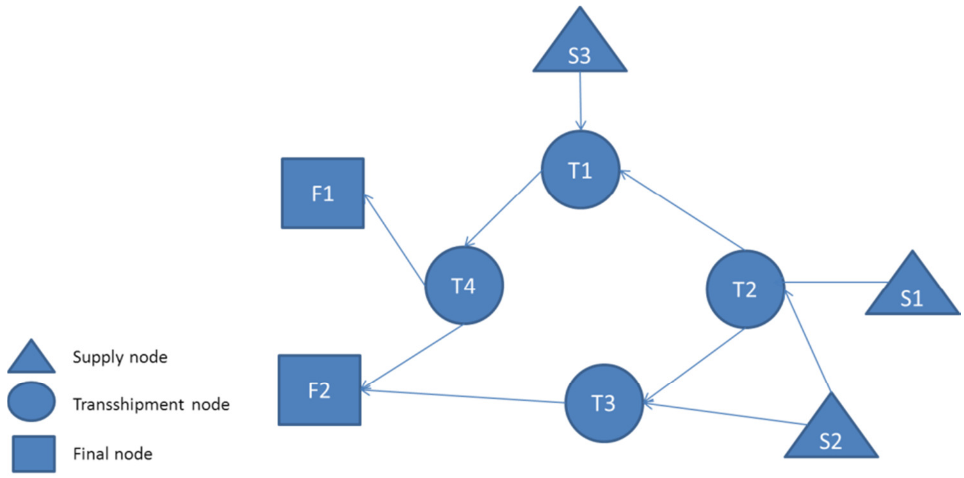
3.2.1 Gas flow simulation model

As discussed in section 2.3, for the purposes of both identifying infrastructure groups that cover CEE gas import requirements and selecting infrastructure groups that help meet the security of supply infrastructure standard (of Regulation 994/2010), a model was developed that simulates the gas flows in the CEE region.

As demonstrated in Figure 3, the flow network model incorporates the following basic features:

- Supply sources (including LNG terminals) are represented as supply nodes, without any 'predecessors';
- The CEE markets are represented as 'trans-shipment' nodes. Gas into each trans-shipment node comes from imports (supply nodes and neighbouring trans-shipment nodes), while gas out of the node goes to indigenous demand (net of production, where relevant) and transit volumes. Local storage facilities are only taken into consideration when examining daily demand, and in that case are treated as additional production equivalent to the daily maximum withdrawal rate of the given storage facility;
- Some markets outside the CEE region, which also transit gas from the supply sources to the final destination markets, are also represented as trans-shipment nodes and treated like the CEE markets;
- Downstream markets that do not transit gas further from the supply sources are represented as final nodes without any successors; and
- The total required gas flows between any two trans-shipment nodes are represented as arcs, connecting the two relevant nodes. Each arc is limited by the maximum technical capacity of the respective interconnection(s).

Figure 3: Diagrammatic representation of the gas flow network model



For each of the above features, the input data required by the model are the following:

- *Supply nodes*: the total supply volumes from each source and year of exports' start-up (if the source is currently not supplying the region). This data is defined in the supply scenarios of the regional analysis (task 1). For the flow model to function, the total supply is always set equal to the total demand in the region. To facilitate this, the Russian supplies are used as a "buffer" to confirm that supply equals demand;
- *Trans-shipment & final nodes*: the net gas demand of each market (that is, demand less domestic production, where relevant) and the daily maximum withdrawal volumes of storage facilities (only when examining daily demand). This data is the result of the work in task 1;
- *Arcs*: the maximum operating capacity of each interconnection (depending on whether annual or daily demand is examined), the start and end node of the interconnections and the year of commissioning (if the pipeline is planned). This data is the result of the work in task 1 (existing infrastructure) and task 2 (planned infrastructure).

The flow model structures a system of equations representing the gas balance in each node (total gas input in the node vs. gas needs in the node and transit requirements). This system is solved to calculate the gas flows through each arc. The deriving gas flows are then compared to the maximum capacity of the respective arc and potential bottlenecks (flows larger than the capacity restrictions), need for reverse flow (negative flows) or pipeline operation at large load factors (flows close to the maximum capacity).

As the number of arcs is larger than the number of nodes, and thus the number of equations, some gas flows must receive arbitrary values, for the system to be solved. To tackle this issue, for each model run we perform the simulation 1000 times, assigning different values to specific gas flows (always within the range of the respective arc's capacity).

To assess the importance of each planned infrastructure, we examine three cases of demand:

- Annual demand;
- Daily peak demand under severe weather;
- 'N – 1' rule (the largest interconnection of each CEE country is considered off-line) with daily demand under severe weather. The 'N – 1' rule is applied for each CEE market separately;
- 'N – 1' rule excluding gas demand of industrial customers. This case allows the examination of an extreme situation in which gas supply is not sufficient and cut – off of less sensitive customers is required.

All demand cases cover the period 2011 – 2030; i.e. the model is run sequentially for each year. The storage facilities are taken into consideration only in the cases of daily demand.

Initially we run the model including only existing infrastructure and infrastructure that is under construction (added in its planned year of commissioning). This way we identify if and when potential bottlenecks occur in the system. Next we run the model again, each time including a different planned infrastructure, to study its effect on bottlenecks. If a planned project is dependent on the development of other infrastructure (e.g. supply projects without existing infrastructure to export gas to neighbouring markets or interconnections that cannot be filled with gas unless supply projects are implemented), then a combination of these projects is examined.

For each examined infrastructure, the output of the model is the timing and the extent to which the project contributes to solving any occurring bottlenecks.

3.2.2 *Multi-criteria analysis*

Multi-criteria analysis (MCA) techniques were employed for the appraisal of the infrastructure options. This is an approach that is particularly suited to public policy options and decisions, particularly where there are a number of objectives being sought, which may require trade-offs. The box below describes the methodological approach and its key features and advantages. Following this, we present the selection criteria together with their scores and weights, which were developed in consultation with the GWG.

Box 1: Project appraisal and evaluation methodology – Multi-criteria analysis

Description	▪ Establishes preferences between options by reference to an explicit set of objectives that the "decision making body" has identified and for which it has established measurable criteria ▪ All MCA approaches require the exercise of judgement by the decision-making team in establishing objectives and criteria, estimating relative importance weights and judging the contribution of each option to each performance criterion ▪ Notwithstanding its subjectivity, MCA provides a degree of structure, analysis and openness to decisions and permits the explicit trade-off between options in a way that is beyond the reach of other conventional evaluation techniques
Advantages	▪ Transparent and explicit ▪ The objectives and criteria are open to discussion, analysis and change if they are felt to be inappropriate ▪ The scores and weights can be cross-referenced to other sources of information and amended if necessary ▪ Provides an audit trail ▪ Commonly used within government including in assessing EU Structural Fund issues ▪ Particularly suited to the ranking of options, especially where (as now) monetary valuations (e.g. cost-benefit analysis (CBA)) are either unavailable or not robust
Key features	▪ A standard feature of MCA is a decision criteria tree (or otherwise known as a value tree) which is a hierarchical representation of the criteria and sub-criteria to be used and facilitates the evaluation of the options ▪ MCA techniques commonly apply numerical analysis to the criteria tree in two stages: ➢ *Weighting*: numerical weights are assigned to define for each criterion (and sub-criterion) the relative valuation of the significance of each – any numbers can be used for the weights so long as their ratios consistently represent the ratios of the valuation of the differences in preferences between the top and bottom scores ➢ *Scoring*: the expected performance or consequence of each option is assigned a numerical score on a scale (which may be qualitative or quantitative) indicating the level of preference or achievement of the criterion
Type of MCA proposed	▪ A linear additive evaluation model was applied, as models of this type have a well-established record of providing robust support to decision-makers ▪ The linear model shows how an option's values on the various criteria can be combined into one overall value ▪ This is done by multiplying the value score for each criterion by the weight of that criterion, and then adding all those weighted scores together ▪ Proper application of this model requires that all criteria be "mutually preference independent" i.e. preference scores assigned to all options on one criterion are unaffected by the preference scores on the other criteria

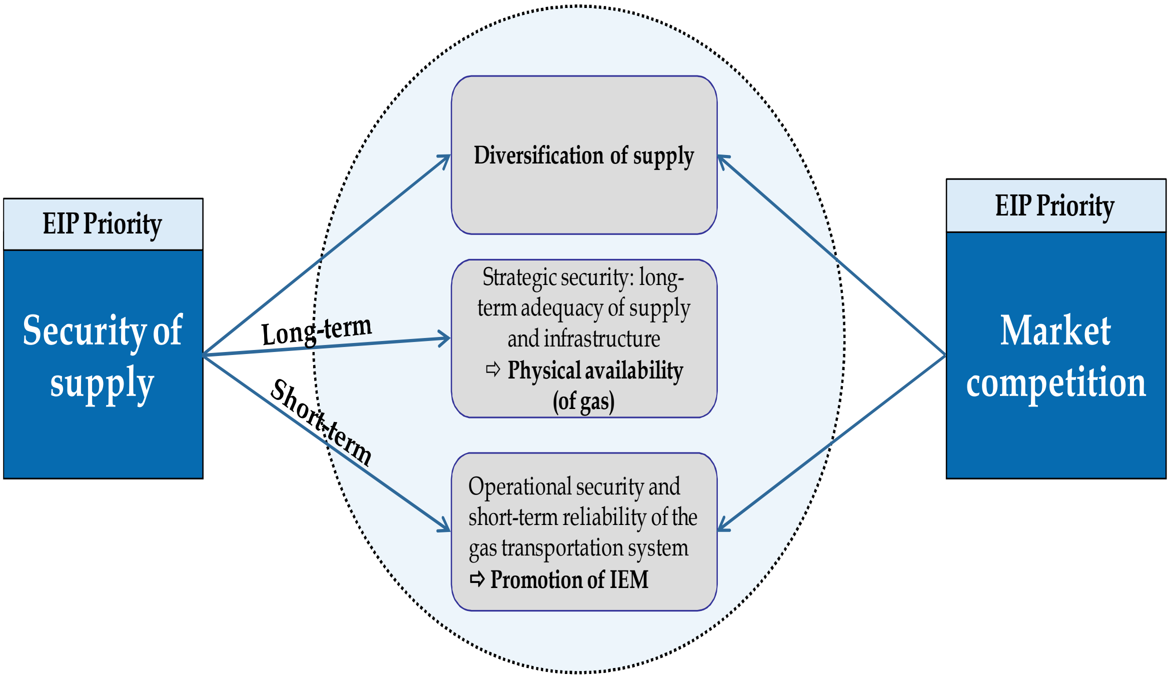
Procedure for deriving criteria weights	▪ The "Analytic Hierarchy Process" (AHP) was employed to derive the weights for each criterion and sub-criterion ▪ AHP is based on pairwise comparisons of the relative importance of any one particular criterion relative to another criterion ▪ As per common practice with AHP, a 9-point scale was employed to express the intensity of the preference of one criterion relative to another (1 = equal importance, 3 = moderate importance relative to the other, 5 = strong or essential importance, 7 = very strong or demonstrated importance, 9 = extreme importance)
Sensitivity analysis	▪ As this methodology will be used to prioritize projects for EU support, the choice of weights may be contentious ▪ For this purpose, we employed sensitivity analysis on the criteria weights as a means for examining the extent to which disagreement over weighting will make a difference to the final overall results ▪ The sensitivity analysis reveals whether preferences or weights affect the overall ordering of the options and also helps highlight the relative advantages and disadvantages of the various options

The specification of the project selection criteria must reflect the priorities and principles of the Energy Infrastructure Package. On our interpretation, the key priorities specified in the EIP are essentially twofold: to ensure security of supply and promote greater market integration and competition. Our general thinking regarding this matter (which is encapsulated in Figure 4 below) was as follows:

- An important element that helps promote both security of supply and the further development of competition is the greater diversification of supply;
- Security of supply has both a long-term and short-term dimension. In the long-term, it is important to ensure there is sufficient supply and infrastructure to meet demand (both average and peak), while in the short-run the system must have sufficient flexibility and reliability to ensure its operational security; and
- Many of the mechanisms for ensuring operational security are also precisely those measures that promote further market integration and competition (e.g. reverse flows, storage, etc.).[15]

[15] The assessment of any benefits must also take into consideration issues of cost. In this respect we note that notwithstanding the prioritisation developed in the context of the present study, if any project is to be supported, this should be conditional upon the demonstration of a positive social benefit-cost ratio.

Figure 4: Proposed selection criteria



On the basis of the above, we proposed three broad criteria categories, namely "Physical availability (of gas)", "Diversification of Supply" and "Promotion of the Internal Energy Market (IEM)". The sub-criteria that we proposed and were agreed for each criterion category together with the scoring system are presented in the table below. These criteria and the scoring system were discussed and accepted by the GWG in its 7th meeting.

Table 4: Proposed sub-criteria and scoring

Criteria	Scoring / Rating
Physical Availability	
Demand coverage	{Capacity to cover peak demand: 4, Capacity to cover peak demand without industry: 3, Capacity to partially cover peak demand without industry: 2, is not required for security of supply: 0} (Applicable to examination of N-1 rule)
Timing	{2011-2013: 4, 2014-2016: 3, 2017-2019: 2, Post-2020: 1}
Independence	{Stand-alone: 4, dependent: 0}
Composition of customer base	(Distribution + heating demand) / total demand in the year of project commissioning
Diversification	
Diversification of external supply	{New supplier + new source + new route (off-take directly in the country): 4, New supplier + new source + new route (off-take in neighboring country): 3, Existing supplier + new route + new or existing source: 1}

Lower import dependence		Capacity (only of infrastructure that provides access to gas produced internally in the EU or to trading hubs, i.e. to EU gas) / Total import needs in the year of project commissioning
Promotion of IEM		
Flexibility / liquidity	**Storage**	Storage capacity / Peak demand in the year of project commissioning
	Reverse flows	Reverse flow capacity / Peak demand in the year of project commissioning
	LNG	{Yes: 4, No: 0}
Integration	**Upgrade of existing capacity**	Interconnection capacity / Market size in the year of project commissioning
	New interconnection	Interconnection capacity / Market size in the year of project commissioning (not applicable to countries that are already connected)

The final step required the attachment of weights to each sub-criterion to arrive at a decision tree. As mentioned above, to derive the weights we used the AHP technique. The final scoring system is depicted in the decision criteria tree of Figure 5.

The AHP is one of the most commonly used methods for deriving criteria weights in MCA. After the decision problem has been structured and the criteria tree has been constructed, the decision maker is called to compare criteria and sub-criteria in pairs[16], deciding which is more important and to what extent. In other words, for each pair of criteria, the decision maker is required to respond to a question such as "How important is criterion A relative to criterion B?" Rating the relative "priority" of the criteria is done by assigning a weight between 1 (equal importance) and 9 (extreme importance) to the more important criterion, whereas the reciprocal of this value is assigned to the other criterion in the pair. The weights are then normalized and averaged in order to obtain an average weight for each criterion.

To define the weights of the criteria, the following procedure was applied:

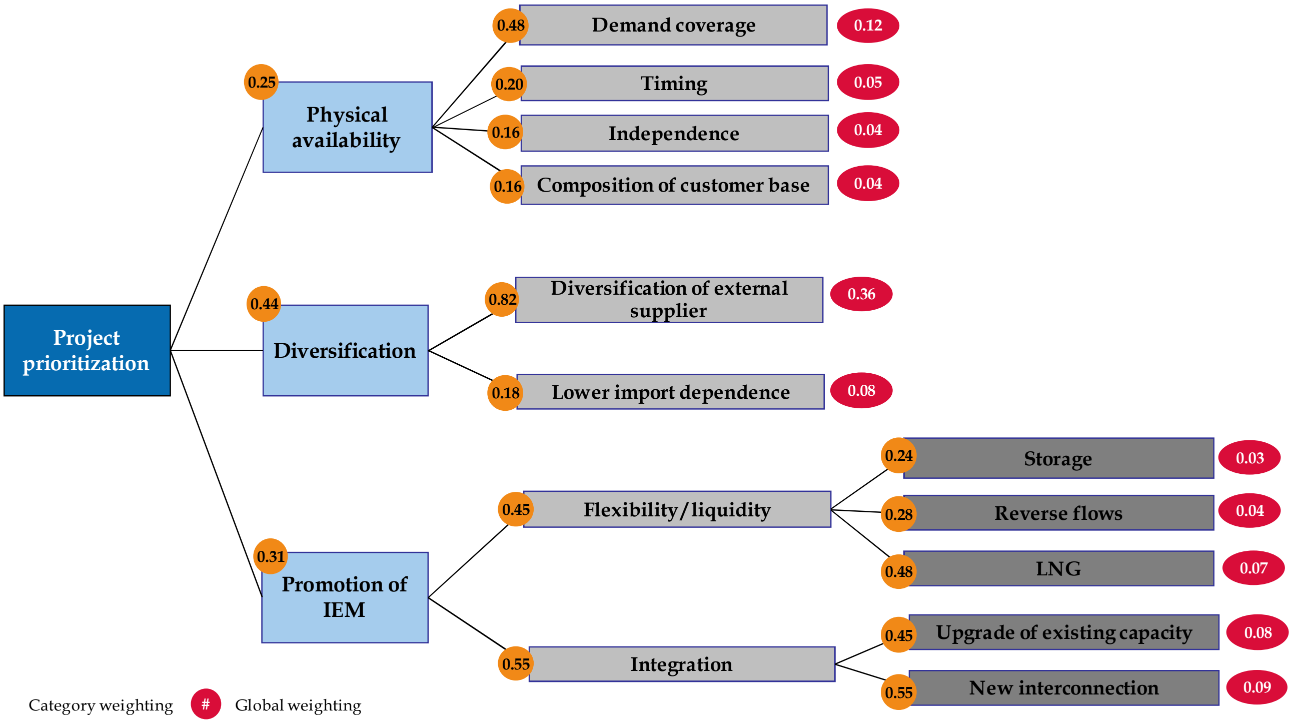
- The GWG was asked to provide their opinion on the importance of each criterion, during the 7th GWG meeting, through a questionnaire comparing all relative criteria and sub-criteria in pairs;
- These qualitative comparisons were translated into criteria weights using the AHP multi-criteria method described above;

[16] Only sub-criteria of the same criterion group are compared.

- In order to consolidate the individual weights into aggregates, we calculated their geometric mean, which is the best way to reflect the decisions of the whole group into one single value.

The weights defined by each delegation as well as the consolidated weights are presented in Annex 13.

Figure 5: Decision criteria tree



4. PROJECT RESULTS

4.1 Results of the demand, transit & supply analysis

In this sub-section we present the results of the demand analysis together with the implications of our assumptions for the CEE transit volumes. We also present our scenarios for the supply analysis.

4.1.1 Demand estimates

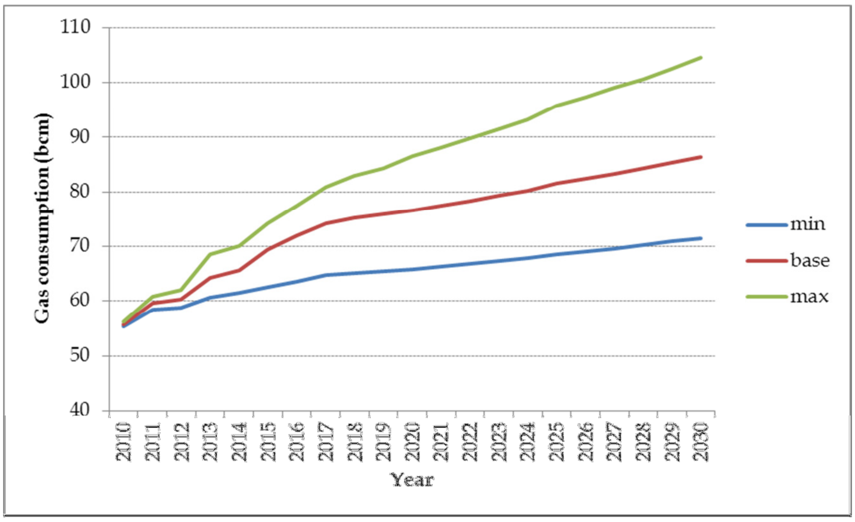
Figures 6(a) and 6(b) present our demand estimates for the region as a whole.

The annual demand forecasts rely primarily on KANTOR's initial calculations, suitably revised for updated information provided by some countries. Where agreement on our projections was not reached, we adopted the figures provided by the GWG members – this was the case only for Croatia. The changes at a regional level were immaterial while at a country level only the Croatian numbers changed significantly (e.g. in 2020 demand is now 5 bcm compared to our initially estimated 3.6 bcm).[17]

According to our estimates the incremental demand in the region compared to 2009 volumes under the base scenario is approximately 23 bcm to 33 bcm by 2020 and 2030, respectively. This represents an average annual growth rate over the entire period (i.e. to 2030) of 2.3%.

Under the base scenario total demand reaches 86 bcm, but could go as high as approximately 100 bcm (under the maximum scenario) or as low as about 70 bcm (low scenario).

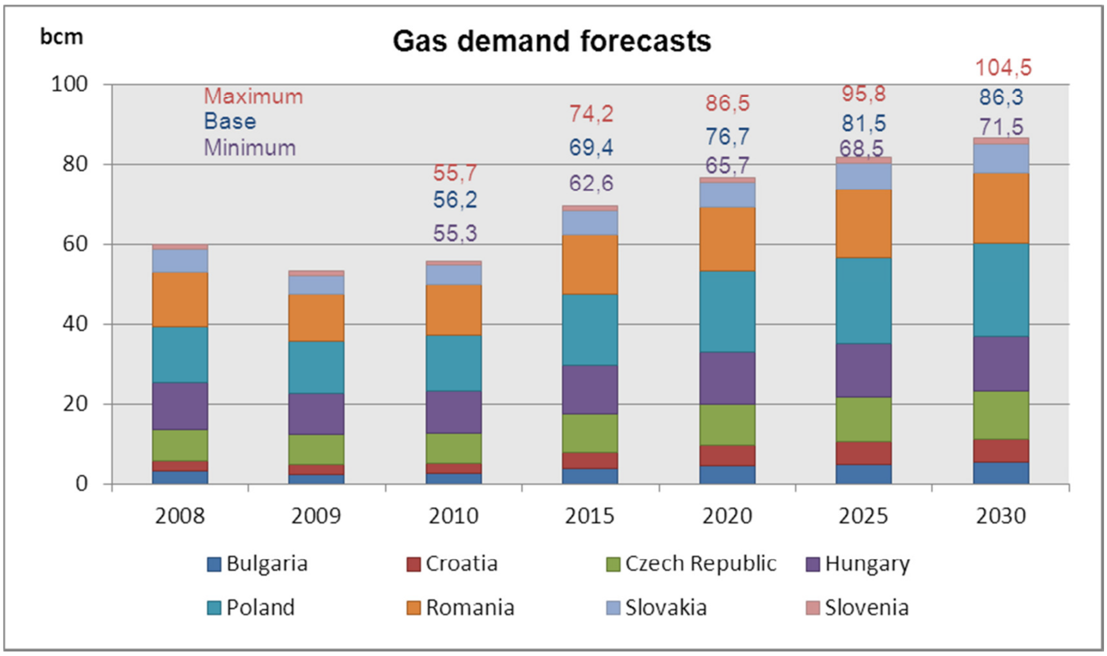
Figure 6(a): Demand projection for CEE countries, three scenarios



[17] We note that the Kantor calculations were adopted for the 'minimum' scenario in the case of Croatia.

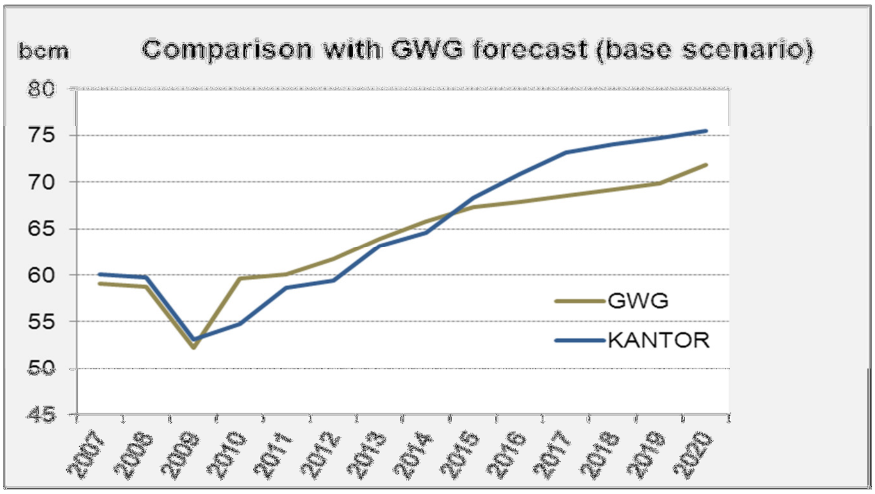
As is the case presently, demand in the region is dominated by the larger countries/markets, with Hungary, Poland and Romania representing about two-thirds of total consumption. The increase in demand is mainly due to the electricity and industry sectors, although this varies by country. The detailed results for each of the CEE countries are presented in annexes 2 to 9.

Figure 6(b): Demand projections for CEE countries, by country



Interestingly, our demand estimates for the region as a whole are very close to those produced by the GWG (see Figure 7). However, the overall results disguise some significant differences – for example, compared to the GWG numbers, our estimates are much higher for Hungary and Slovakia, but significantly lower for Croatia. Again, we refer you to the annexes for the more detailed results.

Figure 7: Comparison between the forecasts of the GWG and the Consultant



4.1.2 Daily peaks of CEE countries

The peak daily demand figures used in our analysis are summarized in Table 4. As in the case of annual demand, our initial projections were revised following feedback we received from the GWG members. Specifically, for Bulgaria, Croatia and the Czech Republic the data provided by the delegations were used, while for the other countries our figures were adopted. The detailed results for each of the CEE countries are presented in annex 12.

Table 5: Peak demand estimates

Peak demand (severe weather), mcm/day				
Country	**2015**	**2020**	**2025**	**2030**
Bulgaria	18.4	18.4	18.4	18.4
Croatia	15.9	18.0	20.7	21.7
Czech Republic	75.2	82.3	82.3	82.3
Hungary	77.3	88.9	95.2	97.7
Poland	82.3	106.1	112.6	119.8
Romania	118.2	124.8	133.2	140.6
Slovakia	39.1	41.0	42.8	44.9
Slovenia	5.7	6.3	7.0	7.5

4.1.3 Transit volumes

Table 6 over the page contains the annual transit flows that result from the assumptions discussed earlier in this report. In Table 7, we present the daily transit flows adopted when assessing the peak demand scenarios in the CEE countries.

Table 6: Assumed annual transit volumes, by downstream market and scenario

Consumption (bcm/yr)		*2010*	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2025*	*2030*
Austria	Min	5.04	5.06	5.08	5.10	5.13	5.15	5.04	4.94	4.84	4.74	4.65	4.67	4.74
	Base	5.60	5.62	5.65	5.67	5.70	5.72	5.60	5.49	5.38	5.27	5.16	5.19	5.27
	Max	6.16	6.19	6.21	6.24	6.27	6.29	6.16	6.04	5.92	5.80	5.68	5.71	5.80
Bosnia & Herzegovina	Min	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.41	0.42	0.52	0.64
	Base	0.31	0.32	0.33	0.34	0.35	0.37	0.39	0.41	0.44	0.47	0.50	0.70	0.95
	Max	0.31	0.32	0.33	0.35	0.36	0.37	0.40	0.43	0.47	0.50	0.55	0.85	1.28
France	Min	10.41	12.41	12.41	5.90	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.80
	Base	11.56	13.78	13.78	6.56	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
	Max	12.72	15.16	15.16	7.21	7.09	7.09	7.09	7.09	7.09	7.09	7.09	7.09	7.09
FYROM	Min	0.10	0.38	0.38	0.38	0.38	0.38	0.38	0.39	0.39	0.39	0.39	0.40	0.44
	Base	0.10	0.43	0.43	0.43	0.43	0.73	0.73	0.74	0.74	0.75	0.77	0.79	0.88
	Max	0.10	0.47	0.47	0.48	0.48	0.83	0.84	0.85	1.22	1.22	1.23	1.29	1.41
Greece	Min	2.02												
	Base	2.24												
	Max	2.46												
Germany	Min	13.89	15.49	19.09	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54	9.54
	Base	15.43	17.21	21.21	10.61	10.61	10.61	10.61	10.61	10.61	10.61	10.61	10.61	10.61
	Max	16.97	18.93	23.33	11.67	11.67	11.67	11.67	11.67	11.67	11.67	11.67	11.67	11.67
Italy	Min	23.37	23.37	23.37	23.37	23.37	23.37	23.37	23.37	23.37	23.37	23.37	21.21	21.21
	Base	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	23.60	23.60
	Max	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	28.56	25.92	25.92
Lithuania	Min	-	-	-	-	-	-	-	2.16					
	Base	-	-	-	-	-	-	-	2.40					
	Max	-	-	-	-	-	-	-	2.64					

Consumption (bcm/yr)		*2010*	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2025*	*2030*
Netherlands	Min							3.17						
	Base							3.52						
	Max							3.87						
Serbia	Min	2.18	2.17	2.19	2.20	2.23	2.41	2.44	2.45	2.48	2.51	2.53	2.65	2.93
	Base	2.21	2.25	2.30	2.36	2.43	2.66	2.73	2.80	3.05	3.12	3.18	3.49	4.07
	Max	2.23	1.98	2.36	2.46	2.55	2.84	2.94	3.06	3.37	3.49	3.60	4.44	5.47
Switzerland	Min							0.29						
	Base							0.32						
	Max							0.35						
Turkey	Min							10.08						
	Base							11.20						
	Max							12.32						

Table 7: Assumed winter daily transit volumes, by downstream market

Consumption (mcm/d)	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2025*	*2030*
Austria						31.11						
Bosnia & Herzegovina	0.88	0.91	0.94	0.97	1.00	1.06	1.13	1.20	1.28	1.36	1.91	2.61
France	57.27	57.27	27.25	26.79	26.79	26.79	26.79	26.79	26.79	26.79	26.79	26.79
FYROM	1.17	1.17	1.17	1.18	2.00	2.01	2.02	2.03	2.06	2.10	2.18	2.42
Greece						7.12						
Germany	126.21	162.54	66.27	66.27	66.27	66.27	66.27	66.27	66.27	66.27	66.27	66.27
Italy	99.93	99.93	99.93	99.93	99.93	99.93	99.93	99.93	99.93	99.93	90.69	90.69
Lithuania	-	-	-	-	-	-			6.58			
Netherlands						16.80						
Serbia	6.16	6.30	6.47	6.65	7.30	7.49	7.68	8.35	8.56	8.71	9.56	11.15
Switzerland						1.42						
Turkey						38.50						

4.1.4 Supply scenarios

There are a number of options available to serve the CEE gas markets, with a range of countries within their economic reach having sufficient reserves to meet the projected levels of demand, including the already connected producing countries of Russia and Norway. The potential of new sources and routes to compete for the incremental import needs of the CEE (and broader European) region is subject to a number of complicated factors including the timing and financing of competing options, domestic developments (political and economic) in the producing countries, the supply costs of the various options and future gas prices, and also broader geopolitical considerations. The major infrastructure and supply options that are relevant for the CEE area of study are the Nabucco and South Stream pipelines.

As it is difficult to draw definitive conclusions about the likely future supply sources for the CEE's/Europe's incremental import needs in general and for the two major transit options of Nabucco and South Stream in particular, we adopted a set of scenarios for the purposes of the gas flow analysis. These are shown in Table 8 below.

Table 8: Supply scenarios

	Pipelines	Timing (year)	Volumes (bcm)
Base case	Nabucco	2017/ 2020	15 / 31
'Complementary routes'	South Stream	2017	50 (northern branch), 13 (southern branch)
	Nabucco	2017/ 2020	15 / 31
'Competitive routes'	South Stream	2017	50 (northern branch), 13 (southern branch)

We note that in each scenario there will also be the existing supply routes from the EU/Norway and Russia. For the former, we will assume that volumes will remain at historical levels of approximately 7 bcm (this seems a reasonable assumption, given the expected depletion of gas fields and reduced production within the EU and Norway). Supply from Russia through existing routes will also be at historical levels in the beginning, but once alternative supplies/routes become available as shown in the table above, these volumes will be deducted from the existing Russian routes. We also note that other (smaller) pipelines that potentially form part of the "Southern Corridor" are separately assessed as part of the gas flow model analysis.

Finally, for each supply scenario above, we ran an additional scenario (six scenarios in total) that includes the possibility of shale gas production in Poland. For this purpose we adopted a modified 'moderate' (as defined by the GWG) production scenario; specifically, we assumed that production commences in 2020 at 5 bcm and increases to a maximum 10 bcm in 2022, which is maintained through to 2030.

4.1.5 *Existing cross-border pipelines and maximum flows*

In the diagram and subsequent table below we show the existing interconnections and cross-border flows that were used as the starting point for the analysis. The proposed projects are progressively added to these when conducting the gas flow analysis.

We note that Figure 8 and the following table (Table 9) need to be seen in conjunction. The arrows in Figure 8 represent arcs (or maximum capacities/flows) between countries, which have been numbered and their corresponding characteristics are shown in Table 9. It is important to note that each arc/number may correspond to more than one actual pipeline interconnection.

Figure 8: Stylized representation of the existing CEE gas grid

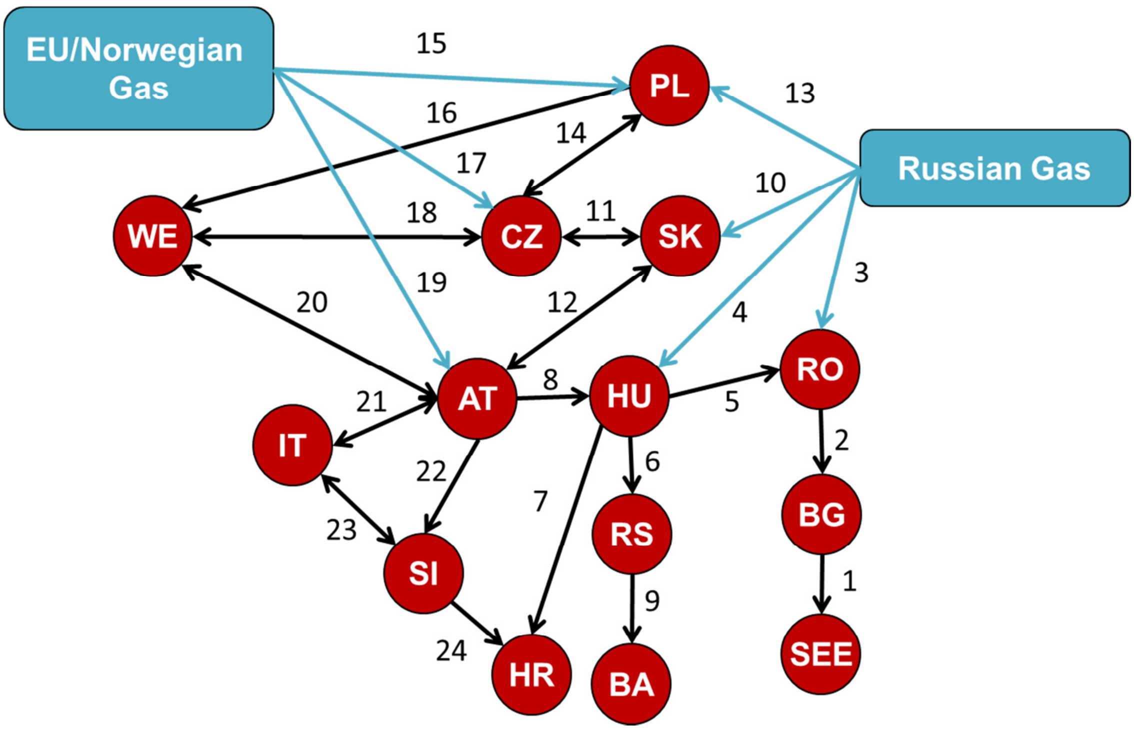


Table 9: CEE cross-border pipelines, capacities and flows

Arc No.	From (Main flow)	To	Max. Capacity (bcm/yr)	Physical dual flow	Virtual dual flow
1	Bulgaria	FYROM	0.8	No	No
1	Bulgaria	Greece	3.6	No	No
1	Bulgaria	Turkey	15.3	No	No
2	Romania	Bulgaria	96.4	No	No
3	Ukraine	Romania	78.8	No	No
4	Ukraine	Hungary	20.5	No	Yes
5	Hungary	Romania	1.8	No	Yes
6	Hungary	Serbia	4.8	No	Yes
7	Hungary	Croatia	6.5	No	Yes
8	Austria	Hungary	4.4	No	Yes
9	Serbia	Bosnia	0.6	No	No
10	Ukraine	Slovakia	101.8	No	Yes
11	Slovakia	Czech Republic	42.7	Yes	N/A
12	Slovakia	Austria	50.0	Yes	N/A
13	Ukraine	Poland	5.7	No	No
13	Belarus	Poland	5.7	No	No
14	Czech Republic	Poland	0.5	No	Yes
15	Germany	Poland	0.9	No	Yes
16	Poland	Germany	30.6	No	Yes
17	Germany	Czech Republic	12.6	Yes*	N/A
18	Czech Republic	Germany	39.0	Yes	N/A
19	Germany	Austria	7.95	Yes	N/A
20	Austria	Germany	12.3	Yes	N/A
21	Austria	Italy	37.1	Yes*	N/A
22	Austria	Slovenia	2.4	No	Yes
23	Italy	Slovenia	0.9	No	Yes
24	Slovenia	Croatia	1.5	No	Yes

* Although these are dual flow pipelines, flow is generally unidirectional to Germany and Italy for numbers 17 and 21, respectively.

4.2 Results of the flow model

As described in section 3.2.1, the flow model was applied for (i) annual demand, (ii) daily peak demand under severe weather, and (iii) the "N – 1" rule (for all customers and excluding the industrial customers). For each of the above demand cases, if the results of the model simulations without the addition of any planned projects demonstrated that demand can be met, there was no need to further assess the new/planned projects.

4.2.1 *Annual demand case*

The run of the model for the annual demand case, for the period 2011 – 2030, has shown that, regardless of the examined supply scenario, there are no occurring bottleneck issues in the CEE markets, despite the increase of demand. The reason is the development of transcontinental infrastructure in the region, i.e. Nord Stream, Nabucco and / or South Stream, that reduce demand and transit needs.

The construction of Nord Stream and either Nabucco or South Stream or both, brings gas directly to the markets, covering part of their demand, without requiring interconnections between the countries. Additionally, the load factor of the existing pipelines is reduced, as large volumes of Russian gas pass through Nord Stream and potentially South Stream. As a result, the existing infrastructure is therefore sufficient to cover the annual demand of the CEE countries and the downstream markets.

As no bottlenecks were identified in this case and thus no additional infrastructure is required to cover demand, the planned projects were not assessed.

Apart from the identification of bottlenecks, some general observations can be made following the examination of the annual demand case:

- **In the absence of the Nabucco pipeline (which would directly supply intermediate markets), CEE lacks interconnections with the rest of the EU that would allow the transport of gas from the Southern corridor to other markets**;
- **Moreover, no such interconnections are planned** - even if reverse flow of the HU-RO pipeline is implemented, its capacity is very limited;
- Similarly, **although several supply infrastructure projects are planned for Croatia, the country lacks sufficient infrastructure to transport gas to other markets**.

4.2.2 *Daily peak demand case*

As in the case of annual demand coverage, the implementation of the transcontinental projects will release capacity in the existing system, thus facilitating gas flows to cover daily peak demand, even under severe weather. However, before the commissioning of Nord Stream in 2013, bottlenecks appear in the SK-AT and the AT-DE interconnections, due to the large gas volumes that need to be transited to the downstream markets.

After the development of the transcontinental pipelines, the only bottleneck identified is in the RS-BH pipeline, from 2023 onwards, due to the increase in Bosnia's demand. However, as both Serbia and Bosnia are out of the scope of this study, none of the projects assessed can address the bottleneck issue. As no bottlenecks relevant to the CEE markets were identified, the planned projects were not assessed under this demand case.

4.2.3 "N – 1" rule case

The flow model was used for two demand cases of the "N – 1" rule, one where all consumers are supplied and one where industrial customers are excluded.[18] The "N – 1" rule is applied to each CEE market separately. In most countries the remaining infrastructure, after the largest one is assumed to be off-line, is not sufficient to cover both demand and transit needs, thus leading to bottlenecks and requirements for flow reversal. As a result, for security of supply reasons new infrastructure must be implemented to facilitate supply of the markets under these extreme conditions.

For each CEE market, the planned projects able to address the occurring supply problems are assessed. In the cases of dual-flow pipelines, both directions of the pipelines are examined.

Bulgaria

The RO – BG interconnection (78 mcm/d) is assumed to be shut down. This is the only entry point of gas in the country, so if it is out, the market cannot be supplied at all under existing conditions. We assume that Greece and Turkey cover gas needs from other sources, as their infrastructure allows for diversification of supply. Gas through Bulgaria is transited only to FYROM, which does not have any other supply options. Gas from Nabucco and South Stream, assumed to flow into Bulgaria, is not sufficient to cover demand, thus new infrastructure is required to supply the market.

[18] We believe it is relevant to examine whether particular projects contribute to meeting demand for the non-industrial sectors and to distinguish them from projects that do not help in meeting demand in the household and small commercial sectors. This is because larger industrial customers are likely to be able to maintain fuel switching capabilities and/or withdraw from the market, options that are not readily available to smaller customers. Indeed, it might make economic sense for larger customers to maintain fuel switching capability, rather than ensuring full demand coverage during a security of supply event.

Figure 9: Existing and planned infrastructure in Bulgaria

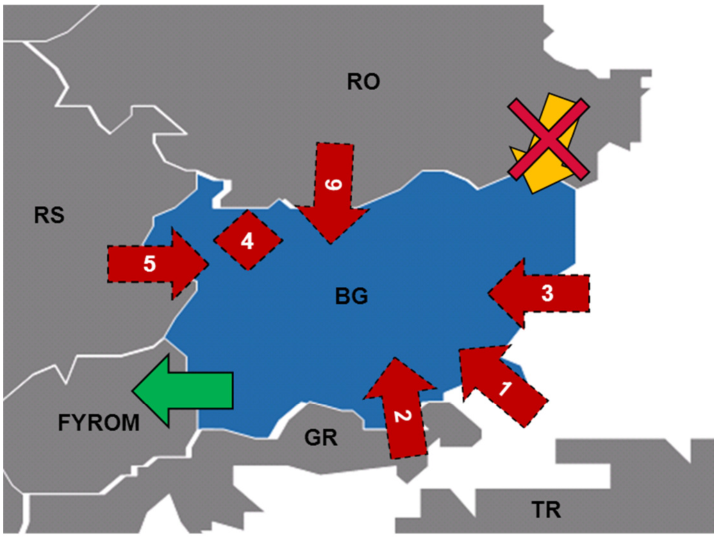


Table 10: Assessed projects in Bulgaria

	Project	Capacity (bcm/yr)	Start-up
1	ITB	5 upgraded to 9 (2017)	2013
2	IGB	3 upgraded to 5 (2020)	2014
3	Varna CNG	2.5	2015
4	Chiren UGS (upgrade)	Increased by 4.25 mcm/d	2017
5	BG ← RS	1.8	2015
6	BG ←RO (new)	1.5	2012

Table 11: Demand coverage in Bulgaria (all customers)

"N – 1" rule for all customers				
Project	**Base**	**Competitive**	**Complementary**	**Comments**
ITB	✓	✓	✓	Has adequate capacity to cover peak demand after 2017, when the upgrade is completed
IGB	✓	✓	✓	Has adequate capacity to cover peak demand after 2020, when the upgrade is completed
Varna CNG	✗	✗	✗	Limited capacity to cover demand
Chiren UGS	✗	✗	✗	Limited capacity to cover demand
BG ← RS	✗	✗	✗	Creates bottleneck in HU-RS interconnection
BG ← RO (new)	✗	✗	✗	Limited capacity to cover demand

Table 12: Demand coverage in Bulgaria (excl. industrial customers)

"N – 1" rule without industrial customers				
Project	**Base**	**Competitive**	**Complementary**	**Comments**
ITB	✓	✓	✓	Has adequate capacity to cover peak demand after 2017
IGB	✓	✓	✓	Has adequate capacity to cover peak demand after 2017
Varna CNG	✗	✗	✓	Has adequate capacity to cover demand after 2017
Chiren UGS	✗	✗	✓	Limited capacity to cover demand
BG ← RS	✗	✗	✗	Creates bottleneck in HU-RS interconnection
BG ← RO (new)	✗	✗	✗	Limited capacity to cover demand

Czech Republic

The SK – CZ interconnection (117 mcm/d) is assumed to be shut down. CZ-PL pipeline is assumed to operate in reverse flow.

Figure 10: Existing and planned infrastructure in Czech Republic

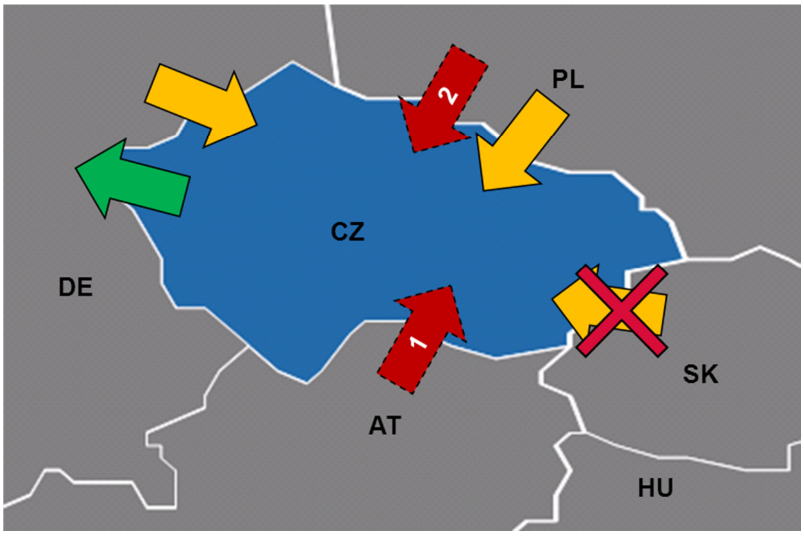


Table 13: Assessed projects in Croatia

	Project	Capacity (bcm/yr)	Start-up
1	AT → CZ	5	2017
2	CZ ← PL upgrade	5	2014

If the SK-CZ pipeline is out, CZ can cover its demand through the use of storage and reverse flow in the DE-CZ line. As a result, the planned AT – CZ pipeline and the upgrade of the CZ – PL interconnection, are not required to cover the gas needs of Czech Republic.

Croatia

The HU – HR interconnection (17.8 mcm/d) is assumed to be shut down. In that case bottlenecks appear in the AT – SI and SI – HR pipelines.

Figure 11: Existing and planned infrastructure in Croatia

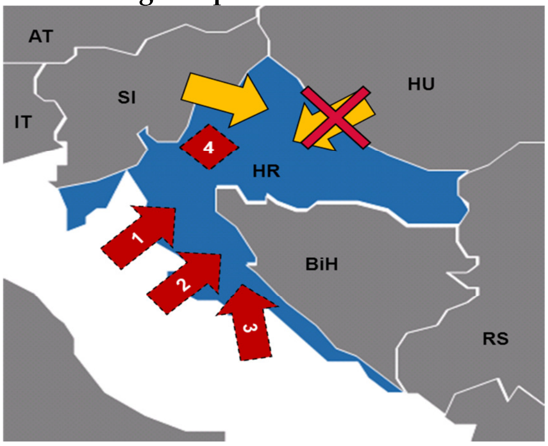


Table 14: Assessed projects in Croatia[19]

	Project	Capacity (bcm/yr)	Start-up
1	Adria LNG	10	2017
2	LNG RV	2	2014
3	IAP	2.5	2020
4	Benicanci UGS	3.4 mcm/d	2016

Table 15: Demand coverage in Croatia (all customers)

"N – 1" rule for all customers				
Project	**Base**	**Competitive**	**Complementary**	**Comments**
Adria LNG	✓	✓	✓	The project has large capacity and thus is only partially used to cover demand
LNG RV	✘	✘	✘	Limited capacity to cover demand
IAP	✘	✘	✘	Limited capacity to cover demand
Benicanci UGS	✘	✘	✘	Limited capacity to cover demand

[19] The SI-HR interconnection, with flow from Slovenia to Croatia is not taken into consideration in Croatia's 'N-1' analysis. The reason is that a main prerequisite for the implementation of the project is the construction of Andria LNG; in that case however Croatia would be in position to cover the 'N-1' rule, regardless of which infrastructure is offline.

Table 16: Demand coverage in Croatia (excl. industrial customers)

"N – 1" rule without industrial customers				
Project	**Base**	**Competitive**	**Complementary**	**Comments**
Adria LNG	✓	✓	✓	Only partially used to cover demand
LNG RV	✓	✓	✓	Has adequate capacity to cover demand
IAP	✓	✓	✓	Has adequate capacity to cover demand
Benicanci UGS	✓	✓	✓	Has adequate capacity to cover demand up to 2025

Hungary

The UA – HU interconnection (56.3 mcm/d) is assumed to be shut down. Large storage capacity and the AT-HU interconnection allow cover of peak demand and transit to HR, RS and BH up to 2023 for all scenarios, even when the UA-HU pipeline is out. In the base and competitive scenarios, a bottleneck appears from 2024 onwards in the AT – HU interconnection. In the complementary scenario, supply from Nabucco and South Stream is adequate to cover demand.

Figure 12: Existing and planned infrastructure in Hungary

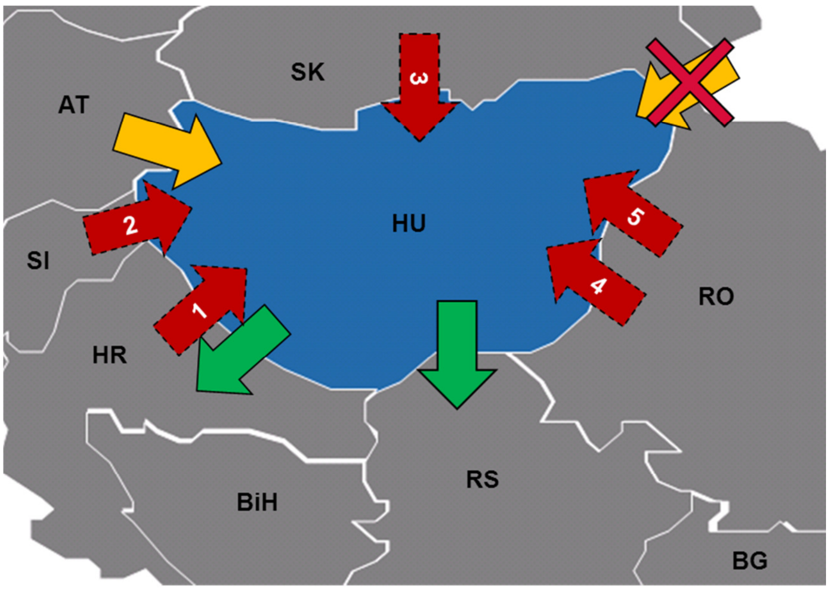


Table 17: Assessed projects in Hungary

	Project	Capacity (bcm/yr)	Start-up
1	HU ← HR (rev. flow)	6.5	2020
2	HU ← SI	1.3	2017
3	HU ← SK	5.2	2015
4	HU ← RO (rev. flow)	1.75	2013

Table 18: Demand coverage in Hungary (all customers)

"N – 1" rule for all customers				
Project	Base	Competitive	Complementary	Comments
HU ← HR (rev. flow)	✓	✓	**N/A**	Has adequate capacity to cover peak demand after the bottleneck appears, however is dependent on the implementation of supply projects in HR
HU ← SI	✗	✗	**N/A**	Limited capacity to cover demand
HU ← SK	✓	✓	**N/A**	Has adequate capacity to cover demand
HU ← RO (rev. flow)	✗	✗	**N/A**	Limited capacity to cover demand

If the industrial customers are not supplied then peak demand is covered without the implementation of any new project. As a result, the planned infrastructure is not examined under this demand case.

Poland

The UA – PL interconnection (15.6 mcm/d) is assumed to be shut down. We also assume that the LNG terminal, currently under construction, will be operational in 2014. If the UA – PL pipeline is out, Poland can cover its peak demand using the existing interconnections, stored gas and LNG up to 2020 when a bottleneck appears in the DE – PL pipeline. If Poland's shale gas resources are developed, then demand can be covered after 2020 without the addition of any new infrastructure.

Figure 13: Existing and planned infrastructure in Poland

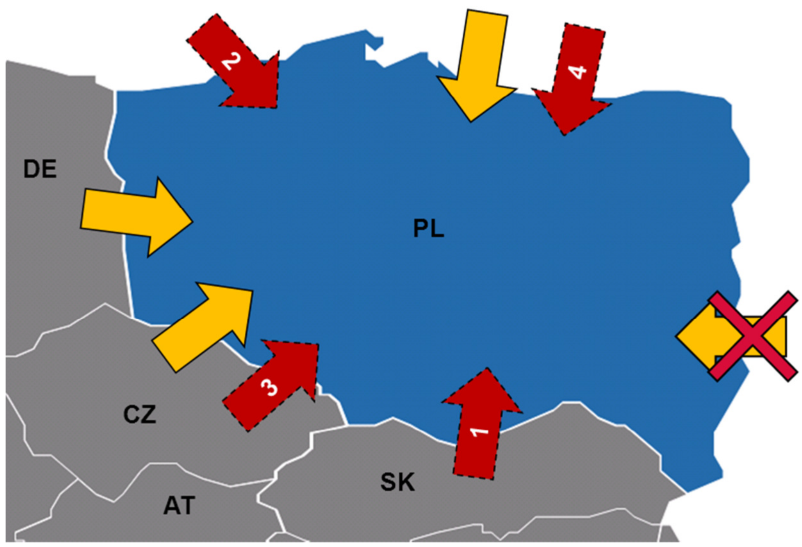


Table 19: Assessed projects in Poland

	Project	Capacity (bcm/yr)	Start-up
1	PL → SK	5	2017
2	Baltic pipe	3	2017
3	CZ → PL upgrade	5	2017
4	LNG upgrade	7.5	2020

Table 20: Demand coverage in Poland (all customers)

"N – 1" rule for all customers				
Project	**Base**	**Competitive**	**Complementary**	**Comments**
PL → SK	✓	✓	✓	Has adequate capacity to cover demand
Baltic pipe	✓	✓	✓	Has adequate capacity to cover demand
CZ → PL upgrade	✓	✓	✓	Has adequate capacity to cover demand
LNG upgrade	✓	✓	✓	Has adequate capacity to cover demand

If the industrial customers are not supplied then peak demand is covered without the implementation of any new project. As a result, the planned infrastructure is not examined under this demand case.

Romania

The UA – RO interconnection (215.9 mcm/d) is assumed to be shut down. We assume that Greece and Turkey cover gas needs from other sources, as their infrastructure allows for diversification of supply. Gas through Romania and Bulgaria is transited only to FYROM, which does not have any other supply options. A bottleneck appears in the HU – RO interconnection, which has very limited capacity to cover the country's large demand. Gas from Nabucco, assumed to flow into Romania is also insufficient to cover demand, thus new infrastructure is required to supply the market.

Figure 14: Existing and planned infrastructure in Romania

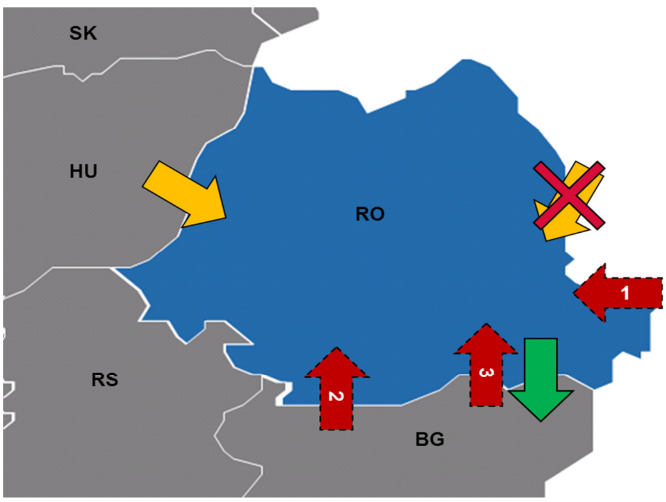


Table 21: Assessed projects in Romania

	Project	Capacity (bcm/yr)	Start-up
1	Constanta LNG	8	2015
2	BG → RO (new)	1.5	2012
3	RO ← BG (rev. flow)	5.3	2012

Table 22: Demand coverage in Romania (all customers)

"N – 1" rule for all customers				
Project	**Base**	**Competitive**	**Complementary**	**Comments**
Constanta LNG	✗	✗	✗	Limited capacity to cover the country's large demand
BG → RO (new)	✗	✗	✗	Limited capacity to cover the country's large demand
RO ← BG (rev. flow)	✗	✗	✗	Limited capacity to cover the country's large demand

Table 23: Demand coverage in Romania (excl. industrial customers)

"N – 1" rule without industrial customers				
Project	**Base**	**Competitive**	**Complementary**	**Comments**
Constanta LNG	✓	✓	✓	Has adequate capacity to cover demand
BG → RO	✗	✗	✗	Limited capacity to cover the country's large demand.
RO ← BG (rev. flow)	✓	✓	✓	Has adequate capacity to cover demand up to 2027. Implementation of the project assumes construction of new supply projects in BG

Slovakia

The UA – SK interconnection (278.9 mcm/d) is assumed to be shut down. As the largest entry point of gas into the EU is considered off – line, under the base supply scenario gas supply in the region is not sufficient to cover demand. In order for the flow model to run, we assume a lower transit requirement to meet demand in Germany (under the assumption that its shortfall can be met from one of its other supply sources). This assumption is not necessary for the competitive and complementary supply scenarios, because we consider that a significant part of Germany's demand is covered by gas deriving from South Stream.

Figure 15: Existing and planned infrastructure in Slovakia

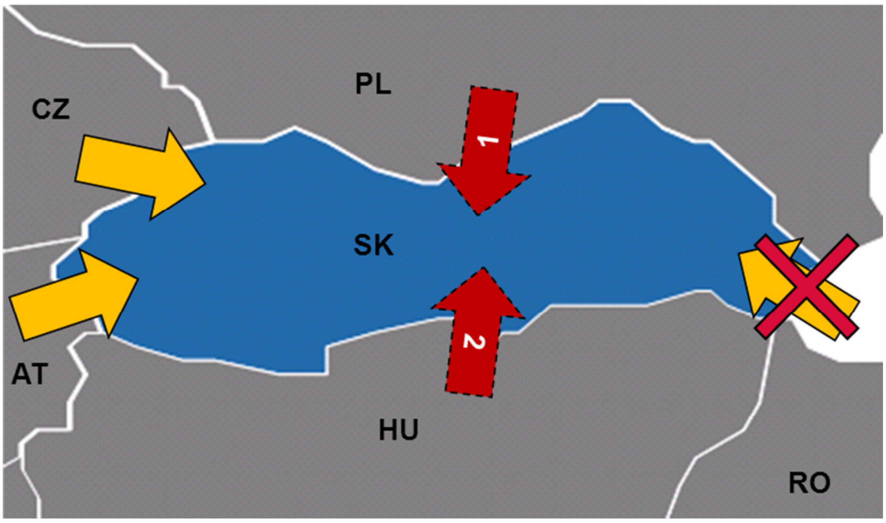


Table 24: Assessed projects in Slovakia

	Project	Capacity (bcm/yr)	Start-up
1	PL → SK	5	2017
2	HU → SK	5.2	2015

Regardless of the scenario, Slovakia can cover its demand through reverse flows in the CZ – DE, SK – CZ and/or SK-AT pipelines. However, although peak demand can be covered with reverse flows from CZ and AT, the interconnections PK – SK and HU – SK can facilitate direct connection to UA – PL and UA – HU pipelines, respectively.

Slovenia

The AT – SI interconnection (6.7 mcm/d) is assumed to be shut down. In the base scenario, bottlenecks appear in AT – IT and IT – SI. In the competitive and complementary scenarios only the bottleneck in IT – SI appears.

Figure 16: Existing and planned infrastructure in Slovenia

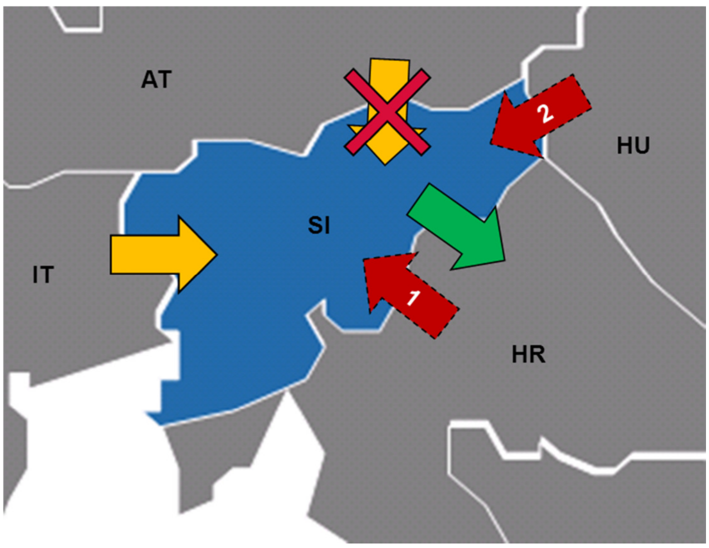


Table 25: Assessed projects in Slovenia

	Project	Capacity (bcm/yr)	Start-up
1	HR → SI	11.6	2017
2	HU → SI	1.3	2017

Table 26: Demand coverage in Slovenia (all customers)

"N – 1" rule for all customers				
Project	**Base**	**Competitive**	**Complementary**	**Comments**
HR → SI	✓	✓	✓	The project has large capacity and thus is only partially used to cover demand
HU → SI	✗	✓	✓	For Base scenario contributes to covering demand only up to 2019; for the other two scenarios, implementation of both this pipeline and South Stream provide adequate capacity to cover demand

If the industrial customers are not supplied then peak demand is covered without the implementation of any new project. As a result, the planned infrastructure is not examined under this demand case.

Key conclusions of the gas flow model analysis

- The CEE region is characterized by significant gas infrastructure and can therefore meet projected annual and peak demand under all reasonable scenarios;
- Supply problems present themselves in the event of outage of the main supply infrastructure, i.e. under the N-1 rule;
- Most of the projects being promoted partially or fully contribute to meeting demand under extreme conditions;
- The projects best suited to meeting demand under the N-1 rule depend on the specific circumstances of each country;
- In the absence of new infrastructure development, the countries most likely to have security of supply problems are Bulgaria, Croatia, Romania and Slovenia.

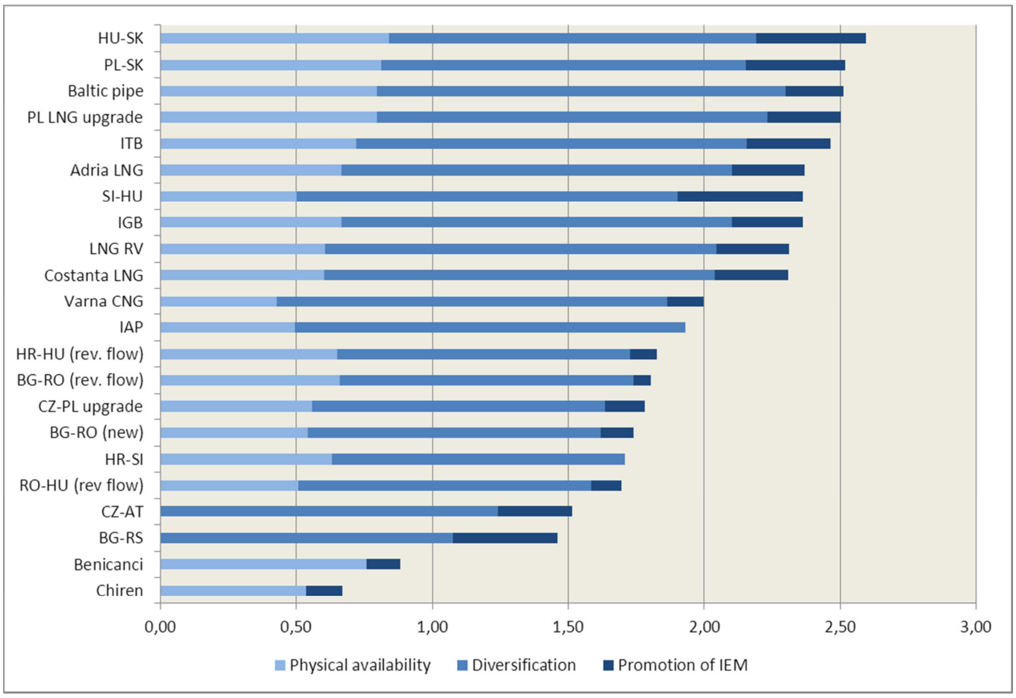
4.3 Results of the project assessment

When assessing projects under the physical availability criterion, we consider only the results of the base supply scenario. To estimate the rate of each project against the criteria and sub-criteria, we apply the rating system of Table 4 in section 3.2.2 of this report. These result in the ranking shown in the Table and Figure below. The detailed assessment of each project is presented in Annex 14.

Table 27: Results of project ranking

Project	Rating
HU-SK	2.59
PL-SK	2.52
Baltic pipe	2.51
PL LNG upgrade	2.50
ITB	2.46
IGB	2.42
Adria LNG	2.37
SI-HU	2.36
LNG RV	2.31
Costanta LNG	2.31
Varna CNG	2.00
IAP	1.93
HR-HU (rev. flow)	1.83
BG-RO (rev. flow)	1.80
CZ-PL upgrade	1.78
BG-RO (new)	1.74
HR-SI	1.71
RO-HU (rev flow)	1.69
CZ-AT	1.52
BG-RS	1.46
Benicanci	0.88
Chiren	0.67

Figure 17: Ranking of projects (overall)



In order to assess the influence of the criteria weights on the final ranking of the projects, we perform sensitivity analysis at the criterion category level, estimating the ranking for each criterion individually. The results of this analysis are presented in Figures 18-20 following.

Figure 18: Ranking for the "Physical availability" criterion

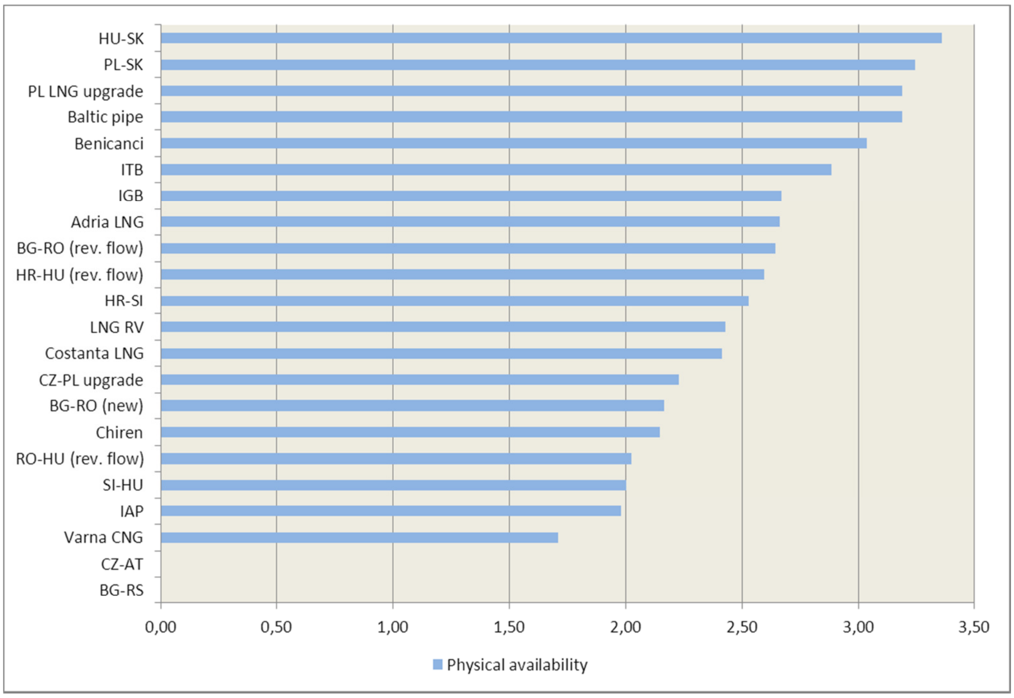


Figure 19: Ranking for the "Diversification" criterion

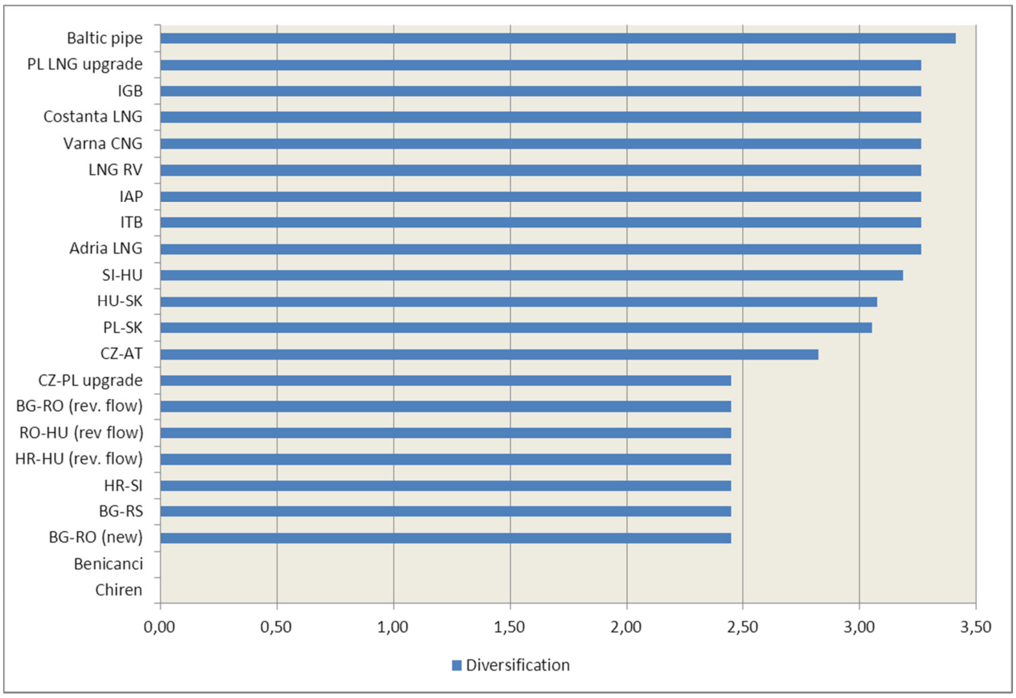
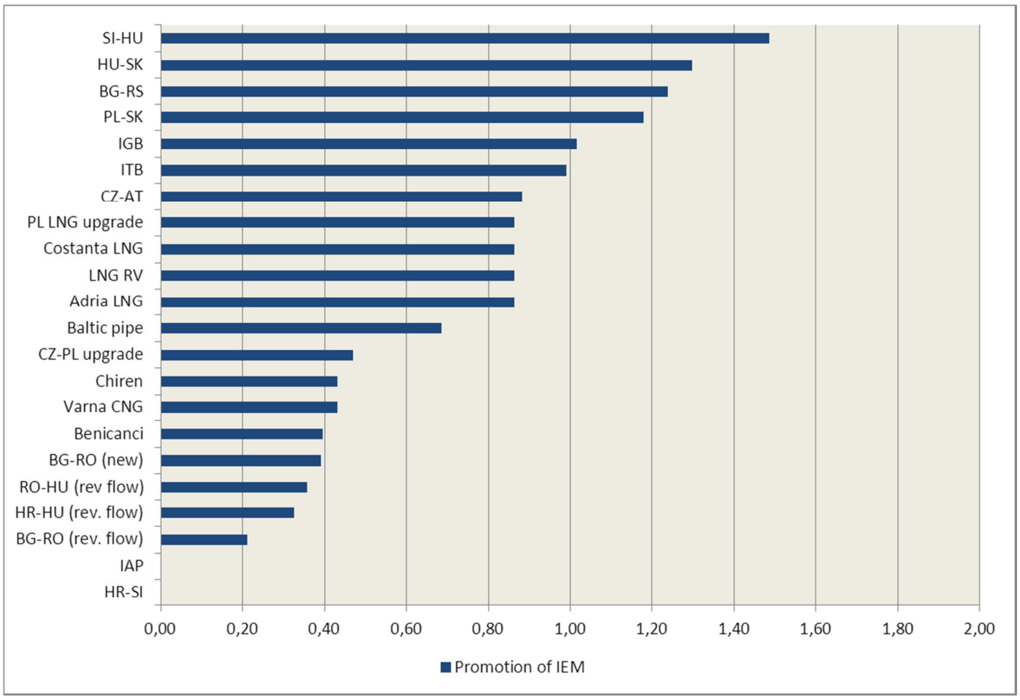


Figure 20: Ranking for the "Promotion of IEM" criterion



4.3.1 *Key conclusions from the project assessment*

- The HU-SK and PL-SK interconnections are ranked highest because they score highly on all three key criteria of physical availability, diversification and promotion of IEM;
- Given the importance placed on diversification of supply, new supply projects – LNG (Adria, RV, Constanta) and southern corridor projects (ITB, IGB, IAP, Varna CNG) – generally rank highly;
- Many of the above projects may be competing (both in destination and source markets) and therefore more detailed feasibility and cost-benefit analyses are required to assess their relative merits;
- Most cross-border pipeline projects are middle ranking because they score well on one or two but not all criteria;
- Storage and reverse flow projects rank highly for physical availability but have low overall scores as they contribute little to diversification;

The above analysis is highly dependent on the assumptions made in the supply scenarios in regards to the implementation of the large trans-continental pipelines in South Eastern Europe. It is advisable to update the analysis after the future development of the Southern Gas Corridor is clearer, especially following the decision (expected in the first quarter of 2012) on which infrastructure projects will be supplied from Shah-Deniz II.

5. ASSESSMENT OF IMPLEMENTATION OBSTACLES

5.1 Legal and regulatory obstacles

The main legal and regulatory barriers that may be hindering the investments in gas infrastructure projects have already been identified in the GWG's "Draft Stocktaking Report" and can be broadly outlined and reconfirmed as described in the sections below.

5.1.1 Delays due to lengthy and complex consultation and permit granting procedures

There are no major specific regional issues associated with permitting procedures in the countries covered by the North-South initiative in gas; these countries also follow similar processes between them. The overall length of the procedure is deemed acceptable by most of the companies. Some good examples and practices have also been identified in the region, which will assist during the next stage of the work where specific actions will need to be identified to tackle the above issues. These include the following:

- The **continuation of the permitting procedure in parallel to issue resolution with owners** (Romania);
- **Special and simplified procedures for projects of national importance (such as LNG terminal development)**, simplifying the compensation process and introducing strict deadlines (Poland); and
- **Cooperation with local authorities** (Bulgaria).

However, some specific issues still exist:

- Most of the problems that arise during permitting in the countries are related to land owners; **negotiations on compensation for land or finding the owner** can cause problems and significant delays in the process. Acquisition of land plots and landowners' consent to right-of-way is difficult in most of the countries. Settlement and expropriation procedures can take several years, or they can completely block a project.
- **Projects are not prioritized** in most of the countries; therefore, there is no special or streamlined treatment of these. There is no differentiation in the permitting procedure between a greenfield project and an upgrade project (or even a simple reconstruction of an existing facility). The latter should require a more simplified process.
- In some of the countries, **many permits from different authorities are required**. There are many steps and several parallel procedures in the permitting process, which creates opportunities for a great number of potential complaints against the project at each step of the procedure.

- There is a **lack of binding time limits** for procedures in some of the countries.

5.1.2 *Difficulties relating to the existing regulatory and/or financing framework*

The investment challenges of the EU's new infrastructure policy will need a different approach to financing, including new financing instruments beside the traditional funds under Cohesion Policy, loans or stock issuing. Companies unable to adapt to the new reality will face potential financing difficulties for their projects. The issue of financing is considered in greater detail in section 5.3.3 below. Other key obstacles in the regulatory area include:

- The **absence** (in many, but not all, countries) **of a stable and predictable regulatory environment**, especially tariff setting methodology for infrastructure projects, which is one of the key requirements to support the realisation of investments.
- **Tariffs do not provide sufficient incentives (i.e. sufficient rates of return)** for companies in some countries which may delay or even block projects.
- **Measures obstructing or prohibiting the flow of gas** (especially for export) exist in some countries which obstructs trade and the incentive for constructing and operating cross-border infrastructure. The **lack of access to gas storage capacities on a regional level** has the same effect. In addition, the inability to fully utilise available storage capacities in neighbouring countries means that the overall cost of provision at the regional level is higher than it otherwise would be.
- **Regulated prices covering too wide a scope of users and/or regulated prices well below potential market prices** (i.e. prices that are not cost-reflective) do not incentivize investments and energy efficiency, and are potentially discriminatory.

5.1.3 *Insufficient framework for regional cooperation*

Strong regional co-operation is required to identify, implement and monitor all necessary investments which are needed to reach the 20-20-20 EU targets. In this regard, the Gas Security of Supply regulation has stimulated increased cooperation in the region, e.g. Visegrad Group or the CEE Gas Regional Investment Plan (GRIP) under preparation by the Transmission System Operators of the relevant countries (Poland, Czech Republic, Germany, Austria, Slovakia, Hungary, Bulgaria, Romania and Croatia). Nevertheless, the following are also needed in our view:

- **Greater cooperation between regulators** on the different regulatory regimes for cross-border investments;
- There should be **a Gas Regional Initiative that comprises North-South participating countries in one group**; and
- There is potential for **cooperation of the North-South group with relevant neighbouring countries** and, especially, with the Energy Community and SE European countries.

5.2 Potential remedies for legal and regulatory obstacles

As a result of the preceding high level analysis, it is evident that there are legal and regulatory constraints to materialising investments in strategic gas infrastructure facilities. Delays in land acquisition and ownership settlement issues along with varying regulations regarding tariff setting methodologies and third party access to gas infrastructure facilities, in conjunction with different licensing and permitting requirements associated with lengthy and cumbersome procedures may adversely affect the financial/economic viability of the gas infrastructure investment projects.

To overcome the legal and regulatory barriers identified in the previous chapters, the following broad recommendations are proposed.

5.2.1 Procedural remedies

The measures below, which build upon experience and structures already employed in some countries and also the broad directions of the EC in its legislative proposal, could be considered by the GWG members:

- **Adoption of a national law to facilitate the implementation of a specific strategic gas infrastructure project** - using Poland and the LNG Terminal in Swinoujscie as an example, a country may choose to adopt a national law on the implementation of any given strategic gas infrastructure project. Such a law could simplify certain licensing and permitting requirements in light of the strategic importance of the project. The shortcomings of such an approach are: (i) the time required for such a law to be adopted and become effective, and (ii) the necessity for adoption of a new law for every major gas infrastructure project. For these reasons, we would recommend the adoption of this approach only for large LNG and/or CNG projects, which may require some 'special' treatment.

- **Establishment of a list of strategic infrastructure projects and the prioritisation of these projects at a national level** – there are various benefits to this approach. Projects which are deemed to be strategic or in the public interest can be subject to the streamlined measures discussed further below. A priority list also increases transparency and can assist in communicating to stakeholders and the general public the reasons for affording them a 'special status'. In addition, once a priority list is established, a single competent body (e.g. a Ministry or regulator) can be authorised with the responsibility of supervising, monitoring and evaluating progress, thereby improving the oversight and management of the projects and ensuring that timely interventions are made (when necessary) to safeguard project implementation.
- **Development of a standardised permitting procedure with binding time durations** – projects of strategic importance should be subject to a generic procedure, which aims to simplify, streamline and shorten existing processes and procedural steps. Moreover, specific time durations should be set for each permitting step, which should be binding on the relevant party responsible for each step. For example, if a construction permit requires the approval of a certain local authority within a given timeframe and no such approval is forthcoming during the specified time, then approval could be deemed to have been granted.
- **Adoption of a 'one stop shop' mechanism at a national level for the priority projects** - a 'one-stop-shop' approach for the gas infrastructure projects of strategic importance entails empowering a single entity to expedite the land acquisition and licensing and permitting procedures of the projects while authorising the same body by law to impose more stringent deadlines on the relevant competent authorities within the country. Employing such an approach would require the necessary legal framework, so as to enable the functioning of such a body and to clearly define the interfaces of interaction with other relevant central or municipal authorities and bodies.
- **Integration of spatial planning and land/easement matters into the permitting procedure** – two significant factors often contributing to project delays are issues of spatial planning and land access. For this purpose, both spatial planning and land issues should explicitly be accounted for in any streamlined generic permitting procedure. In practical terms, this would entail that spatial planning concerns be covered in the overall permitting procedure so that the relevant processes are conducted in parallel with other permitting matters. In the case of land, permits should allow a project developer to commence construction immediately if appeals have not been lodged within a defined time period after the granting of the permit. Moreover, decisions about compensation levels may follow the commencement of construction.
-

- **Standardisation of the permit application documents** – the development of clear guidelines on the scope and content of the application documents that must be submitted by project developers would significantly enhance understanding among the latter and expedite the process of conducting the necessary studies, impact assessments, etc. and submitting all relevant documentation.
- **Limitation of legal recourse and appeals to a single level of jurisdiction** – subject to any limitations imposed by constitutional provisions in the relevant countries, a single court or similar body could be appointed for the examination of appeals against permits, with its decisions being binding on all parties. Further appeals should generally not be permitted or should be limited to issues of due legal process rather than substantive permitting matters.
- **Promotion of effective stakeholder consultation** – public opposition to projects can significantly delay projects. It is therefore important that there be a comprehensive approach to information dissemination and public dialogue. Elements of such an approach could include: the obligation on project developers to conduct public information campaigns and consultation before submitting their applications, the conduct of a communication strategy at a national level promoting the need and benefits for the development of the priority infrastructure projects, appointing a central point of reference for fielding queries and addressing environmental concerns, and ensuring that affected parties are clearly identified and developing appropriate and targeted mitigation measures (including compensation).

5.2.2 Regulatory remedies and enhanced regional cooperation

The remedies in this area have been identified in other forums and in fact many of the measures included in the so-called "third legislative package" are important preconditions for ensuring both effective regional cooperation mechanisms (at both a regulatory and system operator level), and that transparent and stable regulatory frameworks are established, which are important for the promotion of infrastructure investments. There are, however, two particular issues, which we believe ought to be given further consideration in this context:

- **The permission (by regulatory bodies) of sufficient rates of return on the new infrastructure** – as demonstrated earlier in this report, many of the projects that are being promoted under the North-South interconnection initiative are necessary for reasons of security or diversification of supply and may not be justifiable on purely commercial grounds. In this sense, they differ from national gas transmission systems which generally face lower systematic risks and therefore should arguably be permitted higher regulated returns as compensation for the added risk (of under-utilisation). This concept is not new and in fact many EU regulators already treat new investment differently to the existing network (e.g. both Italy and France offer premiums between 1% and 3% for new investment).
- **Examination by regulators of consumers' willingness to pay for supply security** – this is an area which we believe has not been given sufficient consideration and could be a matter for investigation by national regulatory authorities and ACER. That is, given that many of the projects are justified on the grounds of security of supply, regulators should assess the value that consumers place on interruptions avoided with a view to determining the 'security insurance premium' that could potentially be levied on customers so as to internalise the cost of energy security (as opposed to relying on public funding of the relevant investments).

5.3 Innovative financial instruments for natural gas infrastructure projects

5.3.1 Current status

Introduction

The European Commission (EC) has estimated that investments of approximately EUR 200 billion will be required for energy transmission networks, in the period 2014-2020 in order to meet the EU's 2020 targets.

However, it is expected that only about 50% of the required investments for transmission networks will be taken up by the market by 2020. This leaves a gap of about EUR 100 billion. Approximately EUR 40 billion of this gap according to the EC is caused by delays in obtaining the necessary environmental and construction permits. The remaining shortfall of approximately EUR 60 billion is due to difficult access to finance and lack of adequate risk mitigating instruments, especially for projects with positive externalities and wider European benefits, but no sufficient commercial justification. This is particularly the case with regard to multi-country, cross-border connections.

The Commission proposes to work on two fronts: further improving the cost allocation rules and optimizing the European Union's leverage of public and private funding. In this section, we deal with the second initiative.

Overview of current situation

Currently, three institutional vehicles provide financial support to the development of energy infrastructure in the EU:

- The TEN-E framework, established in 1993, aims to promote "the creation of a single energy market, via initiatives which reduce the isolation of less favoured and island regions, securing and diversifying the EU's energy supplies, also through cooperation with third countries, and contributing to sustainable development". The development of Trans-European Networks (TENs) is supported by loans from the EIB as well as Community grants.

  From the inception of the policy in 1993 to December 2008, EIB signed loans amounting to EUR 12.4 billion for energy TENs. This amounts to loans of approximately EUR800 million per year.

  With regard to community grants, for the period 2007-2013, the TEN-E has a budget of EUR155 million (about EUR22 million per year), mainly intended to finance feasibility studies in electricity, gas and olefin transmission networks. TEN-E funds may co-finance up to 50% of eligible costs for studies and 10% of eligible works' costs for projects of European interest.

- The European Energy Programme for Recovery (EEPR) was set up within the framework of the EU in response to the economic crisis in 2009, to grant targeted financial assistance to projects in the field of energy. A budget of EUR3.98 billion (2009-2010) was allocated to the programme, in order to grant support to a limited set of projects that were already mature and to overcome possible funding gaps due to the economic crisis. Eligible areas are gas and electricity interconnection, gas reverse flows and storage, offshore wind energy, and carbon capture and storage.
- An additional source of financial support is provided by cohesion policy. In the current programming period, cohesion policy investments in trans-European energy networks in electricity and gas amount to EUR674 million.

Assessment of current situation

Performance

The TEN-E framework has played an important role in supporting immature and risky projects, mainly by financing feasibility and other technical studies. However, the limited size of the budget constrains its ability to deal with shortfalls in financing infrastructure investments. Furthermore, the TEN Financing Regulation allows only grants and interest rate rebates, while the market could also benefit from innovative financial instruments such as guarantees or equity participations for risk mitigation. In addition, the Regulation does not allow funding of capital expenditure outside the EU, which are an indispensable component for investments in large gas import infrastructure and related connection to upstream sources.

With regard to the EEPR, although evaluation studies are not yet available, initial feedback shows that it has been important in accelerating implementation of major energy projects and stimulating economic recovery.

Initiatives

Throughout various consultation exercises, stakeholders have consistently requested a change in the way the EU funds infrastructure projects. In the energy sector, the public consultation carried out in 2008/2009 for the Second Strategic Energy Review revealed a strong preference for a fundamental review of the TEN-E framework.

The European Council meetings of 4 and 28 February 2011 adopted conclusions supporting the main infrastructure policy directions outlined in the Energy Infrastructure Communication of 2010.

The Commission was specifically requested to report by June 2011 to the Council on figures on the investments likely to be needed, on suggestions on how to respond to financing requirements and on how to address possible obstacles to infrastructure investment. This assessment was based on an evaluation of the infrastructure needed to allow Europe to meet the overarching policy objectives of completing the internal energy market, ensuring security of supply and enabling the integration of renewable sources of energy. It identified about EUR70 billion for high pressure gas transmission pipelines (coming into the EU and between EU Member states), storage, liquefied/compressed natural gas (LNG/CNG) terminals and reverse flow infrastructure.

Requirements

These estimates have in the meantime been confirmed or even exceeded both by national regulators and transmission system operators. In the latest 10-year network development plan (TYNDP), published in March 2011, ENTSOg foresees investments of at least EUR 89 billion until 2020, including projects for which the Final Investment Decision (FID) has been taken and projects for which the FID has not been taken, although they are considered necessary for diversification of supply routes/sources and security of supply inside EU. This is considerably more than the results of a Council of European Energy Regulators (CEER) survey among its members, according to which total investment needs in transmission, LNG and storage infrastructure are estimated at between EUR 51 and EUR 59 billion (about 40 for transmission, 8 for LNG, 5-10 for storage). It should be noted that the CEER survey covers only investments on EU territory.

Furthermore, according to a study commissioned by the Commission and prepared by Roland Berger, investment volumes for the 2010-2020 period will, based on forecasts by transmission system operators (TSOs), increase by 30% for gas.

Obstacles

Investors, such as public banks or investment funds, confirmed that TSOs have largely exploited their ability to raise debt capital and that **future investments will require large equity injections by private investors or the State (in case of publicly owned TSOs)**.

At the same time, **TSOs could face challenges raising sufficient amounts of debt at reasonable cost, especially because of borrowing ceilings or the absence of or insufficient investment grade ratings**. Moreover, regulators will also have to take into account the often limited capacity of national consumers to bear tariff increases.

Investments in the priority corridors as outlined by the Commission Communication, including the projects examined in the present report, generally provide large socio-economic benefits at regional and EU level, but are not necessarily viable from an investor perspective. For example, as demonstrated elsewhere in this report, most of the proposed infrastructure projects provide security of supply 'protection' or enable the development of competition through diversification of supplies – in the former case, substantive utilisation of the infrastructure is not ensured under normal operating conditions, while under the latter the volumes are uncertain and highly dependent on the ability to compete supplies away from strong incumbents. Furthermore, the focus of the national tariff setting frameworks on national networks and consumers as well as the pressure to keep grid tariffs as low as possible in a context of low acceptability of structurally rising energy prices does not incentivize operators to invest in these projects. In particular, they have one or several of the following main features:

- They provide higher regional than national benefits, making the identification of benefits and allocation of costs a long and complex process with uncertain outcome. Examples of this type could be gas pipelines crossing a Member State bringing benefits to the neighbouring Member States or projects involving two or more Member States with asymmetric allocation of costs and benefits, as well as gas storage or LNG terminals serving more than one Member State.
- They use innovative technologies involving higher risks and/or uncertainties that are necessary for building the grid in an optimal and cost-effective way. As of today, such innovative investments are made difficult or impossible due to lack of adequate regulation, risk mitigation and financing instruments.
- They provide externalities not taken into account by market demand. Examples of such externalities are notably the following:

  - the regional or Union-wide gas security of supply provided by increased flexibility of the gas transmission network;
  - the advanced capacity provided for by "oversizing" gas pipelines compared to the short-term demand they cover; and
  - the increased market competition created by new or additional gas interconnection capacities.

The Commission estimated that projects worth 60 billion euros would be subject to the difficulties identified above.

In summary, the relevance of these obstacles has been confirmed by all stakeholders and there is broad consensus in that the existing financing framework does not allow addressing these issues properly, because of difficulties to quantify the benefits and costs and allocate them accordingly.

The way forward

In this regard, in order to overcome such market failures, the Commission has proposed the creation of a **Connecting Europe Facility**. The purpose is to terminate isolation of certain geographic areas and to ensure pan-European access to different sources and providers inside and outside the Union.

The intention is to link local and regional infrastructures to the priority EU infrastructures. **Co-financing will be provided by the structural funds** (cohesion fund and/or ERDF, depending on the situation of each Member State/region). The Commission proposed to allocate EUR 9.1 billion for the energy sector.

As part of the Connecting Europe Facility and in its Budget Review, the Commission has emphasised the need to maximise the impact of European financial intervention by playing a catalytic role in mobilising, pooling and leveraging public and private financial resources, through alternative infrastructure instruments. **The obstacles that need to be overcome include alleviating constraints faced by investors, mitigating project risks, reducing cost of financing and increasing access to capital**.

The Commission intends to continue strengthening EU's partnerships with International Financial Institutions (IFIs) and build on existing joint financial and technical assistance initiatives such as the Marguerite Fund.

In addition, the Commission intends to propose a new set of tools which combine existing and innovative financial mechanisms that are different, flexible and tailored towards the specific financial risks and needs faced by projects at the various stages of their development. Beyond the traditional support forms (grants, interest rate subsidies), the following options could be examined:

- equity participation and support to infrastructure funds;
- loan guarantees;
- public private partnerships;
- leveraging loan finance from IFIs; and
- targeted facilities for project bonds.

All these mechanisms have already been employed for other types of infrastructure (particularly transport) and can have similar application in the gas / energy sector. These options are described in greater detail in the sections immediately following.

5.3.2 *Innovative Financial Instruments*

Equity participation

Publicly supported equity financing involves initiatives such as the Marguerite Fund, set up by a consortium of IFIs. The Marguerite Fund has a target investment volume of EUR 1.5 billion, which is contributed by both public and private investors (such as large pension funds) with an emphasis on long-term investments. The general investment focus is on the transport and energy sectors, particularly greenfield investments (65% of projects) and projects that contribute to key long-term goals of the EC in these sectors. The target sector breakdown is as follows:

- Transport: 30-40%
- Energy (including transmission): 25-35%
- Renewable energy: 35-45%.

Overall, the idea of the Marguerite Fund is viewed as positive by TSOs and financing institutions as it provides an instrument on the equity side that is focused on the long-term investment requirements of the target sectors. The Fund was set up by six main sponsors: the EIB, KfW (DE), Instituto de Crédito Oficial (ES), PKO Bank Polski (PL), Cassa Depositi e Prestiti (IT) and the Caisse des Dépôts (FR). Each of these invested EUR 100 million in the first closing round, of the Fund's target volume of EUR 1.5 billion. Thus public investors play a leading role in the fund.

Concerns have been raised that **the rate of return expected internally is 10-14%**, whereas the existing regulated return structure in the energy transmission sector is in the single-digit range. This return requirement is mainly due to the broad investment focus of the Fund, which is also aiming at projects with higher returns.

The target investment volume of the Fund directed towards the energy sector is EUR 375-525 million. The volume directed towards the transmission segment will be even lower. This compares to an annual investment requirement in the energy transmission infrastructure industry of around EUR 7 billion (assuming a 30% equity share of annual investments in projects of European interest, which have a total value of EUR 20 billion). **Significantly larger equity volumes will therefore be required, even if only part of the equity has to be raised from external equity investors. For these reasons, the Marguerite Fund can be considered a useful first step towards creating better access to equity for the energy transport and transmission industry in Europe**.

Since 2005 three more such funds have been signed by the EIB (the Emerging Europe Convergence Fund; the Dexia Southern EU Infrastructure Fund; and the Dutch/ Northern EU Infrastructure Fund. A recent initiative of the EBRD has been the Meridiam Infrastructure Eastern Europe Fund (MIEE).

Case Study 1: Meridiam Infrastructure Eastern Europe Fund (MIEE), June 2011

Project Description
The EBRD is considering investing up to EUR100 million in the Meridiam Infrastructure Eastern Europe Fund (the "MIEE"), an infrastructure investment fund dedicated to providing investors with predictable and stable long-term cash flows through a diversified portfolio of investments in Public-Private Partnership (PPP) infrastructure projects in Central & Eastern Europe and, on a very selective basis, Turkey. The MIEE will be structured as a sub-fund of Meridiam Infrastructure Europe Fund II SCA (SICAR), a closed-end infrastructure investment fund established in Luxembourg (the "Meridiam Fund").

Transition Impact

The transition impact of the proposed project is expected to include: institution building, enhancing the availability of private capital and know-how in the delivery of PPP projects, promoting increased penetration of private equity PPP infrastructure investing in the region, promoting new methods of financing of PPP infrastructure projects with transparent private sector participation and demonstration effects in improving and enhancing transparency and good corporate governance in investee structures.

Management

The Meridiam Fund and MIEE will be managed by Meridiam Infrastructure Managers S.à r.l., a limited liability company incorporated under the laws of Luxembourg.

EBRD Finance

The EBRD is proposing to make an equity investment of up to EUR100 million.

Project Cost

The target Meridiam Fund size is EUR1 billion at final closing.

Impact

The MIEE will implement Environmental and Social Procedures, customised for application in the PP infrastructure sectors that the MIEE targets, and will structure the sub-investments to meet the Bank's Performance Requirements. The customised Procedures will facilitate the identification, mitigation and monitoring of environmental issues associated with investments across the region. The Fund Manager has agreed to refer all relevant A-category sub-investments to the Bank for review and guidance on ESDD. The MIEE will be required to adhere to the EBRD's Environmental and Social Exclusion and Referral lists, and submit annual environmental and social reports to the EBRD.

Loan Guarantees

The Loan Guarantee Instrument for Trans-European Transport Network projects (LGTT) is an innovative financial instrument set up and developed jointly by the European Commission and the EIB, which is designed to facilitate greater participation by the private sector in the financing of Trans-European Transport Network (TEN-T) infrastructure by significantly improving the risk profile of senior lenders. The LGTT is part of the EU's TEN-T programme and the EIB's Action for Growth initiative.

LGTT is examined in this section as an innovative/alternative instrument that can be used to finance gas infrastructure projects as well.

The LGTT is an EIB guarantee, the risk capital for which is jointly provided by EIB and the European Commission in favour of commercial banks which will provide the stand-by liquidity facility ("SBF") in addition to the usual project finance funding instruments. The SBF can be drawn by the project company in case of unexpected reductions in traffic income of the project during the initial ramp-up period of operation in order to assure service of its senior credit facilities. The SBF, funded by commercial banks, benefits from a guarantee from the EIB and is available for draw-down in the initial ramp-up period only. Under the LGTT the EIB accepts exposure to higher financial risks than under its normal lending activities.

In effect, if the EIB guarantee is called upon by the SBF providers at the end of the availability period, then the EIB reimburses the SBF providers and becomes a subordinated lender to the project but ahead of any payment to the equity providers and related financings. Once the EIB has become a creditor to the project, amounts due under the LGTT also rank junior to the debt service of the senior credit facility. The EIB, by taking such subordinated risk through the LGTT guarantee, helps the project to cope with the revenue risk of the early years of operation while relying on the long-term perspective of the project to be financially viable.

This instrument aims to foster private sector involvement in core European transport infrastructure, which often faces difficulties in attracting private sector funding due to the presence of traffic/revenue risks, especially the risks associated with initial traffic/usage levels.

As the instrument enhances the credit quality of the senior credit facilities, as well as the cost-effectiveness of the overall funding package, LGTT provides crucial support for projects that are based on traffic related revenues, particularly under current market conditions.

LGTT is financed with a capital contribution of EUR 1bn (EUR 500m each from the Commission and the EIB), which is intended to support up to EUR 20bn worth of senior loans.

The stand-by liquidity facility guaranteed by the LGTT does not normally exceed 10 % of the total amount of the senior debt. The amount of the guarantee is subject to a maximum ceiling of EUR 200 million per project pursuant to the EIB Structured Finance Facility rules ("SFF").

The LGTT significantly improves the ability of the borrower to service senior debt during the initial operating period or "ramp-up" phase of the overall project and of its initial traffic revenue. Its design substantially enhances the credit quality of the senior credit facilities, thereby encouraging a reduction of risk margins applied to senior loans to the project. These savings surpass the cost to the borrower of the guarantee, resulting in a financial value-added for the project.

Case Study 2: IP4 Amarante – Vila Real Motorway, Portugal

In May 2008, the EIB signed the first LGTT operation in favour of the IP4 Amarante-Vila Real Motorway in Portugal. The project includes five major interchanges with the existing network, 27 new major structures to be built and three existing structures to be widened.

The project comprises improvements to 29.8 km of the A4/IP4 connection between Amarante (Geraldes) and Vila Real (Parada de Cunhos) as part of a design, build, finance, operate and maintain concession.

The overall concession period is for a maximum of 30 years (from the date of signature of the concession). The project involves:

- widening the existing road between the Geraldes and Padronelo interchanges over 4.2 km to a 2x2 lane motorway standard;
- construction of a new alignment for 25.6 km between Padronelo and Parada de Cunhos, with a 2x2 lane motorway standard; and
- construction of the Marão tunnel (5.7 km).

Located on one of the major motorway connections linking the Iberian peninsula with the rest of Europe, this project is part of a TEN-T priority corridor. The EIB has provided two products to the concessionaire: a EUR 180m "Structured Finance facility" (SFF) project loan and a EUR 20m Loan Guarantee for TEN Transactions ("LGTT"). The IP4 is the first project to benefit from the LGTT.

Public-Private Partnerships

"Public-private partnerships" (PPP) refer to partnerships realised between the Public sector (Government, state owned companies, public agencies) and one or more private sector companies, on the basis of contractual agreements, involving the provision of infrastructure projects (funding, delivery, operation) and/or the provision of a service.

Both parties undertake contributions for the project and/or service to be realised, and both assume certain risks. In certain PPP cases the cost of using the service is borne exclusively by the users of the service and not by the taxpayer. In other types it could be borne by the taxpayer or shared with users. For example, in PFIs - Private Finance Initiatives, capital investment is made by the private entity(ies) based on a contract with Government to provide agreed services and the cost of providing the service is borne wholly or in part by the Government.

Government contributions to a PPP venture may be in kind (notably the transfer of assets – e.g. land, existing infrastructure and production assets, exploitation rights, etc.). Alternatively, Government contributions to a PPP venture may be in the form of financing, often through a combination of grant financing at the start of the project, provision of regular availability or capacity payments throughout the operation of the project/service, tax breaks and/or provision of guaranteed annual revenues for a certain period.

Some of the primary benefits from having private participation in infrastructure projects traditionally undertaken by the public sector, and creation of public-private partnerships (PPPs), include:

- Accelerating the implementation of high priority projects by packaging and procuring services in new ways;
- Turning to the private sector to provide specialized management capacity for large and complex programmes;
- Enabling the delivery of new technology developed by private entities;
- Drawing on private sector expertise in accessing and organizing the widest range of private sector financial resources;
- Encouraging private entrepreneurial development, ownership, and operation and/or related assets; and
- Allowing for the reduction in the size of the public agency and the substitution of private sector resources and personnel.

The extent to which these advantages are realized depends on the modalities employed for the incorporation of the private sector, the degree of its participation, the level of commitment from the parties and the efficiency and effectiveness in the management and administration of the whole process. The primary benefits of using PPPs to deliver projects include:

- Expedited completion compared to conventional project delivery methods;
- Project cost savings;
- Improved quality and system performance from the use of innovative materials and management techniques;
- Substitution of private resources and personnel for constrained public resources;
- Access to new sources of private capital; and
- Risk sharing between the parties involved.

Success relies on a transparent government and/or agency that has instituted a competitive procurement process; a focused and well-prepared implementation plan; and the effective negotiation of each agreement to yield the greatest value based on the type of PPP.

The EIB, the EC and EU Member States and Candidate Countries have jointly created the European PPP Expertise Centre (EPEC). EPEC helps strengthen the capacity of its public sector members to enter into PPP transactions, sharing experience and expertise, analysis and best practice relating to all aspects of PPPs. Finally EPEC aims to facilitate the effective sharing of experience and best practice in PPPs and to provide support for project preparation and advisory services to the public sector promoters. EU gas TSOs could obtain expertise through the use of EPEC.

Case Study 3: E18 motorway, Finland

In October 2005, the EIB signed a public-private partnership (PPP) loan for EUR 153 million for the construction and operation of a new section of the E18 motorway. The 51.4 km section between Muurla and Lohja in south-west Finland includes eight interchanges, seven tunnels and 49 bridge sites.

The Bank's financing of the project contributed towards an overall improvement in motorway standards and transport infrastructure in general in south-west Finland, serving the fastest developing areas of the country and supporting many growth centres. It also helped to considerably shorten journey times and improve accessibility, capacity and safety.

The project forms part of the Nordic Triangle, a TEN-T priority project and multimodal transport corridor of strategic importance, as it links the capital cities of the Nordic countries to each other and will improve connections to both Central Europe and Russia.

International Financial Institutions (IFIs)

The Commission has stated its intention to continue strengthening the EU's partnerships with International Financial Institutions (IFIs) and build on existing joint financial and technical assistance initiatives. Current sources of IFI financing include the following:

European Investment Bank (EIB)

Small and medium-sized TSOs in Eastern Europe in particular use EIB loans as a major source of funding on the debt side. The main advantages of EIB loans are their low interest rates (the EIB assigns a AAA rating to TSOs with relatively low spreads) and long maturities – 15 years on average – which meet the requirements of energy infrastructure investments.

EIB loans can cover up to 50% of the total investment in a specific project. In addition, there is a limit on unsecured loans of up to 10% of the equity volume of the TSO; further EIB loans must be backed by third-party guarantees.

The EIB provides loans typically on a corporate level, which function as senior debt, with guarantees from the state or the corporation. The overall annual lending volume of the EIB for energy grid investments was EUR 6 billion in 2010, of which approximately EUR 3 billion related to actual transmission infrastructure investments.

European Bank for Reconstruction and Development (EBRD)

The EBRD is active in Eastern and South-Eastern Europe, with a current focus on Russia, Serbia, Romania, FYR of Macedonia, Ukraine, and Bulgaria, for both inland lines and cross-border lines. The current overall debt volume is approximately EUR 1 billion, with a related total project value of approximately EUR 2.1 billion. The EBRD typically follows commercial bank pricing with a 1-7% spread and tries to involve corporate banks as co-lenders. It offers loans on both a project and corporate level. Loans are typically backed by sovereign guarantees to lower the debt capital costs. The EBRD plays an important role in the sector in Eastern Europe, bundling regional competence and providing expertise in smaller deals with a greater structuring need.

Other IFIs

A range of other IFIs are involved in debt financing for projects. Especially for quasi-public projects, multilateral agencies (MLAs) also play an important role in projects by either guaranteeing a certain amount of purchases of output produced by the project (either by agreeing to be a project off-taker directly, or helping arrange and secure off-take agreements by providing guarantees and subsidies to actual off-takers). In addition, many MLAs will provide political risk insurance to protect a project participant against the risks of capital controls, expropriation, or other adverse and unexpected political events. MLAs often assist project borrowers by providing credit enhancements or guarantees that enable the Special Project Entity (SPE) to increase the amount of its total borrowing and/or decrease its cost of debt capital. MLAs often associated with gas projects include the Nordic Investment Bank (focused on Northern and Eastern Europe), the World Bank through the IBRD (focused on Eastern Europe), the German Kreditanstalt für Wiederaufbau (KfW), International Finance Corporation (IFC), regional development banks, export-import banks, and other export credit agencies (ECAs).

In addition, the majority of the committed portfolio of other IFIs, such as the German Investment Corporation (DEG), Finish Development Finance Company (Finnfund), Netherlands Development Finance Company (FMO), and the French Investment and Promotion Company for Economic Corporation (Proparco) is through loans.

Case Study 4: NorNed

The NorNed project is the world's longest undersea power transmission cable. This major innovative trans-European network project consists of the construction of a 580 km-long HVDC hybrid bipolar submarine power cable link across the North Sea between Eemshaven (in the Netherlands) and Feda (in Norway), crossing Danish and German waters and interconnecting the two national power grids. Its promoters are the transmission system operators (TSOs) of the Netherlands and Norway, TenneT B.V. and Statnett S.F.

In this joint venture, TenneT and the Norwegian TSO Statnett will together invest a total of some EUR 600 million, of which nearly 50% is being financed by the EIB (EUR 280 million).

By interconnecting the electricity markets of the Netherlands and Norway, NorNed will enable the transmission and trading of electricity between the two countries, taking advantage of differences in the power generation structures in both countries and in the near future making market coupling between Scandinavia and central western Europe possible.

The NorNed cable will link the Dutch and Nordic national grid systems and electricity markets, which are currently not connected. This will help ensure the continued security of supply and enable more efficient use of the generation capacities in both countries, for example with better utilisation of thermal capacity in the Netherlands during off-peak hours and of hydro resources in Norway during wet years.

Project Bond Initiatives

The principal idea behind the **Europe 2020 Project Bond Initiative that is currently under consultation** is to provide EU support to project companies issuing bonds to finance large-scale infrastructure projects. The Initiative aims to attract additional private sector financing of individual infrastructure projects by improving the rating of the senior debt of project companies, thereby ensuring that this can be placed as bonds with institutional investors.

The Europe 2020 Project Bond Initiative would make use of project financing techniques that rank the future claims on a project's cash flows in order of seniority, whereby senior claims are served before subordinated claims, which in turn are repaid before equity holders.

By providing support at the subordinated level, the Initiative would absorb much of the risk of insufficient cash being available to service the senior debt, thereby raising its credit quality. This is known as "credit enhancement". The EU-supported credit enhancement would allow the senior project debt to be issued in the capital markets in the form of a new class of project bonds, resulting in reduced funding costs for longer maturities for project entities, while meeting the demand of institutional investors (such as pension funds and life insurance companies) for stable, long term assets.

For loans, a similar mechanism is already used in existing EU-EIB financing instruments such as the Loan Guarantee Instrument for TEN-T projects (LGTT) discussed above. In principle, the Europe 2020 Project Bond Initiative would apply this technique to bonds issued to finance infrastructure projects and would cover all project-related risks arising over the full term of the project debt.

The EU-backed EIB support could take the form of a debt service guarantee or an additional layer of debt at the subordinated level. The choice of a guarantee or a loan would depend on the exact financial characteristics of the project, but neither would substitute for shareholder contributions in the form of equity or shareholder loans.

The debt service guarantee could be in the form of a contingent credit line provided to the project entity by the EIB (or another financing partner), which would inject funds into the entity if the project were unable to generate sufficient cash in the short to medium term to service its debt for any reason. During the construction period, the credit line could be called upon to meet funding shortfalls and thus ensure that projects will reach the operating period.

The Initiative could also support, under certain conditions, refinancing efforts of infrastructure projects currently under construction. To ensure that the senior debt is and remains investment-grade at a level attractive to the investors in most scenarios, a guarantee amounting to maximum 20% of the total bond funding of an individual project would be required. If fully drawn, the guarantee would be able to cover several years' debt service, which experience shows to be sufficient when the guarantor can benefit from the diversification of a portfolio of projects.

The precise amount would be calculated with the objective of achieving a protection effect significant enough to ensure an investment grade rating of the project bonds. Ideally, the rating should be around A or higher to allow the debt to be financed via project bonds. A significantly higher coverage ratio could potentially prompt private project sponsors and other equity providers to lower their risk by providing less equity, while simply making the initiative more expensive for the EU and EIB.

The EU and the EIB would share the risk of the losses of the project portfolio. The EU risk would be ring-fenced and its participation therefore capped at an agreed annual budgetary amount. The EIB would be covering the residual risk up to its maximum exposure on any individual transaction. The risk-taking of the EU and the EIB would be compensated via a risk premium charged up-front to the project entity at the time of agreement of the guarantee. This premium will be priced to reflect the subordinated status of the credit line and the associated risks for the EIB and the EU as well as covering expected management and other costs. The appropriate pricing system, while similar to that used in the LGTT, will require further finetuning in order to ensure that it is at a level where it does not deter the bond financing it tries to support, while covering the above-mentioned factors.

The intention is to build a portfolio of transactions sufficiently diversified in particular in terms of size and sector so as to benefit from risk reduction through the "portfolio effect". This would increase the impact of EU budgetary funds and EIB interventions in terms of credit enhancement volumes available for projects.

The initiative is also open to other financing partners, such as IFIs and/or other Member States banks with a public sector mandate, with experience in the financing of EU infrastructure projects and the willingness to carry the associated risks in partnership with the European Commission.

ANNEX 1: DEMAND PROJECTIONS BY COUNTRY AND SCENARIO

Consumption (bcm/yr)		*2010*	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2025*	*2030*
Bulgaria	Min	2.60	2.61	2.66	3.33	3.32	3.37	3.41	3.64	3.65	3.66	3.68	3.84	4.04
	Base	2.62	2.66	2.75	3.52	3.56	3.64	3.73	4.45	4.51	4.58	4.65	4.99	5.42
	Max	2.65	2.71	2.83	3.85	3.93	4.05	4.18	5.17	5.30	5.44	5.59	6.67	7.73
Croatia	Min	2.67	2.72	2.76	3.04	3.09	3.36	3.40	3.45	3.49	3.54	3.59	3.88	4.22
	Base	2.67	3.13	3.27	3.90	4.13	4.43	4.48	4.53	4.86	4.91	4.99	5.62	5.91
	Max	2.67	3.44	3.59	4.29	4.54	4.87	4.92	4.98	5.34	5.41	5.48	6.18	6.51
Czech Republic	Min	7.39	7.75	7.86	8.27	8.39	8.52	8.67	8.91	8.95	9.00	9.09	9.63	10.21
	Base	7.46	7.86	8.00	8.65	8.81	9.40	9.58	9.96	10.08	10.19	10.31	11.04	11.84
	Max	7.52	7.96	8.14	9.03	9.23	9.93	10.15	10.63	11.35	11.58	12.03	13.34	14.83
Hungary	Min	10.28	10.72	10.66	10.60	10.56	10.53	10.50	11.00	10.93	10.87	10.82	11.06	11.32
	Base	10.33	10.82	10.80	11.35	11.35	12.15	12.39	13.06	13.04	13.03	13.02	13.36	13.74
	Max	10.43	11.01	11.09	12.29	12.38	13.36	14.23	15.36	15.46	15.55	16.23	16.78	17.42
Poland	Min	13.77	14.52	14.76	15.07	15.43	15.78	16.19	16.36	16.53	16.71	16.89	17.83	18.85
	Base	13.98	14.92	15.18	15.42	16.07	17.61	19.28	19.53	19.79	20.05	20.31	21.71	23.25
	Max	14.18	15.31	15.76	16.24	16.91	18.33	19.94	20.31	20.70	21.11	21.53	23.81	26.43
Romania	Min	12.49	13.46	13.48	13.71	13.95	14.19	14.45	14.49	14.54	14.59	14.64	14.95	15.31
	Base	12.56	13.60	13.67	14.38	14.63	14.90	15.17	15.30	15.44	15.58	15.73	16.79	17.72
	Max	12.62	13.72	13.87	15.71	15.88	16.17	16.45	16.68	16.91	17.15	17.40	19.39	21.01
Slovakia	Min	5.15	5.60	5.67	5.73	5.79	5.86	5.94	5.95	5.97	5.98	6.00	6.16	6.41
	Base	5.17	5.65	5.75	5.94	6.02	6.14	6.24	6.29	6.33	6.38	6.43	6.72	7.05
	Max	5.20	5.70	5.82	6.03	6.14	6.32	6.43	6.65	6.74	6.84	6.94	8.00	8.64
Slovenia	Min	0.91	0.95	0.96	0.97	0.98	0.99	1.00	1.01	1.02	1.03	1.04	1.10	1.17
	Base	0.91	0.96	0.97	1.01	1.02	1.10	1.11	1.12	1.14	1.15	1.23	1.31	1.41
	Max	0.92	0.97	0.99	1.05	1.07	1.15	1.17	1.18	1.20	1.22	1.31	1.64	1.97
Total	Min	58.8	60.7	61.5	62.6	63.6	64.8	65.1	65.4	65.7	58.8	60.7	68.5	71.5
	Base	60.38	64.17	65.60	69.37	71.98	74.23	75.18	75.87	76.66	60.38	64.17	81.54	86.34
	Max	62.1	68.5	70.1	74.2	77.5	81.0	83.0	84.3	86.5	62.1	68.5	95.8	104.5

ANNEX 2: QUESTIONNAIRE ISSUED TO THE GWG MEMBERS

No	Required information	Priority
1	**Electricity Sector**	
1.1	What is the installed capacity of the existing power generation plants (including CHPs) by fuel type (oil, gas, coal, nuclear, RES)?	High
1.2	Are there plans for the decommissioning of power plants? If so, which plants (name, fuel type and capacity) and by when?	High
1.3	Are there plans for new gas-fired power plants (including CHPs)? When is their commissioning expected? What is their planned capacity and status (planned, under construction, etc.)?	High
1.4	What is the expected RES contribution in electricity generation?	Low
1.5	What is the projected electricity consumption elasticity factor (% change in electricity consumption for a 1% change in GDP growth rate)?	Medium
2	**Heating Sector**	
2.1	Are there plans for the decommissioning of heat-only plants? If so, which plants (fuel type, capacity) and when?	Medium
2.2	Are there plans for rehabilitation of heat-only plants? If so, which plants (fuel type, capacity) and when?	Medium
2.3	How is promotion of energy efficiency expected to affect heat consumption?	Medium
3	**Industrial Sector**	
3.1	Are there particular industrial segments that have been so severely affected by the recent economic crisis that demand is unlikely to recover (i.e. 'demand destruction' due to, for, example, production delocalization)? How is overall industrial gas consumption expected to be affected by such 'demand destruction'?	High
4	**Household / Commercial Sector**	
4.1	How has the recent economic crisis impacted on the energy consumption of households? Are there data on gas consumption for households for 2010 and projections for 2011?	Medium
4.2	How is promotion of energy efficiency expected to affect gas consumption in households / services?	Low
4.3	Are there plans for gasification of new regions in the country? If so, what is the timing and location of the planned networks?	Medium
4.4	What is the average gas consumption per household?	Medium

ANNEX 3: PEAK DEMAND CALCULATION FOR THE CEE MARKETS

Peak demand (severe weather), mcm/day

Country	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025	2030
Bulgaria	16.60	17.40	17.40	18.40	18.40	18.40	18.40	18.40	18.40	18.40	18.40	18.40
Croatia	14.33	14.50	14.70	14.83	15.95	16.12	16.30	17.49	17.70	17.95	20.66	21.75
Czech Republic	65.20	66.22	71.27	75.25	75.25	79.31	82.29	82.29	82.29	82.29	82.29	82.29
Hungary	79.02	72.75	81.60	76.50	77.31	80.02	86.28	85.91	85.95	88.89	95.23	97.70
Poland	69.67	70.89	72.00	75.06	82.26	90.06	102.43	103.62	104.83	106.07	112.61	119.78
Romania	107.87	108.41	114.06	116.09	118.18	120.32	121.37	122.47	123.60	124.77	133.16	140.57
Slovakia	35.97	36.61	37.84	38.34	39.13	39.75	40.05	40.35	40.66	40.96	42.83	44.92
Slovenia	5.34	5.36	5.58	5.65	5.75	5.79	5.83	5.91	5.97	6.32	6.96	7.46