Bruksela, dnia 19 listopada 2010 r.

KANCELARIA SENATU
Przedstawiciel Kancelarii Senatu
przy Unii Europejskiej

Sprawozdanie nr 86/2010

INFRASTRUKTURA ENERGETYCZNA
KOMISJA PRZEDSTAWIA PROPOZYCJE DOTYCZĄCE PRIORYTETOWYCH KORYTARZY UE DLA SIECI ENERGETYCZNYCH I GAZOCIĄGÓW

Komisja Europejska przedstawiła w dniu 17 listopada priorytety dotyczące infrastruktury energetycznej na kolejne dwie dekady, mające na celu dostosowanie sieci do wymogów XXI wieku. W swoim komunikacie Komisja określa priorytetowe korytarze unijne na potrzeby przesyłu energii elektrycznej, ropy i gazu. Tego rodzaju mapa priorytetów stanowić będzie podstawę przyszłych decyzji dotyczących udzielania pozwoleń i finansowania konkretnych projektów UE.

Günther Oettinger, komisarz UE ds. energii, powiedział: „Infrastruktura energetyczna ma kluczowe znaczenie dla osiągnięcia wszystkich naszych celów dotyczących energii: od bezpieczeństwa dostaw, poprzez włączenie odnawialnych źródeł energii i efektywność energetyczną, do prawidłowego funkcjonowania rynku wewnętrznego. Konieczne jest zatem połączenie naszych zasobów i przyspieszenie realizacji priorytetowych projektów UE".

W komunikacie określono ograniczoną liczbę priorytetowych korytarzy UE, wymagających pilnego rozwoju, aby realizować cele polityki Unii Europejskiej w zakresie konkurencyjności, stabilności i bezpieczeństwa dostaw poprzez przyłączenie tych państw członkowskich, które są niemal odizolowane od pozostałych europejskich rynków energetycznych, znaczące wzmocnienie istniejących transgranicznych połączeń międzysystemowych oraz włączenie do sieci energii ze źródeł odnawialnych. Te wcześniej określone korytarze będą podstawą dla wskazania w roku 2012 konkretnych projektów leżących w interesie Europy, które powinny otrzymać finansowanie i pozwolenia na budowę ze strony UE, łącznie z terminem ostatecznej decyzji, przy zapewnieniu pełnego poszanowania prawa UE, w szczególności przepisów dotyczących ochrony środowiska i udziału społeczeństwa. Podczas planowania i realizacji tych projektów Komisja będzie wspierać współpracę regionalną między państwami. Ponadto w komunikacie określono cele długoterminowe, takie jak „europejskie autostrady elektroenergetyczne".

W przypadku sektora elektroenergetycznego określone zostały 4 priorytetowe korytarze UE:

- **sieć przesyłowa morskiej energii wiatrowej na północnych morzach oraz połączenie z Europą Północną i Środkową**, umożliwiające przesyłanie energii elektrycznej wytworzonej przez morskie elektrownie wiatrowe do konsumentów w dużych miastach oraz magazynowanie energii w elektrowniach wodnych położonych w Alpach i krajach nordyckich;
- **połączenia międzysystemowe w Europie Południowo-Zachodniej** umożliwiające przesyłanie energii wytworzonej w elektrowniach wiatrowych, słonecznych i wodnych do pozostałej części kontynentu;
- **połączenia w Europie Środkowej i Południowo-Wschodniej** służące wzmocnieniu sieci regionalnej;
- **integracja rynku energetycznego państw bałtyckich z rynkiem europejskim**.

W przypadku sektora gazowego określone zostały 3 priorytetowe korytarze UE:

- **korytarz południowy** umożliwiający dostarczanie gazu bezpośrednio z regionu Morza Kaspijskiego do Europy w celu dywersyfikacji źródeł gazu;
- **integracja rynku energetycznego państw bałtyckich oraz połączenie z Europą Środkową i Południowo-Wschodnią;**
- **korytarz Północ-Południe w Europie Zachodniej** mający na celu usunięcie wąskich gardeł oraz umożliwienie jak najlepszego wykorzystania dostaw zewnętrznych.

- **Kontekst:**

UE zobowiązała się do zmniejszenia emisji gazów cieplarnianych o 20 proc. do 2020 r., zwiększenia do 20 proc. udziału energii odnawialnej w końcowym zużyciu energii oraz poprawy efektywności energetycznej o 20 proc. Aby osiągnąć wspomniane cele w zakresie energii i klimatu, potrzeba ok. 200 miliardów euro na same inwestycje związane z przesyłem energii, w zakresie gazociągów i sieci energetycznych. Szacuje się, że jedynie część tej kwoty pochodzić będzie z sektora prywatnego, co pozostawia lukę finansową w wysokości ok. 100 miliardów euro.

- **Więcej informacji:**

Więcej informacji dotyczących komunikatu w sprawie infrastruktury energetycznej można znaleźć pod adresem: http://ec.europa.eu/energy/infrastructure/strategy/2020_en.htm

Opracowała:
dr Magdalena Skulimowska[1]

[1] Na podstawie informacji Komisji Europejskiej

Załączniki:

1. Komunikat Komisji Europejskiej pt. *Energy infrastructure priorities for 2020 and beyond -A Blueprint for an integrated European energy network.*
2. Dokument roboczy Komisji Europejskiej nt. *On redefining and the supply of petroleum products in the EU.*
3. Dokument roboczy Komisji Europejskiej – *Impact Assessment*
4. Dokument – *Energising Europe*

EUROPEAN COMMISSION

Brussels, 17.11.2010
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COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS

Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network

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COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS

Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network

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1. INTRODUCTION

Europe's energy infrastructure is the central nervous system of our economy. EU energy policy goals, as well as the Europe 2020 economic aims, will not be achievable without a major shift in the way European infrastructure is developed. Rebuilding our energy system for a low-carbon future is not just a task for the energy industry. Technological improvements, greater efficiencies, resilience to a changing climate and new flexibility will be necessary. This is not a task which a single Member State can achieve on its own. A European strategy, and funding, will be necessary.

The Energy Policy for Europe, agreed by the European Council in March 2007[1], establishes **the Union's core energy policy objectives of competitiveness, sustainability and security of supply**. The internal energy market has to be completed in the coming years and by 2020 renewable sources have to contribute 20% to our final energy consumption, greenhouse gas emissions have to fall by 20%[2] and energy efficiency gains have to deliver 20% savings in energy consumption. The EU has to assure security of supply to its 500 million citizens at competitive prices against a background of increasing international competition for the world's resources. The relative importance of energy sources will change. For fossil fuels, notably gas and oil, the EU will become even more dependent on imports. For electricity, demand is set to increase significantly.

The **Energy 2020**[3] Communication, adopted on 10 November 2010, called for a step change in the way we plan, construct and operate our energy infrastructures and networks. Energy infrastructures are at the forefront of the flagship initiative[4] "Resource efficient Europe".

Adequate, integrated and reliable energy networks are a crucial prerequisite not only for EU energy policy goals, but also for the EU's economic strategy. Developing our energy infrastructure will not only enable the EU to deliver a properly functioning internal energy market, it will also enhance security of supply, enable the integration of renewable energy sources, increase energy efficiency and enable consumers to benefit from new technologies and intelligent energy use.

The EU pays the price for its outdated and poorly interconnected energy infrastructure. In January 2009, solutions to the gas disruptions in Eastern Europe were hindered by a lack of reverse flow options and inadequate interconnection and storage infrastructures. Rapid development of offshore wind electricity generation in the North and Baltic Sea regions is hampered by insufficient grid connections both off- and onshore. Developing the huge renewables potential in Southern Europe and North Africa will be impossible without additional interconnections within the EU and with neighbouring countries. The risk and cost of disruptions and wastage will become much higher unless the EU invests as a matter of urgency in smart, effective and competitive energy networks, and exploits its potential for energy efficiency improvements.

In the longer term, these issues are compounded by the EU decarbonisation goal to reduce our greenhouse gas emissions by 80-95% by 2050, and raise the need for further developments,

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1 Presidency conclusions, European Council, March 2007.
2 30% if the conditions are right.
3 COM(2010) 639.
4 Europe 2020 strategy - COM(2010) 2020.

such as an infrastructure for large-scale electricity storage, charging of electric vehicles, CO_2 and hydrogen transport and storage. The infrastructures built in the next decade will largely still be in use around 2050. It is therefore crucial to keep in mind **the longer term objective**. In 2011, the Commission plans to present a comprehensive roadmap towards 2050. The roadmap will present energy mix scenarios, describing ways to achieve Europe's long-term decarbonisation goal and the implications for energy policy decisions. This Communication identifies the energy infrastructure map which will be needed to meet our 2020 energy objectives. The 2050 low carbon economy and energy roadmaps will further inform and guide EU energy infrastructure implementation by offering a long term vision.

The energy infrastructures planned today must be compatible with the longer term policy choices.

A new EU energy infrastructure policy is needed to coordinate and optimise network development on a continental scale. This will enable the EU to reap the full benefits of an integrated European grid, which goes well beyond the value of its single components. A European strategy for fully integrated energy infrastructures based on smart and low-carbon technologies will reduce the costs of making the low-carbon shift through economies of scale for individual Member States. A fully interconnected European market will also improve security of supply and help stabilise consumer prices by ensuring that electricity and gas goes to where it is needed. European networks including, as appropriate, with neighbouring countries, will also facilitate competition in the EU's single energy market and build up solidarity among Member States. Above all, integrated European infrastructure will ensure that European citizens and buinesses have access to affordable energy sources. This in turn will positively contribute to Europe's 2020 policy objective of maintaining a strong, diversified and competitive industrial base in Europe.

Two specific issues that need to be addressed are project authorisation and financing. Permitting and cross-border cooperation must become more efficient and transparent to increase public acceptance and speed up delivery. Financial solutions must be found to meet investment needs– estimated at about one trillion euros for the coming decade of which half will be needed for energy networks alone. Regulated tariffs and congestion charges will have to pay the bulk of these grid investments. However, under the current regulatory framework, **all necessary investments will not take place or not as quickly as needed**, notably due to the non-commercial positive externalities or the regional or European value-added of some projects, whose direct benefits at national or local level is limited. The slowdown in investment in infrastructure has been further compounded by the recession.

Moves for a new energy strategy for the EU have the full support of Europe's heads of state and government. In March 2009, the European Council[5] called for a thorough review of the trans-European Networks for Energy framework (TEN-E)[6] by adapting it to both the challenges outlined above and the new responsibilities conferred to the Union by Article 194 of the Treaty of Lisbon.

This Communication outlines a Blueprint which aims to provide the EU with a vision of what is needed for making our networks efficient. . It puts forward a new method of strategic planning to map out necessary infrastructures, qualify which ones are of European

[5] European Council Presidency Conclusions of 19/20 March 2009, 7880/09.

[6] The TEN-E Guidelines and TEN Financial Regulation. See the TEN-E implementation report 2007-2009 - COM(2010) 203.

interest on the basis of a clear and transparent methodology, and provide a toolbox to ensure their timely implementation, including ways to speed up authorisations, improve cost allocation and target finance to leverage private investment.

2. INFRASTRUCTURE CHALLENGES CALL FOR URGENT ACTION

The challenge of interconnecting and adapting our energy infrastructure to the new needs is significant, urgent, and concerns all sectors[7].

2.1. Electricity grids and storage

Electricity grids must be upgraded and modernised to meet **increasing demand** due to a major shift in the overall energy value chain and mix but also because of the multiplication of applications and technologies relying on electricity as an energy source (heat pumps, electric vehicles, hydrogen and fuel cells[8], information and communication devices etc.). The grids must also be urgently extended and upgraded to foster market integration and maintain the existing levels of system's security, but especially to transport and balance **electricity generated from renewable sources**, which is expected to more than double in the period 2007-2020[9]. A significant share of generation capacities will be concentrated in locations further away from the major centres of consumption or storage. Up to 12% of renewable generation in 2020 is expected to come from offshore installations, notably in the Northern Seas. Significant shares will also come from ground-mounted solar and wind parks in Southern Europe or biomass installations in Central and Eastern Europe, while decentralised generation will also gain ground throughout the continent. Through a well **interconnected and smart grid including large-scale storage** the cost of renewable deployment can be brought down, as the greatest efficiencies can be made on a pan-European scale. Beyond these short-term requirements, electricity grids will have to evolve more fundamentally to enable the shift to a decarbonised electricity system in the 2050 horizon, supported by new **high-voltage long distance** and **new electricity storage** technologies which can accommodate ever-increasing shares of renewable energy, from the EU and beyond.

At the same time the grids must also become smarter. Reaching the EU's 2020 energy efficiency and renewable targets will not be possible without more **innovation and intelligence** in the networks at both transmission and distribution level, in particular through information and communication technologies. These will be essential in the take up of demand side management and other **smart grid** services. Smart electricity grids will facilitate transparency and enable consumers to control appliances at their homes to save energy, facilitate domestic generation and reduce cost. Such technologies will also help boost the competitiveness and worldwide technological leadership of EU industry, including SMEs.

2.2. Natural gas grids and storage

Natural gas will continue, provided its supply is secure, to play a key role in the EU's energy mix in the coming decades and will gain importance as the **back-up fuel** for variable electricity generation. Although in the long run unconventional and biogas resources may

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7 For more detailed analysis, see the Annex and the Impact assessment, accompanying this Communication.

8 Large scale roll-out will require the development of a substantial hydrogen trasnport and storgae infrastructure.

9 Based on the national renewable energy action plans notified by 23 Member states to the Commission.

contribute to reducing the EU's import dependency, in the medium term depleting indigenous conventional natural gas resources call for additional, diversified **imports**. Gas networks face additional flexibility requirements in the system, the need for bi-directional pipelines, enhanced storage capacities and flexible supply, including liquefied (LNG) and compressed natural gas (CNG). At the same time, markets are still fragmented and monopolistic, with various barriers to open and fair competition. **Single-source dependency**, compounded by a lack of infrastructure, prevails in Eastern Europe. A diversified portfolio of physical gas sources and routes and a fully interconnected and bidirectional gas network, where appropriate[10,] within the EU are needed already by 2020. This development should be closely linked with the EU's strategy towards third countries, in particular as regards our suppliers and transit countries.

2.3 District heating and cooling networks

Thermal power generation often leads to conversion losses while at the same time natural resources are consumed nearby to produce heating or cooling in separate systems. This is both inefficient and costly. Similarly, natural sources, such as sea- or groundwater, are seldom used for cooling despite the cost savings involved. The development and modernisation of district heating and cooling networks should therefore be promoted as a matter of priority in all larger agglomerations where local or regional conditions can justify it in terms of, notably heating or cooling needs, existing or planned infrastructures and generation mix etc. This will be addressed in the Energy Efficiency Plan and the 'Smart Cities' innovation partnership, to be launched early 2011.

2.4. CO_2 capture, transport and storage (CCS)

CCS technologies would reduce CO_2 emissions on a large scale while allowing the use of fossil fuels, which will remain an important source for electricity generation over the next decades. The technology, its risks and benefits, are still being tested through pilot plants which will come on line in 2015CCS commercial rollout in electricity generation and industrial applications is expected to start after 2020 followed by a global rollout around 2030. Due to the fact that potential CO_2 storage sites are not evenly distributed across Europe and the fact that some Member States, considering their significant levels of CO_2 emissions, have only limited potential storage within their national boundaries, construction of European pipeline infrastructure spanning across State borders and in the maritime environment could become necessary.

2.5. Oil and olefin transport and refining infrastructure

If climate, transport and energy efficiency policies remain as they stand today, oil would be expected to represent 30% of primary energy, and a significant part of transport fuels are likely to remain oil based in 2030. Security of supply depends on the integrity and flexibility of the entire **supply chain**, from the crude oil supplied to refineries to the final product distributed to consumers. At the same time, the future shape of crude oil and petroleum product transport infrastructure will also be determined by developments in the European refining sector, which is currently facing a number of challenges as outlined in the Commission Staff Working Document accompanying this Communication.

10 See the regulation on security of gas supply, (EC) No 994/2010

2.6. The market will deliver most of the investments but obstacles remain

The policy and legislative measures the EU has adopted since 2009 have provided a powerful and sound foundation for European infrastructure planning. The **third internal energy market package**[11] laid the basis for European network planning and investment by creating the requirement for Transmission System Operators (TSOs) to co-operate and elaborate regional and European 10-year network development plans (TYNDP) for electricity and gas in the framework of the European Network of TSOs (ENTSO) and by establishing rules of cooperation for national regulators on cross-border investments in the framework of the Agency for the Cooperation of Energy Regulators (ACER).

The third package creates an obligation for regulators to take into account the impact of their decisions on the EU internal market as a whole. This means they should not evaluate investments solely on the basis of benefits in their Member State, but on the basis of EU-wide benefits. Still, **tariff setting** remains nationally focussed and key decisions on infrastructure interconnection projects are taken at national level. National regulatory authorities traditionally have aimed mainly at minimising tariffs, and thus tend not to approve the necessary rate of return for projects with higher regional benefit or difficult cost-allocation across borders, projects applying innovative technologies or projects fulfilling only security of supply purposes.

In addition, with the strengthened and extended **Emission Trading System** (ETS) there will be a unified European carbon market. ETS carbon prices influence already and will increasingly shift the optimal electricity supply mix and location towards low carbon supply sources.

The **regulation on security of gas supply**[12] will enhance the EU's capacity to react to crisis situations, through increased network resilience and common standards for security of supply and additional equipments. It also identifies clear obligations for investments in networks.

Long and uncertain **permitting procedures** were indicated by industry as well as TSOs and regulators, as one of the main reasons for delays in the implementation of infrastructure projects, notably in electricity[13]. The time between the start of planning and final commissioning of a power line is frequently more than 10 years[14]. Cross-border projects often face additional opposition, as they are frequently perceived as mere "transit lines" without local benefits. In electricity, the resulting delays are assumed to prevent about 50% of commercially viable projects from being realised by 2020[15]. This would seriously hamper the EU's transformation into a resource efficient and low carbon economy and threaten its competitiveness. In offshore areas, lack of coordination, strategic planning and alignment of national regulatory frameworks often slow down the process and increase the risk of conflicts with other sea-uses later on.

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11 Directives 2009/72/EC and 2009/73/EC, Regulations (EC) No 713, (EC) No 714 and (EC) No 715/2009.

12 Regulation (EC) No 994/2010

13 Public consultation on the Green Paper Towards a secure, sustainable and competitive European energy network - COM(2008) 737.

14 ENTSO-E 10-year network development plan, June 2010.

15 See accompanying impact assessment.

2.7. Investment needs and financing gap

Around one trillion euros must be invested in our energy system between today and 2020[16] in order to meet energy policy objectives and climate goals. About half of it will be required for networks, including electricity and gas distribution and transmission, storage, and smart grids.

Out of these investments **about 200 bn € are needed for energy transmission networks alone.** However, 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 100 bn €. Part of this gap is caused by delays in obtaining the necessary environmental and construction permits, but also by difficult access to finance and lack of adequate risk mitigating instruments, especially for projects with positive externalities and wider European benefits, but no sufficientcommercial justification[17]. Our efforts also need to focus on further developing the internal energy market, which is essential to boosting private sector investment in energy infrastructure, which in turn will help to reduce the financial gap in the coming years.

The cost of not realising these investments or not doing them under EU-wide coordination would be huge, as demonstrated by offshore wind development, where national solutions could be 20% more expensive. Realising all needed investments in transmission infrastructure would create an additional 775,000 jobs during the period 2011-2020 and add 19 bn € to our GDP by 2020[18], compared to growth under a business-as-usual scenario. Moreover, such investments will help promote the diffusion of EU technologies. EU industry, including SMEs, is a key producer of energy infrastructure technologies. Upgrading EU energy infrastructure provides an opportunity to boost EU competitiveness and worldwide technological leadership.

3. ENERGY INFRASTRUCTURE BLUEPRINT: A NEW METHOD FOR STRATEGIC PLANNING

Delivering the energy infrastructures that Europe needs in the next two decades requires a completely new infrastructure policy based on a European vision. This also means changing the current practice of the TEN-E with long predefined and inflexible projects lists. The Commission proposes a new method which includes the following steps:

– Identify the energy infrastructure map leading towards a European smart supergrid interconnecting networks at continental level.

– Focus on a limited number of **European priorities** which must be implemented by 2020 to meet the long-term objectives and where European action is most warranted.

– Based on an agreed methodology, identification of **concrete projects** necessary to implement these priorities – declared as projects of European interest – in a flexible manner and building on regional cooperation so as to respond to changing market conditions and technology development.

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16 PRIMES model calculations.
17 See accompanying impact assessment.
18 See accompanying impact assessment.

– Supporting the implementation of projects of European interest through **new tools**, such as improved regional cooperation, permitting procedures, better methods and information for decision makers and citizens and innovative financial instruments.

4. EUROPEAN INFRASTRUCTURE PRIORITIES 2020 AND BEYOND

The Commission proposes the following short term and longer term priorities to make our energy infrastructure suitable for the 21st century.

4.1. Priority corridors for electricity, gas and oil

4.1.1. Making Europe's electricity grid fit for 2020

The first 10-year network development plan (TYNDP) [19] forms a solid basis to identify priorities in the electricity infrastructure sector. However, the plan does not take full account of infrastructure investment triggered by important new offshore generation capacities, mainly wind in the Northern Seas[20] and does not ensure timely implementation, notably for cross-border interconnections. To ensure timely integration of **renewables** generation capacities in Northern and Southern Europe and further **market integration**, the European Commission proposes to focus attention on the following priority corridors, which will make Europe's electricity grids fit for 2020:

1. **Offshore grid in the Northern Seas and connection to Northern as well as Central Europe** – to integrate and connect energy production capacities in the Northern Seas[21] with consumption centres in Northern and Central Europe and hydro storage facilities in the Alpine region and in Nordic countries.

2. **Interconnections in South Western Europe** to accommodate wind, hydro and solar, in particular between the Iberian Peninsula and France, and further connecting with Central Europe, to make best use of Northern African renewable energy sources and the existing infrastructure between North Africa and Europe.

3. **Connections in Central Eastern and South Eastern Europe** – strengthening of the regional network in North-South and East-West power flow directions, in order to assist market and renewables integration, including connections to storage capacities and integration of energy islands.

4. **Completion of the BEMIP** (Baltic Energy Market Interconnection Plan) – integration of the Baltic States into the European market through reinforcement of their internal networks and strengthening of interconnections with Finland, Sweden and Poland and through reinforcement of the Polish internal grid and interconnections east and westward.

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[19] The 500 projects identified by national TSOs cover the whole of the EU, Norway, Switzerland and Western Balkans. The list does not include local, regional or national projects, which were not considered to be of European significance.

[20] It is expected that the next edition of the TYNDP planned for 2012 will take a more top-down approach, assuming the achievement of the 2020 legal obligations concerning integration of renewables and emissions reductions with a view beyond 2020, and address these shortcomings.

[21] This includes the North Sea and North-Western Seas.

4.1.2. Diversified gas supplies to a fully interconnected and flexible EU gas network

The aim of this priority area is to build the infrastructure needed to allow gas from any source to be bought and sold anywhere in the EU, regardless of national boundaries. This would also ensure security of demand by providing for more choice and a bigger market for gas producers to sell their products. A number of positive examples in Member States demonstrate that diversification is key to increased competition and enhanced **security of supply**. Whilst on an EU level, supplies are diversified along three corridors - Northern Corridor from Norway, Eastern corridor from Russia, Mediterranean Corridor from Africa – and through LNG, single source dependency still prevails in some regions. Every European region should implement infrastructure allowing physical **access to at least two different sources**. At the same time, the balancing role of gas for variable electricity generation and the infrastructure standards introduced in the Security of Gas Supply Regulation impose additional flexibility requirements and increase the need for bi-directional pipelines, enhanced storage capacities and flexible supply, such as LNG/CNG. In order to achieve these objectives, the following priority corridors have been identified:

1. **Southern Corridor** to further diversify sources at the EU level and to bring gas from the Caspian Basin, Central Asia and the Middle East to the EU.

2. Linking the Baltic, Black, Adriatic and Aegean Seas through in particular:

   – the implementation of **BEMIP** and

   – the **North-South Corridor** in Central Eastern and South-East Europe.

3. North-South Corridor in Western Europe to **remove internal bottlenecks** and increase short-term deliverability, thus making full use of possible alternative external supplies, including from Africa, and optimising the existing infrastructure, notably existing LNG plants and storage facilities. .

4.1.3. Ensuring the security of oil supply

The aim of this priority is to ensure uninterrupted crude-oil supplies to land-locked EU countries in Central-Eastern Europe, currently dependent on limited supply routes, in case of lasting supply disruptions in the conventional routes. Diversification of oil supplies and interconnected pipeline networks would also help not to increase further oil transport by vessels, thus reducing the risk of environmental hazards in the particularly sensitive and busy Baltic Sea and Turkish Straits. This can be largely achieved within the existing infrastructure by reinforcing the interoperability of the **Central-Eastern European pipeline network** by means of interconnecting the different systems and removing capacity bottlenecks and/or enabling reverse flows.

4.1.4. Roll-out of smart grid technologies

The aim of this priority is to provide the necessary framework and **initial incentives for rapid investments** in a new "intelligent" network infrastructure to support i) a competitive retail market, ii) a well-functioning energy services market which gives real choices for energy savings and efficiency and iii) the integration of renewable and distributed generation, as well as iv) to accommodate new types of demand, such as from electric vehicles.

The Commission will also **assess the need for further legislation** to keep smart grid implementation on track. In particular, promoting investment in smart grids and smart meters will require a thorough assessment of what aspects of smart grids and meters need to be regulated or standardised and what can be left to the market. The Commission will also consider further measures to ensure that smart grids and meters bring the desired benefits for consumers, producers, operators and in terms of energy efficiency. The results of this assessment and possible further measures will be published in the course of 2011.

In addition, the Commission will set up **a smart grids transparency and information platform** to enable dissemination of the most up-to-date experiences and good practice concerning deployment across Europe, create synergies between the different approaches and facilitate the development of an appropriate regulatory framework. The timely establishment of technical standards and adequate data protection will be key to this process. To that end, focus on smart grid technologies under the SET-Plan should be intensified.

4.2. Preparing the longer term networks

In the context of the longer term perspective due to be presented in the 2050 Roadmap, the EU must start today designing, planning and building the energy networks of the future, which will be necessary to allow the EU to further reduce greenhouse gas emissions. There is only a **limited window of opportunity**. It is only through a coordinated approach towards an optimised European infrastructure that costly approaches at Member State or project level and sub-optimal solutions in the longer run can be avoided.

4.2.1. European Electricity Highways

Future '**Electricity Highways**' must be capable of: i) accommodating ever-increasing wind surplus generation in and around the Northern and Baltic Seas and increasing renewable generation in the East and South of Europe and also North Africa; ii) connecting these new generation hubs with major storage capacities in Nordic countries and the Alps and with the major consumption centres in Central Europe and iii) coping with an increasingly flexible and decentralised electricity demand and supply[22].

The European Commission therefore proposes to immediately launch work to establish **a modular development plan** which would allow the commissioning of first Highways by 2020. The plan would also prepare for their extension with the aim of facilitating the development of large-scale renewable generation capacities, including beyond EU borders and with a view to potential developments in new generation technologies, such as wave, wind and tidal energy. The work would be best carried out in the framework of the Florence Forum, organised by the European Commission and ENTSO-E, and building on the SET-Plan European Electricity Grid Initiative (EEGI) and European Industrial Wind Initiative.

4.2.2. European CO_2 transport infrastructure

This priority area includes the examination and agreement on the **technical and practical modalities of a future CO_2 transport infrastructure.** Further research, coordinated by the European Industrial Initiative for carbon capture and storage launched under the SET-Plan, will allow a timely start of infrastructure planning and development at European level, in line

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22 Whilst it is likely that such a grid would ultimately be based on DC technology, it needs to be built stepwise, ensuring compatibility with the current AC grid.

with the foreseen commercial roll-out of the technology after 2020. Regional cooperation will also be supported in order to stimulate the development of focal points for future European infrastructure.

4.3. From priorities to projects

The above mentioned priorities should translate into concrete projects and lead to the establishment of a **rolling programme**. First project lists should be ready in the course of 2012 and be subsequently updated every two years, so as to provide input to the regular updating of the TYNDPs.

Projects should be identified and ranked according to **agreed and transparent criteria** leading to a limited number of projects. The Commission proposes to base the work on the following criteria, which should be refined and agreed upon with all relevant stakeholders, notably ACER:

– *Electricity*: contribution to security of electricity supply; capacity to connect renewable generation and transmit it to major consumption/storage centres; increase of market integration and competition; contribution to energy efficiency and smart electricity use.

– *Gas*: diversification, giving priority to diversification of sources, diversification of supplying counterparts and diversification of routes; as well as increase in competition through increase in interconnection level, increase of market integration and reduction of market concentration.

The projects identified would be examined at EU level to ensure **consistency across the priorities and regions** and ranked in terms of their urgency with regard to their contribution to the achievement of the priorities and Treaty objectives. Projects meeting the criteria would be awarded a '**Project of European Interest**' label. This label would form the basis for further assessment[23] and consideration under the actions described in the following chapters. The label would confer political priority to the respective projects.

5. TOOLBOX TO SPEED UP IMPLEMENTATION

5.1. Regional clusters

Regional cooperation as developed for the Baltic Energy Market Interconnection Plan (BEMIP) or for the North Seas Countries' Offshore Grid Initiative (NSCOGI) has been instrumental in reaching agreement on regional priorities and their implementation. The mandatory regional cooperation set up under the internal energy market will help to speed up market integration, while the regional approach has been beneficial for the first electricity TYNDP.

The Commission considers that such **dedicated regional platforms** would be useful to facilitate the planning, implementation and monitoring of the identified priorities and the drawing up of investment plans and concrete projects. The role of the existing **Regional**

[23] The economic, social and environmental impacts of the projects will be assessed according to the common method referred to in the next chapter.

Initiatives, established in the context of the internal energy market, should be reinforced, where relevant, with tasks related to infrastructure planning, whilst *ad hoc* regional structures could also be proposed where needed. In this regard, the EU strategies for so called macro-regions (such as the Baltic Sea or the Danube Region) can be used as cooperation platforms to agree on transnational projects across sectors.

In this context, to kick start the new regional planning method in the short term, the Commission intends to set up a **High Level Group** based on cooperation of the countries in Central Eastern Europe, e.g. in the Visegrad group[24], with the mandate to devise an action plan, in the course of 2011, for North-South and East-West connections in gas and oil as well as electricity.

5.2. Faster and more transparent permit granting procedures

In March 2007, the European Council invited the Commission "to table proposals aiming at streamlining approval procedures" as a response to the frequent calls of the industry for EU measures to facilitate permitting procedures.

Responding to this necessity, the Commission will propose, in line with the principle of subsidiarity, to introduce permitting measures applying to projects of "European interest" **to streamline, better coordinate and improve** the current process while respecting safety and security standards and ensuring full compliance with the EU environmental legislation[25]. The streamlined and improved procedures should ensure the timely implementation of the identified infrastructure projects, without which the EU would fail to meet its energy and climate objectives. Moreover, they should provide for transparency for all stakeholders involved and facilitate **participation of the public** in the decision-making process by ensuring open and transparent debates at local, regional and national level to enhance public trust and acceptance of the installations.

Improved decision-making could be addressed through the following:

1. The establishment of a contact authority ("**one-stop shop**") per project of European interest, serving as a single interface between project developers and the competent authorities involved at national, regional, and/or local level, without prejudice to their competence. This authority would be in charge of coordinating the entire permitting process for a given project and of disseminating the necessary information about administrative procedures and the decision-making process to stakeholders. Within this framework, Member States would have full competence to allocate decision-making power to the various parts of the administration and levels of government. For cross-border projects, the possibility of coordinated or joint procedures[26] should be explored in order to improve project design and expedite their final authorisation.

2. The introduction of a **time limit** for a final positive or negative decision to be taken by the competent authority will be explored. Given the fact that delays often occur due to poor administrative practice, it should be ensured that each of the necessary steps in the process is completed within a specific time limit, while fully respecting

[24] See Declaration of the Budapest V4+ Energy Security Summit of 24 February, 2010.
[25] See accompanying impact assessment.
[26] Including in particular the relevant EU environmental legislation

Member States' applicable legal regimes and EU law. The proposed schedule should provide for an early and effective involvement of the public in the decision-making process, and citizens' rights to appeal the authorities' decision should be clarified and strengthened, while being clearly integrated in the overall timeframe. It will further be explored whether, in case a decision has still not been taken after the expiry of the fixed time limit, special powers to adopt a final positive or negative decision within a set timeframe could be given to an authority designated by the concerned Member States.

3. The development of **guidelines to increase the transparency and predictability** of the process for all parties involved (ministries, local and regional authorities, project developers and affected populations). They would aim at improving communication with citizens to ensure that the environmental, security of supply, social and economic costs and benefits of a project are correctly understood, and to engage all stakeholders in a transparent and open debate at an early stage of the process. Minimum requirements regarding the compensation of affected populations could be included. More specifically, for offshore cross-border energy installations maritime spatial planning should be applied to ensure a straight-forward, coherent but also a more informed planning process.

4. In order to enhance the conditions for timely construction of necessary infrastructure, the possibility of providing rewards and incentives, including of a financial nature, to regions or Member States that facilitate timely authorisation of projects of European interest should be explored. Other mechanisms for benefit sharing inspired by best practice in the renewable energy field could also be considered.[27]

5.3. Better methods and information for decision makers and citizens

In order to assist the regions and the stakeholders in identifying and implementing projects of European interest, the Commission will develop a **dedicated policy and project support tool** to accompany infrastructure planning and project development activities at EU or regional level. Such a tool would inter alia elaborate energy-system wide and joint electricity-gas modelling and forecasting and a common method for project assessment[28] appropriate to reflect short and long term challenges, covering notably climate proofing, to facilitate prioritisation of projects. The Commission will also encourage Member States to better coordinate existing EU environmental assessment procedures already at an early stage. Moreover, tools will be developed to better explain the benefits of a specific project to the wider public and associate them with the process. These tools should be complemented by communication on the benefits of infrastructure development and smart grids for consumers and citizens, in terms of security of supply, decarbonisation of the energy sector and energy efficiency.

5.4. Creating a stable framework for financing

Even if all permitting issues are resolved, an **investment gap estimated at about 60 bn €** is likely to remain by 2020, mainly due to the non-commercial positive externalities of projects with a regional or European interest and the risks inherent to new technologies. Filling this

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27 See e.g. www.reshare.nu

28 See e.g. "Guide to cost-benefit analysis of investment projects", July 2008: http://ec.europa.eu/regional_policy/sources/docgener/guides/cost/guide2008_en.pdf

gap is a significant challenge, but a prerequisite if infrastructure priorities are to be built on time. Therefore, further internal energy market integration is needed to boost infrastructure development and EU coordinated action is required to alleviate investment constraints and mitigate project risks.

The Commission proposes to work on two fronts; further improving the cost allocation rules and optimising the European Union's leverage of public and private funding.

5.4.1. Leveraging private sources through improved cost allocation

Electricity and gas infrastructure in Europe are regulated sectors, whose business model is based on regulated tariffs collected from the users, which allow recovering the investments made ("**user pays principle**"). This should remain the main principle also in the future.

The third package asks regulators to provide appropriate tariff incentives, both short and long term, for network operators to increase efficiencies, foster market integration and security of supply and support the related research activities[29]. However, while this new rule could cover some innovative aspects in new infrastructure projects, it is not designed to address the major technological changes, notably in the electricity sector, concerning offshore or smart grids.

Moreover, tariff setting remains national and hence not always conducive to advance European priorities. Regulation should recognise that sometimes the most efficient approach for a TSO to address customer needs is to invest in a network outside its territory. Establishing such principles for cost-allocation across borders is key for fully integrating European energy networks.

In the absence of agreed principles on European level, this will be difficult to do, particularly as long term consistency is required. The Commission envisages to put forward, in 2011, **guidelines or a legislative proposal to address cost allocation** of major technologically complex or cross-border projects, through tariff and investment rules.

Regulators have to agree on common principles in relation to cost-allocation of interconnection investments and related tariffs. In electricity, the need for the development of long term forward markets for cross-border transmission capacity should be explored, whereas in the gas sector, investment costs could be allocated to TSOs in neighbouring countries, both for normal (based on market-demand) investments, as well as those motivated by security of supply reasons.

5.4.2. Optimising the leverage of public and private sources by mitigating investors risks

In the Budget Review, the Commission 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 for infrastructures of European interest. It requires maximising societal returns in view of scarce resources, alleviating constraints faced by investors, mitigating project risks, reducing cost of financing and increasing access to capital. A "two-front" approach is proposed:

Firstly, the Commission will continue strengthening EU's partnerships with International Financial Institutions (IFI) and **build on existing joint financial and technical assistance's**

[29] Cf. Article 37 of Directive 2009/72/EC and Article 41 of Directive 2009/73/EC.

initiatives[30]. The Commission will pay particular attention at developing synergies with these instruments and for some of them, will examine the possibility to adjust their concepts to the energy infrastructure sector.

Secondly, without prejudice to the Commission's proposal for the next multi-annual financial framework post 2013, due in June 2011, and taking into account the results of the Budget Review[31], as regards the mainstreaming of energy priorities into different programmes, the Commission intends to propose a new set of tools. These tools should 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), innovative market-based solutions addressing the shortfall in equity and debt financing may be proposed. The following options will notably be examined: equity participation and support to infrastructure funds, targeted facilities for project bonds, test option for advanced network related capacity payments mechanism, risk sharing facilities (notably for new technological risks) and public private partnerships loan guarantees. Particular attention will be paid to foster investments in projects which contribute to meeting the 2020 targets or cross EU borders, in projects enabling the roll-out of new technologies such as smart grids, and in other projects where EU-wide benefits cannot be achieved by the market alone.

6. CONCLUSIONS AND WAY FORWARD

The constraints on public and private funding possibilities over the coming years should not be an excuse to postpone building of the identified infrastructure and making the corresponding investments. Indeed, today's investments are a necessary condition for future savings, thereby reducing the overall cost of achieving our policy goals.

Based on the views expressed by the institutions and stakeholders on this blueprint, the Commission intends to prepare, in 2011, as part of its proposals for the next multiannual financial framework, appropriate initiatives. These proposals will address the regulatory and financial aspects identified in the Communication, notably through an Energy Security and Infrastructure Instrument and mainstreaming of energy priorities in different programmes.

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30 Notably Marguerite, Loan Guarantee Instrument for TEN-T, Risk Sharing Finance Facility, Jessica, Jaspers.

31 EU Budget Review, adopted on 19 October 2010.

ANNEX

Proposed energy infrastructure priorities for 2020 and beyond

1. INTRODUCTION

This annex provides technical information on the European infrastructures priorities, put forward in chapter 4 of the Communication, on progress of their implementation and the next steps needed. The priorities chosen grow out of the major changes and challenges, which Europe's energy sector will face in the coming decades, independently of the uncertainties surrounding supply and demand of certain energy sources.

Section 2 presents the expected evolutions of supply and demand for each energy sector covered under this communication. The scenarios are based on the "Energy Trends for 2030 – update 2009"[32], which rely on the PRIMES modelling framework, but do also take into account scenario exercises done by other stakeholders. While the PRIMES Reference scenario for 2020 is based on a set of agreed EU policies, notably two legally binding targets (20% renewables share in final energy consumption and 20% greenhouse gas emission reductions compared to 1990 in 2020, PRIMES baseline is based only on the continuation of already implemented policies, whereby these targets are not achieved. For the period between 2020 and 2030, PRIMES assumes that no new policy measures are taken. These evolutions allow identifying major trends, which will drive infrastructure development over the coming decades[33].

In sections 3 and 4, the infrastructure priorities (Map) identified in the Communication are presented by looking at the situation and challenges faced in each case and by providing, as relevant, technical explanations on the recommendations made in the Communication. It is understood that the presentations of the priorities vary in terms of:

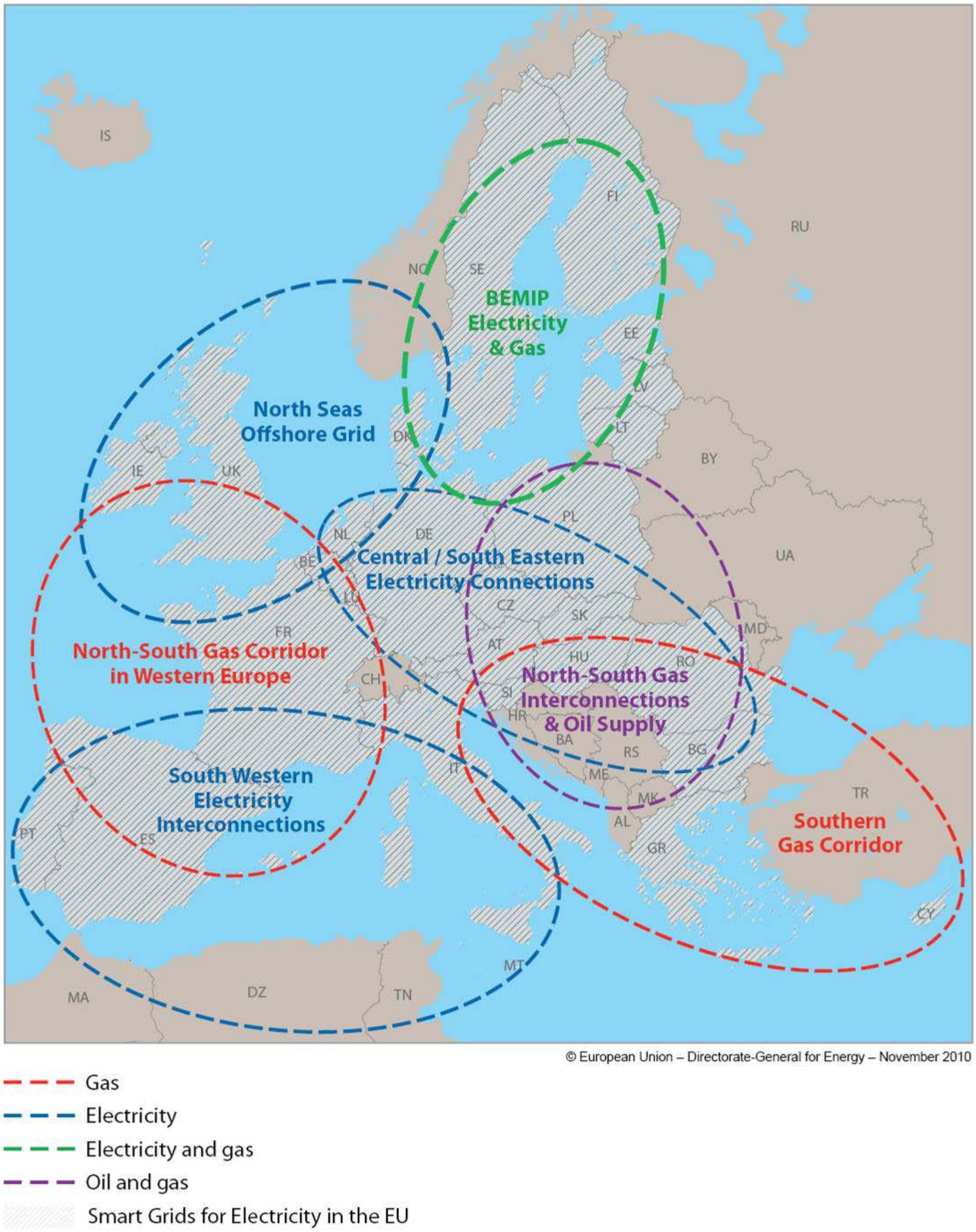
– nature and maturity: Certain priorities concern very specific infrastructure projects, which can be, for some, very advanced in terms of project preparation and development. Others cover broader and often also newer concepts, which will need considerable additional work before being translated into concrete projects.

– scope: Most priorities focus on a certain geographic region, both electricity highways and CO_2 networks covering potentially many if not all EU Member States. Smart grids however are a thematic, EU -wide priority.

– level of engagement proposed in the recommendations: Depending on the nature and maturity of the priorities, the recommendations concentrate on concrete developments or address a broader range of issues, including aspects of regional cooperation, planning and regulation, standardisation and market design or research and development.

[32] http://ec.europa.eu/energy/observatory/trends_2030/doc/trends_to_2030_update_2009.pdf

[33] In the absence of further policy measures and under certain assumptions



Map 1: Priority corridors for electricity, gas and oil

2. EVOLUTION OF ENERGY DEMAND AND SUPPLY

The latest update of the "Energy Trends for 2030 – update 2009"[34] based on the PRIMES modelling framework foresees slight growth of primary energy consumption between today

[34] http://ec.europa.eu/energy/observatory/trends_2030/doc/trends_to_2030_update_2009.pdf

and 2030 according to the so-called Baseline scenario (Figure 1), while growth is set to remain largely stable according to the Reference scenario[35] (Figure 2). It should be noted that these projections do not include energy efficiency policies to be implemented from 2010 onwards, a possible step-up of the emission reduction target to -30% by 2020[36] or additional transport policies beyond CO_2 and cars emissions regulation. They should therefore rather be seen as upper limits for the expected energy demand.

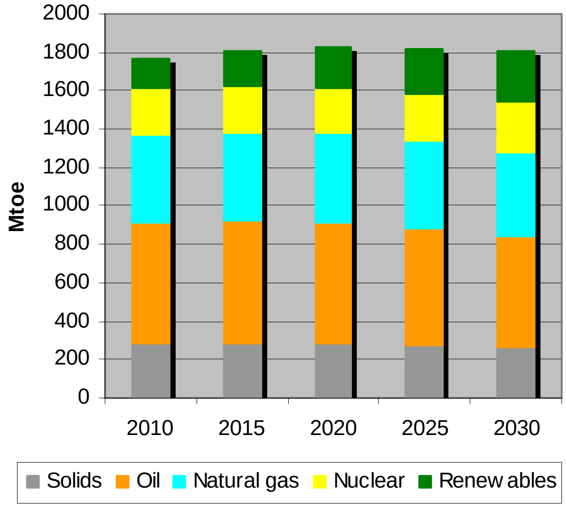


Figure 1: Primary energy consumption by fuel (Mtoe), PRIMES baseline

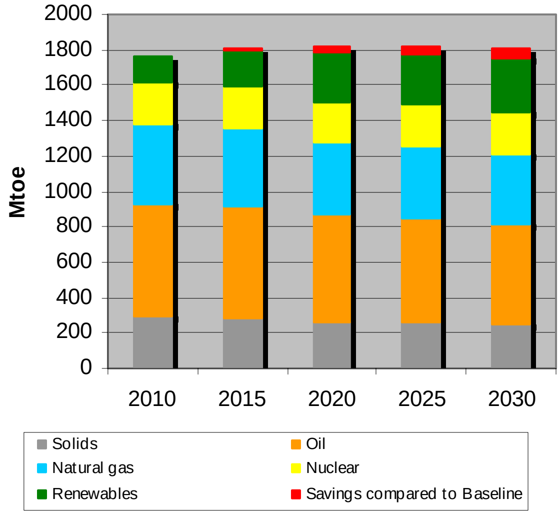


Figure 2: Primary energy consumption by fuel (Mtoe), PRIMES Reference scenario

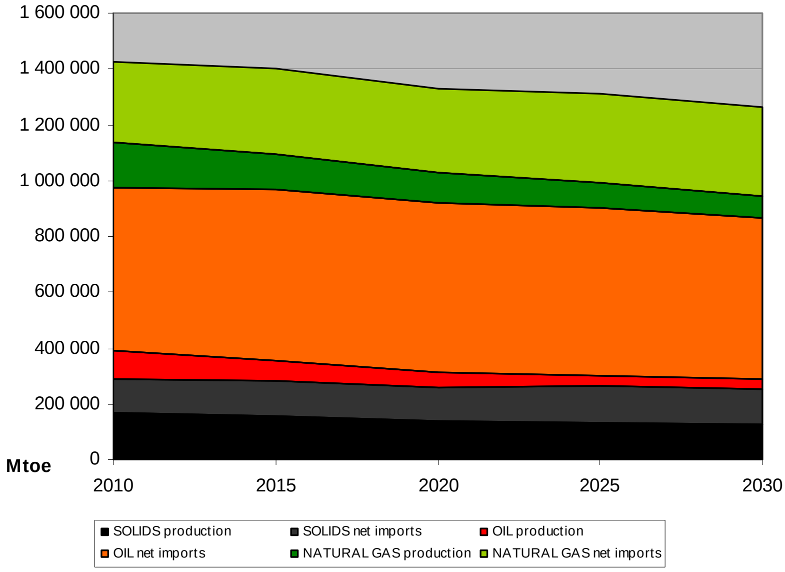


Figure 3: EU-27 fossil fuel consumption by origin in Mtoe (including bunker fuels), PRIMES reference scenario

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35 Under this scenario, it is assumed that the two binding targets for renewables and emission reduction are achieved. In the PRIMES baseline, based only on continuation of already implemented policies, these targets are not achieved.

36 For a more detailed analysis of its implications see Commission Staff Working Document accompanying the Commission Communication "Analysis of options to move beyond 20% greenhouse gas emission reductions and assessing the risk of carbon leakage" - COM(2010) 265. Background information and analysis Part II - SEC(2010) 650.

In these scenarios, the share of coal and oil in the overall energy mix declines between today and 2030, while gas demand remains largely stable until 2030. The share of renewables is set to increase significantly, both in primary and final energy consumption, while the contribution of nuclear, at about 14% of primary energy consumption, is set to remain stable. The EU's dependency on imported fossil fuels will continue to be high for oil and coal and will increase for gas, as shown in Figure 3.

As regards **gas**, the dependency on imports is already high and will be growing further, to reach about 73-79% of consumption by 2020 and 81-89%[37] by 2030, mainly due to the depletion of indigenous resources. Based on the different scenarios, the additional import need ranges from 44 Mtoe to 148 Mtoe by 2020 and from 61 to 221 Mtoe by 2030 (compared to 2005).

Increased flexibility will be required due to the increasing role of gas as primary back-up for variable electricity generation. This means a more flexible use of the pipeline systems, need for additional storage capacities, both in terms of working volumes, as also withdrawal and injection capacities and need for flexible supplies, such as LNG/CNG.

The recently adopted regulation on security of supply requires investing in infrastructures to increase the resilience and robustness of the gas system in the event of a supply disruption. Member States should fulfil two infrastructure standards: N-1 and reverse flow. The N-1 formula describes the ability of the technical capacity of the gas infrastructure to satisfy total gas demand in the event of disruption of the single largest gas supply infrastructure, during a day of exceptionally high gas demand occurring with a statistical probability of once every 20 years. The N-1 can be fulfilled at national or regional level and a Member State may use also production and demand-side measures. The Regulation also requires that permanent physical bi-directional capacity is available on all cross-border interconnection between Member States (except for connections to LNG, production or distribution).

Currently five countries do not meet the N-1 criterion (Bulgaria, Slovenia, Lithuania, Ireland and Finland), taking into account the projects underway under the European Energy Programme for Recovery but excluding demand side measures[38]. Regarding investments on reverse flow, according to Gas Transmission Europe's study on reverse flow (July 2009), 45 projects have been identified in Europe as vital for enhancing reverse flows within and between Member States and providing a greater flexibility in transporting gas where it is needed. The main challenge is to finance projects to fulfil the infrastructure obligations, notably when the infrastructures are not required by the market.

Oil demand is expected to see two different developments in parallel: decline in the EU-15 countries and constant growth in new Member States, where demand is expected to grow by 7.8% between 2010 and 2020.

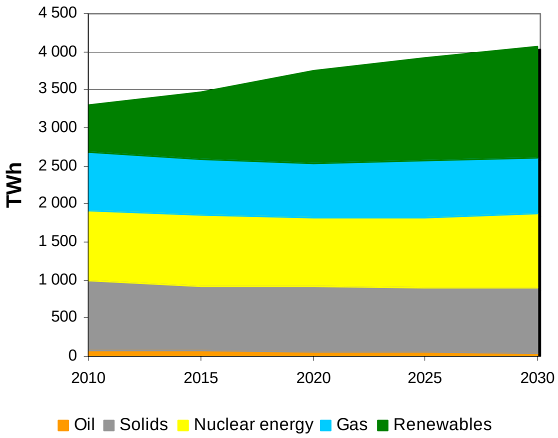
The main challenges for **electricity** infrastructure is growing demand and increasing shares of generation from renewable sources, in addition to additional needs for market integration and security of supply. EU-27 gross electricity generation is projected to grow by at least 20% from about 3,362 TWh in 2007 to 4,073 TWh in 2030 under the PRIMES reference scenario

[37] All lower figures refer to the PRIMES reference scenario, while the higher figures are derived from the Eurogas Environmental Scenario published in May 2010, based on a bottom-up collection of Eurogas members' estimates.

[38] See the impact assessment at http://ec.europa.eu/energy/security/gas/new_proposals_en.htm

and to 4,192 TWh under PRIMES baseline, even without taking into account the possible effects of strong electro-mobility development. The share of renewables in gross electricity generation is expected to be around 33% in 2020 according to the Reference scenario, out of which variable sources (wind and solar) could represent around 16%[39].

Figure 4 shows the evolution of gross electricity generation by source according to the PRIMES Reference scenario for the 2010-2030 period:



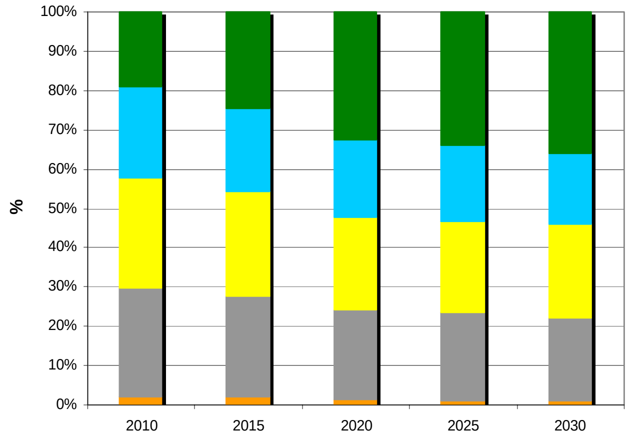


Figure 4: Gross power generation mix 2000-2030 by source in TWh (left) and corresponding shares of sources in % (right), PRIMES reference scenario

More detailed information for the horizon up to 2020 is provided by the national renewable energy action plans (NREAP) that Member States have to notify to the Commission according to article 4 of directive 2009/28/EC. Based on the first 23 national renewable energy action plans and largely in line with PRIMES reference scenario results for 2020, there will be about 460 GW of renewable electricity installed capacity that year in the 23 Member States covered[40], against only about 244 GW today[41]. Approximately 63% out of this total would be related to the variable energy sources wind (200 GW, or 43%) and solar (90 GW, out of which about 7 GW concentrated solar power, or 20%) (Table 1).

RES type	Installed capacity 2010 (GW)	Installed capacity 2020 (GW)	Share 2020 (%)	Variation 2010-2020 (%)
Hydro	116.9	134.2	29%	15%
Wind	82.6	201	43%	143%
Solar	25.8	90	19%	249%

39 The respective figures for 2030 are 36% and 20%. Note that the 2030 Reference scenario does not take into account potential future renewable energy policies in the EU or in individual Member States after 2020.

40 Austria, Bulgaria, Czech Republic, Cyprus, Germany, Denmark, Greece, Spain, Finland, France, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, the Netherlands, Portugal, Romania, Sweden, Slovakia, Slovenia and the United Kingdom.

41 "Renewable Energy Projections as Published in the National Renewable Energy Action Plans of the European Member States", update for 19 countries. L.W.M. Beurskens, M. Hekkenberg. Energy Research Centre of the Netherlands, European Environment Agency. 10 September 2010. Available at: http://www.ecn.nl/docs/library/report/2010/e10069.pdf

RES type	Installed capacity 2010 (GW)	Installed capacity 2020 (GW)	Share 2020 (%)	Variation 2010-2020 (%)
Biomass	21.2	37.7	8%	78%
Other	1	3.6	1%	260%
TOTAL	**247.5**	**466.5**	**100%**	**88%**

Table 1: Projected evolution of installed renewables capacities in GW, 2010-2020

Renewables in the 23 Member States are projected to account for over 1150 TWh of electricity generation, with about 50% of it from variable sources (Table 2).

RES type	Generation 2010 (TWh)	Generation 2020 (TWh)	Share 2020 (%)	Variation 2010-2020 (%)
Hydro	342.1	364.7	32%	7%
Wind	160.2	465.8	40%	191%
Biomass	103.1	203	18%	97%
Solar	21	102	9%	386%
Other	6.5	16.4	1%	152%
TOTAL	**632.9**	**1151.9**	**100%**	**82%**

Table 2: Projected evolution of renewables electricity generation in GW, 2010-2020

Most of the growth in wind capacities and generation will be concentrated in Germany, the United Kingdom, Spain, France, Italy and the Netherlands, while solar capacities and generation growth will be even more concentrated in Germany and Spain and to a lesser extent Italy and France.

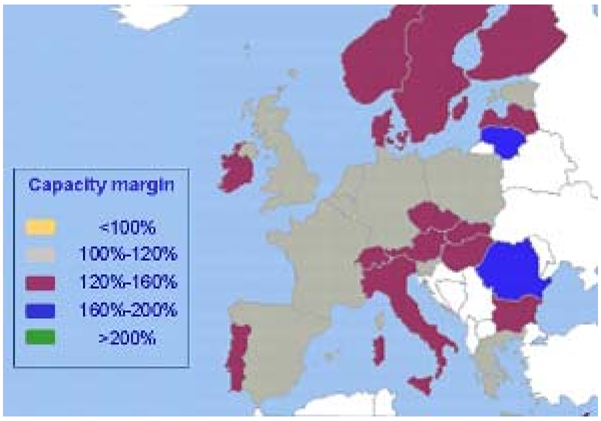
Alongside renewables, fossil fuels will continue to play a role in the electricity sector. Ensuring compatibility with climate change mitigation requirements of fossil fuel use in the electricity and industrial sectors may therefore require the application of **CO_2 capture and storage (CCS)** on a large and trans-European scale. PRIMES scenarios envisage the transport of about 36 million tons (Mt) of CO_2 by 2020, on the basis existing policies, and 50-272 Mt[42] by 2030 as CCS becomes more widely deployed.

According to the analysis carried out by KEMA and Imperial College London based on the PRIMES reference scenario, electricity generation capacity in 2020 should be sufficient to meet peak demand in virtually all Member States, despite the development of variable generation from renewable energies (Map 2 and Map 3[43]). However, while imports should

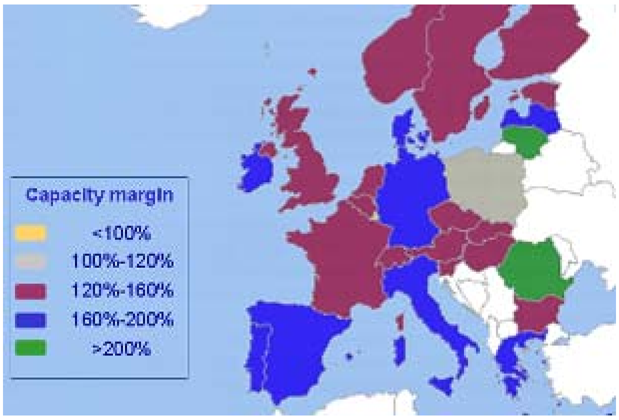
42 50 Mt according to the PRIMES reference scenario and 272 Mt according to PRIMES baseline, given the higher CO2 price.

43 The maps show the capacity margins, i.e. the ratio of firm capacity (excluding variable renewables) / all capacity (including variable renewables) vs. peak electricity demand, as modelled by KEMA and Imperial College London for all EU Member States plus Norway and Switzerland in 2020, on the basis of the PRIMES reference scenario (source: KEMA and Imperial College London).

therefore not be necessary for Member States to ensure their security of supply, more integration of the 27 European electricity systems could significantly reduce prices and increase overall efficiency by lowering the cost of balancing supply and demand at any given moment in time.



Map 2: Firm capacity vs. peak demand in 2020, PRIMES reference scenario



Map 3: All capacity vs. peak demand in 2020, PRIMES reference scenario

The evolution of electricity trade across borders is shown on Map 4 and Map 5[44]. Under the PRIMES Reference scenario, today's general pattern of electricity exports and imports is likely to remain as such until 2020 for most Member States.

Map 4: Net import/export situation in winter (October to March) 2020, PRIMES reference scenario

Map 5: Net import/export situation in summer (April to September) 2020, PRIMES reference scenario

This would result in the following interconnection capacity requirements between Member States, based on the optimisation of the existing European electricity grid as described in ENTSO-E's pilot Ten-Year Network Development Plan[45] (Map 6). It should however be noted that these requirements have been calculated on the basis of simplifying assumptions[46] and should be seen as indicative only. Results could also be significantly different, if the

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44 Source: KEMA and Imperial College London

45 https://www.entsoe.eu/index.php?id=282

46 The grid modelling done by Imperial College London and KEMA uses a "centre of gravity" approach, according to which each Member State's electricity grid is represented by a single node, from and to which transmission capacity is calculated. The associated investment model compares the costs of network expansion between Member States with the costs of additional generation capacity investments, based on certain input cost assumptions and evaluates the cost-optimal interconnection level between Member States on this basis.

European energy system was optimised on the basis of a newly designed, fully integrated European grid, instead of existing nationally centred electricity networks.

Map 6: Interconnection capacity requirements 2020 in MW[47], PRIMES Reference scenario (source: KEMA, Imperial College London)

3. PRIORITY CORRIDORS FOR ELECTRICITY, GAS AND OIL

3.1. Making Europe's electricity grid fit for 2020

3.1.1. Offshore grid in the Northern Seas

The 2008 Second Strategic Energy Review identified the need for a coordinated strategy concerning the offshore grid development: "*(…) a Blueprint for a North Sea offshore grid should be developed to interconnect national electricity grids in North-West Europe together and plug-in the numerous planned offshore wind project*"[48]. In December 2009, nine EU Member States and Norway[49] signed a political declaration on the North Seas Countries Offshore Grid Initiative (NSCOGI) with the objective to coordinate the offshore wind and

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47 The following interconnection capacities are not shown on the map for the sake of clarity: Austria-Switzerland (470 MW); Belgium-Luxemburg (1000 MW); Germany-Luxemburg (980 MW); Norway-Germany (1400 MW); Switzerland-Austria (1200 MW).

48 COM(2008) 781. The communication also underlined that "[the North Sea Offshore Grid] should become, (…) one of the building blocks of a future European supergrid. The Blueprint should identify the steps and timetable that need to be taken and any specific actions that need to be adopted. It should be developed by the Member States and regional actors involved and facilitated where necessary by action at Community level." In the Conclusions of the Energy Council on 19 February 2009, it was clarified that the blueprint should cover the North Sea (including the Channel region) and the Irish Sea.

49 Countries participating in the NSCOGI are Belgium, the Netherlands, Luxembourg, Germany, France, Denmark, Sweden, the United Kingdom, Ireland and Norway.

infrastructure developments in the North Seas. The nine EU members will concentrate about 90% of all EU offshore wind development. According to the information contained in their NREAPs, installed capacity is projected at 38.2 GW (1.7 GW other marine renewable energies) and production at 132 TWh in 2020[50]. Offshore wind could represent 18% of the renewable electricity generation in these nine countries.

Applied research shows that planning and development of offshore grid infrastructure in the North Seas can only be optimised through a strong regional approach. Clustering of wind farms in hubs could become an attractive solution compared to individual radial connections, when distance from the shore increases and installations are concentrated in the same area[51]. For countries where these conditions are met, such as Germany, the connection costs of offshore wind farms could thereby be reduced by up to 30%. For the North Sea area as a whole, cost reduction could reach almost 20% by 2030[52]. In order to realise such cost reductions, a more coordinated, planned and geographically more concentrated offshore wind development with cross-border coordination is absolutely necessary. This would also allow reaping the combined benefits of wind farm connection and cross-border interconnections[53], if the connection capacity is well dimensioned and hence results in a positive net benefit. Offshore development will strongly influence the need for reinforcements and expansion of onshore networks, notably in Central Eastern Europe, as highlighted in the priority 3. Map 7 is an illustration of a possible offshore grid concept as developed by the OffshoreGrid study[54].

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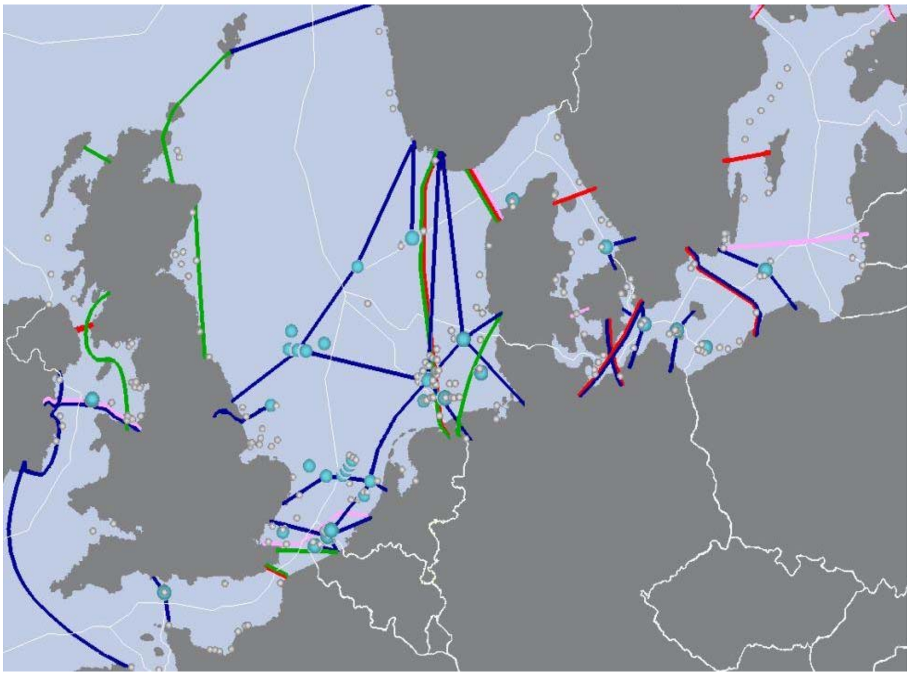
50 Ireland has also prepared a baseline and a more ambitious export scenario. According to this latter scenario, the respective figures would be: over 40 GW offshore wind, 2.1 GW other marine renewables generating 139 TWh in 2020. For the EU as a whole (taking into account the baseline for Ireland), offshore wind installed capacity is estimated to be over 42 GW in 2020, with a possible yearly electricity generation of over 137 TWh.

51 Based on a cost-benefit analysis, the OffshoreGrid study, carried out by 3E and partners and financed by the Intelligent Energy Europe Programme, finds that radial grid connections make sense up to 50 km distance from their connection points onshore. For larger distances (in the range of 50 to 150 km) from the onshore connection point, the concentration of the wind farms is a determining factor for the benefits of clustering. If the installed capacity is in a radius of 20 km (in certain cases 40 km) around the hub, and if it is in the order of the largest available rating for high voltage direct current cables, a cluster through a hub connection would be beneficial. Above 150 km distance, offshore grid hubs are considered as typical solutions. More information is available at: www.offshoregrid.eu. These results seem to be corroborated at the Member State level: The benefits of clustering or a more modular design were considered in the Netherlands for its second phase of offshore wind development. Given the small size of the wind farms and their short distance from shore, the assessment however showed that clustering is not the most cost effective approach in this phase.

52 According to the OffshoreGrid study, strong offshore grid infrastructure development would cost 32 billion euros until 2020 and up to 90 billion euros until 2030 considering radial connections. In case of clustering, the infrastructure cost could be reduced to 75 billion euros by 2030.

53 Integrated development could follow two main drivers. In case an interconnector is developed first, wind farms could be connected later. If connections for wind farms are developed first, interconnectors could be developed later between hubs, instead of building new interconnectors from shore to shore.

54 Work package D4.2 "Four Offshore Grid scenarios for the North and Baltic Sea" (OffshoreGrid study, July 2010). More information is available at http://www.offshoregrid.eu/images/pdf/pr_pr100978_d4%202_20100728_final_secured.pdf.



Map 7: Illustration of a possible offshore grid concept for the North Seas and the Baltic Sea ("mixed approach" scenario showing existing (red), planned (green) and commissioned (pink) transmission lines as well as additional lines (blue) necessary according to OffshoreGrid calculations)

Existing offshore development plans in certain Member States show that significant development in the North Seas will take place along or even across the borders of territorial waters of several Member States, raising planning and regulatory issues of European dimension[55]. Onshore reinforcements of the European network will be needed to transmit electricity to the major consumption centres further inland. However, ENTSO-E's pilot Ten Year Network Development Plan (TYNDP) does not include an adequate assessment of the infrastructure needed to connect upcoming new offshore wind capacities. ENTSO-E has committed to addressing this urgent issue more in detail in the second edition of it's TYNDP to be published in 2012.

Member States have adopted or are planning to adopt different approaches concerning offshore grid development. Most Member States (Germany, Denmark, France, Sweden, Ireland) have assigned the offshore extension of their onshore grid to national TSOs. The UK has so far chosen to tender the connection of each new offshore wind farm separately[56]. In Belgium and the Netherlands, grid development is currently the responsibility of the wind farm developer. In addition, current national regulatory frameworks encourage exclusively point-to-point solutions connecting wind farms with an onshore connection point, with the aim to minimise the connection cost for each project. Connection of wind farm clusters via a hub, with the associated advanced capacity provision and technology risk, is not covered under current national regulation. Finally, optimisation across borders, in order to facilitate electricity trade between two or several Member States, does not take place.

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55 Integrated solutions combining offshore wind power plant connections and trade interconnections to another country, or cross-border connections of a wind power plant (sitting in the territorial waters of one country, but connected to the grid of another country) need to be developed.

56 Any company can participate in these tenders, which creates a competitive environment for the development and operation of the new network.

As a consequence, the opportunities offered by a regional approach for integrated offshore and onshore infrastructure development as well as the synergies with international electricity trade are missed. This might lead to suboptimal and more expensive solutions in the longer term.

Other challenges for the development of an offshore grid are related to permitting and market design. As for other infrastructure projects, authorisation procedures are frequently fragmented even in the same country. When a project crosses the territory of different Member States, this can considerably complicate the overall process, resulting in very long lead times. Furthermore, the insufficient integration of electricity markets, the insufficient adaptation of connection regimes and national support schemes to offshore renewable energy generation and the absence of market rules adapted to electricity systems based on more variable renewable energy sources can impede the development of offshore projects and of a truly European offshore grid.

Planning offshore wind development and the necessary offshore and onshore grid infrastructure requires coordination between Member States, national regulatory authorities, transmission system operators and the European Commission. Maritime spatial planning and definition of offshore wind and ocean energy development zones can enhance development and ease investment decisions in this sector.

Recommendations

Structured regional cooperation has been set up by the Member States in the NSCOGI[57]. While the commitment of the Member States to develop the grid in a coordinated way is very important, it should now be turned into concrete actions for it to become the major driving force for the development of a North Seas offshore grid. The initiative should, in line with the strategy presented in the Communication, establish a working structure with adequate stakeholder participation and set a work plan with concrete timeframe and objectives concerning grid configuration and integration, market and regulatory issues and planning and authorisation procedures.

Under the guidance of the NSCOGI, different options should be prepared on grid configuration by national TSOs and ENTSO-E in its next TYNDP. The design options should consider planning, construction and operational aspects, the costs associated to the infrastructure and the benefits or constraints of the different design options. TSOs should in particular review planned wind farm development in order to identify possibilities for hub connections and interconnections for electricity trade, also taking into account possible future wind development. Regulators should consider overall development strategies and regional and longer-term benefits when approving new offshore transmission lines. Options to revise the regulatory framework and make it compatible should be examined, covering inter alia operation of offshore transmission assets, access to and charging of transmission, balancing rules and ancillary services.

[57] The NSCOGI has a regional approach, is driven by the participating Member States and builds on existing works and other initiatives. Its members intend to agree on a strategic work plan by means of a memorandum of understanding to be signed by end 2010.

3.1.2. Interconnections in South Western Europe

France, Italy, Portugal and Spain will host significant future developments of variable renewable electricity generations capacities over the coming decade. At the same time, the Iberian Peninsula is almost an electric island. Interconnections between France and Spain suffer already today from insufficient capacity, with only four tie-lines (2 of 220 kV and 2 of 400 kV) between the countries, the last one having been built in 1982. All face continuous congestions[58]. A new 400 kV line in the Eastern Pyrenees should be ready by 2014, increasing the current interconnection capacity from 1,400 MW to about 2,800 MW, but some congestion might remain even afterwards[59].

Moreover, these countries play a key role in connecting to Northern Africa, which could become increasingly important because of its huge potential for solar energy.

By 2020, about 10 GW of new renewables generation could be built in the countries East and South of the Mediterranean, out of which almost 60% solar and 40% wind capacities[60]. However, as of today, there is only one interconnection between the African and the European continent (Morocco-Spain) with about 1,400 MW capacity, which could be increased to 2,100 MW in the coming years. A direct current submarine 1,000 MW power line is being planned between Tunisia and Italy, to be operational by 2017. The use of these existing and new interconnections will create new challenges in the medium term (after 2020) with regard to their consistency with the evolutions of the European and North African network, both as regards their capacity and the corresponding regulatory framework. Any further interconnection must be accompanied by safeguards to prevent risks of carbon leakage through power imports to increase.

<u>*Recommendations*</u>

To ensure the adequate integration of new capacities, mainly from renewables, in South Western Europe and their transmission to other parts of the continent, the following key actions are necessary up to 2020:

– the adequate development of the interconnections in the region and the accommodation of the existing national networks to those new projects. An interconnection capacity of at least 4,000 MW between the Iberian Peninsula and France will be needed by 2020. Corresponding projects will have to be developed with the utmost attention to public acceptance and consultation of all relevant stakeholders.

– concerning connections with third countries, the development of Italy's connections with countries of the Energy Community (notably Montenegro, but also Albania and Croatia), the realisation of the Tunisia-Italy interconnection, the expansion of the Spain-Morocco interconnector, the reinforcement, where necessary, of South-South interconnections in North African neighbour countries (including as regards the efficient management of these

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58 ENTSO-E pilot TYNDP.

59 During the merger procedure for the acquisition of Hidrocantábrico in 2002, EDF-RTE and EDF had offered to increase the commercial interconnection capacity of then 1,100 MW by a minimum of 2,700 MW (Case No COMP/M.2684 - EnBW / EDP / CAJASTUR / HIDROCANTÁBRICO – decision dated 19 March 2002).

60 "Study on the Financing of Renewable Energy Investment in the Southern and Eastern Mediterranean Region", Draft Final Report by MWH, August 2010. The countries included in this study are Algeria, Egypt, Israel, Jordan, Lebanon, Morocco, Syria, Tunisia, West Bank / Gaza.

infrastructures)and preparatory studies for additional North-South interconnections to be developed after 2020.

3.1.3. Connections in Central Eastern and South Eastern Europe

The connection of new generation is a major challenge in Central and Eastern Europe. For example, in Poland alone about 3.5 GW are foreseen until 2015 and up to 8 GW until 2020[61].

At the same time, power flow patterns have recently changed significantly in Germany. Onshore wind power capacities, summing up to about 25 GW at the end of 2009, and offshore development, together with new conventional power plants, concentrate in the Northern and North-Eastern parts of the country; demand however rises mostly in the Southern part, increasing distances between generation and load centres or balancing equipment (e.g. pump storage). Huge North-South transit capacities are therefore needed, taking fully into account the grid development in and around the Northern Seas under priority 3.1.1. Given the impact of the current interconnection insufficiencies on the neighbouring grids especially in Eastern Europe, a coordinated regional approach is vital to solve this issue.

In South Eastern Europe, the transmission grid is rather sparse compared to the grid of the rest of the continent. At the same time, the whole region (including the countries of the Energy Community) has a lot of potential for further hydro generation. There is a need for additional generation connection and interconnection capacities in order to increase power flows between South East European countries and with Central Europe. The extension of the synchronous zone from Greece (and later Bulgaria) to Turkey will create additional needs for reinforcement of the grids in these countries. Ukraine and the Republic of Moldova having expressed their interest to join the European continental interconnected electricity networks, further extensions will have to be examined in the longer term.

Recommendations

To ensure adequate connection and transmission of generation, notably in Northern Germany and better integration of South-Eastern European electricity networks, the following key actions are necessary up to 2020 and should notably be supported by the countries of Central Eastern Europe, by extending the already existing cooperation in the gas sector:

– the development of adequate interconnections, notably within Germany and Poland, to connect new, including renewable, generation capacities in or close to the North Sea, to the demand centres in Southern Germany and to pumped storage power plants to be developed in Austria and Switzerland, while also accommodating new generation in Eastern countries. New tie-lines between Germany and Poland will become important, once new interconnections are developed with the Baltic States (in particular the Poland-Lithuania interconnection, see below). Due to increasing North-to-South parallel flows, cross-border capacity expansion will be necessary between Slovakia, Hungary and Austria in the medium term (after 2020). Internal relief of congestion through investments is needed to increase cross-border capacity in Central Europe.

– the increase of transfer capacities between South East European countries, including those of the Energy Community Treaty, in view of their further integration with Central European electricity markets.

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61 ENTSO-E pilot TYNDP.

This cooperation should be covered under the Central Eastern European cooperation already existing in the gas sector.

3.1.4. Completion of the Baltic Energy Market Interconnection Plan in electricity

In October 2008, following the agreement of the Member States of the Baltic Sea Region, a High Level Group (HLG) chaired by the Commission was set up on Baltic Interconnections. Participating countries are Denmark, Estonia, Finland, Germany, Latvia, Lithuania, Poland, Sweden and, as an observer, Norway. The HLG delivered the Baltic Energy Market Interconnection Plan (BEMIP), a comprehensive Action Plan on energy interconnections and market improvement in the Baltic Sea Region, both for electricity and gas, in June 2009. The main objective is to end the relative "energy isolation" of the Baltic States and integrate them into the wider EU energy market. The BEMIP provides an important example of successful regional cooperation. The lessons learnt from this initiative will be taken into account for other regional cooperation structures.

Internal market barriers had to be cleared in order to make investments viable and attractive. This involved aligning regulatory frameworks to lay the foundation for the calculation of fair allocation of costs and benefits, thus moving towards the "beneficiaries pay" principle. The European Energy Programme for Recovery (EEPR) was a clear driver for timely implementation of infrastructure projects. It provided an incentive to quickly agree on outstanding issues. The EU's Strategy for the Baltic Sea Region has also provided a bigger framework for the energy infrastructure priority. The strategy already proposed a framework to focus existing financing from structural and other funds into the areas identified by the strategy as priority areas.

Several factors have led to this initiative being seen by stakeholders around the Baltic Sea as a success: (1) the political support towards the initiative, its projects and actions; (2) the high-level involvement of the Commission as a facilitator and even driving force; (3) the involvement of all relevant stakeholders in the region from inception to implementation (ministries, regulators and TSOs) to implement the defined infrastructure priorities.

Despite the progress achieved so far, further efforts are still necessary to fully implement the BEMIP: continuous monitoring of the Plan's implementation by the Commission and the High Level Group will be necessary in order keep to the agreed actions and timeline.

In particular support is necessary for the key but also more complex cross-border projects, namely the LitPolLink between Poland and Lithuania, which is essential for integration of the Baltic market into the EU, and for which an EU coordinator was assigned.

3.2. Diversified gas supplies to a fully interconnected and flexible EU gas network

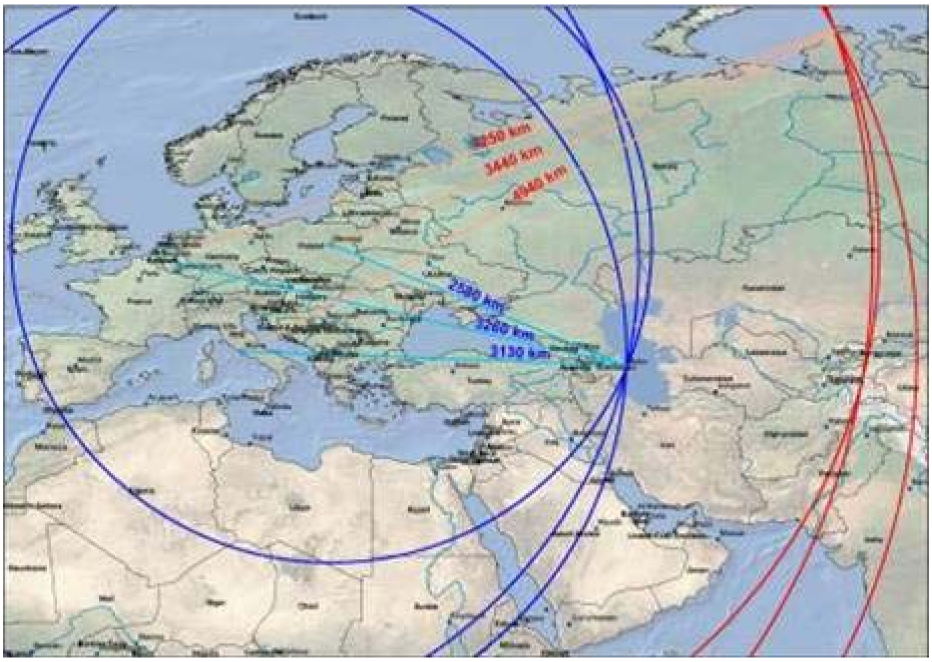
3.2.1. Southern Corridor

Europe's growing dependence on imported fuels is evident in the gas sector. The Southern Corridor would be – after the Northern Corridor from Norway, the Eastern corridor from Russia, the Mediterranean Corridor from Africa and besides LNG – the fourth big axis for diversification of gas supplies in Europe. Diversification of sources generally improves competition and thus contributes to market development. At the same time, it enhances security of supply: as seen also in the January 2009 gas crisis, the most severely affected countries were those relying on one single import sources. However, often the defensive attitude of gas producers and incumbent players in monopolistic markets hampers diversification. The implementation of the Southern Corridor requires close co-operation between several Member States and at European level, as no country individually requires the incremental gas volumes (new gas) sufficient to underpin the investment in pipeline infrastructure. Therefore, the European Union must act to promote diversification and provide for the public good of security of supply by bringing Member States and companies together in order to reach a critical mass. This is the underlying principle for the EU Southern Gas Corridor strategy. Its importance was underlined in the Commission's Second Strategic Energy Review of November 2008, which was endorsed by the European Council of March 2009.

The aim of the Southern Corridor is to directly link the EU gas market to the largest deposit of gas in the world (the Caspian / Middle East basin) estimated at 90.6 trillion cubic meters (for comparison, Russian proven reserves amount to 44.2 tcm[62]). Furthermore, the gas fields are geographically even closer than the main Russian deposits (Map 8).

The key potential individual supplier states are Azerbaijan, Turkmenistan and Iraq; yet, if political conditions permit, supplies from other countries in the region could represent a further significant supply source for the EU. The key transit state is Turkey, with other transit routes being through the Black Sea and the Eastern Mediterranean. The strategic objective of the corridor is to achieve a supply route to the EU of roughly 10-20% of EU gas demand by 2020, equivalent roughly to 45-90 billion cubic meters of gas per year (bcma).

The operational objective for the development of the Southern Corridor strategy is that the Commission and Member States work with gas producing countries, as well as those countries which are key for transporting hydrocarbons to the EU, with the joint objective of rapidly securing firm commitments for the supply of gas and the construction of gas transportation infrastructures (pipelines, Liquefied/Compressed Natural Gas shipping) necessary at all stages of its development.



Map 8: Comparison of distances of main Eastern gas supplies to main EU consumption hubs

62 BP Statistical Review of World Energy, June 2009.

The major challenge for the success of the Southern Corridor is to ensure that all elements of the corridor (gas resources, infrastructure for transport and underlying agreements) are available both at the right time and with significant scope. To date, substantial progress has been made to this end. With the financial support from the Commission (EEPR and/or TEN-E programmes) and great effort of pipeline companies, concrete transportation projects, namely Nabucco, ITGI, TAP and White Stream, are already in development stage and other possibly options are being studied. Nabucco as well as Poseidon, the Italy-Greece subsea interconnector which is part of ITGI, have received partial exemption from Third Party Access (so called "Article 22 exemption"). Moreover, the Nabucco Intergovernmental Agreement, signed in July 2009, has provided Nabucco with legal certainty and terms for transporting gas through Turkey and created a precedent for further extension of transportation regimes.

The key challenge for the future is to ensure that gas producing countries become ready to open towards exporting gas directly to Europe, which for them may often imply accepting high political risk linked to their geopolitical situation. The Commission, in cooperation with the Member States involved in the Southern Corridor, needs to further emphasize its engagement to build long term relations with gas producing countries in this region and provide them with a stronger link to the EU.

The Southern Gas Corridor pipeline components are also reinforced by preparation of options for delivering substantial additional quantities of Liquefied Natural Gas (LNG) to Europe in particular from the Middle East (Persian Gulf and Egypt). In the first phase it encompasses the development of LNG reception points in Europe (and connecting them to the wider network). Furthermore, cooperation with producer countries on developing energy policies and long-term investment plans which are conducive to LNG, is expected to be gradually built.

3.2.2. North-South gas interconnections in Eastern Europe

The strategic concept of the North-South natural gas interconnection is to link the Baltic Sea area (including Poland) to the Adriatic and Aegean Seas and further to the Black Sea, covering the following EU Member States (Poland, the Czech Republic, Slovakia, Hungary, Romania, and possibly Austria) and Croatia. This would provide the overall flexibility for the entire Central East European (CEE) region to create a robust, well-functioning internal market and promote competition. In the longer term, this integration process will have to be extended to the non EU member countries of the Energy Community Treaty. An integrated market would provide the necessary security of demand[63] and attract suppliers to make the best use of existing and new import infrastructures, such as new LNG regasification plants and projects of the Southern Corridor. The CEE region thus would become less vulnerable to a supply cut through the Russia/Ukraine/Belarus route.

There is one main supplier in the CEE region; the current linear (from East to West) and isolated networks are the heritage of the past. While the proportion of gas imported from Russia constitutes 18% of the EU-15 consumption, in the new Member States this indicator is 60% (2008). Gazprom deliveries are the overwhelming bulk of gas imports in the region (Poland: 70%, Slovakia: 100%, Hungary: 80%, certain Western Balkan countries: 100%).

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[63] The net import demand of the biggest market (Hungary) among the eight countries was 8.56 Mtoe in 2007 (Eurostat), while the demand of all seven markets together was 41 Mtoe, compared to German imports of about 62 Mtoe.

Due inter alia to monopolistic, isolated and small markets, long-term supply contracts and regulatory failures, the region is not attractive for investors or producers. The lack of regulatory coordination and of a common approach towards missing interconnections jeopardises new investments and hinders the entrance of new competitors on the market. Moreover, security of supply constitutes a concern and the investments needed to comply with the infrastructure standards imposed by the Security of Gas Supply Regulation are concentrated in this region. Finally, a considerable share of the population spends a relatively high share of their income on energy, leading to energy poverty.

The declaration of the extended Visegrad group[64] expresses already a clear commitment within the region to tackle these challenges. Based on the BEMIP experience and work already concluded by the signatories of the declaration, the High Level Group (HLG) proposed in the Communication should provide a comprehensive action plan to build interconnections and to complete market integration. The HLG should be assisted by working groups focusing on concrete projects, network access and tariffs. The work should include the experiences gained through the New Europe Transmission System (NETS) initiative[65].

3.2.3. Completion of the Baltic Energy Market Interconnection Plan in gas

While implementation of electricity projects within the BEMIP is well underway, little progress has been achieved in gas since the Action Plan was endorsed by the eight EU Member State Heads of State and President Barroso in June 2009. The HLG managed only to define a long list of projects with overall investment costs too high compared to the size of the gas markets in the region. Internal market actions were not agreed at all. The gas sector now enjoys the strong focus of the BEMIP work on two fronts: East-Baltic and West-Baltic areas.

The Eastern Baltic Sea region (Lithuania, Latvia, Estonia and Finland) requires urgent action to ensure security of supply through connection to the rest of the EU. At the same time Finland, Estonian and Latvia enjoy derogations from market opening under the third internal market package as long as their markets are isolated. The derogation will end once their infrastructure is integrated with the rest of the EU, for example through the Lithuania-Poland gas interconnection. Even though the annual gas consumption of the three Baltic States and Finland together is only about 10 bcm, all the gas they consume comes from Russia. As a share of total primary energy supply, Russian gas amounts to 13% for Finland, 15% for Estonia and to about 30% for Latvia and Lithuania, while the EU average is around 6.5%. The main supplier also has decisive stakes in the TSOs of all four countries. Moreover, also Poland is very reliant on Russian gas. Therefore there is little market interest to invest in new infrastructure. The minimum necessary infrastructure has been agreed and a major breakthrough in this area is the now ongoing dialogue – politically supported by both sides – between the companies on the Polish-Lithuanian gas link. Discussions on a regional LNG terminal are also ongoing within an LNG task force.

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[64] See the Declaration of the Budapest V4+ Energy Security Summit of 24 February, 2010 (http://www.visegradgroup.eu/). V4+ countries, in the sense of the Declaration, are: the Czech Republic, the Republic of Hungary, the Slovak Republic and the Republic of Poland (as Member States of the Visegrad Group), the Republic of Austria, Bosnia and Herzegovina, the Republic of Bulgaria, the Republic of Croatia, the Republic of Serbia, the Republic of Slovenia and Romania.

[65] The New Europe Transmission System (NETS) aims to facilitate the development of a competitive, efficient and liquid regional gas market that also reinforces security of supply, by creating a unified infrastructure platform to increase the level of cooperation/integration between the regional TSOs.

In the West Baltic, the task force's objective are to find ways to replace supply from depleting Danish gas fields expected from 2015 onwards, as well as to enhance security of supply in Denmark, Sweden and Poland. An action plan will be delivered at the end of 2010. Both task forces also focus on regulatory obstacles and the identification of common principles that would allow regional investments to take place.

As a key action, regional cooperation needs to be kept strong to establish the following projects: PL-LT, regional LNG terminal and a pipeline connecting Norway and Denmark and possibly Sweden and Poland. The objectives of market opening and improved security of gas supply can be achieved more cost-effectively on a regional level than a national scale. Commission's support is also continuously requested by the Member States in order to steer the BEMIP process. Finally, solutions must be found to break the vicious circle of "If there's no market, there is no incentive to invest in infrastructure; and without infrastructure, market will not develop".

3.2.4. North-South Corridor in Western Europe

The strategic concept of the North-South natural gas interconnections in Western Europe, that is from the Iberian peninsula and Italy to North-west Europe is to better interconnect the Mediterranean area and thus supplies from Africa and the Northern supply Corridor with supplies from Norway and Russia. There are still infrastructure bottlenecks in the internal market which prevent free gas flows in this region, such as for example the low interconnection level to the Iberian peninsula, preventing the use of the well-developed Iberian gas import infrastructure to its best. The Spain-France axis has been a priority for over a decade, but is still not completed. However, progress has been achieved in recent years, thanks to the better co-ordination of the national regulatory frameworks – taken up also as a priority by the South-West Gas Regional Initiative – and the active involvement of the European Commission. Another indication for imperfect market functioning and the lack of interconnectors are the systematically higher prices on the Italian wholesale market compared to other neighbouring markets.

At the same time, as the development of electricity from variable sources is expected to be particularly prominent in this corridor, the general short-term deliverability of the gas system needs to be enhanced to respond to the additional flexibility challenges to balance electricity supply.

The main infrastructure bottlenecks preventing the correct functioning of the internal market and competition need to be identified in this corridor and stakeholders, Member States, NRAs and TSOs, shall work together to facilitate their implementation. Secondly, an integrated analysis between the electricity and gas system – taking into account both generation and transmission aspects – should lead to the assessment of the gas flexibility needs and the identification of projects with the objective to back-up variable electricity generation.

3.3. Ensuring the security of oil supply

Contrary to gas and electricity, oil transport is not regulated. This means that there are no rules, e.g. on rates of return or third party access for new infrastructure investments. Oil companies are primarily responsible for ensuring continuous supply. Nonetheless, there are certain aspects, mainly concerning the free access to pipelines supplying the EU, but lying in countries outside the EU (in Belarus, Croatia and Ukraine in particular), which cannot be addressed through commercial arrangements only and need political attention.

The Eastern European crude oil pipeline network (an extension of the Druzhba pipeline) was conceived and built during the Cold War period and had, at that time, no pipeline link with the Western network. As a result, insufficient connections between the Western European pipeline network and Eastern infrastructures exist. Hence alternative pipeline supply possibilities of crude oil or petroleum products from Western Member States to CEE countries are limited. In case of an enduring supply disruption in the Druzhba system (currently used capacity: 64 million tons/year), these limitations would lead to a big increase in tanker traffic in the environmentally sensitive Baltic area[66], in the Black Sea and in the extremely busy Turkish Straits[67], increasing the risks of accidents and oil spills. In case of the Lithuanian Mažeikiai refinery[68] the alternative supply requires shipping approximately 5.5 to 9.5 million tons/year through the Baltic Sea to the Lithuanian Butinge oil terminal.

According to a recent study[69], the potential responses to supply disruptions include: (1) the creation of the Schwechat-Bratislava pipeline between Austria and Slovakia; (2) the upgrade of the Adria pipeline (linking the Omisalj oil terminal in on the Croatian Adriatic coast to Hungary and Slovakia); and (3) the upgrade of the Odessa-Brody pipeline in Ukraine (connecting the Black Sea oil terminal to the Southern branch of Druzhba at Brody) and its planned extension to Poland (Brody-Adamowo). These routes represent an alternative supply capacity of at least 3.5, 13.5, and 33 million tons/year respectively. An additional improvement would be the creation of the Pan-European Oil Pipeline to link the Black Sea supply with the Transalpine Pipeline with an envisaged capacity between 1.2 million and 1.8 million barrels per day.

For the above reasons, political support for mobilising private investment in possible alternative infrastructures is a priority, in order to ensure the security of oil supply of land-locked EU countries, but also to reduce oil transport by sea, thereby reducing environmental risks. This does not necessarily require the building of new pipeline infrastructure. Removing capacity bottlenecks and/or enabling reverse flows can also contribute to security of supply.

3.4. Roll-out of smart grid technologies

Smart grids[70] are energy networks that can cost efficiently integrate the behaviour and actions of all users connected to it. They are changing the way, in which the electricity grid is operated in terms of transmission and distribution and re-structuring the present generation and consumption pathways. Through integration of digital technology and a two-way

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66 The Baltic Sea is one of the busiest seas in the world, accounting for more than 15% of the world's cargo transport (3,500-5,000 ships per month). About 17-25% of these ships are tankers transporting approximately 170 million tons of oil per year.

67 The Turkish Straits comprise the Bosporus and Dardanelles and connect the Black Sea, through the Sea of Marmara, with the Aegean Sea. Less than a kilometre wide at their narrowest point, they are among the world's most difficult and dangerous waterways to navigate, due to their sinuous geography and high traffic (50,000 vessels, including 5,500 oil tankers, per year).

68 In 2006, noting some leaks on the Druzhba pipeline, Transneft, the Russian pipeline operator, stopped the delivery of crude to the Lithuanian Mažeikiai refinery, the only oil refinery in the Baltic States. Since then this particular pipeline segment remains closed.

69 "Technical Aspects of Variable Use of Oil Pipelines coming into the EU from Third Countries", study by ILF and Purvin & Gertz for the European Commission, 2010.

70 ERGEG and the European Task Force for Smart Grids define smart grids as electricity networks that can cost efficiently integrate the behaviour and actions of all users connected to it – generators, consumers and those that are both – in order to ensure economically efficient, sustainable power systems with low losses and high levels of quality and security of supply and safety. See http://ec.europa.eu/energy/gas_electricity/smartgrids/taskforce_en.htm for more information.

communication system, smart grids establish direct interaction between the consumers, other grid users and energy suppliers. They enable consumers to directly control and manage their individual consumption patterns, notably if combined with time differentiated tariffs, providing, in turn, strong incentives for efficient energy use. They allow companies to improve and target the management of their grid, increasing grid security and reducing costs. Smart grid technologies are needed to allow for a cost-effective evolution towards a decarbonised power system, allowing for the management of vast amounts of renewable on-shore and off-shore energy, while maintaining availability for conventional power generation and power system adequacy. Finally, smart grid technologies, including smart metering, enhance the functioning of retail markets, which gives a real choice to consumers, as energy companies as well as information and communication technology companies can develop new, innovative energy services.

Many countries have developed smart grid projects, including smart meter deployment, namely Austria, Belgium, France, Denmark, Germany, Finland, Italy, Netherlands, Portugal, Sweden, Spain and UK[71]. In Italy and Sweden almost all customers already have smart meters.

The Bio Intelligence 2008 Study[72] concludes that smart grids could reduce the EU annual primary energy consumption of the energy sector in 2020 by almost 9%, which equals to 148 TWh of electricity or savings reaching almost 7.5 billion euros/year (based on average 2010 prices). Industry estimates for individual consumption argue that an average household could save 9% of its electricity and 14% of its gas consumption, corresponding to savings of ca. 200 euros/year[73].

The Commission promotes the development and deployment of smart grids through financial support for research and development (R&D). The SET Plan European Electricity Grids Initiative (EEGI), launched in June 2010, has been developed by a team of network operators in electricity distribution and transmission supported by the Commission and aims at developing the technological issues of smart grids further. It will consolidate smart grids experiments so far through large size demonstrations and promote R&D and innovation in smart grid technologies. It will also stimulate wider deployment by addressing challenges stemming from technology integration at system level, user acceptance, economic constraints and regulation.

In addition to this technology push, market pull for the Europe-wide implementation of smart grids has been created with the adoption of the third internal energy market package in 2009, which foresees the obligation for Member States to ensure wide implementation of intelligent metering systems by 2020[74]. Moreover, the Directive on energy end-use efficiency and energy

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71 An ERGEG report, presented and disseminated at the annual Citizens' Energy Forum in London in September 2009, gives the most up-to-date and complete overview regarding the smart meter implementation status in Europe. Available at: http://ec.europa.eu/energy/gas_electricity/forum_citizen_energy_en.htm

72 "Impacts of Information and Communication Technologies on Energy Efficiency", Bio Intelligence Service Final Report, September 2008. Supported by the European Commission DG INFSO.

73 http://www.nuon.com/press/press-releases/20090713/index.jsp

74 Annex 1 of the Directive 2009/72/EC and Annex 1 of the Directive 2009/73/EC request the Member States to ensure implementation of intelligent metering systems that shall assist the active participation of consumers in the energy supply market. Such obligation might be subject to an economic assessment by Member States by 3 September 2012. According to the Electricity Directive, where roll-out of smart

services[75] has identified smart meters as one of the main contributors to energy efficiency improvement. The Renewables Directive[76], finally, views smart grids as an enabler for integration of increasing renewable energy into the grid and obliges Member States to develop transmission and grid infrastructure towards this aim. Jointly, these directives constitute the main policy and legal framework on which further action to stimulate the development of and deployment of smart grids will be built.

To ensure that smart grids and smart meters are developed in a way that enhances retail competition, integration of large-scale generation from renewable energy sources, and energy efficiency through the creation of an open market for energy services, the Commission has established a Task Force on smart grids in November 2009. It consists of about 25 European associations representing all relevant stakeholders. Its mandate is to advise the Commission on the EU level policy and regulatory actions and to coordinate the first steps towards the implementation of smart grids under the provisions of the third package. Initial work of the Task Force has been led by three Expert Groups[77], each focusing on (1) functionalities of smart grid and smart meters, (2) regulatory recommendations for data safety, data handling and data protection, and (3) roles and responsibilities of actors involved in the smart grids deployment.

Despite the expected benefits of smart grids and the aforementioned policy measures in place, the transition towards smart grids and meters is not progressing as fast as needed to reach the EU's energy and climate objectives.

The success of Smart Grids will not just depend on new technology and the willingness of networks to introduce them, but also on best practice regulatory frameworks to support their introduction, addressing market issues, including impacts on competition, and changes in the industry (i.e. to industry codes or regulation) and the way, in which consumers use energy. Creating the right regulatory framework for a well-functioning energy services market is the main challenge. It will require enabling the cooperation of a wide range of different market actors (generators, network operators, energy retailers, energy service companies, information and communication technology companies, consumers, appliance manufacturers). This regulatory framework will also have to ensure the adequate open access and sharing of operational information between actors and might also have to address tariff setting issues in order to provide proper incentives for grid operators to invest in smart technologies. National regulatory authorities also have a very important role as they approve tariffs that set the basis for investments in smart grids, and possibly meters. Unless a fair cost sharing model is developed and the right balance between short-term investment costs and longer term profits found, the willingness of grid operators to undertake any substantial future investments will be limited.

Unambiguous (open) standards for smart grids and meters are needed to ensure interoperability, addressing key technological challenges and enabling successful integration of all grid users, while providing high system reliability and quality of electricity supply. Given competing efforts to develop worldwide standards, relying and investing in one specific

metering is assessed positively, at least 80% of consumers shall be equipped with intelligent metering systems by 2020.

75 Annex 3 of Directive 2006/32/EC.

76 Article 16 of Directive 2009/28/EC.

77 Task Force Smart Grids – vision and work programme: http://ec.europa.eu/energy/gas_electricity/smartgrids/doc/work_programme.pdf

(European) technical solution today might tomorrow translate into stranded costs. This is why the Commission launched a smart meters standardisation mandate for relevant European standardisation bodies in 2009. A new mandate to review related standards and develop new standards for smart grids will be launched by the Commission to the same standard bodies at the beginning of 2011. International collaboration is therefore essential to ensure the compatibility of solutions.

Persuading and winning the trust of consumers as regards the benefits of smart grids constitutes another challenge. As long as price elasticity of electricity remains low, the overall benefits of smart grids unverified and the risk of data abuse unaddressed[78], it may be difficult to overcome consumer reluctance, given the time and behavioural changes required to reap the benefits of smart technologies.

Last but not least, the possible lack of skilled workforce that would be ready to operate the complex smart grid system is another, non-negligible challenge.

The transition towards smart grids is a complex issue and a single leap from existing network to smart grids is not realistic. A successful transition will require fine-tuned cooperation between all stakeholders in order to find the right cost-effective solutions, avoid duplication of work and exploit existing synergies. To gain public awareness and acceptance and customer support, the benefits and costs of smart grids implementation will have to be objectively discussed and carefully explained, through active participation of consumers, small and medium enterprises and public authorities.

Recommendations

To ensure such approach and to overcome identified challenges the following key actions are recommended:

- **Specific legislation:** As outlined in the Communication, the Commission will assess whether any further legislative initiatives for smart grid implementation are necessary under the rules of third internal energy market package. The assessment will take into account the following objectives: i) ensuring the adequate open access and sharing of operational information between actors and their physical interfaces; ii) creating a well-functioning energy services market; and iii) providing proper incentives for grid operators to invest in smart technologies for smart grids. Based on this analysis, the final decision concerning specific legislation for smart grids will be taken during the first half of 2011.

- **Standardisation and Interoperability:** The Task Force has defined a set of six expected services and about 30 functionalities of smart grids. The Task Force and the CEN/CENELEC/ETSI Joint Working Group on Standards for the Smart Grid will produce by end 2010 a joint analysis on the status of European standardization for smart grid technologies and identify further work needed in this area. By beginning of 2011 the Commission will set up a standardisation mandate for the relevant European standardisation bodies to develop smart grid standards and ensure interoperability and compatibility with standards being elaborated worldwide.

[78] A draft bill on smart grid deployment was refused by the Dutch Parliament in 2009 on grounds of data protection concerns.

- **Data protection:** Based on the work of the Task Force, the Commission, in close cooperation with the European Data Protection Supervisor, will assess the need for additional data protection measures, the roles and responsibilities of different actors concerning access, possession and handling of data (ownership, possession and access, read and change rights, etc.), and propose, if necessary, adequate regulatory proposals and/or guidelines.

- **Infrastructure investments:** Large parts of the necessary investments for the deployment of smart grids can be expected to come from network operators, notably at distribution level, and private companies, under the guidance of national regulatory authorities. Where funds are missing, public-private alliances could provide solutions. Where the rate of return for an investment is too low and the public interest evident, public finances must have the opportunity to step in. The Commission will encourage Member States to set up funds for the support of the Smart Grid deployment. The Commission will also examine particular support for smart technologies under the policy and project support programme mentioned in the Communication, as well as innovative funding instruments targeted at a rapid roll-out of smart grid technologies in transmission and distribution networks.

- **Demonstration, R&D and innovation projects:** In line with the above infrastructure investment policy, a clear European R&D and demonstration policy is necessary to boost innovation and accelerate the evolution towards smart networks, based on the EEGI and the smart grids activities of the European Energy Research Alliance, which focuses on longer-term research. Particular attention should be paid to electricity system innovations combined with R&D on power technologies (cables, transformers, etc.) with R&D on information and communication technologies (control systems, communications, etc.). Proposed measures should also address consumer behaviour, acceptance and real-life barriers to deployment. Member States and the Commission should promote R&D and demonstration projects, e.g. with a combination of public support and regulation incentives, ensuring that the EEGI can start the proposed projects as planned, despite the current difficult financial situation in the EU. This work should be closely coordinated with activities proposed in the Communication concerning Europe's electricity highways. To ensure full transparency on ongoing demonstration/pilot projects and their results and the development of a future legal framework, the Commission might create a platform to enable dissemination of good practices and experiences concerning practical deployment of smart grids across Europe and coordinate the different approaches so that synergies are ensured. The SET Plan Information system, managed by the European Commission's Joint Research Centre (JRC), includes a monitoring scheme that can be used as a starting point.

- **Promoting new skills:** To fill the gap between low-skilled and high-skill jobs due to smart grid deployment requirements, ongoing initiatives could be used such as the training actions under the SET Plan, the Knowledge and Innovation Communities of the European Institute of Technology, the Marie Curie Actions[79] and other actions such as the "New Skills for New Jobs" initiative. However, Member States will need to address seriously possible negative social consequences and launch programmes to retrain workers and support the acquisition of new skills.

[79] http://cordis.europa.eu/fp7/people/home_en.html

4. PREPARING THE LONGER TERM NETWORKS

4.1. European electricity highways

An electricity highway should be understood as a an electricity transmission line with significantly more capacity to transport power than existing high-voltage transmission grids, both in terms of the amount of electricity transmitted and the distance covered by this transmission. To reach these higher capacities, new technologies will have to be developed, allowing notably direct current (DC) transmission and voltage levels significantly higher than 400 kV.

For the period beyond 2020 and up to 2050, a long-term solution will be needed to overcome the main challenge electricity networks are facing: accommodating ever-increasing windsurplus generation in the Northern Seas and increasing renewable surplus generation in the South Western and also South Eastern parts of Europe, connecting these new generation hubs with major storage capacities in Nordic countries and the Alps and with existing and future consumption centres in Central Europe, but also with the existing alternating current (AC) high-voltage grids. The new highways will have to take account of existing and future surplus areas, such as France, Norway or Sweden, and the complexity of the existing Central European North-South transmission corridor bringing surplus electricity from the North through Denmark and Germany to Southern German and Northern Italian deficit areas.

Despite technological uncertainties, it is clear that any future electricity highway system will need to be built stepwise, ensuring compatibility of AC/DC connections and local acceptance[80], on the basis of the other priorities up to 2020 described in chapter 3.1, in particular concerning offshore grids.

This highway system will also have to prepare for possible connections beyond EU borders to the South and the East, in order to fully benefit from the considerable renewables potential in these regions. In addition to the already synchronous connections with the Maghreb and Turkey, connections with other Mediterranean and Eastern countries might therefore be necessary in the long term. To this end, a dialogue with Northern African states on the technical and legal requirements for the development of trans-Mediterranean electricity infrastructures could be envisaged.

While there is growing awareness about the future need for a pan-European electricity grid, there is significant uncertainty concerning the moment in time, when this grid will become necessary, and the steps to be taken to build it. Action coordinated at EU level is therefore indispensable to start coherent development of this grid and reduce uncertainties and risks. European coordination will also be necessary to establish an appropriate legal, regulatory and organisational framework to design, plan, build and operate such an electricity highway system.

This action will need to integrate ongoing research and development work, notably under the SET plan European Electricity Grid Initiative (EEGI) and European Industrial Wind Initiative, to adapt existing and to develop new transmission, storage and smart grid

80 This could include the need for partial underground of electricity lines, taking into account that investment costs for underground cables are at least 3-10 times higher compared to overhead lines. See "Feasibility and technical aspects of partial undergrounding of extra high voltage power transmission lines", joint paper by ENTSO-E and Europacable. November 2010.

technologies. In this context, it will also need to integrate the potential for large-scale hydrogen transport and storage. When coupled with fuel cells, it is particularly suited for distributed and transport applications. Commercialisation for residential applications could be expected as of 2015 and for hydrogen vehicles around 2020.[81]

Recommendations

The following key actions are necessary to prepare European electricity highways:

– In line with the conclusions of the June 2009 Bucharest Forum, initiate dedicated work on the Electricity Highways, in the framework of the Florence Forum, to structure the work carried out by all stakeholders for the preparation of the electricity highways. This work should be organised by the European Commission and ENTSO-E and bring together all relevant stakeholders. It should focus on establishing mid- and long-term generation development scenarios, assessing concepts of pan-European grid architecture and design options, analysing socio-economic and industrial policy consequences of deployment, and designing an appropriate legal, regulatory and organisational framework.

– Develop the necessary **research and development**, building on the SET-plan European Electricity Grid Initiative (EEGI) and European Industrial Wind Initiative, to adapt existing and develop new transmission, storage and smart grid technologies as well as needed grid design and planning tools.

– Establish a **modular development plan**, to be prepared by ENTSO-E by mid-2013, with the aim of commissioning first Electricity Highways by 2020. The plan would also prepare for the extension with the aim of facilitating the development of large-scale renewable generation capacities beyond the borders of the EU.

4.2. European CO_2 transport infrastructure

Given that potential CO_2 storage sites are not evenly distributed across Europe, large-scale deployment of CO_2 capture and storage in Europe, may be needed to achieve significant levels of decarbonisation of the European economies post-2020, and will necessitate the construction of an infrastructure of pipelines and, where suitable, shipping infrastructure, that could span across Member State borders, if countries do not have adequate CO_2 storage potential.

The component technologies of CCS (capture, transport and storage) are proven. However, they have not yet been integrated and tested at an industrial scale, and, currently, CCS is not commercially viable. To date, the implementation of the technology has been limited to smaller-scale plants often designed to demonstrate one or two of the components in isolation. At the same time it is commonly agreed that in order to have a profound impact on emission reductions, and thus enable a 'lowest-cost' portfolio of climate change mitigation measures, the viability of CCS technologies has to be demonstrated on large scale around 2020.

In response, the 2007 Spring European Council decided to support deployment of up to 12 large-scale CCS demonstration plants in Europe by 2015 in order to drive the technology to

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[81] To this aim, in the framework of the SET Plan, the Fuel Cells and Hydrogen Joint Undertaking will launch a first study on EU hydrogen infrastructure planning by end 2010, leading the way for commercial deployment starting in a 2020 timeframe.

commercial viability. There are currently six large-scale CCS projects under construction designed to demonstrate the technology in electricity generation. They will have an installed capacity of at least 250MW and will also feature transport and storage components. These projects are co-financed by the Commission with grants amounting to €1 billion in total. A further funding mechanism, embedded in the Emission Trading System, became operational in November 2010[82]. In addition, the Commission supports CCS related research and development and has established a dedicated knowledge sharing network for large-scale CCS demonstrators.

The Joint Research Centre (JRC) prepared in 2010 an assessment on the requirements for investment in CO_2 transport infrastructure[83]. Under PRIMES baseline assumptions, the study shows that 36 Mt of CO_2 will be captured in 2020 and transported in 6 EU Member States. The resulting CO_2 transport network stretches for approximately 2,000 km and requires 2.5 billion euros of investment (Map 9). Nearly all pipelines are planned to accommodate the additional CO_2 quantities anticipated to flow in the following years[84].

For 2030, the study finds that the amount of CO_2 captured increases to 272 Mt (Map 10). Many of the pipelines built earlier now operate at full capacity, and new pipelines are built, to become fully utilised in the ramp-up towards 2050. The CO_2 transport network stretches now for about 8,800 km and requires cumulative investment of 9.1 billion euros. First regional networks form across Europe around the first demonstration plants. The JRC analysis also highlights the benefits of European coordination if Europe is to achieve an optimal solution for CO_2 transport, as its results indicate that up to 16 EU Member States could be involved in cross-border CO_2 transport by 2030.

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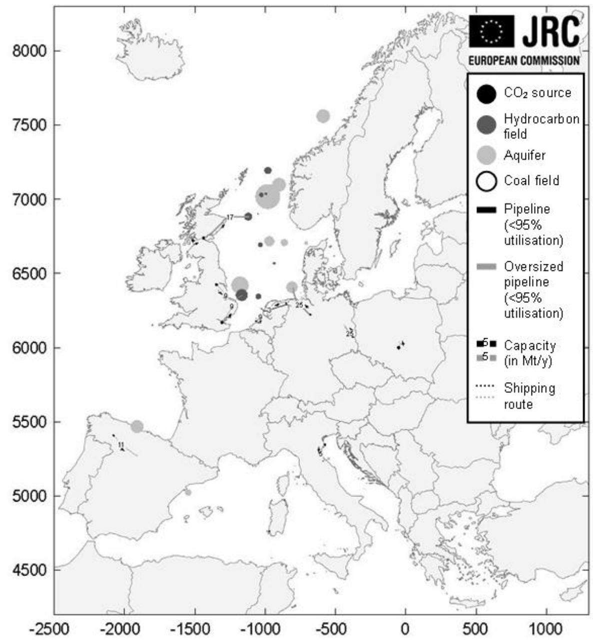
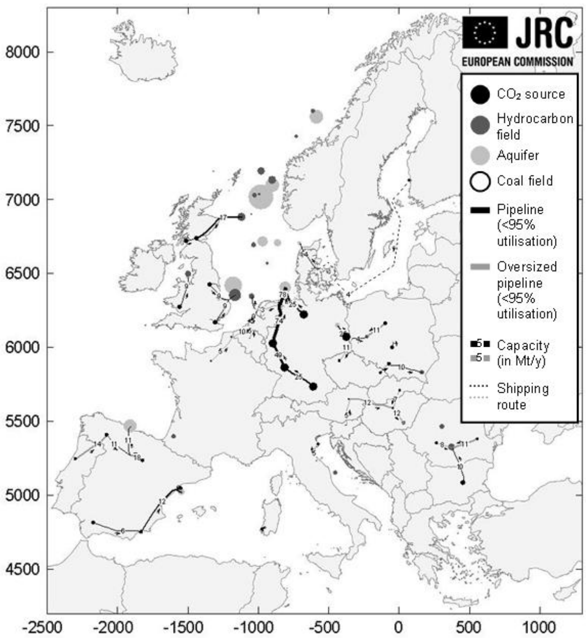
82 http://ec.europa.eu/clima/funding/ner300/index_en.htm

83 "The evolution of the extent and the investment requirements of a trans-European CO2 transport network", European Commission, Joint Research Centre, EUR 24565 EN. 2010.

84 Oversized pipelines are shown in red, while pipelines operating at full capacity are shown in blue.



Map 9: CO_2 network infrastructure in 2020, PRIMES baseline



Map 10: CO_2 network infrastructure in 2030, PRIMES baseline

A second analysis, done by Arup in 2010 and focussing on the feasibility of Europe-wide CO_2 infrastructures[85], aims at determining the optimal CO_2 transport network in Europe and its evolution over time, based on predefined volumes of CO_2, identification of suitable storage sites and a cost-minimisation approach. The most conservative scenario calculates a network of 6,900 km for 50 Mt of CO_2 transported in 2030. The study argues that, as certain countries will lack storage capacity, only a trans-boundary network could allow wider deployment of CCS.

These conclusions are corroborated by the EU Geocapacity study (2009) on European capacity for geological storage of CO_2[86]: a future CO_2 transport network depends critically upon the availability of onshore storage or the availability and development of offshore saline formations. Considering the level of public awareness on CO_2 storage and CCS technology in general, the study suggests that priority should be given to storage in saline formations offshore. The study also points out that availability of storage capacities can not yet be confirmed, additional work is therefore necessary to verify the real storage potential. However, the main driver for CCS development in the near future will be the CO_2 price, which is highly uncertain and dependent on the evolution of the ETS. Any analysis outlining a possible CO_2 network beyond 2020 should thus be treated with great caution.

All studies confirm that the evolution of the CO_2 network in Europe will be determined by the availability of storage sites and the level of CCS deployment and the degree of coordination for its development already now. The development of integrated pipeline and shipping networks, planned and constructed initially at regional or national level and taking into

85 "Feasibility of Europe-wide CO_2 infrastructures", study by Ove Arup & Partners Ltd for the European Commission. September 2010.

86 "EU GeoCapacity - Assessing European Capacity for Geological Storage of Carbon Dioxide", Project no. SES6-518318. Final Activity Report available at: http://www.geology.cz/geocapacity/publications

account the transport needs of multiple CO_2 sources would take advantage of economies of scale and enable the connection of additional CO_2 sources to suitable sinks in the course of the pipeline lifetime[87]. In the longer run, such integrated networks would be expanded and interlinked to reach sources and storage sites spread across Europe, similar to today's gas networks.

Recommendations

Once CCS becomes commercially viable, the pipelines and shipping infrastructure built for demonstration projects will become focal points for a future EU network. It is important that this initially fragmented structure can be planned in a way that ensures Europe-wide compatibility at a later stage. Lessons learned about the integration of initially fragmented networks as those for gas would have to be taken into account to avoid a similarly laborious process for creating common markets.

The examination of the technical and practical modalities of a CO_2 network should be pursued and an agreement on a common vision sought. The Sustainable Fossil Fuels Working Group for stakeholder dialogue (within the Berlin Forum) should be used for discussions on possible actions in this area. The CCS Project Network could be used for gathering experience from the operating demonstration projects. This in turn will allow assessing any need and extent of potential EU intervention.

Regional cooperation should also be supported in order to stimulate development of clusters constituting the first stage of a possible, future integrated European network. Existing support structures, including the CCS Project Network and the Information Exchange Group established under Directive 2009/31/EC on the geological storage of CO_2, could speed up development of regional clusters. This could include i.a. establishing focused working groups and sharing knowledge on the subject in the context of the CCS Project Network, exchanging best practice on permitting and cross-border cooperation of competent authorities within the Information Exchange Group. Global CCS discussion fora will also be used by the Commission to exchange existing knowledge on regional clusters and hubs worldwide.

The Commission will also continue working on a European CO_2 infrastructure map that can facilitate advance infrastructure planning, concentrating on the issue of cost efficiency. An important part of this task will include identification of the location, capacity and availability of storage sites, especially offshore. In order to make sure that the results of such a mapping exercise are comparable across the continent and can be used for optimal network design, efforts will be undertaken to elaborate a common storage capacity assessment methodology. For the sake of transparency with regard to storage and CCS in general, the Commission will pursue the publication of a European CO_2 Storage Atlas to visualise storage potential.

[87] The Pre-Front End Engineering Design Study of a CCS network for Yorkshire and Humber showed that initial investment in spare pipeline capacity would be cost effective even if subsequent developments joined the network up to 11 years later. The study also confirmed experience from other sectors, i.e. that investing in integrated networks would catalyse the large scale deployment of CCS technologies by consolidating permitting procedures, reducing the cost of connecting CO_2 sources with sinks and ensuring that captured CO_2 can be stored as soon as the capture facility becomes operational.

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EUROPEAN COMMISSION

Brussels, 17.11.2010
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COMMISSION STAFF WORKING DOCUMENT

IMPACT ASSESSMENT

Accompanying document to the

COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS

Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network

{COM(2010) 677 final}
{SEC(2010) 1396 final}

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GLOSSARY

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
BAU	Business As Usual
BEMIP	Baltic Energy Market Interconnection Plan
CCS	Carbon Capture and Storage
CNG	Compressed Natural Gas
CRE	Commission de Régulation de l'Energie (National Regulatory Authority in France)
DC	Direct Current
EBRD	European Bank for Reconstruction and Development
EIA	Environmental Impact Assessment
EEPR	European Energy Plan for Recovery
EESII	European Energy Security and Infrastructure Instrument
EIB	European Investment Bank
EIP	Energy Infrastructure Package
ENPI	European Neighbourhood and Partnership Instrument
ENTSO-E	European Network of Transmission System Operators in Electricity
ENTSOG	European Network of Transmission System Operators in Gas
ERGEG	European Regulators' Group for Electricity and Gas
ETS	Emission Trading Scheme
EU	European Union
GDP	Gross Domestic Product
GW	Giga Watt
ICT	Information and Communication Technology
INOGATE	European Union programme supporting international cooperation between the EU, the littoral states of the Black and Caspian Seas and their neighbouring countries
IPA	Instrument for Pre-Accession Assistance
LNG	Liquefied Natural Gas
Mtoe	Million tons of oil equivalent
NGO	Non-Governmental Organisation

NIF	Neighbourhood Investment Facility
NSCOGI	North Sea Countries Offshore Grid Initiative
OFGEM	Office of Gas and Electricity Markets (National Regulatory Authority in the UK)
PEI	Project of European Interest
RES	Renewable Energy Sources
SME	Small and Medium Enterprises
TEN-E	Trans-European Networks for Energy
TFEU	Treaty on the Functioning of the European Union
TSO	Transmission System Operators
TWh	Tera Watt hour
TYNDP	Ten-Year Network Development Plan
UPS	Unified Power System (synchronised power system currently covering Russia and the three Baltic States)
VSC	Voltage Source Converter (technology to improve overall system performance for both high voltage alternating current and direct current transmission)

1. PROCEDURAL ISSUES AND CONSULTATION OF INTERESTED PARTIES

Lead DG: ENER

Services involved in the Interservice Group: AGRI, AIDCO, BEPA, BUDG, CLIMA, COMP, DEV, ECFIN, ELARG, ENTR, ENV, ESTAT, INFSO, JLS, JRC, MARE, MARKT, MOVE REGIO, RELEX, RTD, SANCO, SJ, SG, TRADE, TAXUD

Reference to Roadmap:

http://ec.europa.eu/governance/impact/planned_ia/docs/19_ener_energy_infrastructure_package_en.pdf

Background:

Europe's future economic growth and stability depend on the availability of appropriate energy infrastructure ensuring the achievement of the EU energy and climate goals, cost-efficient functioning of the internal energy market and security of supply. In 1996, as part of EU moves to complete the single market, the Trans-European Energy Networks (TEN-E) policy was developed. Its purpose was to provide a more political impulse to energy infrastructure development from the European perspective, by focussing on the feasibility stage for gas and electricity network projects, notably those crossing borders, which contribute to the working of the internal market. At that time, the EU had no common energy policy and no functioning internal energy market. In most Member States, state-run companies managed network investments, which were mainly driven by national security of supply considerations. Later revisions to TEN-E incorporated sustainability and supply security criteria. It was assumed throughout that EU intervention in the implementation phases of such projects would not be necessary, as commercial interests would drive projects forward. The TEN-E budget consequently remained very low – some € 22 million annually in the period 2007-2013. The currently valid TEN-E Guidelines were adopted in September 2006 replacing those of 1996[1] and 2003[2].

This impact assessment was prepared to support the forthcoming communication on energy infrastructure priorities (phase 1 of the so called "Energy Infrastructure Package") for a new policy to promote the development of TEN-E to enable adequate and timely development of energy infrastructures. This impact assessment covers the development of energy infrastructure for the period 2010-2020, with a view beyond to 2030 - having in mind the energy challenges for the century - and assesses investment needs for new transmission infrastructure, evaluates the current TEN-E framework and financing possibilities, compares various policy options for implementing sufficient infrastructure to support the achievement of the EU's energy and climate policy goals in the most cost efficient way and thereby examines the possibility of integrating CCS and oil transport networks in the future policy.

Building on the present document, a separate assessment will be carried out to prepare the legislative proposal for a new European energy security and infrastructure instrument, which is to be presented in 2011 (phase 2 of the Energy Infrastructure Package). Therefore, the present impact assessment does neither include a detailed analysis of the way, in which infrastructure investments are currently financed, nor possible solutions in terms of tariff regulation or financing to address the identified investment gap or other financing shortcomings.

The detailed list of documents and studies that have been used for the preparation of this impact assessment can be found in Annex 5.

[1] Decision No 96/391/EC
[2] Decision No 1229/2003/EC

1.1. Green paper and public consultation

The main consultation for this impact assessment took place in the framework of the green paper "Towards a secure, sustainable and competitive European Energy Network", which was endorsed by the European Council and Parliament and published with the Second Strategic Energy review[3]. The green paper pointed out that the current EU network policy was not able to deal with global security of supply challenges, to effectively diversify the EU's energy sources, to ensure solidarity in the case of an energy crisis or to draw on the benefit of new technologies. It also stressed the direct link between energy import infrastructure and the EU's external relations. The Green Paper recommended that energy infrastructure development should be driven by the energy policy goals: the "20-20-20" objectives[4], security of supply and solidarity, sustainability and innovation, as well as competitiveness. The implications of climate change for Europe's energy networks, concerning for example the location of power plants, electricity lines and pipelines, were identified as an important element to be taken into account for infrastructure projects. It moreover recommended:

- to extend the scope beyond electricity and gas transport infrastructures (including liquefied natural gas terminals and storage) to oil and CO_2 transport infrastructure;
- to let the market drive planning with a clear remit for the European Network of Transmission System Operators and the Agency for the Cooperation of Energy Regulators, as well as the EU as active facilitator and mediator;
- to narrow down the number of priorities to a limited number of European strategic projects, to be incorporated in national infrastructure plans;
- to build up accompanying measures to disseminate information and exchange best practices;
- to consider, in exceptional cases, the appointment of a European Coordinator, building on the experience of the past/current coordinators;
- to improve the effectiveness of the TEN-E instrument within existing means through better coordination with other EU financial instruments, while also considering ways of increasing the TEN-E budget, notably to support investments with a public good character.

Questions at the end of the Green Paper addressed the main barriers to the development of a European electricity and gas network and the role the EU should play in overcoming these barriers. Concerning TEN-E, the questions asked advice on the main recommendations listed above and additional measures the EU could take to secure sustainable infrastructures.

During the four month consultation exercise, ending on 31 March 2009, The Commission received 91 written replies to the questions raised in the Green Paper. 13 came from Member States (2 from a regional and a local government), 1 from regulators, 60 from the industry, 2 from academia and 13 from individual citizens, NGOs and other organisations.
The energy sector dominated the industrial responses. Contributions were received from system operators, the upstream sector, the energy equipment sector, and cogeneration and district heating companies as well as shippers, traders and firms involved in infrastructure construction. The renewable industry was mainly represented by wind and solar industry players.

A clear message from the public consultations was that there is a strong need to better align the energy network policies of the EU and the EU energy and climate targets. There was also general support for a fundamental review of the TEN-E framework. The Commission's concern to give more attention to energy infrastructure as a factor of energy security was

[3] COM (2008) 781 "An EU energy security and solidarity action plan" endorsed by the Council in its March 2009 summit conclusions
[4] 20% reduction in greenhouse gas emissions, 20% share of renewable energy in EU final energy consumption and 20% improvement in energy efficiency by 2020

also vindicated. The possibility to also cover transport infrastructure for carbon dioxide capture and storage (CCS) was generally supported, while the replies were more hesitant on oil transport networks. A specific area where a broad consensus emerged was in the relevance of energy networks to EU external energy relations. The role of the EU in facilitating infrastructure projects in third countries was welcomed, and the importance of external energy relations to infrastructure policies was reaffirmed.

1.2. Stakeholder consultations

Stakeholder consultation included discussions in the Gas Coordination Group[5] (March and June 2010) comprising representatives of 27 Member States and gas industry and gas consumers' associations, in the different working group meetings (Sustainable Fossil Fuel and Security of Supply working groups) of the Berlin Fossil Fuels Forum (May 2010). Regular exchange of information took place with the two European Networks of Transmission System Operators (ENTSO) for gas and for electricity and the European Regulators' Group for Electricity and Gas (ERGEG). The 10 year network development plans developed by the ENTSOs served as an important input for the infrastructure needs assessment. A high level conference was organised under the Spanish Presidency on 28 May 2010. Regarding the development of offshore grids, inputs from the so-called "Adamowitsch working group[6]" and the workshop organised by the North Seas Countries' Offshore Grid Initiative (March 2010) have been incorporated.

Several bilateral meetings with industry representatives and stakeholder organisations took place providing similar results to the public consultation. The electricity industry expressed particular concern about lengthy and uncertain permitting procedures and supported the Commission's intention to tackle those. A further concern was the need for better regulation of grid investment financing and cost sharing. The industry also pleaded for the definition of priority infrastructure corridors rather than pre-defined project lists. The gas industry generally emphasised the environmental advantages of gas in terms of lower CO2 emissions in comparison to other fossil fuels. The CCS sector was strongly in favour of the inclusion of CO2 transportation infrastructure in the trans-European networks policy, while there was no common position concerning the inclusion of oil pipelines within the oil industry (generally, Eastern EU oil companies supported the idea, while Western European companies did not have a position).

Regarding smart grids, this impact assessment has benefited from the input given by the European Technology Platform smart grids for the preparation of the Strategic Energy Technologies plan (June 2007) and by the three experts groups of the European Task Force for smart grids, which presented their intermediate reports in June 2010.

Following the recommendations for improvement included in the opinion of the Impact Assessment Board on the 27th September 2010, a better explanation is provided on the issues, which will be tackled in the forthcoming Communication and are thus included in this impact analysis, and on the issues, which would need to be further explored for the legislative proposal and its accompanying Impact Assessment, to be prepared next year. Chapters 2.3 and 3 have been amended accordingly. To provide more transparency on the underlying modelling, its assumptions and investment estimates, specific boxes have been inserted in Chapters 2.4 and 5.1. Chapter 2.4 has generally been amended to better highlight what the expected impact of the implementation of the 3rd Package on the internal energy market will be in the baseline scenario. In these chapters, the current tariff setting rules and their shortcomings as well as the definition of "commercial viability" are better explained; however, an in-depth analysis of these issues is foreseen for the IA report accompanying the

[5] Commission Decision 2006/791/EC
[6] Consultative group set-up by the EU Coordinator for off-shore wind, Mr. Georg-Wilhelm Adamowitsch

legislative proposal. Concerning the issue of permitting Chapters 4.4 and 5.5 have been amended, including clearer explanations and indications on the further analysis to be undertaken to provide a more thorough assessment of the options aiming at accelerating permitting – i.a. the assessment of the compatibility of the options with national legal systems and their costs – and included in the Impact Assessment for the legislative instrument. Finally, the options and impacts for the policy areas of coordination and design of new policy instrument have been clarified in Chapter 4.2, 4.3, 5.3 and 5.4. Following the second opinion of the Board (18th October 2010), further improvements have been included with reference to the estimates on the investment needs and in the conclusions.

2. PROBLEM DEFINITION

2.1. A dramatically changed policy context

This chapter summarises the current energy policy context which has changed dramatically since the TEN-E policy was last revised in 2006. More details on existing legislation and its impact on future infrastructure development will be given in chapter 2.4 (Baseline scenario).

The **EU Energy Policy**[7] and its implementing legislation, pursuing the objectives of sustainability, competitiveness and security of energy supply, set ambitious goals and binding targets for 2020 on greenhouse gas emissions[8] (-20%%; -30% if a satisfactory international agreement is reached), energy from renewable sources[9] (20% of final energy consumption) and energy efficiency (20% reduction in energy consumption compared to business as usual). This legislation includes the energy and climate package (Renewable energy directive[10] and CCS directive[11]), the third internal energy market package[12] and the recently agreed regulation on security of gas supply[13].

Adequate, reliable energy networks are a prerequisite to meet all these objectives. Europe's networks will have to undergo important evolutions to meet this challenge – evolving from a patchwork of national networks to a truly integrated EU-wide network. At the same time, these networks are aging and urgently need refurbishment and modernisation. Therefore, massive investments in network infrastructure will be needed in the coming decades, challenging the TEN-E policy framework as a whole and the existing regulatory model for electricity and gas infrastructure development in Europe.

The regulatory framework itself has evolved with the adoption of the third internal energy market package in July 2009. It introduces several new rules for infrastructure planning, coordination and investment, which address many of the weaknesses (detailed in chapter 2.4.2). Transmission System Operators (TSOs) are required to establish national 10-year network development plans and to co-operate and elaborate regional and European 10-year network development plans (TYNDP) for electricity and gas with a focus on cross-border interconnections, in the framework of the European Network of TSOs (ENTSO). The package also establishes an Agency for the Co-operation of Energy Regulators (ACER) that – among other tasks – will have to monitor the implementation of European TYNDPs. The

[7] COM (2007) 1 endorsed by the Council on 15 February 2007 (C/07/24)
[8] Directive 2009/29/EC amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community, Decision No 406/2009/EC on the effort of Member States to reduce their greenhouse gas emissions to meet the Community's greenhouse gas emission reduction commitments up to 2020
[9] Directive 2009/28/EC on the promotion of the use of energy from renewable sources
[10] Directive 2009/28/EC OJ L140 of 5.06.2009 p. 16
[11] Directive 2009/31/EC establishes a legal framework for safe geological storage of carbon dioxide (CO_2).
[12] http://ec.europa.eu/energy/gas_electricity/third_legislative_package_en.htm: see notably Directives 2009/72/EC and 2009/73/EC and Regulations (EC) 713/2009, 714/2009 and 715/2009
[13] http://www.europarl.europa.eu/oeil/FindByProcnum.do?lang=2&procnum=COD/2009/0108

third package finally sets the target, where possible, to equip at least 80% of consumers with smart meters by 2020[14] as a first step towards the implementation of smart grids.

Furthermore, the European Council[15] has set as an EU objective an 80-95% reduction in greenhouse gas emissions by 2050 compared to 1990 levels, in the context of necessary reductions by developed countries as a group. The Europe 2020 strategy therefore includes the establishment of a vision of changes required to move to a low carbon, resource efficient and climate resilient economy by 2050. In this context, there is work on-going within the Commission to outline a vision concerning climate action and possible roadmaps for a transition to a low-carbon energy system by 2050. Infrastructure development and planning of today has to ensure that investments made in the next two decades are compatible with the long term vision.

2.2. Current TEN-E framework and European Energy Plan for Recovery

The **TEN-E framework** has been developed and shaped in the 1990's through the successive TEN-E Guidelines and the corresponding financing Regulation[16]. The current objectives of the TEN-E policy are to (1) support the completion of the EU internal energy market while encouraging the rational production, transportation, distribution and use of energy resources, (2) reduce the isolation of less-favoured and island regions, (3) secure and diversify the EU's energy supplies also through co-operation with third countries, (4) contribute to sustainable development and protection of the environment (including *inter alia* a greater use of renewable energy sources and the reduction of environmental risks associated with the transportation of energy). The current TEN-E policy framework includes electricity, gas and olefin transmission networks, but not CO2 transportation, neither oil pipeline infrastructure. The guidelines establish a framework for closer cooperation, for example through better exchange of information and coordination between Member States. The guidelines foresee that, when projects encounter significant delays or problems, a European coordinator may be appointed to the project in order to facilitate coordination and monitor progress. Four coordinators have been appointed in September 2007[17], on the basis of the Priority Interconnection Plan[18].

The 2006 guidelines for Trans-European Energy Networks listed about 550 projects eligible for Community support according to the above-mentioned objectives, ranking them in the following three categories: projects of European interest (42 in total); priority projects and projects of common interest. These projects cover only electricity and gas infrastructure, no oil, olefin or CO2 transportation infrastructure.
The report on the implementation of the TEN-E framework in the period 2007-9[19], published in April 2010, concluded that the policy made a positive contribution to selected projects by giving them political visibility and the TEN-E label facilitates communication to and collaboration with third parties. However, there is a lack of focus within the current guidelines and not enough clarity between the categorisation of projects (common interest, priority project, European interest). The list of targeted projects is rigid: new projects and technologies (e.g. electricity storage, CNG etc.) cannot be included. The guidelines are based on a bottom-up selection of existing projects but do not leave space for a top-down approach to fill identified infrastructure gaps. There is no mechanism to ensure that Member States grant projects of EU importance the same priority as their national projects. The

[14] Annex 1 of Directive 2009/72/EC
[15] European Council conclusions, 30 October 2009
[16] Decision No 1364/2006/EC laying down a series of guidelines for trans-European energy networks and repealing Decision 96/391/EC and Decision No 1229/2003/EC; Regulation (EC) No 680/2007 laying down general rules for the granting of Community financial aid in the field of the trans-European transport and energy networks
[17] http://ec.europa.eu/energy/infrastructure/tent_e/coordinators_en.htm
[18] COM(2006)846
[19] COM(2010)203 and SEC(2010)505

current TEN-E framework is not binding and places no obligations on Member States or project promoters to really invest and construct infrastructure. TEN-E support may be given to competing and – within a given timeframe – mutually exclusive infrastructure projects. While there is a strong link between the EU's external energy policy and infrastructure development, coordination between TEN-E and external aid programmes has been insufficient.

The TEN financing Regulation[20] adopted on 20 June 2007 sets out the conditions for TEN-E funding and, in particular, states that co-financing can be granted for up to 50% of studies' cost and 10% of eligible works' cost, in particular to projects of European interest. The budget for the period 2007-2013 is 155 million euro (about 22 mln € per year). Currently, TEN-E plays a particularly important role for immature or risky projects and feasibility studies. However, no precise methodology was established to assess the "additionality" of EU support, i.e. the specific contribution of TEN-E funds to making projects actually bankable.
The TEN-E Programme's limited financial resources may have been adequate when focused on studies for remaining problematic interconnections, but the paradigm shift to a low carbon energy system and hence the major evolution and investment needed in energy infrastructures in the coming years call for a reassessment of the TEN-E instrument to ensure its future effectiveness. The TEN financing Regulation allows only grants and interest rate rebates, while the market rather needs innovative financial instruments such as guarantees or equity participations for risk mitigation. The current financing Regulation does not allow the funding capital expenditures outside the EU, while large gas import infrastructure and related connection to upstream sources or even electricity interconnections with third countries go well beyond EU borders.

This demonstrates that the current TEN-E policy and financing framework is not effective enough given the above described dramatic changes in the wider policy context.

Set up in the context of the economic and financial crisis, the **European Energy Plan for Recovery**[21] has responded to some of the weaknesses identified above by allocating, for the first time, significant amounts (around 4 bn€) to a rather limited number of eligible projects in the domain of electricity and gas interconnectors, gas reverse flows and storages, off-shore wind and CCS demonstration projects. The objective was to help overcoming possible financial difficulties caused by the economic and financial crisis and thus to contribute to the expenditure for the implementation of the most mature projects, in order to speed up and secure investments and accelerate their construction.

2.3. Main problems

The challenges and drivers as well as the obstacles hampering energy infrastructure development and the resulting main consequences of insufficient infrastructure are summarised below:

[20] Regulation (EC) No 680/2007
[21] Regulation (EC) No 663/2009 of the European Parliament and of the Council of 13 July 2009 establishing a programme to aid economic recovery by granting Union financial assistance to projects in the field of energy (OJ L200, 31.7.2009)

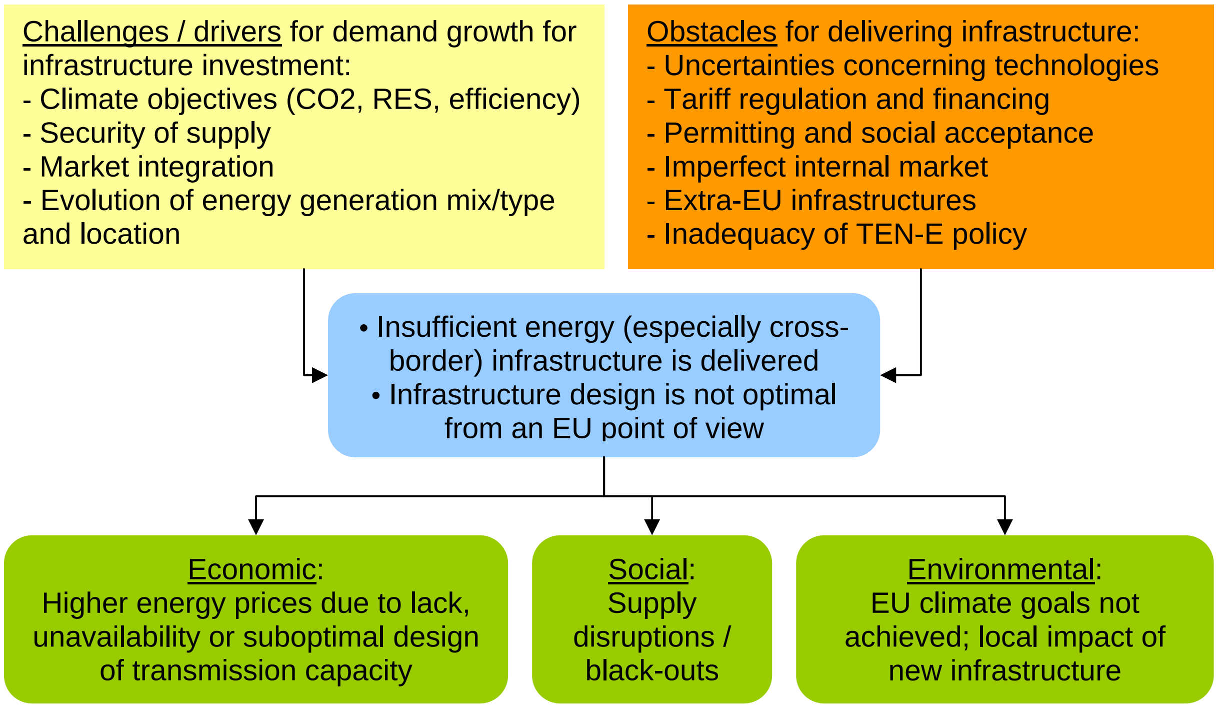

Figure 1

As pointed out in the introduction, the new policy context triggers substantial needs for new energy infrastructure investment in the EU, which is estimated at about 200 billion euros up to 2020 (see chapter 0 for details). However, due to the obstacles described in this chapter, not all the necessary investment will materialise under current conditions. The obstacles to adequate development of infrastructure can be described in detail as follows:

1) **Huge uncertainties concerning future technologies** in terms of their availability, possible risks and cost competitiveness, standards for the interoperability and scalability of systems (notably for certain renewable energy technologies, offshore grids and smart grid infrastructure, but also for electricity storage and CCS, currently not included in the TEN-E framework), **energy mix and geographical distribution** of future plants (electricity), **and new sources** (unconventional gas, green gas, LNG/CNG, new import infrastructure and upstream development in third countries) add to the overall uncertainty of future energy market developments and lead to sub-optimal market solutions (from an EU point of view).
The market players and/or regulators do not anticipate future demand / capacity needs if it is not commercially viable or would result in higher tariffs in the short term. This will result in increased cost over time (in the long term) and higher environmental impact (for example a number of smaller pipelines instead of one large).

2) **Tariff regulation and financing:** Transmission is a regulated business at national level and cost allocation to final beneficiaries is difficult or impossible for large trans-European infrastructure. In order to keep transmission tariffs as low as possible, tariff regulation in most Member States has been based on the principle of cost-efficiency, allowing recovery of costs only for projects based on real market needs or cheapest available solutions. There are in particular three types of projects, whose realisation is typically hindered through this approach:
    a. Projects with higher regional than national benefit:
    The higher the regional or EU benefit of a project, i.e. the more Member States are involved, the more complex it often is (cross-border issues including e.g. different regulatory regimes concerning rates of return or investment amortisation

periods, different permitting procedures etc.) and the more difficult cross-border coordination gets, especially if the costs and benefits of the project are shared asymmetrically between Member States. This complexity increases the project risks and hence the financial needs, which will not be covered by the market and new third package rules alone. It will result in sub-optimal solutions in terms of overall European or regional benefit.

b. Projects using innovative technologies[22] typically involve higher risks, as their industrial-scale applicability and business case are not fully proven yet. Nevertheless, market players do often not ask for and/or regulators do not approve a higher rate of return to make them bankable. Thus, first-of-their-kind projects that use new technologies for generation (e.g. carbon capture and storage) or transmission (e.g. DC VSC offshore grid technology, storage, smart grid applications), and which are necessary for the achievement of the EU energy and climate goals, will not be implemented within the set timeframe[23].
Uncertainty on the appropriate market model and regulatory approach for the above mentioned technologies also lead to suboptimal solutions.

c. Infrastructure with the objective to enhance security of supply – in pursuit of the infrastructure standards included in the new regulation on security of gas supply (N-1 and reverse flow) – is needed all over the EU, but is only rarely if ever justified by market demand and transported volumes as it is used only in case of supply disruptions (low probability / high impact events), but not under normal market conditions. In many Member States, most of them with relatively low per capita GDP levels, there has so far been no regulatory solution on how to recover the costs of these investments, and financing through tariff increases will be difficult to achieve[24].

In addition, there are externalities concerning the financing of infrastructure: TSO's must justify their investment to the national regulator by looking at future revenues only from transmission; they cannot factor in revenues from business opportunities such as price arbitrage between markets or market contestability (lower prices in a given market due to the threat of competition). For the same reason, supply shortage or increased market prices (due to lack of infrastructure) have no or little impact on TSO revenues, while they have a huge economic impact on commodity markets.
Finally, as a result of the financial crisis, and the current rapid evolution of rules in the financial sector, access to capital has become more difficult since 2008. Credit ratings of many TSOs have deteriorated and still continue to do so. There is also a lack of adequate financing instruments, risk capital and loans at sufficiently long maturity. Furthermore, there seems to be a lack of knowledge within the financial sector, notably among potentially interested investors (such as private wealth funds), on how to evaluate energy infrastructure investments.

3) **Permitting and social acceptance:** Long and uncertain permitting procedures were indicated by industry as one of the main reasons for delays in the implementation of infrastructure projects, notably in electricity. This puts a major additional risk on investments in power generation and transmission and has slowed down or even stopped new projects. In several Member States, public opinion is turning progressively against new projects and in particular overhead electricity lines, adding to the obstacles faced by projects due to inappropriate authorisation procedures and administrative practice.

[22] Cf. Impact Assessment of the SET Plan (SEC (2009) 1297)

[23] The European Electricity Grid Initiative (EEGI), launched in the framework of the SET Plan, has identified research and development priorities for both electricity transmission and distribution covering the period up to 2018. The functional areas covered include improved grid planning, renewables integration, both on- and offshore, and smart grid applications, with a budget estimated at 2 bn€, out of which about 560 m€ for transmission activities alone. However, the projects focus on studies only and do not cover industrial-scale works.

[24] Cf. "Commission Declaration on long term security of supply measures" related to Regulation XXX/2010 concerning measure to safeguard security of gas supply and repealing Directive 2004/67/EC

Therefore, the time between start of planning and final commissioning of a power line is frequently more than 10 years, be it a domestic or a cross-border project. With significant permitting obstacles and public opposition, projects can take up to 20 years to be completed[25]. Cross-border projects often face additional opposition, as they are frequently perceived as mere "transit lines" without local benefits. Limited public understanding for the benefits of a given project or technology might also limit in particular the roll-out of smart-grid applications.

4) **Imperfect internal market**: there is weak competition in some Member States where national markets are still dominated by incumbents (such as Belgium, France, Greece, Latvia, Luxembourg or Slovakia in electricity and Finland, Greece, Latvia, Lithuania, Luxembourg, Poland, Slovakia and Slovenia in gas)[26]. Lack of infrastructure constitutes a high entry barrier for new entrants, especially in markets, which are dominated by historic operators and will most likely remain so over the coming years, despite third package provisions on unbundling. Lack of market development does not allow TSOs to have sufficient firm capacity contracts to invest in an interconnector between two markets; at the same time, the market is unlikely to be able to develop as long as there is no interconnector.

5) **Infrastructures external to the EU.** For energy infrastructures outside the EU that will be required to meet the EU's growing need for imported gas and oil and to improve security of supply through diversified supply sources and routes, or to import "green electricity", there are additional political risks. Beside the need to engage politically with third countries to identify and ensure a mutual benefit from new energy infrastructures, risks may range from an unattractive or non-transparent investment framework in the third countries through to the risk of changes in the fiscal/tax or legal environment once the investment has been made.

6) **Inadequacy of the current TEN-E policy** as described in chapter 2.2.

It clearly derives from the above that the new energy policy context has created huge challenges for EU infrastructure development at a continental scale. Current policies aiming at connecting national grids will not be sufficient, as there is a need to build a fully interconnected European network for electricity and gas, including through new electricity super-grids.

To meet the EU's energy and climate goals for 2020 and beyond up to 2050, massive investments are required in energy networks and particularly in Europe's electricity grids over the next two decades up to 2030 as a necessary condition for change to happen in energy generation, supply and demand. Given the problems encountered, these investments will not happen quickly enough without strong action both at national and Community level.

This Impact Assessment aims at supporting the forthcoming Communication with the objective to establish a broad policy direction for future infrastructure development. This initiative hence broadly addresses the above identified problems, in particular the uncertainties, the issues surrounding permitting, external policy aspects of infrastructure and the inadequacy of the current TEN-E, including inter alia the lack of focus and the rigidity of the identified project list.

The proposals included in the Communication and the remaining problems will be addressed and followed up next year through the legislative proposal for an EU Energy Security and

[25] ENTSO-E 10-year network development plan, June 2010

[26] Benchmarking Report (COM (2010) 84) and technical annexes (SEC (2010) 251)

Infrastructure Instrument, for which a specific impact assessment will be prepared with particular focus on financing, tariff regulation and an in-depth analysis on permitting.

2.4. Baseline scenario

This chapter presents the likely evolution of networks and bottlenecks in terms of infrastructure development under the current policy framework.

Box 1: Methodology used for infrastructure investment needs assessment

The analytical tools used are the following:

a) for determining energy balances in 2020 and 2030, the PRIMES model (using the results of GEM-E3, PROMETHEUS and GAINS modelling as inputs);
b) for evaluating resulting infrastructure needs in the electricity and gas sector, a specialized grid modelling framework developed by KEMA and Imperial College London;
c) for assessing infrastructure needs for CO_2 transport, two specialized analysis and modelling tools developed by ARUP and JRC. Experience from on-going investments was also analysed.

a) PRIMES modelling of energy balances

The PRIMES model is a modelling system that simulates a market equilibrium solution for energy supply and demand. The model is organized in sub-models (modules), each one representing the behaviour of a specific (or representative) agent, a demander and/or a supplier of energy. Several EU baselines and scenarios have been established at different points in time using a framework contract with National Technical University of Athens (author and owner of the PRIMES model). Energy modelling is a tool for informed policy making. For instance, the PRIMES 2007 baseline was used to analyse impacts of the energy and climate package in 2008. This analysis relies on the 2009 update of PRIMES. Two recent scenarios have been developed:

- the **Baseline 2009** that takes into account the policies implemented in the Member States up to April 2009;
- the **Reference scenario**, which includes policies up to the end of 2009 and assumes the achievement of the legally binding targets on renewables and greenhouse gas reduction.

The latest update is based on an average GDP growth of 1.7% per year for the period 2005-2030 as opposed to 2.2% in the 2007 baseline. The energy projections are based on a relatively high oil price environment compared with previous projections and similar to reference projections from other sources, with oil prices of 59 $/barrel in 2005 rising to 106 $/barrel in 2030 (in year 2008-dollars). Significant changes in these assumptions alter the energy outlook for the next 20 years. Primary energy consumption stabilizes at today's level as compared to rising consumption in 2007 baseline. Less electricity is projected but with more RES in the system (impacts on electricity grid) as well as lower demand for gas (lower gas imports). More information can be downloaded from the Europa website:
http://ec.europa.eu/energy/observatory/trends_2030/index_en.htm

b) Modelling of electricity and gas infrastructure requirements

Investment needs were assessed for electricity and gas infrastructure, taking into account the available information in the 10-year network development plans prepared by the two European Networks of Transmission System Operators (ENTSO, introduced by the 3rd package),taking into account also the interdependencies between the two sectors. It should be noted that a forecasting exercise with a time horizon of up to two decades can only give indicative results, given the uncertainties surrounding future supply, demand and price developments.

Electricity

The requirements for investment in **electricity infrastructure** were estimated using a modelling framework developed by KEMA and Imperial College London (ICL), which divides the investment requirements into two parts:
- an investment estimate for the interconnection requirements between Member States to evaluate cost-optimal regional interconnection and generation capacity requirements for system security purposes, and the annual operating costs of the system;
- an investment estimation for the cost of integration of offshore wind capacity based on a separate estimation tool.

The investment model divides the EU27 countries plus Norway and Switzerland into 29 regions. The model trades off the various investment elements and optimises based upon input cost assumptions. The scope of the transmission system analysis is focused on incremental capacity requirements between the regions for each future scenario relative to the current 2010 baseline, but respecting the anticipated 2020 transmission capacities contained within the ENTSO-E TYNDP, i.e. all investments in the ENTSO-E TYNDP are assumed to happen in all scenarios.

Three scenarios were modelled, two based on PRIMES 2010 Reference scenario in 2020 and 2030 and a further High Renewable Energy Source scenario (High RES) in 2030. The modelling results provide snapshots of electricity transmission network investment requirements, additional generation investments and associated operational costs aligned with the respective time horizon.

For each scenario, the European electricity system is modelled as a 29-node system with 54 defined interconnection possibilities between these nodes. The system consumption and peak demand characteristics are common in the two 2030 scenarios and greater than the overall electrical energy requirement assumed in the 2020 scenario. The consumption data for all scenarios is aligned with PRIMES consumption forecasts including the net electricity import/export position.

The modelling approach relies on a cost estimation methodology. It seeks to provide an indication of the capital costs associated with expanding the interconnection capacity between Member States to maintain a power system with security characteristics similar to those experienced today. The modelling framework does not provide specific costs for any particular circuits to form the indicated transmission capacity. Nor does it assess the investment requirements for connections due to growing demand or investment in the distribution network.

Both technical and cost assumptions were developed in the framework of a previous extensive analysis of industry standards and learning rates and vetted by key industry stakeholders. Assumptions and results were also discussed in detail with ENTSO-E experts in charge of the TYNDP preparation, which have confirmed the validity of the general modelling approach and the indicative nature of the investment need results.

It must be underlined that this modelling exercise covers only transmission needs for interconnection and offshore connection. Changes in the generation capacity mix (e.g. due to structural variations in fossil fuel prices), in energy demand (e.g. due to slower or faster than expected economic growth) or in the costs for certain specific transmission technologies could have a significant impact on the outputs of the model. While it is assumed that assumption errors for the individual transmission investments will offset each other to some extent, it has been estimated that the aggregate error on investment costs could be in the range of +/–15%.

The evaluation of investment needs in Smart Grids has been based on the most recent available literature, in particular the findings of the High-Level Advisory Group on ICT for Smart Electricity Distribution Networks. The figures used are only very first indications and could vary significantly, depending on future technology cost evolutions.

Gas

The requirements for investment in gas infrastructure were based on gas demand projections from the PRIMES baseline 2009 and Reference scenario 2010 for 2020. These projections were matched for consistency against data coming from stakeholders (preliminary ENTSOG estimates, Eurogas) and analysing the most recent studies[27] and available documentation regarding gas infrastructure

[27] "Model-based Analysis of Infrastructure Projects and Market Integration in Europe with Special Focus on Security of Supply Scenarios", study by EWI Institute of Energy Economics at the University of Cologne. May

development projects, including investment in LNG terminals, natural gas storage and reverse flow projects. The estimation of gas infrastructure investment need is to some extent dependent on the assumptions concerning future gas demand, which again depend to a limited extent on assumptions concerning GDP growth, but to a far higher extent on a series of other factors such as gas prices (partly based on mainly oil-indexed long-term contracts, partly decoupled from oil price and based on global supply and demand balance), the role of gas in electricity generation and in particular as back-up for variable electricity energy from renewable sources, the level of market integration and the infrastructure and supply standards for security of gas supply and finally the cost of infrastructure (which can vary highly based on the routing for pipelines, cost of steel, the geological conditions for storage etc.). This would add an overall +-25-30% range to the identified figures (about +-20% for storage and interconnectors and up to 50% for import infrastructure).

c) Modelling of CO2 infrastructure requirements

The requirements for investment in CO_2 transport infrastructure were determined, based on the amount of CO_2 indicated as captured under both the PRIMES baseline 2009 and Reference scenario 2010. Modelling was prepared by JRC, using a dedicated analytical tool (InfraCCS) and the following four methodological steps:
- Identification and clustering of CO_2 sources and sinks;
- Assumptions about the evolution of captured CO_2 emissions and storage capacities;
- Routing of potential pipelines between nodes;
- Selection of the optimal network and evolution over time.

Given the fact that the EEPR CCS projects are already under development, the model runs under both PRIMES scenarios resulted in the same required network length, with the Reference scenario delivering slightly lower investment needs due to the fact the pipelines to be deployed would not have to be oversized. Uncertainties remain concerning the evolution of CO_2 demand beyond 2020, which will have to be analysed in more detail to confirm the need for pipeline oversizing.

ARUP prepared a separate analysis to determine the optimal CO_2 transport network in Europe and its evolution over time, based on predefined volumes of CO_2, identification of suitable storage sites and a cost-minimisation approach. The study analysed snapshots for 2030 and 2050. The results can therefore not be directly compared with the results of JRC analysis. However important similarities have been recorded in the shape of the future network proposed by both studies, confirming that a regional approach to developing the future network will be essential.. Assumptions of the study were discussed in detail with the EC Fossil Fuels Forum (Berlin Forum) stakeholders. Zero Emission Technology Platform (ZEP TP) was also consulted. Moreover, ZEP's Chairman in his letter of 30 June 2010 addressed to the Energy Commissioner stressed that the policy objective of ensuring the development of networks to permit the achievement of the EU’s energy and climate objectives should explicitly be extended to include the development of new CO_2 pipeline infrastructure. EURELECTRIC was also consulted. It xtended its support to a coordinated approach to the development of a CO_2 pipeline network across Europe and recommends that CO2 infrastructure should be included in the upcoming infrastructure instrument. Furthermore, EURELECTRIC supported assumptions of ARUP's study, in particular as regards developing scenarios outlining different transportation roadmaps. A number of other stakeholders supported Commission's approach.

It is important to point out that deployment of CCS could have an important contribution to meeting the GHG reduction targets as described in the Energy and Climate package. The impact assessment prepared for the Directive on the geological storage of carbon dioxide proves that without enabling policy for CCS at EU level (that is, achievement of climate objectives without CCS), the costs of meeting a reduction in the region of 30% GHG in 2030 could be up to 40% higher than with CCS. Thus not enabling CCS would have substantial negative impacts on Europe’s capacity to meet the 2 degrees Celsius target and on competitiveness, and also for employment, and would have a slight negative impact on security of supply.

2010 and "The revision of the trans-European energy network policy (TEN-E)", impact assessment study by COWI, Cambridge Econometrics and KEMA

2.4.1. *Energy trends and infrastructure needs*

The PRIMES reference scenario has been used to estimate future demand for energy up to 2030, the impact assessment itself being limited to 2020. The results have been compared to the PRIMES baseline scenario[28] and other scenario results. It is assumed that the two binding targets (20% renewables share and -20% greenhouse gas emissions) are achieved in the Reference scenario, implying that all other necessary implementing provisions (such as the energy infrastructure policy) will be completed. In the baseline scenario, based only on continuation of already implemented policies, these targets are not achieved. While primary energy consumption is projected to remain largely stable at 1,800 Mtoe and final energy demand at 1,200 Mtoe between 2010 and 2030 in both the PRIMES baseline and the PRIMES reference case scenario, the use of electricity and in particular renewable energies tends to increase significantly over the period, while the use of coal, but also oil and gas decline under both scenarios, however at a substantially different pace. In the following, we give a more detailed overview of the likely evolutions by sector.

The **electricity** sector is expected to face <u>increasing demand</u>, partly because of a major fuel shift in the overall energy mix as a result of the greenhouse gas reduction goals, but also because of its convenient use and the multiplication of applications relying on it as an energy vector (heat pumps, electric vehicles, information and communication technology devices etc.). EU-27 gross electricity generation is projected to grow from about 3,362 TWh in 2007 to 4,073 TWh in 2030. At the same time, the electricity generation mix is changing, with less fossil fuels and <u>more renewable and variable energy sources</u>. According to the Reference scenario, their share in gross electricity generation is expected to be around 33% by 2020 and 36% in 2030, out of which variable sources (wind and solar) could represent around 16% in 2020 and almost 20% in 2030. Significant new renewable capacities will be concentrated in locations further away from the major centres of consumption (offshore wind parks, ground-mounted solar parks), while decentralised generation will also gain field. This change in the nature of both generation and consumption patterns will require both electricity transmission and distribution <u>grids to play an ever more important role</u> in flexibly balancing supply and demand over increasing distances, while maintaining the same levels of security of supply. At the same time, the correct functioning of the internal electricity market will require additional cross-border interconnections and reinforcements of domestic grids. Annex 1 shows the major additional cross-border transmission capacity needs until 2015 and beyond, as estimated by ENTSO-E.

All these factors trigger <u>large-scale investment needs at a level not seen over the past decades</u>, both within Member States and cross-border, including in areas almost not covered today by electricity grids such as the Northern and the Baltic Seas. ENTSO-E's first TYNDP compiles a list of about 500 projects selected by national TSO's and identified as being of European significance because of their contribution to market integration, integration of renewables or security or supply[29]. This list amounts to a total of about 42,100 km (35,300 km new connections, 6,900 km upgraded connections). For new lines alone, this corresponds to doubling the annual extension of the currently operational European transmission grid, with a growth rate of about 1.5% between 2010 and 2020, compared to an annual average of 0.8% for the EU-15 during the period 1989-2003[30]. This corresponds to an

[28] EU Energy Trends to 2030: Update 2009 (Baseline 2009 and Reference scenario 2009). A detailed description of these scenarios and their assumptions is available at http://ec.europa.eu/energy/studies/index_en.htm.

[29] It must be stressed that this list does not include local, regional or national projects, which are not considered to be of European significance. As many transmission grids were built in the 1950's and 1960's and near the end of their lifetime, important additional investment needs will arise from the renewal or refurbishment of existing local, regional and national lines.

[30] "Lessons from Liberalised Electricity Markets", OECD/IEA 2005, p.145

annual investment of about 3.3-4.7 bn € per year for projects of European significance. According to ENTSO-E's own calculations, these projects correspond to an overall investment need of 50-70 bn€[31] for the period 2010-2025[32]. According to KEMA calculations, these projects would need to be operational in 2020 to reach the 20-20-20 targets[33].

As underlined by ENTSO-E, the first TYNDP does not take full account of needed infrastructure investment triggered by important new offshore wind generation capacities in the Northern Seas[34]. According to the national renewable energy action plans submitted by 19 Member States in application of directive 2009/28/EC[35], 2020 installed capacity is estimated at over 40GW, while 56 GW are needed according to the PRIMES reference scenario. According to calculations done by KEMA, this adds investment needs of about 32 bn€ for offshore connection infrastructure by 2020. In the medium term up to 2030, more offshore wind and development of solar energy generation capacities in Southern Europe and beyond will trigger further transmission grid development needs. According to KEMA estimates, overall offshore connection and cross-border interconnection needs could amount to an additional 18 bn€ in the period 2021-2030 under a PRIMES reference scenario with about 36% of renewables in gross electricity generation in 2030, or as much as 100 bn€ under a more ambitious High-RES scenario developed by KEMA with about 50% of renewables by 2030[36].

Moreover, reaching the EU's energy efficiency and renewable targets might not be possible without more intelligent networks, based in particular on more demand side management and smart grid technologies. Digitised electricity grids enable two-way communication between suppliers and consumers and feature an intelligent monitoring system to track electricity flows in all directions. This will contribute to reducing network losses, increasing the reliability of the grid and allowing large amounts of variable renewable power to be connected to the grid. Moreover, smart grids will enable consumers to control appliances at their homes to save energy, facilitate domestic generation, reduce cost and increase transparency. The investment needs in smart grid technology to make networks "intelligent" as a whole and get the expected benefits out of 200 million smart meters has been estimated at 40 billion € by 2020[37]. By 2030, total additional investment in smart grids deployment in the EU could reach 176 bn€, out of which 50 bn€ for smart metering, according to the final High-

[31] Note that transmission investment costs are highly sensitive to technology choices. The investment cost for undergrounding cables, e.g. to reduce their environmental impact, is typically 3 to 10 times higher than the investment cost for an overhead line or even more if specific structures are needed (Source: ENTSO-E and Europacable).

[32] By comparison, the average investment on *all* transmission infrastructure in the EU from 1996 to 2004 has been around 3.1 bn € per year. The largest part was devoted to substations (40%), internal lines (33%) and other assets (23%), such as telecommunication, protection and control, and special equipment, while only 4% of the total has been devoted to cross-border lines, mostly for HVDC interconnections through submarine cables (source: TEN-Energy-Invest study). While the resulting increase in annual investment would be significant (up to over 50%), it is not expected to overstretch the absorption capacity of the industry. On the one hand, TSOs are preparing themselves for this "wave" of investments over the coming years. On the other hand, the supply chain is fully ready to answer such increased demand, as it supplies already today significant volumes to strongly growing electricity transmission markets in e.g. China or India.

[33] "The revision of the trans-European energy network policy (TEN-E)", chapter 3

[34] It is expected that the next edition of the TYNDP planned for 2012 will take a more top-down approach, with a view beyond 2020, and address these shortcomings.

[35] Plans received and analysed as of 1st of September 2010

[36] It should be noted that these scenarios also have significant impacts on both back-up capacity needs and operating costs. KEMA has calculated that additional generation investment of about 42 bn € would be needed by 2030 under PRIMES reference to ensure current levels of system reliability. Under High-RES, this investment would reach 93 bn €. This would however be compensated by lower total annual generation operating costs under High-RES 2030 (130 bn €) compared to PRIMES reference 2030 (160 bn €). Note that this calculation does not take into account costs for developing the corresponding renewables generation capacity, which should be far higher than the related grid or back-up capacity investment.

[37] DG ENER calculations based on DG INFSO report "Impacts of Information and Communication Technologies on Energy Efficiency". The 80% target of Directive 2009/72/EC corresponds to equipping 200 million European households with smart meters. The cost for this equipment amounts to another 40 billion €.

Level Advisory Group on ICT for Smart Electricity Distribution Networks. The evolution towards smart grids faces multiple challenges, given the technology changes involved, the absence of harmonised standards and markets rules. Because of the uncertainties and high costs, no single one party is able to afford smart grid investment at transmission level on its own. Moreover, even if cost-benefit analyses in Member States show overall smart metering benefits, absence of appropriate regulation leads to unequal allocation of cost and benefits to the different parties in the value chain. In the medium term, new high-voltage long distance grid technologies and new electricity storage technologies will also be necessary. Uncertainties remain today as regards the potentials and risks of these different technologies.

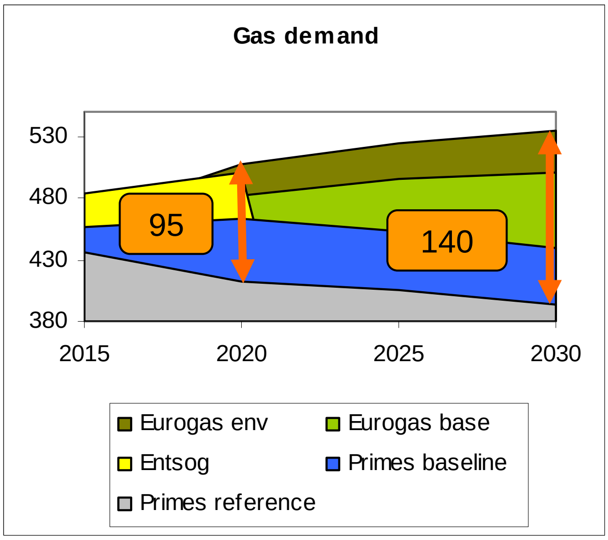

Figure 2, in Mtoe

The overall investment need for electricity networks (including offshore and smart grids) is estimated at 142 bn€ until 2020[38]. However, the attainment of this target is currently highly unlikely because of the delays observed for the planning and authorisation of overhead electricity lines, because of uncertainties concerning technologies needed, planning coordination and cost-benefit allocation for offshore grids deployment, and because of uncertainties related to technologies, common standards and appropriate market models and incentive regulation for smart grids. It is estimated that only about 30% of the total investment needed would be delivered under a business-as-usual scenario.

Gas demand is highly dependent on energy policy choices. High uncertainty is surrounding the future of gas demand, as is demonstrated by the difference between various demand scenarios presented in Figure 2. While binding RES targets may crowd out gas fired generation (37% of gas demand in 2006) as base-load, they will also increase its role as back-up. At the same time, the development of new technologies, such as CCS, which is highly dependent on the price of emission allowances in the EU ETS, may increase the importance of gas in power generation. On the other hand, efficiency gains in buildings may reduce gas demand.

The main challenge that **gas** infrastructure faces is the high and growing dependence on gas imports (to reach about 73-79% by 2020 and 81-89% of consumption by 2030) mainly due to the depletion of indigenous resources. Based on the different scenarios, the additional import need ranges from 44 Mtoe to 148 Mtoe by 2020 and from 61 to 221 Mtoe by 2030[39] (compared to 2005). Import dependency calls for sufficient and diversified import infrastructure from various sources. This development should be closely linked with the EU's strategy towards third countries.

[38] The level of in-country, cross-border and offshore grid infrastructure also determines additional back-up capacity requirements in the different Member States. According to KEMA calculations based on PRIMES reference, additional generation investment based on the cheapest available flexible generation technology would amount to 18 bn € by 2020.

[39] For the whole section on gas, the lower figures refer to the PRIMES 2010 reference scenario, while the higher figures are derived from the Eurogas Environmental Scenario published in May 2010, based on a bottom-up collection of the members' estimates.

In addition, the increase of electricity production from variable renewable energy sources requires additional flexible back-up generation. A large part of it is expected to be provided by gas-fired power plants. Given current interconnection and forecast error levels, Eurelectric estimates that 200 GW of installed wind capacity correspond to about 20-30 GW of back-up capacity needs. This increases the need for flexibility, such as LNG/CNG, more flexible use of pipelines and in particular **gas storage** (both working volume as well as injection and withdrawal capacity), moving away from the traditional "injection in the summer, withdrawal in the winter" patterns. According to some estimates, about 30-39 million cubic meters of annual working volume are needed to balance 1 GW of installed wind capacity in the absence of other measures (such as demand side management).

Thus the investment need for gas infrastructure in the coming decade has been estimated (according to internal calculations based on conservative gas consumption assumptions) to reach 71 bn€[40], including EU internal interconnectors (including reverse flows), new import infrastructure (pipelines and LNG) and storage requirements[41]. However, given the problems faced by these projects as outlined above, notably in terms of authorisation delays, insufficient market development, lack of cross-border coordination and economic viability, it is estimated that only about 80% of the corresponding projects would be delivered under a business-as-usual scenario. More details to the figures are given in Box 2 under chapter 5.1.

80% of imported crude **oil** is currently delivered to the EU by tankers. An important feature of the internal EU oil transport network is that the Western part is connected via pipeline to major European ports while most of the refineries in Central and Eastern Europea (EU12) are supplied through the Druzhba oil pipeline system from Russia (about 60 million tons/year). There are limited connections between the Western European pipeline network and the eastern infrastructures. This is a consequence of the fact that the Eastern European pipeline network (an extension of the final part of the Druzhba pipeline) was conceived and built during the Cold War period and had, at that time, no pipeline link with the western network. Moreover, in these countries, unlike in the EU15, the oil demand is expected to grow by 7.8% between 2010 and 2020 (see **Error! Reference source not found.**). In case of supply disruptions in the Druzhba system, the limited alternative supply options would lead to a big increase in tanker traffic in the environmentally sensitive Baltic area[42], in the Black Sea and in the extremely busy Turkish Straits[43], creating big concerns about the potential danger of accidents and oil spills. This puts pressure to develop oil pipeline infrastructure to ensure security of supply in this region.

CCS is a novel technology, which comprises the capturing of CO2 at emission points, its transportation and underground storage in suitable geological formations. To date, the implementation of CCS has been limited to pilot plants and the first large-scale demonstration projects are under development to be deployed around 2015 supported by Community funds, the New Entrants' Reserve of the EU Emissions Trading Scheme (the so called "NER300 initiative"[44]), state aid and contributions from developers. The Commission's

[40] The investment need may range from about 50 to 89 bn € based on various factors described in Box 1.

[41] ENTSOG is currently elaborating on the investment need for the coming ten years to be included in their next TYNDP to be published in December 2010. To date, their non exhaustive analysis (work in progress) has estimated about 41 bn € of identified investment need. The above mentioned figures have been checked also against available (partial) studies.

[42] The Baltic Sea today is one of the busiest seas in the world, accounting for more than 15% of the world's cargo transportation. Each month 3,500-5,000 ships cross the waters of the Baltic Sea. Approximately 17-25% of these ships are tankers transporting approximately 170 million tonnes of oil a year.

[43] The Turkish Straits comprise the Bosporus and Dardanelles. Less than a kilometre wide at their narrowest point, the Turkish Straits are one of the world's most difficult waterways to navigate, due to their sinuous geography. With 50,000 vessels, including 5,500 oil tankers, passing through the straits annually, they are one of the world's busiest and most dangerous chokepoints.

[44] Cf. article 10(a) 8 of the revised Emissions Trading Directive 2009/29/EC

ambition, supported also by the Council, is to have up to 12 such plants. The demonstration projects will include integrated value chains consisting of CO2 capture installations, transport and storage infrastructure. The use of pipelines is widely considered to be the most reliable for long-term bulk movement of CO2. Whilst storage capacity in Europe is plentiful, it is not evenly distributed geographically and in some cases distant from significant emission sources. Moreover, some EU Member States, considering their significant levels of CO2 emissions, have limited potential storage within their state boundaries which calls for cross-border transport infrastructure. The development and marketability of CCS technologies – and hence the need for a CO2 transportation network - are highly dependent on the CO2 prices. This is shown in the PRIMES reference scenario (lower CO2 prices due to lower demand for emission permits due to higher share of RES and more energy efficiency in the system) where the share of CCS use in power generation is only 1.4 % in 2030 corresponding to 37.6 Mt of captured CO2. The PRIMES baseline with higher carbon prices allows for more CCS development reaching 8.7% of power generation in 2030[45].

Without intervention, CO2 pipelines installed during 2014-2020 will be relatively short in length, associated with specific projects and therefore tailored to their needs. They will also rather remain geographically remote (i.e. unconnected) from one another. For the period beyond 2020, technology experts expect a commercial rollout of CCS in lead countries followed by a global rollout of CCS after 2025. Beyond 2030, the need for CO2 transport infrastructure could be even more important due to the expected share of CCS in the energy supply mix. This implies a need for early infrastructure development and advanced capacity investment, despite current low price of emission allowances due to the economic crisis. As the results of recent private sector analysis show, it is still more economical to oversize the pipelines initially and wait around 10 years until the spare capacity is fully utilised than to build pipelines fit for one emission point and one CO2 sink[46].

The CO2 infrastructure investment need has been estimated by the JRC at about 2.5 bn€ until 2020. Under a business-as-usual scenario, i.e. without creating the necessary conditions for the early deployment of a European CO2 infrastructure network adapted to future needs, it is estimated that no significant investment will take place.

Moreover, the increased interconnection of energy networks and the use of advanced information technologies represent additional challenges in the event of external events, such as those resulting from natural hazards and human-made malicious threats. The aspects of physical protection of infrastructures, their interoperability under disrupted conditions, and coordinated planning of contingencies will need to be addressed with a European dimension in every future development of energy infrastructures as they are key factors in the overall resilience of the energy supply system.

As a result, the overall investment need amounts to 215.5 bn€ (142 bn€ electricity, including interconnections, offshore connections and smart grids; 71 bn€ gas, out of which 14 bn€ of investment outside the EU; 2.5 bn€ CCS). Taking into account assumptions on business-as-usual market and regulatory conditions determining the commercial viability of projects (see chapter 2.4.2) and delays for project implementation in each sector (electricity, gas and CO2) (see chapter 5.1 and Annex 3 for more details), one can estimate the business-as-usual investment: it would reach in electricity and gas 102 bn€ over the period 2010-2020 (45 bn€ electricity, 57 bn€ gas). No significant investment would take place for the CO2 transport infrastructure as identified in the JRC and ARUP studies..

[45] It must be noted that projections up to 2050 can feature significant changes to these prices, depending on the scenario chosen.
[46] Pre-FEED (front end engineering and feasibility) studies on industrial-scale carbon capture and storage (CCS) demonstration projects in the United Kingdom (2009)

2.4.2. *Infrastructure delivery under current market, regulatory and financing conditions*

Electricity and gas infrastructure in Europe are regulated sectors, whose business model is based on regulated tariffs collected from the users, which allow recovering the investments made ("user pays principle"). The regulatory framework for infrastructure (including planning and investment) has evolved through the 3rd internal market package for electricity and gas that was adopted mid 2009, to be implemented by mid 2011. It enhances the separation ("unbundling") between transmission and supply activities. On the one hand, this may translate into more difficulties for TSOs to forecast future demand and no more possibilities of cross-subsidies. Thus regulated tariffs and congestion rents are the only way to recover costs. On the other hand, effective unbundling will give them more independence and increase their incentives to better plan infrastructure investment. The new transparency guidelines will lead to better information within the market, thus to possibly more available capacity for shippers in the case of gas, more optimal use of infrastructure and better signals on congestions where TSOs should invest in additional infrastructure. Generally, a more efficient market should provide better price signals: price differentials will indicate where additional or new interconnection capacities are needed within the European network.

The third package provides for new rules in terms of infrastructure development across borders, which will facilitate the implementation of grid investments in electricity and gas:

- The third package establishes new rules for national regulatory authorities to cooperate on cross-border issues, including operational arrangements, networks codes and congestion management[47]. For electricity only, provisions are made as regards an inter-transmission system operator compensation mechanism for costs incurred as a result of hosting cross-border flows, which should clarify the sharing of costs and benefits for a given cross-border infrastructure[48]. ACER will intervene in particular to establish and monitor implementation of network codes, to coordinate regulatory differences affecting cross-border infrastructure and to monitor the implementation of interconnection projects[49]. Notably the new rules on inter-TSO compensation, which are in the final stage of the comitology procedure, are expected to facilitate the implementation of needed grid investments.

- The new ENTSOs for electricity and gas will facilitate co-operation and co-ordination between TSOs, notably for investment planning. The first European TYNDPs are based on a bottom-up approach and were successful in consolidating existing projects in one single document, thus giving more transparency to network planning. However, they do not provide a top-down vision suited to identify all future infrastructure gaps as a consequence of the new energy and climate policy challenges. More top-down oriented second versions of the European TYNDPs will be published in December 2010 for gas and in 2012 for electricity, giving the start for bi-annual revisions. These plans are ultimately expected to deliver a longer-term vision and setting strategic priorities for future development.

- While the third package gives the necessary powers to national regulators to ensure implementation of investments foreseen in the binding national plans[50], no provision is made to ensure implementation of the European TYNDPs, which are non-binding plans[51]. However, the third package does require that national plans are consistent with the European TYNDP and gives the Agency a monitoring role in this respect. Enforcing

[47] Cf. article 38 of Directive 2009/72/EC and article 42 of Directive 2009/73/EC
[48] Cf. article 13 of Regulation (EC) No 714/2009
[49] Cf. articles 6 and 8 of Regulation (EC) No 713/2009
[50] Cf. articles 22 of Directive 2009/72/EC and Directive 2009/73/EC
[51] Cf. articles 8 of Regulation (EC) No 714/2009 and Regulation (EC) No 715/2009

realisation according to the planning and timing foreseen will be impossible for certain projects listed as being of European interest.

The third package also asks national regulators to provide appropriate tariff incentives, both short and long term, for network operators to increase efficiencies, foster market integration and security of supply and support the related research activities[52]. Although regulators furthermore will have an obligation to take into account the impact of their decisions on the internal EU internal market as a whole, still, tariff setting remains national competence and hence not always conducive to advance European priorities.
Furthermore, this regulatory approach is not designed to address the major technological changes, notably in the electricity sector, concerning offshore or Smart Grids.

As demonstrated above, the measures adopted and, for many, still to be implemented will not be sufficient to ensure full delivery, given the lack of regulatory solutions to allocate costs and cross-border benefits and especially the obstacles identified in chapter 2.3. They will resolve some coordination issues for simple cross-border projects. However, they may not provide sufficient incentives for investments in public goods – e.g. gas reverse flow or storage for security of supply – or projects with information asymmetry – e.g. new technologies or innovative solutions (interconnected offshore grids, smart grid applications) or cross-border projects with complex cost and benefit allocations involving several countries, notably in gas, where no inter-TSO compensation or any other mechanism to allocate costs for domestic investment to final beneficiaries outside the domestic territory has been established. Moreover, while the energy and climate policy goals adopted at EU level and the corresponding support schemes for renewable energies do speed up their development, they have also a distorting effect, notably on the internal electricity market. Finally, they are currently not matched by corresponding measures for infrastructure development to ensure adequate grid integration.

Finally, both the internal markets for electricity and gas are still incomplete, partly due to missing infrastructure[53]. Eastern Europe has inherited East-West gas infrastructures with little or no interconnections between neighbours. As the gas crisis in January 2009 showed, lack of infrastructure and insufficient transmission capacity were the main barriers to the handling of the crisis[54]. The new regulation on security of gas supply has just introduced a compulsory "N-1" rule for infrastructure, meaning that all Member States should be able to compensate the disruption of the single largest infrastructure by the remaining other infrastructures to ensure that total gas demand is met. An obligation to implement reverse flows was also set. In order to meet these standards, additional infrastructure needs to be constructed. However, such projects will not always be bankable under a business-as-usual scenario.

In addition to traditional private financing on the basis of regulated tariffs, EU-funded support has been granted to current TEN-E projects through a number of instruments, such as the TEN-E budget, EEPR, IPA, ENPI (such as NIF or INOGATE) and loans from EIB and EBRD (see Annex 2 for more details). Under current rules – valid until 2013 –, EU TEN funding will continue to give small grants to finance feasibility studies or riskier projects, which may have an important EU-wide benefit. Interest rate rebates figure in the Regulation, but have never been used as they may have a market distorting effect. Projects that are not commercially viable but that may be important for other reasons (security of supply, market integration,

[52] Cf. article 37 of Directive 2009/72/EC and article 41 of Directive 2009/73/EC
[53] In electricity, interconnections have historically been good between Eastern European Member States, which used to be connected synchronously among each other and with the Russian power system. Following disconnection from the Russian system and connection to the synchronous grid of continental Europe (i.e. the grid of the Union for the Co-ordination of Transmission of Electricity / UCTE) in 1995, interconnections between East and West have developed (e.g. between the Czech Republic or Poland and Germany), but certain bottlenecks remain as of today.
[54] SEC(2009)979

new technology or innovative solution), would not be constructed. In addition, the current policy does not address permitting issues, market or regulatory failures, the mismatch between national and European priorities and the need for strong political support. This would lead to insufficient infrastructure development. Finally, oil and CCS infrastructure as well electricity storage and smart grid technologies would remain excluded from the policy. No new electricity/gas projects would be added to the current list, non feasible or outdated ones could not be removed.

Concerning CCS, integrated backbone pipeline networks would probably be the most efficient long-term option, but the incremental cost of building optimized networks ahead of point-to-point pipelines may not satisfy project-specific commercial evaluation criteria. Concerning oil, the current supply situation, in particular with regard to Central and Eastern Europe, is satisfactory. If the uninterrupted and smooth flows from Russia through transit countries could not be ensured in the future, alternative supply routes would have to be explored, either through existing infrastructure (Odessa-Brody pipeline in Ukraine or Adria pipeline in Croatia) or through new West-East interconnections. However, the corresponding investments, which would then become necessary, are limited[55]. They are not regulated by EU legislation concerning e.g. rates of return or third-party access to infrastructure.

2.5. Main geographical bottlenecks

In the business as usual scenario, the main bottlenecks would occur in the below listed regions or domains, as a result of the observed future energy trends, infrastructure needs and combination of several of the identified obstacles:

BEMIP (Baltic Energy Market Interconnection Plan)

The three Baltic States – and in terms of gas also Finland – are practically isolated from the EU energy markets. In electricity, the Baltic energy grids are synchronously connected to the Russian UPS (Unified Power System). As of today, there is only one asynchronous interconnection to the West between Estonia and Finland. New connections are planned with Finland, Sweden and Poland, but not yet all realised. In gas, all four countries depend on a single supplier, and in most cases through one import route, which raises security of supply concerns. This same supplier also has a stake in the TSOs of the countries. With no real functioning market, cross-border and additional import infrastructure needs (such as LNG) to improve market integration and security of supply cannot be met by market demand. Coordination between Member States, TSOs and regulators is necessary in order to align regulatory approaches – a barrier for further investments and market opening – that would allow a fair distribution of regional infrastructure development costs as well as benefits.

Offshore grid in the Northern Seas

Offshore wind is expected to be an important means to reach the EU's 20% renewable target. Potential for this energy source is mainly in the North Sea and neighbouring waters. At the same time, there is also an increased need for interconnection capacities between countries in the North (e.g. Norway, Sweden) and Central Europe (e.g. Germany, the Netherlands), both for more electricity trade and enhanced security of supply. This creates the need for an integrated offshore grid solution both to connect large amounts of offshore wind and ocean energy capacities and to function as an international interconnector.
The creation of such a new grid is subject to several important challenges: coordination among Member States and entities in charge of planning and execution (ministries,

[55] Concerning existing infrastructure, the cost for upgrading the Odessa-Brody pipeline capacity from 14.5 to 33 million tons per year (mta) was estimated at about 450-500 million euros, while upgrading the Adria pipeline from 9.8 to 14 mta would add another 70 million euros. Concerning new West-East interconnections, the Schwechat-Bratislava pipeline for example would require about 50 million euros investment for up to a capacity of 5 mta. (calculations done by ILF and Purvin&Gertz).

regulators, TSOs, developers etc.); designing a new regulatory scheme; defining appropriate market rules for multilateral investments; developing appropriate technical standards and operational solutions.

So far, Member States have adopted different approaches to develop their national offshore wind potential and the corresponding grid. National regulation encourages radial connections of wind farms with an onshore connection point, to maximise benefits while minimising project risks and costs (see Annex 4 for more details). Under these conditions, projects using innovative but riskier technologies (e.g. offshore voltage source conversion) and new grid designs involving more than two countries are difficult to realise, preventing further cross-border optimisation. Moreover, individual planning and building of wind farm connections makes the anticipation of future development needs difficult, which might lead to increased overall cost and environmental impact in the long term. Integrated solutions such as a meshed offshore grid, associated with appropriate cost-benefit allocation mechanisms, are lacking, preventing the full benefits of both renewables connection and electricity trade to realise[56].

Such a grid will only be possible with strong regional or even European level coordination and planning and the necessary technological developments (notably concerning direct current (DC) breakers and multi terminal control systems). The need for this coordinated approach has been identified by the countries that are participating in the North Sea Countries Offshore Grid Initiative (NSCOGI)[57]. It is finally important to note that this offshore grid development, together with the onshore wind development near to the coasts, will trigger major interconnection requirements with existing and new generation and hydro pumping capacities both in the North (Norway, Sweden) and the Alpine region (Austria, Switzerland).

Renewables in Southern Europe and the Mediterranean

In the Southern countries of the EU, solar energy will offer important new generation capacities, notably in France, Italy, Portugal and Spain. The role of solar electricity could still increase, if additional generation in Mediterranean third countries is imported into the EU through interconnections between Morocco and Spain or Tunisia and Italy. As for wind energy in the North, these new capacities will trigger major grid reinforcement and new interconnection investment needs in this region, especially concerning the Spain-France and the Italy-France, Italy-Switzerland and Italy-Austria links. As recent experience has shown, development of additional cross-border infrastructure in the regions has faced major difficulties in reaching public acceptance, leading to lengthy authorisation procedures and costly solutions. Concerning interconnectors between the EU and third countries, problems arise from the often complex political situation. In addition, questions remain concerning the applicable regulatory framework.

New supply sources – Southern Corridor

The objective of the development of the Southern Corridor is to further diversify sources and to bring gas and oil from the Caspian Basin and the Middle East to the EU. The projects in the Southern Corridor face on one hand the necessity of coordination between several Member States and with non-EU members, the establishment of a legal regime to transport gas through these territories and on the other hand the challenge to co-ordinate the timings to develop the up-stream resources and necessary infrastructure with the timings of the import infrastructure projects. At the same time, this is also the opportunity for the European Union to enter closer energy partnership with Central-Asian and Middle-East countries.

[56] Currently the analysis is not done at regional or European level, where these synergies could be identified. An integrated interconnector / offshore wind connection solution might cause different proportion of costs and benefits for the different actors.

[57] In December 2009, the Political Declaration of the NSCOGI was signed by 9 Member States (Belgium, the Netherlands, Luxembourg, Germany, France, Denmark, Sweden, the UK and Ireland). Norway joined the initiative in early 2010. The 10 countries are aiming at signing a Memorandum of Understanding by the end of 2010. The mission of the NSCOGI is to facilitate coordinated offshore electricity infrastructure development with a joint commitment in view of large offshore wind power development in the region.

Central and South-East European interconnections

Concerning gas, Central and Eastern EU countries, as well as South-East Europe (Energy Community countries) often depend on one single import source and hence limited, weak competition. Furthermore, they often depend on one single pipeline infrastructure both for oil and gas. Practically all of the problems identified in chapter 2.3 converge in this area: no complete implementation of internal energy market rules, missing infrastructure development due to lack of market development and vice versa, the lower creditworthiness of local companies due to their lower capitalisation, the effects of the economic crisis (thus deteriorating country risk ratings) and the higher exposure to external transit or supply risks. Furthermore, the investment need to meet the infrastructure standards set out in the security of gas supply regulation is very high in this region compared to the investment capacity of the concerned countries/companies, given current tariff levels and households' ability-to-pay.

Concerning electricity, challenges arise from the evolution of power flows and the need for further market integration in the countries of the region. North-South flows will rise in importance as new generation in Bulgaria, Hungary or Croatia will get connected to the network. East-West interconnections could need reinforcement, as new systems (Turkey, but also Moldova and Ukraine) join the continental synchronous system. Moreover, these systems will have to be connected to the dominant storage capacities in the Alpine region.

2.6. Key players and affected population

Various actors in the energy sector and beyond are affected by the proposal:

- Transmission and distribution system operators will be first and foremost affected, as any new initiative will touch upon planning and realisation of new transmission infrastructure;
- Operators and developers of existing and new power plants (including CCS) and electricity and gas suppliers, as a new policy will have an impact on the evolution of grid capacity;
- Member State governments, administrations and regulators who will be in charge of implementing any new rules related to tariff regulation, financing, planning and permitting;
- Energy consumers, as optimised and smarter grids will contribute to better balancing of supply and demand and hence to reduced and less volatile energy prices;
- Citizens in the neighbourhood of new infrastructure, that might be affected temporarily (construction) or permanently (local environmental or visual impacts etc.);
- EU citizens at large, as a new policy will contribute to making the energy system more reliable, competitive and sustainable in terms of environmental and climate impacts.

2.7. EU right to act

Under Article 194 TFEU, Union policy on energy shall aim at: (a) ensure the functioning of the energy market; (b) ensure security of energy supply in the Union; (c) promote energy efficiency and energy saving and the development of new and renewable forms of energy; and (d) promote the interconnection of energy networks. Energy transmission infrastructure (including an interconnected off-shore grid and smart grid infrastructure) has Trans-European, regional or at least cross-border nature or impacts. Member State level regulation is not suited and individual national administrations have no competence to deal with these infrastructures as a whole. They are therefore covered under Article 170 and 171 TFEU. Article 170 specifies that "the Union shall contribute to the establishment and development of trans-European networks in the areas of transport, telecommunications and energy infrastructures". Article 171 sets the obligation that "the Union shall establish a series of guidelines covering the objectives, priorities and broad lines of measures envisaged in the sphere of trans-European networks; these guidelines shall identify projects of common interest".

The Second Strategic Energy Review proposed that a new EU Energy Security and Infrastructure Instrument should be tabled to replace the existing TEN-E framework (policy and financing). At its extraordinary session in January 2009, the Transport, Telecommunications and Energy Council invited the Commission to "to carry out a thorough assessment of network interconnection, identify gaps, suggest action and to speed up the revision of the TEN-E framework with a view to considering the development of a comprehensive EU Energy Security and Infrastructure Instrument as suggested in the 2nd Strategic Energy Review." At its March 2009 summit, the European Council concluded that "Energy infrastructures and interconnections must be developed. To that end, the Commission, in cooperation with Member States, is invited to rapidly present the detailed actions required to realise the priority areas identified in the SER. […] The Commission is invited to present […] its proposal for a new EU Energy Security and Infrastructure Instrument." This instrument will be dealt with in a legislative proposal following a communication on energy infrastructure priorities.

Moreover, the Second Strategic Energy Review stated that "a Blueprint for a North Sea offshore grid should be developed to interconnect national electricity grids in North-West Europe together and plug-in the numerous planned offshore wind projects."[58] In the conclusions of the Energy Council on 19 February 2009, the plans for the blueprint were endorsed with the small change that the scope was changed from North Sea to "the North Sea and North West Offshore Grid", thus clearly covering also the Irish Sea. In its conclusions, the Council also agreed to "promote a co-ordinated approach between Commission and Member States, where appropriate, in order to support in a cost effective way large scale deployment of offshore wind power in the European seas while preserving the reliability of the grid".

More recently, the Europe 2020 strategy[59] put again energy infrastructures in the forefront as part of the flagship initiative "Resource efficient Europe". It underlined the need to urgently upgrade Europe's networks towards a European "smart" supergrid, interconnecting them at the continental level, in particular to integrate renewable energy sources. It also highlighted the need to promote infrastructure projects of major strategic importance to the EU in the Baltic, Balkan, Mediterranean and Eurasian regions.

3. OBJECTIVES

The general objective of the initiative is to ensure **sufficient and timely infrastructure development across the EU and beyond** in order to:

- further develop the internal energy market so as to ensure reliable energy provision at affordable prices to European customers,
- ensure security of supply,
- meet the EU's energy and climate targets.

In order to sustain infrastructure development, its main hindrances are to be tackled. The planned Communication on infrastructure priorities hence has the objectives to propose clear priorities and improve focus of EU action for all relevant energy infrastructure, reinforce regional co-operation and coordination, highlight the difficulties linked to permitting procedures and build public acceptance to help reducing planning and permitting uncertainties. Clear infrastructure priorities will also provide a political message towards third countries.

[58] COM(2008) 781 p. 5
[59] COM(2010) 2020, 3.3.2010

The abovementioned objectives are fully in line with the Europe 2020 strategy and in particular the "Resource efficient Europe" flagship initiative and support directly the achievement of the two binding targets of 20% share of renewables and 20% of greenhouse gas emission reductions by 2020. In addition, the uptake of smart grid technologies directly promotes energy efficiency. The objectives are furthermore consistent with the EU policies on competitiveness and innovation.

The objectives explained above are consistent with the Commission's on-going work to outline possible roadmaps for a transition to a low-carbon energy system by 2050. While the development of electricity and CO2 transport infrastructure is recognised as a key factor for success under almost any future scenario, uncertainties concerning future gas and oil demand do not reduce the need for infrastructure development in the near term future[60].

4. POLICY OPTIONS

In order to better analyse solutions to the main problems identified above, it is suggested to split the analysis in policy areas and propose separate options for each area (see Table 1). The policy options are evaluated against the criteria of effectiveness, subsidiarity and proportionality. The main criterion for effectiveness is how much adequate infrastructure investment the single options are likely to deliver. All the options are coherent with the overarching EU objectives, strategies and priorities. Based on this evaluation, the most effective and efficient options will be combined into a preferred policy set.

Policy area A: Scope of the policy instrument

Option 1: Business as usual (electricity and gas)

Option 2: Enlarged electricity and gas

Option 3: Enlarged electricity and gas, inclusion of CO2 networks and oil pipelines

Policy area B: Design of policy instrument

Option 1: Business as usual (project lists as today)

Option 2: Updated project list

Option 3: Limited number of priority projects/regional corridors and smart selection criteria

Policy area C: Coordination

Option 1: Business as usual (national approach, EU coordinators), voluntary regional structures

Option 2: EU coordinators and mandatory regional or thematic priority structures

Option 3: EU TSO

Policy area D: Permitting

Option 1: Business as usual (national competence), exchange of best practices

Option 2: Inclusion of projects of European interest in national priorities and application of fastest national procedure (where existing)

Option 3: National one-stop-shop approvals with streamlined time limits (5 years)

Option 4: New harmonised permitting scheme at the EU level

Table 1: Policy options

[60] Indeed, while the evolution of gas demand is uncertain until 2030 and even more so until 2050, gas is expected to have an increasing share until 2020, which is unlikely to drop dramatically after 2030 from a projected share of 22.4%-24.3% of total energy demand under the PRIMES reference scenario, especially if carbon capture and storage technologies develop. Similarly, the projected oil share of around 32% by 2030 is unlikely to drop drastically, especially considering its slow substitution in the transport sector.

4.1. Policy area A: Scope of policy instrument

All proposed options in this policy area are considered to meet the subsidiarity and proportionality principles.

Option 1: Business as usual: electricity and gas

This option would cover electricity, gas and olefin transmission infrastructure, gas storage and liquefied natural gas (LNG) infrastructure, as is the case with the current TEN-E policy.

Option 2: Enlarged electricity and gas

Under this option, the electricity infrastructure targeted would be enlarged to cover also smart grids and storage projects, in addition to the traditional transmission projects. Compressed natural gas (CNG) infrastructure would be added under the targeted gas infrastructure. This option can in principle be combined with all options of policy areas B, C and D.

Option 3: Enlarged electricity and gas, inclusion of CO2 networks and oil pipelines

This option would include electricity transmission, storage as well as smart grid technologies; gas pipelines, storage, LNG and CNG, as is the case in option 2. But it would also cover both CO2 transportation and oil pipeline infrastructure, thus overall energy transport infrastructure. This option can in principle be combined with all options of policy areas B, C and D. However, oil pipelines could a priori not be treated under option C3 (EU TSO, see below), as they are privately operated without central management through an independent TSOs.

4.2. Policy area B: Design of policy instrument

All proposed options in this policy area are considered to meet the subsidiarity and proportionality principles.

Option 1: Business as usual

The “business as usual” option would mean to continue with the TEN-E policy as it is, including the current project list divided into three categories and re-confirmation of the existing priority axes.

Option 2: Updated project list

Option 2 would mean to continue with the general TEN-E policy, but to revise and update the priority projects defined in the annexes of the decision and to possibly enlarge the scope under options 2 or 3 of policy area A (through ordinary legislative procedure). New projects would benefit from political support and an EU label, as is the case in the current TEN-E policy.

Option 3: Limited number of priority projects/regional corridors and smart selection criteria

This option would propose new broad priority areas and regional corridors of European interest, focusing on the main bottlenecks identified (see chapters 2.4 and 2.5), thus not fixing a list of projects beforehand. These broad priority corridors would be complemented with smart and transparent criteria for identifying projects in need of more focused attention at the regional or EU level. The approach is based on a European top-down (thematic or regional) perspective rather than on individual projects. This differs from the current approach laid down in the TEN-E guidelines, where the list of projects is fixed in the Annexes and has been identified bottom-up, reflecting Member States' national priorities. The criteria for the identification of projects should be based on the following principles and further discussed and refined with relevant stakeholders, so that the more detailed criteria can be included in the future legislative proposal[61].

Principles to be applied in the electricity sector would cover the major objectives of EU energy and climate policy: (1) contribution to security of electricity supply; (2) capacity to connect renewable generation and transmit it to major consumption centres; (3) increase of market integration and competition; (4) contribution to energy efficiency and smart electricity use.

The principles suggested for gas infrastructure are derived from the objectives of the EU energy and climate policy to improve security of supply and market development: (1) diversification, giving priority to diversification of sources, counterparts and in last place routes; (2) ratio of increase in interconnection level; (3) reduction of market concentration.

4.3. Policy area C: Coordination

Option 1: Business as usual

This option would continue the current approach based on largely national initiatives, with support from EU coordinators and voluntary regional structures for certain projects.

Option 2: EU coordinators and mandatory regional or thematic priority structures

While maintaining the involvement of EU coordinators, existing regional structures would be given the task of identification of concrete priority projects and implementation and monitoring of infrastructure priorities in a given region or sector, with the involvement of all relevant stakeholders (national administrations, National Regulatory Authorities, NGOs and TSOs). A compulsory framework would ensure that there is a regional view and that approaches do not remain fragmented at national level. The identification of the priorities would be linked to the criteria referred to under option B3.

There is already mandatory regional co-operation in the framework of the internal energy market rules (second and third package) in various areas: regional 10-year network development plans shall be prepared by the TSOs and national regulatory authorities co-operate within the “regional initiatives”. The Regional Initiatives are currently under revision and a new proposal is expected in 2011. The overall EU optimum would be ensured through the already existing EU-level institutions such as ACER, the ENTSOs and regulatory for a. Building on the positive example of the BEMIP or the NSCOGI, the Commission may support ad-hoc regional co-operation on request, such as the Visegrad+ initiative to implement North-South interconnections in Central-Eastern and South East Europe. This solution would simplify the cooperation, build on synergies with other discussion areas (defined in the third package) and reduce the number of fora and meetings for all stakeholders. The constitution of regional initiatives under this option will be closely linked to the identification of priorities under policy area B.

Option 3: EU Transmission System Operator

The idea of a single European TSO for gas was raised by a group of EU gas companies and outlined also in the Green Paper. The European Parliament concluded that "*forward-looking initiatives, such as the European transmission system operator and the establishment of a single European gas network, should be encouraged*"[62]. The aim could be to build progressively independent companies to manage unified transport networks throughout the EU in gas, but also in electricity or CO2. The progressive merging of national networks, provided that it is organised in a manner compatible with competition law, would allow looking at network development from a truly EU perspective and enhance incentives to invest in infrastructure where it is needed regardless of national boundaries.

[61] As long as these detailed criteria have not been elaborated, an estimation of the precise number of projects qualifying or not qualifying under the new regime is not possible.

[62] European Parliament resolution of 3 February 2009 on the Second Strategic Energy Review (2008/2239(INI))

An EU TSO would facilitate more regulatory and technical standardisation and thus allow energy to cross borders more easily. This could lead to a situation where national regulators would not any more be capable to regulate transmission. A European regulator would be needed – a future role that could be played by ACER. Such a solution would also allow introducing “European transmission tariffs” to cover the TSO’s costs (and wider EU benefit).
In the case of electricity, such a TSO could also be charged with the design and implementation of integrated offshore grids or new European high-voltage long distance grid. For CO2, this would also allow the up-front planning of an optimal CO2 network.
These single EU TSOs would have to take into account all objectives of the EU energy policy (market integration, security of supply and the climate goals).
An EU TSO would become a monopoly and have a huge asset base. This would increase its creditworthiness and capacity to invest. To be a truly EU TSO, it should be given exclusivity over infrastructure development in the EU, which would eliminate the possibility for other market players to construct "merchant lines" dedicated to trade, where the owners reserve all or part of the capacity for their own use. Past experiences for strong monopolies demonstrate, however, that such a TSO would need to be closely regulated and monitored with full transparency in order to make sure that transmission costs are correctly allocated to the users and to prevent abuse of its dominant market position. No individual supplier should be allowed to acquire a controlling stake in the EU TSO in order to maintain its neutral position and non-discriminatory approach on the market.
It is also considered that the process towards an EU TSO may rather take place on a progressive and voluntary basis and that the Treaty does not provide the powers to impose this solution. This solution furthermore is unlikely to respect the principles of subsidiarity and proportionality, as strengthened or mandatory regional co-operation and infrastructure planning may lead to similarly effective results. Therefore this option is discarded from further analysis.

4.4. Policy area D: Permitting

Option 1: Business as usual: national competences, exchange of best practice

In this option (current TEN-E approach), national competences would be maintained, their obligation being to make best efforts to facilitate implementation of identified TEN-E infrastructure. They would be enhanced through the publication of national best-practice measures. Member States would apply these measures on a voluntary basis.

Option 2: Inclusion of projects of European interest in national priorities and application of fastest possible procedure (where existing)

This option would oblige Member States to include projects declared to be of European interest (PEI)[63] in their national priorities and to apply the fastest existing authorisation procedure (where these exist). The principles of subsidiarity and proportionality would be respected as this option does not provide for concrete procedures, which would be left to the Member States. This policy option would be applicable only in Member States where national priorities have been defined and where “fast-track” procedures exist. In the other Member States, “business as usual” would be maintained.

Option 3: National one-stop-shop approvals with streamlined time limits

The Presidency of the European Council invited the Commission in March 2007 "*to table proposals aiming at streamlining approval procedures*"[64], and industry expressed the need for EU measures to facilitate permitting procedures. This option would introduce a "one-stop-shop" permitting scheme for projects of European interest, under which all Member States

[63] NB: The definition of "project of European interest" could be revised and does not necessarily correspond to the currently used definition in the TEN-E guidelines.
[64] See European Council Presidency Conclusions of 8/9 March 2007, 7224/1/07 REV 1

would have to nominate a national contact authority. It would be left up to Member States, whether this authority would have decision making powers or be a coordination body where decision-making competence would remain with the competent authorities at national, regional, and/or local level. The one-stop shop would serve as a single interface between the project developer and the competent authorities. It could include more detailed objectives and specify the procedures to implement, including guidelines for public consultations, for minimum transparency requirements and for compensation of affected populations, as well as tacit approval or sanction mechanisms in case of delays. This option may ideally introduce a time limit of 5 years[65] for a final authorisation decision to be taken by the competent authority for a given project, feasibility of which still would need further assessment.
The introduction of a one-stop-shop would facilitate administrative procedures for project developers, and a time limit would lead to accelerated authorisation and more certainty in the process. Such an option would also apply to all Member States, not only to those where national strategies exist. Effects could further be enhanced by more specific guidelines. Tacit approval or sanction mechanisms would incentivise authorities to meet the timeline. With respect to the principle of proportionality, a legislative proposal would introduce general guidelines on the implementation of these measures. The concrete formulation of measures would still be left to the Member States, giving them freedom and flexibility how to meet the stipulated objectives.

Option 4: New harmonised permitting scheme at EU level

Option 4 would create a new harmonised permitting scheme, based on some of the measures as outlined under option 3 (one-stop-shop approach, time limit for final authorisation decisions), but with an aim at harmonising national approaches and giving final decision making power to the EU level in case problems cannot be resolved at Member State level. This should in certain cases allow overriding other interests on the basis of "European interest", similarly to the "Déclaration d'utilité publique" (DUP) procedure applicable in certain Member States. The impact of this approach would be substantial because of the harmonised and hierarchical decision making approach. However, this policy option is unlikely to respect the principles of subsidiarity and proportionality, as the same results could be achieved by implementing option 3. Thus this option is discarded from further analysis.

5. ANALYSIS OF IMPACTS

We first analyse impacts for the business as usual (BAU) scenario, which includes the policy option 1 for each of the four policy areas. We then analyse the impacts of the different other options sequentially in each policy area A (scope), B (design), C (coordination) and D (permitting) as compared to BAU. The impact analysis for all options is based on qualitative and, where available, quantitative evaluation, covering, as relevant, economic (including administrative and compliance costs), social and environmental aspects. This methodology will allow identifying a limited number of policy sets for further, more detailed assessment and comparison.

5.1. Baseline ("business as usual")

Under business as usual (BAU), implementation of third internal market measures would help to resolve some of the identified problems in infrastructure planning and implementation of cross-border projects. The shortcomings of the current TEN-E instrument would however remain as such, with a focus on electricity and gas, rigid project lists, insufficient cross-border coordination and persistent delays in permitting. Nationally focussed and for technologies "conservative" tariff-setting would still render certain projects commercially not viable (see

[65] See recommendation of Priority Interconnection Plan (2007), COM(2006) 846 final/2, p.12f.

more details in Box 2). Moreover, due to the limited amounts of available EU funding and their focus on studies rather than works, only market based investments would take place, i.e. investments that are commercially viable under current market and regulatory conditions. Planning and permitting difficulties would lead to a remarkable mismatch between planned investments and investments actually carried out.

Box 2: Methodology used for assessing the impact of identified problems on investment

Quantifying the impacts of the problems identified under BAU is only possible to a limited extent, given the complexity of electricity and gas markets and corresponding infrastructure development. It was therefore decided to limit the quantitative analysis of impacts for this study to the following two dimensions, whose impacts can be estimated, based on existing theoretical and empirical evidence:
- uncertainties about technologies, imperfect tariff regulation and internal market, assessed through their impact on the commercial viability of projects;
- permitting, assessed through its impact on the realisation ratio of projects.

Commercial viability

While it is very difficult to circumscribe precisely the field of commercially viable projects in regulated markets such as those for electricity and gas transmission infrastructure, one can consider in a simplified manner that an investment concerning a new corporate financed asset is commercially viable if its cost-benefit analysis results lead the concerned TSO(s) to submit the investment project for approval to the regulator, for a given set of market and regulatory conditions (related to future utilisation rate forecasts, expected congestion rents etc. on the one hand, and a given set of rules concerning the asset base, regulated rate of return, amortisation etc. on the other hand).
Concerning project financed assets, commercial viability can also be tested through the ability of the project to secure commercial financing (equity and debt). One can further consider that regulated investments, which are approved by the regulator but afterwards not implemented by the concerned TSO because the regulated rate of return for the project is considered too low, given its expected risk and return profile, are not commercially viable.
Obviously, the field of commercially viable projects is a function of the applicable regulation, which itself should evolve with the implementation of the third internal market package. However, as described in chapter 2.4.2, the definition of commercial viability applied here takes already into account these evolutions.

Based on this definition and the investment needs analysis carried out in chapter 0, infrastructure investment needs and effective investment under BAU for **electricity** for the period 2010-2020 were calculated as follows:

- 70 bn€ for transmission infrastructure (source: ENTSO-E), out of which 28 bn€ are assumed to be dedicated to cross-border interconnections (source: KEMA). It was assumed that these investments will be commercially viable, although, given problems related to cost-benefit allocation for complex cross-border projects, some of them might actually not be so.
- 32bn€ for offshore grid infrastructure, based on an estimated 40 GW of installed offshore wind generation capacity by 2020 (source: ENTSO-E, OffshoreGrid study). Given the technological and regulatory uncertainties and the lack of incentives to develop optimised grid architecture, it was assumed that the corresponding investments will not be commercially viable, although some of them will happen under BAU. One must also note that first results from the OffshoreGrid study indicate that overall costs for connecting offshore wind farms and interconnecting electricity markets across the Northern Seas could be reduced with an optimised integrated grid infrastructure.
- 40bn€ for smart grid infrastructure in distribution and transmission networks (not related to smart metering). Given the technological and market design uncertainties as well as the lack of incentives for individual market actors to develop such grid infrastructure on their own, it was assumed that 50% of this investment (20bn€) will not be commercially viable.

Infrastructure investment needs and effective investment under BAU for **gas** for the period 2010-2020 were calculated as follows (source: PRIMES / DG ENER analysis):

- 28bn€ for import pipelines, out which an estimated 50% (14 bn€) will be built within the EU. It was assumed that intra-EU investments will be commercially viable under current market und regulatory conditions.

- 21bn€ for intra-EU interconnectors. It was assumed that intra-EU investments will be commercially viable under current market und regulatory conditions.
- 21 bn€ for storage. It was assumed that about 1/3 of these investments (7bn€) will not be commercially viable under current market and regulatory conditions;
- 1bn€ for reverse flow infrastructure. It was assumed that the corresponding investments will not be commercially viable under current market and regulatory conditions.

Given the technological, regulatory and market uncertainties surrounding CO2 transport infrastructure and the lack of incentive to build an optimised network, it was assumed that none of the estimated 2.5bn€ of investment needed over the period 2010-2020 will be commercially viable.

Realisation ratio

The impact of delays in planning and permitting on the effective commissioning of projects has been analysed based on stakeholder consultations as well as on empirical evidence from the literature. The 2005 "TEN-Energy-Invest" study concluded that the ratio “performed investments”/”scheduled investments” could be as low as 60% for certain electricity TSOs. It is highly likely that this ratio has further declined since, given the increased levels of local opposition and associated media focus on certain projects since 2005. This assumption seems to be validated when examining in detail the list of projects presented in the first TYNDP: despite conservative estimates for commissioning dates, delays are expected for about 20% of all projects identified and for about 50% of cross-border interconnectors in particular.

For gas infrastructure projects, consulted stakeholders have confirmed that planning and permitting problems exist but are less acute. Under BAU, it was therefore assumed that the realisation ratio is 50% of the total commercially viable investment for electricity and 90% for gas.

Based on the analysis described in Box 2, the total investment need amounts to 142 bn€ for electricity, out of which about 90 bn€ are assumed to be commercially viable under current market and regulatory conditions. The total investment need is 71 bn€ for gas, with 63 bn€ assumed to be commercially viable. For CO2 transport infrastructure, the number is 2.5 bn€. Applying the assumptions made on commercial viability and realisation ratios under BAU, electricity infrastructure delivery would reach about 30% (45 bn€ out of 142 bn€), while gas infrastructure delivery would reach about 80% (57 bn€ out of 71 bn€). No significant investment would take place for CO2 transport infrastructure. These figures are average figures taken as reference for simplification. In terms of overall economic impacts, BAU would therefore result in insufficient and sub-optimal development of electricity and gas transmission infrastructure, with an estimated investment shortfall of 113.5 bn€ over the period 2010-2020, corresponding to an overall infrastructure delivery rate of only 47%.

Error! Reference source not found. Table 2 below summarises these numbers:

Sector (investment 2010-2020, bn€)	Business-as-usual delivery	Commercially viable delivery	Total need
Electricity	45	90	142
Gas	57	63	71
CO2 transport	0	0	2.5
TOTAL	**102**	**153**	**215.5**
Investment gap	***113.5***	***62.5***	***0***
Total (%)	47%	71%	100%

Table 2: Business-as-usual, commercially viable and needed investment by sector 2011-2020

Concerning **electricity**, transmission would continue to be optimised mainly at national rather than EU level, thus bearing significantly higher costs. For offshore grids in particular, certain projects would not be realised at all up to 2020, given delays and difficulties in the planning and permitting process, while for other projects, national, technologically mature and mostly radial connections to shore would be preferred over cross-border or technologically more advanced and integrated designs. Concerning onshore projects, planning and permitting delays and obstacles due to the imperfect internal market would affect in particular cross-border connections, maintaining certain transmission bottlenecks and hence congestion rents. Between 2006 and 2009, total congestion rents of 26 European electricity TSOs (EU-27 without CY, MT and UK plus Norway and Switzerland) have varied between about 1.2 bn€ and 1.95 bn per year[66]. The energy imbalances between Member State price zones would generate price differences, leading to significant social welfare impacts. These differences reached in 2008 on average between 15 and 29 €/MWh for 12 different interconnectors linking two Member States, with corresponding welfare losses estimated at over 3 bn€[67]. Increased price volatility and negative prices would be another consequence of insufficient transmission capacity in a given price zone.
Concerning both <u>economic and social impacts</u>, risks of system instability would increase due to higher balancing constraints, leading to more black-outs. Despite their relatively low probability, research shows that black-outs have unusually costs, notably for industry or services (production shortfalls, restarting of machinery, and damage to machinery or raw material) or households (loss of food, comfort and potentially free time). For the case of Germany, it has been estimated that overall costs could amount to 8-16 €/kWh, or about 30 to 150 times more than the current electricity price[68]. Therefore, even slightly deteriorated security of supply could induce macroeconomic losses of several billion euros for this country alone[69]. The social impacts of a black-out on society and daily life were felt clearly in November 2006 when a black-out, originated in North-West Germany, struck France, Austria, Belgium, Italy, Spain and even Morocco, leaving a total of about 15 million people without electricity for up to two hours. Among the concrete consequences affecting directly EU citizens were about 100 train delays in Germany and hundreds of passengers trapped in lifts in Paris due to the outage.

Concerning **smart grids**, BAU would lead to insufficient development, given their inherent risks, with associated negative impacts in terms of power outages, losses in the electricity system (technical, e.g. thermal losses, but also non technical, due to sub-optimal systems planning and asset management) and greater difficulty if not impossibility to integrate an increasing share of renewables and integrate and operate grids at European-level. But it would also prevent the EU from benefiting from directly quantifiable positive <u>economic impacts</u>: The French regulator CRE has estimated that with the implementation of smart metering the supplier switch capability for households will increase by a factor of 10 (50% instead of 5%). In the longer term, smart grids would contribute to price reductions on the electricity market by increasing transparency of supply and demand, hence reducing congestions, optimising system flows and providing the information needed for dynamic pricing. Moreover, the Bio Intelligence Report concludes that smart grids could reduce the EU's annual primary energy consumption in the energy sector by almost 9% by 2020[70], which equals to about 148 TWh of electricity. In 2010 prices, this amounts to annual savings of almost 7.5 bn€.

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[66] European Commission consultation on an Inter-TSO Compensation Mechanism, 2008; ENTSO-E

[67] "Influence of National and Company Interests on European Electricity Transmission Investments", Study by Matti Supponen, Helsinki University of Technology, August 2010

[68] German electricity prices were about 11c€/kWh for industry and 23c€/kWh for household customers during the second half of 2009 (Eurostat).

[69] "Hohe Versorgungszuverlässigkeit bei Strom wertvoller Standortfaktor für Deutschland", David Bothe and Christoph Riechmann in Energiewirtschaftliche Tagesfragen, 10/2008

[70] Pilot projects with smart metering in various European Member States have yielded annual reductions of consumption between 5 and 15%.

Lack of sufficient **gas** infrastructure would increase the probability of supply shortages or supply disruptions, or limit the possibilities to mitigate actual supply disruptions, in a context of decreasing domestic production (all over Europe) and higher import dependency. The example of the winter 2005/2006 in the UK illustrates the possible economic impact of supply shortages: due to higher prices, the extra cost paid by British consumers amounted to about 2 billion £[71] (about four times the value of the BBL pipeline between NL and UK). This shortage was mainly due to an infrastructure failure (storage burn) combined with insufficient import capacity to bring additional gas from other sources (through pipelines or LNG).
The economic damage caused by the January 2009 gas supply disruption in South East Europe has been estimated at 1.65 billion €[72] for Slovakia, Hungary, Croatia, Serbia and Bulgaria. This amount is by far higher than the total cost of all reverse flow projects and Central-Eastern European interconnector and storage projects included in the EEPR (around 1.2 bn€), which could have mitigated the supply disruption had they been operational at the time of the crisis. It was mainly inadequacies in gas transport which constrained flows (capacities, reverse flow capabilities, unusual routes, insufficient integration of gas networks in Central and South Eastern Europe), not lack of gas[73].
Social impacts on consumers could also be significant, especially in the winter. During the January 2009 gas crisis, many Bulgarian households remained without heating for up to 48 hours. While transit disputes, such as the one that lead to the above described crisis, have occurred on average 2 to 3 times each year in Europe over the past years[74], they resulted only twice (January 2006 and January 2009) in effective supply shortfall/disruption to the EU.

Lack of infrastructure would also increase dependency from only a few or a single source and hence hinder market integration and competition, leading to higher prices. This can be demonstrated by looking at the price evolution at existing trading hubs. North-West Europe seems to be rather well integrated, as the prices of TTF (Netherlands), Zeebrugge (Belgium), Gaspool or Net-Connect (Germany), PEG (France) and NBP (UK) generally seem to converge. However, the prices at the Italian PSV are constantly higher than the prices in the North-West. In Eastern Europe, liquid and transparent hubs are still under development (or to be developed), making the assessment of price differentials and missing links more difficult. However, as confirmed by stakeholder consultations, there are significant price differences between Central-Eastern European Member States[75]. These Member States (who joined the EU in 2004 and 2007) and the member countries of the Energy Community Treaty are therefore those exposed to the highest risks in terms of supply shortage or disruptions, lack of market and integration and therefore possible negative economic and social impacts.

Finally, the impacts of over- or under-investment in both electricity and gas infrastructures are asymmetric. As the cost of transmission is limited in the final energy price, over-investment in infrastructure will cause only a limited increase of the final price[76]. But a lack of infrastructure can cause energy shortages, disruptions or price increases with far higher economic and social impacts. For electricity in particular, transmission on average only amounts to about 10% of overall electricity cost. Investing in more generation and/or back-up capacity to avoid energy shortages and black-outs would result in higher overall costs for the concerned Member States compared to the construction of interconnectors to obtain EU-

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[71] "Crossing Borders in European Gas Networks: The Missing Links", Clingendael Energy Paper, September 2009
[72] Estimates were provided by the concerned Member States to DG ENER.
[73] SEC(2009) 979 Impact Assessment of the gas security of supply regulation
[74] Such disputes arise for supplies coming from Russia through Ukraine, but also for those coming from Algeria through Morocco, the most recent one being the dispute between Belarus and Russia in July 2010.
[75] Note that even in the case of perfect interconnectivity and market integration, price differentials between distant regions would remain due to transport costs. However, prices should converge within a region if the market works well and sufficient interconnection capacities are available.
[76] For gas, transmission costs account on average for only 2-4% of the final gas price in Western Europe, although this share may be significantly higher in individual Member States, in particular in Eastern Europe.

wide or regional balancing, thus again increasing prices to final consumers. This effect would be even stronger, if missing transmission infrastructure prevents the development of renewable generation capacities and hence favours the use of fossil fuel based generation with higher fuel-dependent operating costs. This in turn could lead to increased problems of energy poverty for low income households, notably in Eastern Europe.

Concerning **CO2 transportation**, the BAU scenario would prevent any significant investment in networks and give rise to piecemeal development (at project or national level) with a high risk of future redundancy or bottlenecks in through-flow capacity (similarly to the electricity and gas grids) and limited market integration with a risk of higher energy prices in the long term.

Concerning environmental impacts, less infrastructure development would diminish negative local impacts for those directly concerned by new energy infrastructure projects, both temporarily (e.g. during the construction period for underground gas pipelines or electricity lines) and permanently (notably for overhead electricity lines or offshore grid infrastructure). It would also limit potential losses of biodiversity due to energy infrastructure crossing natural habitats. However, these impacts should be put in perspective with the negative global climate impacts generated by insufficient infrastructure development. Under BAU, lack of transmission infrastructure and smart grids would limit the possibilities to inject electricity from renewable sources into the grid to reach final customers, hindering the achievement of the 20% renewables target and preventing CO2 emission reductions, with the related consequences on the climate and the environment. Concerning renewables, given the difficulties and shortcomings identified above for offshore grid development, it is estimated that a significant share of the 32 bn€ of investments needed for offshore connection infrastructure by 2020 will not be realised. As demonstrated by KEMA and confirmed by ENTSO-E, reaching the 20% renewables target in 2020 will therefore be impossible, given the important contribution expected from offshore wind (over 12% of total renewable electricity production in 2020 or about 20% of the additional renewables capacity to be installed between today and 2020[77]). Concerning emissions, the Smart 2020 study estimates that global emissions could be reduced by 15% thanks to smart grids, mainly through their contribution to energy efficiency.
Similarly, absence of sufficient transportation capacity and lack of interconnection between CO2 producing sites in one Member State and CO2 storage sites in another Member State would slow down the uptake of CCS technologies, again maintaining higher CO2 emissions.
Gas supply shortages or disruption due to lack of infrastructure or alternative sources (such as LNG or CNG) would on the one hand lower CO2 emissions under BAU, as less gas is consumed. On the other hand however, one can realistically assume that gas would be replaced by other more emitting fossil fuels, typically oil or coal. The overall effect of insufficient gas infrastructure can be assumed to be higher CO2 emissions.
This environmental impact analysis is confirmed at the macro-level: cumulated CO2 emissions for the EU between 2010 and 2030 under the PRIMES baseline scenario (corresponding to BAU) are projected to be about 2,500 millions tons or over 3% higher than under the Reference scenario, where all necessary infrastructure is supposed to be operational.
In addition, the absence of additional energy infrastructures might also lead to negative local environmental impacts (e.g. air pollution), due to longer lifetimes or development of new capacities for non renewable, higher emission electricity generation capacities. In the case of **oil** transport, the alternatives to bringing additional oil to the EU in case of an oil supply disruption would be an increased tanker traffic in the environmentally sensitive Baltic Sea and the Bosporus to compensate a shortfall in the Druzhba pipeline system (the stop of the entire supply of this system would require to redirect approximately 60 million tons of crude

[77] DG ENER calculations

oil/per year[78]). Developing alternative supply routes would require investments, which might not happen without political support and awareness-raising at EU level.

5.2. Policy area A: Scope of policy instrument

From the impact assessment of the BAU scenarios, one can clearly conclude that major positive impacts are expected at the economic and social level from extending the scope of the policy instrument to new sectors in electricity (smart grids including storage) and gas (CNG), but also to CO2 transportation. This would address some of the uncertainties and the shortcomings of the current TEN-E framework, outlined in Chapter 2.3. Moreover, by focussing attention on new technologies such as smart grids, electricity storage or carbon capture and storage, extending the scope would also foster innovation in these fields. The extension to oil would also provide positive environmental impacts, by ensuring diversified oil supply routes to the EU to reduce the environmental risk related to increased tanker traffic on the Baltic Sea and in the Bosporus. Nevertheless, these would be limited to countries in Central and Eastern Europe supplied through the Druzhba pipeline system. Including all these new sectors in the scope of the policy instrument (option A3) is therefore the preferred option.

5.3. Policy area B: Design of policy instrument

Compared to BAU with a fixed and rigid project list defined in 2006, the update of this list (option B2) based on an enlarged scope (option A3) would allow taking into account new or changed priorities in terms of infrastructure development. This improved focus would have an overall positive impact, but would maintain the rigidity of a project list, which might again need adaptation in the future up to 2020 and beyond.

By contrast, a complete reform of the current approach (option B3), with a very limited number of broad priorities of European interest, no *ex ante* list of priority projects and smart and transparent selection criteria instead of the current three-tiered categorisation of projects, would yield far bigger positive economic, social and environmental impacts. Indeed, this option would allow focussing all attention on those priorities, which are of major European interest and for which EU intervention will be most beneficial, or on areas with strong innovation and high positive environmental impacts such as renewables' integration into the grid, smart grids, storage or CO2 transport. More generally, this approach based on European priorities would draw attention on economic and environmental trans-boundary and regional effects, while option B2 would be influenced more by national or even local level effects. Establishing smart and transparent selection criteria would minimise possible distorting effects on the internal market, by designing rules that are in line with current legislation and regulation. It would also allow evolution over time of the concrete support given to projects, optimising the use of the policy instrument even in the longer term. It is therefore considered to be the preferred option.

Transition from old guidelines projects list to new priorities and projects:

- Some projects are implemented or well underway (will be implemented by 2014).
- Some projects have been abandoned (proved unfeasible or uninteresting).
- Some will be taken up under the new priorities (if identified so by the respective regions).
- Projects, which lose their status acquired under the former guidelines, will do so because they are not of European, but of national or sub-regional interest, and should be promoted at these respective levels.

[78] "Technical aspects of variable use of oil pipelines coming into the EU from third countries", feasibility study by ILF and Purvin & Gertz

5.4. Policy area C: Coordination

As seen in chapter 2.2 and 2.3, the current TEN-E design with voluntary regional structures and EU coordinators has not provided all the necessary incentives for effective regional coordination and rapid implementation of cross-border infrastructure projects. Option C2 with mandatory regional structures and, where necessary, EU coordinators, would have significant positive impacts in terms of infrastructure development and is therefore considered as the preferred option compared to BAU. These regional structures would be particularly positive for projects with a clear regional delimitation such as the offshore grid in Northern Europe or the development of a gas corridor in South-Eastern Europe. They would also contribute positively to market integration and better functioning of regional markets. Their negative impacts in terms of administrative burden would be very limited to the meeting and coordination requirements created for various actors (national governments, regulators, TSOs, energy companies) through the newly established or extended regional structures. As existing regional structures, for example the so-called Regional Initiatives, would be used for this task, no additional administrative costs are expected.

5.5. Policy area D: Permitting

Both measures would introduce more efficiency in the decision making process by clarifying existing rules and ways or recourse, optimising the number of steps needed for a given decision to be taken and reducing as much as possible delays for each of these steps. While BAU is expected to lead to very limited streamlining and acceleration of permitting procedures only, option D2 would allow an accelerated treatment for European priority projects in those countries where priorities have been defined or where fast-track procedures exist. It is considered that this would partially shorten the delays observed under BAU and allow improving infrastructure delivery significantly in the electricity sector by raising the ratio "performed investments"/"scheduled investments" for the period 2010-2020 from 50% to 75%. In the gas sector, the effect would be more limited (from 90% to 95%). This would considerably increase infrastructure investment from 102 bn€ under BAU to 130 bn€ over the period 2010-2020.
The one-stop-shop approach (option D3) however would further facilitate administrative procedures and, combined with the limit of 5 years for a final authorisation decision to be taken by the authority for a given project, accelerate permitting and increase project delivery compared to the investment needs. It is assumed that 100% of the scheduled market based investments in electricity, gas and CO2 transportation would be realised during the period 2010-2020. The additional investment due to option D3 would be about €53bn compared to BAU, further increasing infrastructure investment to 155.5 bn€, with most of the contribution coming from the electricity sector, where the problems due to delays in planning and permitting are biggest..

The table below summarises the realisation rates assumed under BAU and with both options D2 and D3:

Sector	Selected scenarios	Realisation rate assumption (% of total investment[1])
Electricity	business as usual (D1)	50%
	fastest national procedure (D2)	75%
	one-stop-shop (D3)	100%
Gas	business as usual (D1)	90%

Sector	Selected scenarios	Realisation rate assumption (% of total investment[1])
	fastest national procedure (D2)	95%
	one-stop-shop (D3)	100%

Table 3: Realisation rates under different scenarios (2010-2020)

Concerning the macroeconomic impacts assessed using the E3ME model, both options would have significant positive overall effects on GDP and employment compared to BAU, with a cumulative effect of +0.42% of GDP and 410,000 additional jobs over the period 2011-2020 for option D3 (see Annex 3 for more details). This would correspond to a net cumulative increase in GDP of about 8.8 bn€ over the period[79]. The positive impact of option D2 would only be about half (+0.22% of GDP, about 150,000 additional jobs). In any case, the additional investment made possible would have positive impacts on small and medium enterprises, through the need for more employment generated in construction, mechanical engineering and business services. This would in turn increase incomes and household spending, confirming the positive social impacts of the policy.

Contrary to policy areas A and B and C, policy area D would have considerable impact on the administrative burden and compliance cost for both companies and national administrations compared to BAU. The industry repeatedly pointed out reduced administrative burden as a major desired change. Option D2 would simplify procedures and reduce administrative burdens only for projects in those Member States, where national priorities and fast-track procedures exist. The national "one-stop-shop" of option D3 however would reduce the amount of interlocutors for project promoters to a single identified authority per Member State, as opposed to the current situation where the number of authorities can reach up to 20, yielding the largest positive administrative impact. It must be noted however that, while option D2 is assumed to be easy to comply with, option D3 would create compliance costs for Member State governments in terms of national transposition of new rules, re-design of existing permitting procedures and re-organisation of authorities in charge of these procedures. While this option would also necessitate more administrative resources to process permitting for projects of European interest, it is not considered that this would lead to crowding out effects when compared to the processing of national projects, given the limited number of projects concerned.

Concerning environmental impacts, it must be underlined that both options D2 and D3 do not aim at reducing environmental standards for the evaluation of energy infrastructure projects. The compliance with EU environmental legislation is extremely important for the smooth implementation of energy infrastructure projects. All projects, if so required, will be subject to the appropriate environmental assessment in accordance with existing EU legislation (mainly SEA directive[80], EIA directive[81] Habitats directive[82] and Water framework directive[83]), as is already the case in the current TEN-E guidelines. As a result, certain projects might have to change their technology choice (e.g. from overhead line to underground cable or special measures for gas pipelines in order to be able to cross Natura 2000 sites; direct current instead of alternating current to reduce the size of power poles). Others would have to change their routing or to adopt measures in order to prevent and mitigate the possible

[79] Based on 2000 prices, the cumulative investment taking place under business as usual between 2011 and 2020 is about 73.9 bn€ (down from 89 bn€ in 2008 prices), while it is 117.8 bn€ under S1, yielding a difference of 43.9 bn€. Comparing this number to the cumulative annual GDP increase of 52.7 bn€, one obtains the net absolute GDP impact in 2000 prices.

[80] Directive 2001/42/EC on the assessment of the effects of certain plans and programmes on the environment

[81] Directive 85/337/EEC on the assessment of the effects of certain public and private projects on the environment

[82] Directive 92/43/EEC on the conservation of natural habitats and of wild fauna and flora

[83] Directive 2000/60/EC establishing a framework for the Community action in the field of water policy

adverse effects on the environment or, if not possible, to compensate negative impacts, in particular on the conservation objectives and integrity of Natura 2000 sites.

Following this assessment, it is considered that option D3 would be the most effective, while option D2 would imply lower compliance costs at Member State level.

However**,** the Communication covered by this impact assessment will only consider principles to make permitting procedures more efficient and transparent, whereas concrete rules to achieve this in the Member States will only be proposed in the Energy Security and Infrastructure Instrument to be tabled in 2011. A more detailed impact assessment will be prepared for this instrument, providing for an in-depth assessment of the different policy options with regard to the sectors covered, their compatibility with national legal systems and their compliance with the principle of subsidiarity, taking into account the importance of transparency and public acceptance. It will also include an analysis of the administrative burden and compliance costs for each policy option. It must be noted that these rules concerning permitting will only cover electricity transmission infrastructure as well as gas infrastructure transmission and storage infrastructure. Smart grid projects, which do not involve large visible infrastructure investment with high environmental impacts, and CO2 transport projects, which will see only limited investment up to 2020, should not be covered under these new rules.

In view of the next impact assessment, a study has been launched and will deliver first results by May 2011. The study will analyse the legal and regulatory framework as well as the effective practice concerning planning and permitting for electricity and gas infrastructure (covering spatial planning, environmental protection and public consultation rules), on which procedures and decisions are based. It will in particular assess the number and tasks of the authorities involved during each step of the permitting and licensing for typical infrastructure projects, as well as their respective level (local, regional, national).

Based on this analysis, the study will make recommendations for improving the existing legal, regulatory and incentive framework at EU level, taking into account differences in the Member States, notably in terms of legal systems and local acceptance. The recommendations will pay due respect to the impact of the solutions proposed in terms of simplifying and accelerating permitting procedures, and their viability in terms of how administrations will be able to implement them technically and legally. The recommendations will further be reflected against the principles of proportionality and subsidiarity.

In addition to the study, extensive stakeholder consultations, involving national administrations, TSOs and NGOs are foreseen. A dialogue with representatives from Member States where accelerated procedures have been or are about to be implemented has been initiated to enquire about best-practices and compliance costs incurred.

6. COMPARISON OF POLICY OPTIONS AND CONCLUSION

The four different policy areas, with between 2 and 3 maintained policy options for each, can be combined in numerous ways. In addition to BAU (analysed in the previous chapter), there are 8 possible policy sets combining different policy options in each area: 2 in area A, 2 in area B, 1 in area C and 2 in area D. However, the impacts of the different options within one policy area can be independent of those of another policy area. On the one hand, the scope of the policy instrument (policy area A) does not influence the effectiveness of the design of the instrument (policy area B); and the coordination between regional players (C) will impact each sector independently of the number of sectors targeted (A). On the other hand, while the impacts of the different permitting schemes (D) on the speed of project implementation will not be affected by a variation in scope (A), it is likely that certain permitting policy options will be more effective if combined with certain options of policy instrument design (B) or coordination (C).

The following table summarises the main impacts of each maintained policy option presented in chapter 5 in terms of economic, social and environmental impacts:

	Economic impacts	Social impacts	Environmental impacts
A: Scope			
A1	- more power losses, more energy consumption and less transparency for the consumer due to insufficient smart grid - limited innovation in new technologies such as electricity storage, smart grids, CCS		- higher air pollution and CO_2 emissions (due to limited development of renewables, smart grids, CCS) - higher environmental risks in case of oil supply disruption (due to increased oil tanker traffic)
A2	- slightly diminished negative impacts compared to A1, notably for new technologies such as smart grids, electricity storage and CNG		- higher air pollution and CO_2 emissions (due to limited development of CCS) - higher environmental risks in case of oil supply disruption (due to increased oil tanker traffic)
A3	- best coverage of all sectors, in line with energy and climate policy objectives		- air pollution reduction and less CO_2 emissions - more nuisance and negative local environmental impacts (due to additional infrastructure development)
B: Design			
B1	- insufficient adequate transmission and storage capacity due to rigid, suboptimal priority setting, leading to congestion rents, price differences, price volatility - increased risk of electricity black-outs or gas supply shortages / disruptions	- negative impacts on both electricity and gas consumers in case of black-outs/shortages - energy poverty due to higher energy prices	- local nuisance and environmental impacts limited - more CO_2 emissions
B2	- reduced impacts compared to B1, due to slightly improved priority setting	- slightly reduced impacts as compared to B1	- slightly diminished effects as compared to B1
B3	- significant positive impacts on market (price convergence, lowering effect on prices) and security of supply - significant development of renewables, smart grids, electricity storage and CCS, in line with energy and climate policy objectives	- reduced security of supply risks and lowering effect on energy prices beneficial to final consumers	- increased local nuisance and environmental impacts - lower CO_2 emissions
C: Coordination			

C1	- insufficient cross-border infrastructure investment, insufficient market integration and bigger risks to security of supply	- negative impacts on both electricity and gas consumers in case of black-outs/shortages - energy poverty due to higher energy prices	- local nuisance and environmental impacts limited - more CO2 emissions
C2	- more cross-border infrastructure development and optimised design, better (regional) market integration - very limited administrative burden for various stakeholders	- reduced security of supply risks and lowering effect on energy prices beneficial to final consumers	- more CO2 emission reduction (e.g. through focus on offshore grids, CCS)
D: Permitting			
D1	- significant delays in infrastructure delivery, insufficient development		- local nuisance and environmental impacts limited - more CO2 emissions
D2	- reduced delays in infrastructure delivery, improved development - positive effect on GDP (+0.22% over the period 2010-2020) - limited administrative cost	- positive impact on job creation (+150,000 over the period 2010-2002)	- more local nuisance and environmental impacts than in D1 - CO2 emission reduced compared to D1
D3	- full delivery of commercially viable infrastructure projects - significant positive impact on GDP (+0.42%) - less administrative cost for operators - significant compliance cost for national administrations	- significant positive impact on job creation (+410,000) and, to a lesser extent, SMEs	- more local nuisance and environmental impacts than in D2 - CO2 emission reduced compared to D2

As summarised above, the combination of options with the largest positive impacts would be A3, B3, C2 and D3, noting that the policy area of permitting will still have to be analysed more in depth. While BAU would lead to only 102 bn€ of investment, leaving an investment gap of 113.5 bn€, the most effective policy set as described above would significantly raise infrastructure delivery, with an investment level of 155.5 bn€. Our analysis also shows that this policy set would be most beneficial in economic, social and environmental terms.

It must however be noted that even the most effective policy set would deliver 60 bn€ less than the identified investment need of 215.5 bn€. Indeed, the mere enlargement of the scope, as well as the proposed reforms on the design of the policy instrument, regional cooperation structures and permitting, will not, *ceteris paribus*, close the remaining huge investment gap and will not make those projects bankable, which are commercially non viable under BAU market and regulatory conditions. This applies in particular to certain cross-border electricity grid, smart grid[84] and offshore grid infrastructure, to gas cross-border, reverse flow and storage infrastructure and to certain CO2 transport infrastructure. At the same time, the potential for tariff increases to be able to create the regulatory conditions to

[84] First studies and experiences do highlight the long-term economic viability of smart metering deployment alone. The UK Department for Energy and Climate Change (DECC) has estimated that fitting 26 million homes with smart meters by 2020 would cost over 8 bn £. But this cost would be more than compensated for by 14.5 bn £ of savings in operational costs for power companies and lower bills for customers. However, the corresponding "smart" investments on the grid are not currently covered by the market.

cover these investments is limited, given the investment amounts at stake[85]. Therefore, one could expect significantly higher positive impacts under a policy set using public funding or dedicated regulatory measures to enable the implementation of all projects of European interest, including those, which are not commercially viable[86]. Establishing principles for the cost-allocation across borders could solve the issues where the commercial viability of a project is due to its uneven cost-benefit allocation to users. Regulators could agree on common principles in relation to cost-allocation of interconnection investments and related tariffs. In electricity the development of long term forward markets for cross-border capacity should be explored, whereas in the gas sector the investments costs could be allocated to TSOs in neighbouring countries, both for normal (based on market-demand) investments as well as those motivated by security of supply reasons. The Commission plans to put forward, in 2011, a proposal or guidelines to address cost allocation of major technologically complex or cross-border projects, through tariff and investment rules. Where a higher rate of return would be required to match the project risks and thus make them bankable, a regulatory approach could also be envisaged. Public funding could be explored for those areas, where the above-mentioned measures would fail. However, this needs detailed further analysis which will be included in the Impact Assessment to be prepared for the EU Energy Security and Infrastructure instrument.

7. MONITORING AND EVALUATION

Specific indicators to monitor the evolution of the policy will be:

- The number of projects constructed, under construction or commissioned by given target dates such as 2015, 2020 and 2030, compared to the number of projects identified as being of European interest. This indicator could also be measured in terms of installed capacity and length of new power lines or gas pipelines and capacity of other new electricity and gas infrastructure (storage, LNG/CNG).
- To measure diversification of gas imports: the share of each import source and their concentration within the overall import (at national, regional and EU level), for example through the Herfindahl index[87].
- To measure the integration of renewables: the share of (variable) electricity produced from renewable sources in the overall electricity generation. This will be monitored through the bi-annual reports Member States must submit to the Commission under article 22 of the renewables directive.
- To measure market integration: the interconnection level between Member States and the evolution of energy prices. Concerning electricity, interconnector capacity defined as the ratio between import capacity and installed generation capacity in a given Member State could be used, as well price differentials observed between international interconnectors. Concerning gas, prices at major European hubs could

[85] There are strong signs that energy prices will increase in the short and medium term to respond to changes in the EU's energy system. In comparison to investments linked to increased electricity generation from renewables and investments in distribution grids, the impact of grid investments is forecasted to be minor. ENTSO-E has calculated that 100 bn € of transmission investment over the period 2010-2020 would represent only about 2% of bulk power prices. However, the combined impact of all needed investments on prices could be significant. The UK energy regulator (OFGEM) for example has calculated that prices could increase over the next 10 years by as much as 25%, while France has discussed a price increase of 20% over three years during 2009.

[86] The E3ME model confirms that such funding, if compensated e.g. by a small increase in direct taxation rates, would be revenue neutral at macroeconomic level compared to full funding of all the investment through higher energy prices.

[87] The Herfindahl index, also known as Herfindahl-Hirschman Index or HHI, is a measure of the size of firms in relation to the industry and an indicator of the amount of competition among them. It is defined as the sum of the squares of the market shares of the 50 largest firms (or summed over all the firms if there are fewer than 50) within the industry, where the market shares are expressed as fractions. The result is proportional to the average market share, weighted by market share. As such, it can range from 0 to 1.0, moving from a huge number of very small firms to a single monopolistic producer.

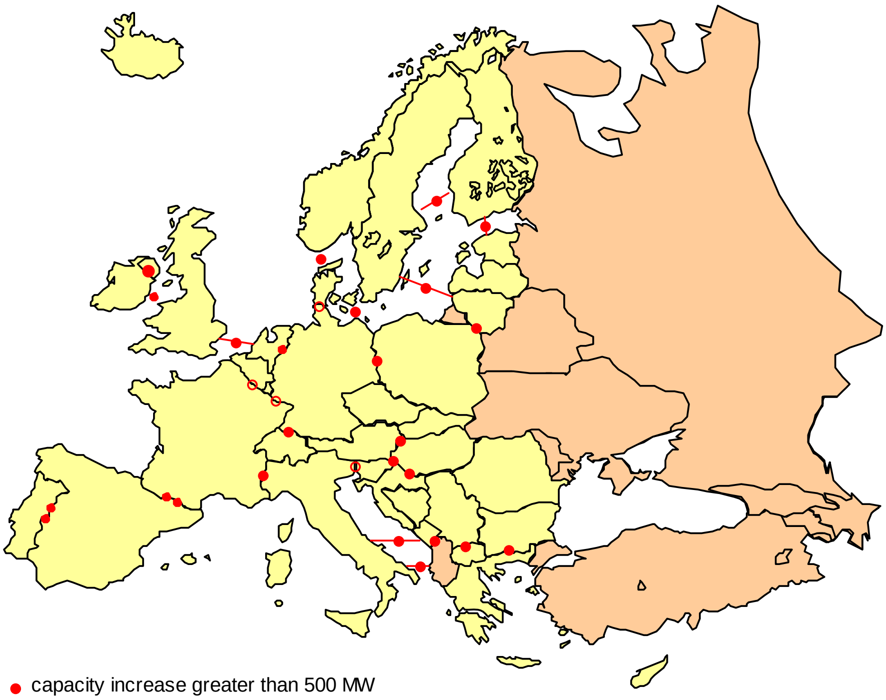
be used. Price monitoring is already being done by DG ENER's Energy Market Observatory.

- To measure the adoption of smart grid technologies: the share of grid infrastructure (including lines, converter stations, substations etc.) equipped with new communication technologies compared to the total infrastructure for a given TSO as well as the number of electricity costumers having signed up to smart grid enabled services.
- To measure security of supply of gas: the compliance with the N-1 and reverse flow standards will be monitored under the security of gas supply directive.
- To measure progress concerning permitting: the average duration of authorisation procedures for projects of European interest compared to the average duration of procedures for all infrastructure projects. This activity could be carried out by the ENTSOs.

For monitoring and evaluation, like in the past, the Commission would assess the evolution via an implementation report on a bi-annual basis.

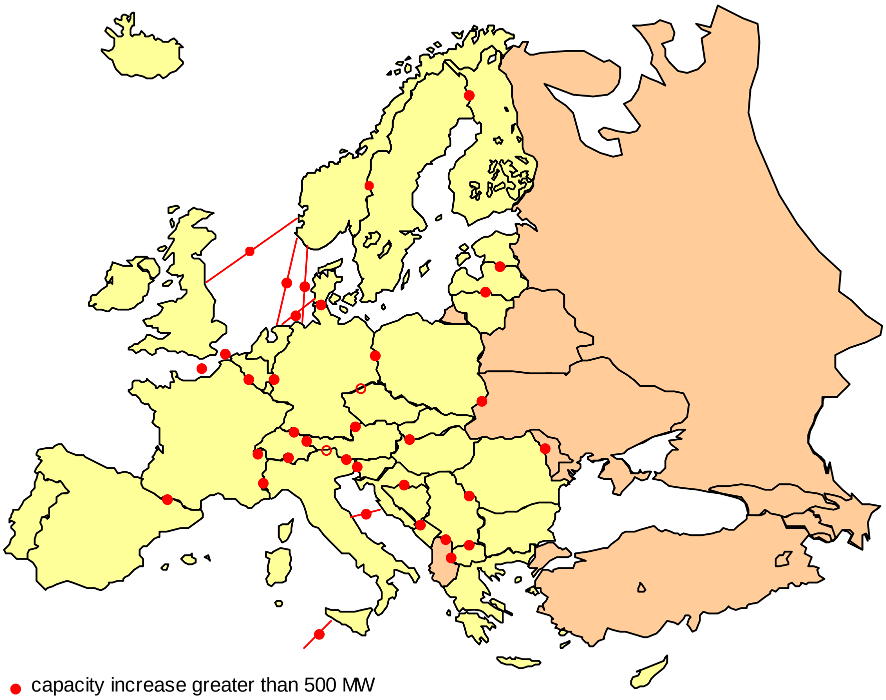
ANNEX 1: ELECTRICITY TRANSMISSION CAPACITY INCREASES FOR THE PERIOD 2010-2015 AND 2015-2025

Major transmission capacity increase in Europe in the next 5 years (mid-term)



● capacity increase greater than 500 MW
○ lower capacity increase

Major transmission capacity increase in Europe in 2015 and beyond (longer term)



● capacity increase greater than 500 MW
○ lower capacity increase

Source: ENTSO-E

ANNEX 2: CURRENT FINANCING OF TEN-E PROJECTS

Investments in infrastructure are mainly financed from private sources, whereby the TSOs' own resources can vary between 20% and 100% of the total investment depending on the risks and the scale of the overall investment. The rest is typically covered by loans from commercial banks and international financial institutions. Partnerships with companies active in the gas and power sector, other than TSOs, may offer additional capital in the form of equity participations. Energy infrastructure can be corporate financed or project financed. The involved risks are different. As a general rule, if a project lies within the TSOs' own network and is mainly linked to domestic transmission or distribution, TSOs will invest at their own risk and cover the investment from their own corporate sources. Larger mid-stream (gas) and cross-border (gas or electricity) projects are often project-financed, with special purpose companies set up for them. Member States in most cases do not participate directly in financing the of energy infrastructure and in particular TEN-E projects.

EU-funded support to TEN-E projects was based so far on the following instruments:

- TEN budget of 155 mln € for the period 2007-2013 (see chapter 2.2): Although the maximum co-financing rate is up to 50% for studies and 10% of eligible costs for works, it has so far rarely amounted to more than 0,01-1% of the total investment cost of a project.
- The European Investment Bank plays an important role in the implementation of the TEN-E projects. In 2007-2009 the financial envelopes providing senior loans amounted to 2.561 bn€ and 3.407 bn€ respectively for gas and electricity projects.
- In recognition of their social and economic importance, energy infrastructure projects have risen in priority in other EU funding sources, including the Structural Funds, Instruments for Pre-Accession (IPA) and European Neighbourhood Policy (ENPI/NIF) as well as the RTD Framework Programme. These programmes have a significantly larger budget than TEN-E for energy-related measures. However, from a total sum of 1.33 bn€ available under the structural funds for 2007-2013, only a fraction has been allocated to projects so far: 0.7% (7.5 mln €) for gas and 0.04% (12,000 €) for electricity. This is mainly due to the same difficulties as identified in chapter 2.3.
- In 2009, the Council agreed exceptionally to allocate 3.98 bn€ to energy infrastructure and technology through the European Energy Programme for Recovery (EERP), out of which 2.365 bn€ went to electricity and gas infrastructure projects. These funds targeted projects where delays caused by credit withdrawal would not only have been detrimental to the EU's security of supply, and therefore to future economic growth, but would also have had a serious impact on employment and skills in the energy and construction sectors. The remaining funds were aimed at the introduction of renewables (offshore wind, 565 m€) and other low carbon technologies (CCS, 1.05 bn€) into energy networks. For the supported offshore grid projects, a European added value was required, namely an "innovation component of large scale projects with cross-border significance", suggesting that "Such projects should include an integrative approach for interconnecting offshore wind power to provide transmission capacity in view of trading electricity between Member States." A large proportion of EERP funding will benefit the most mature Trans-European energy infrastructure projects, in order to speed up and secure investments and accelerate their realisation.

ANNEX 3: E3ME MODELLING SCENARIOS AND RESULTS

1. Presentation of E3ME model

The E3ME model was used to carry out a more advanced macro-economic analysis of the impacts of the different policy options examined in chapter 5. E3ME is a computer-based model of Europe's economic and energy systems and the environment. It was originally developed through the European Commission's research framework programmes and is now widely used in Europe for policy assessment, for forecasting and for research purposes.

The structure of E3ME is based on the system of national accounts, as defined by ESA95 (European Commission, 1996), with further linkages to energy demand and environmental emissions. The labour market is also covered in detail, with estimated sets of equations for labour demand, supply, wages and working hours. In total there are 33 sets of econometrically estimated equations, also including the components of GDP (consumption, investment, international trade), prices, energy demand and materials demand. Each equation set is disaggregated by country and by sector.

E3ME's historical database covers the period 1970-2008 and the model projects forward annually to 2050. The main data sources are Eurostat, DG ECFIN's AMECO database and the IEA, supplemented by the OECD's STAN database and other sources where appropriate. Gaps in the data are estimated using customised software algorithms.

The other main dimensions of the model are:

- 29 countries (the EU27 member states plus Norway and Switzerland)
- 42 economic sectors, including disaggregation of the energy sectors and 16 service sectors
- 43 categories of household expenditure
- 19 different users of 12 different fuel types
- 14 types of air-borne emission (where data are available) including the six greenhouse gases monitored under the Kyoto protocol.
- 13 types of household, including income quintiles and socio-economic groups such as the unemployed, inactive and retired, plus an urban/rural split.

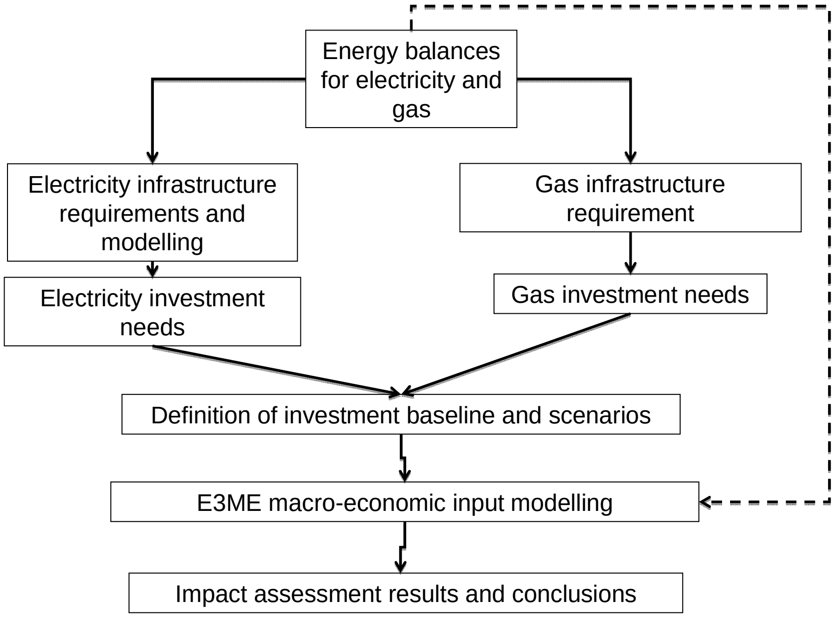
Typical outputs from the model include GDP and sectoral output, household expenditure, investment, international trade, inflation, employment and unemployment, energy demand and CO2 emissions. Each of these is available at national and EU level, and most are also defined by economic sector.

The econometric specification of E3ME gives the model a strong empirical grounding and means it is not reliant on the assumptions common to Computable General Equilibrium (CGE) models, such as perfect competition or rational expectations. E3ME uses a system of error correction, allowing short-term dynamic (or transition) outcomes, moving towards a long-term trend. The dynamic specification is important when considering short and medium-term analysis (e.g. up to 2020) and rebound effects[88], which are included as standard in the model's results.

More detailed information on the E3ME model can be found in the impact assessment study done by COWI, Cambridge Econometrics and KEMA.

[88] Where an initial increase in efficiency reduces demand, but is negated in the long run as greater efficiency lowers the relative cost and increases consumption.

The graph below depicts the methodology applied to analyse the macroeconomic impacts of infrastructure investment in the framework of this study.



2. Policy sets

Different combinations of policy options (policy sets) were designed to analyse the macroeconomic impacts of various policy options[89]. In addition to policy set (S1) combining all preferred options (A3, B3, C2 and D3), a policy set (S2) was established, where option D3 is replaced by option D2 to diminish Member State compliance costs. For the sake of comparison, an additional policy set (S3) was designed to take into account possible measures targeted at non commercially viable projects. Indeed, S3 assumes public support or regulatory measures (such as guidelines on remuneration of non commercially viable projects including for example capacity payments, compensation schemes, rate-of-return bonuses) to ensure full delivery of all investments needed, including non commercial projects. The three abovementioned scenarios (S1, S2 and S3) were compared to business as usual, using the E3ME model.

The following table summarises the **policy sets** and the **investment assumptions**[90] made for their development, based on existing studies and expert analysis:

[89] It must be noted that these policy sets could not stylise the impacts of the options in each policy area, but mainly relied on assumptions arising from policy area A and D.

[90] Under BAU and policy sets S1 and S2, total investment corresponds to the investment assumed to be commercially viable under current market and regulatory conditions, not taking into account potential delays due to planning and permitting, which can reduce the realisation rate for a given period. Only under policy set S3, which assumes support targeted both at commercially viable and non-commercially viable projects, total investment corresponds to the identified investment need.

Scenarios	Input assumptions for E3ME modelling (investment in the EU only)	
Business as usual (A1, B1, C1, D1) (alias *CS1*)	Investment electricity (including smart grids): 45BN€ (50% of total market based investment needs) Investment gas: 44.7BN€ (90% of total market based investment needs) **TOTAL: 89.7BN€**	 2010-2020 2010-2020
	Financing: Energy price + x M€ EU funding[91] (60% electricity, 40% gas)	
Policy set S1 (A3, B3, C2, D3) (alias *CS4*)	Investment electricity transmission: 90BN€ (100% of a total commercially viable needs) Investment gas: 49.7BN€ (100% of a total commercially viable needs[92]) Investment CCS: 2.5BN€ **TOTAL: 142.2BN€**	 2010-2020 2010-2020 2015-2020
	Financing method: Energy price + x M€ EU funding (11/30 gas, 11/20 electricity, 1/12 CCS)	
Policy set S2 (A3, B3, C2, D2) (alias *CS3*)	Investment electricity transmission: 68BN€ (75% of a total commercially viable needs) Investment gas: 47.2BN€ (95% of a total commercially viable needs) Investment CCS: 2.5BN€ – 2015-2020 **TOTAL: 117.7BN€**	1/4 for 2010-2015, 3/4 for 2015-2020 2010-2020 2015-2020
	Financing method: Energy price + x M€ EU funding (11/30 gas, 11/20 electricity, 1/12 CCS)	
Policy set S3 (A3, B3, C2, D3 and public support) (alias *CS6*)	Investment electricity transmission: 142BN€ Investment gas: 57BN€ Investment CCS: 2.5BN€ **TOTAL: 201.5BN€**	2010-2020 2010-2020 2015-2020
	Financing method: Energy price + y M€ EU funding to be determined (11/30 gas, 11/20 electricity, 1/12 CCS)	

[91] The available amount under the current TEN-E programme is 155M€ for the period 2007-2013.
[92] It is important to note that the E3ME model only takes into account investment taking place within the EU and therefore assumes a total investment need for gas of 57 bn€, with 49.7 bn€ corresponding to commercially viable projects.

For oil, given the limited (around 600 million euros) and only hypothetical investment needs for the considered period, it was assumed that no investments would take place.

3. Modelling results

Concerning the macroeconomic impacts of the different scenarios on GDP and employment, it appears that policy set S1 has a significant positive overall impact compared to BAU. The positive impact of S2 is only about half. The biggest increase in GDP and employment could be expected from policy set S3. Table 4 gives a detailed presentation of impacts for each policy set[93].

Policy set	**Infrastructure investment** (in billion €, 2011-2020)	**GDP** (cumulative percentage point difference compared to BAU, 2011-2020)	**Employment** (000s, cumulative difference compared to BAU, 2011-2020)
BAU	89.7	0	0
S1	142.2	0.42	409
S2	117.7	0.22	153
S3	201.5	0.9	774

Table 4: Impacts on GDP and employment 2011-2020 (E3ME model results)

Indeed, more investment creates the need for more employment in a first phase, notably in construction, mechanical engineering and business services. This in turn leads to higher incomes and household spending. Multiplier effects contribute in a second phase to increased employment in consumer sectors such as retail, even if these effects can be delayed in time. The model also concludes that the forecasted investment will have small positive impacts on small and medium enterprises, even if the size of certain of the bigger infrastructure projects (notably in the gas sector) might favour large companies. This confirms the positive social impacts of the different policy sets studied. Table 5 summarises the positive impacts of all policy sets on the main macroeconomic parameters for the year 2020 when compared to BAU[94]. The cumulative impact of S1 on household spending, investment, exports and imports roughly doubles the impacts of S2. The positive effect of S3 compared to S1 is even bigger, as it more than doubles investment, exports and imports.

Cumulative percentage point difference compared to BAU 2011-2020	**S1**	**S2**	**S3**
Household spending	0.15	0.07	0.27
Investment	1.30	0.68	2.93
Exports	0.21	0.10	0.45
Imports	0.21	0.10	0.48

[93] Increases in GDP vary significantly between Member States depending on the level of investment taking place in each of them and can be superior to 1% in 2020 for smaller countries.

[94] As the model does not take into account the different impact loops of infrastructure investment on gas and electricity prices, changes in inflation and sectoral prices are close to zero for all policy sets. No distributional impacts appear, i.e. no differentiated impact according to different income levels.

Table 5: Impacts on other macroeconomic parameters 2020 (E3ME model results)

It must be pointed out that due to the complexity of possible interactions between energy infrastructure investment and energy prices the analysis of their correlation at the macroeconomic level was only indicative and limited to gas. The model confirms that gas prices would decrease gradually over time compared to BAU as new interconnection capacities come on stream, which in turn would have a positive effect on GDP outweighing the additional investment cost. Concerning electricity, it was assumed that there would be no direct knock-on effects on prices (through increased and smoother supply) from new interconnection investments[95]. Given the positive price impact of the various policy options described in chapter 5, it can therefore be assumed that the model gives conservative estimates of the benefits provided by the different policy sets as compared to BAU.

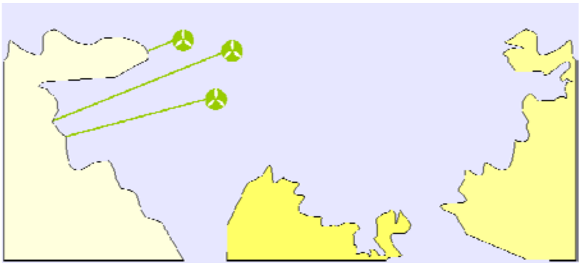
[95] Additional cross-border flows typically only occur at times of peak electricity demand and may be in both directions, making it difficult to estimate changes on the average annual electricity prices used in the model.

ANNEX 4: DESIGN OPTIONS FOR AN INTEGRATED OFFSHORE GRID

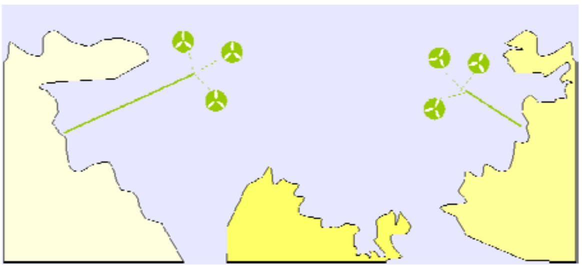
Various design options are currently studied for developing offshore grids (see graphs below). The OffshoreGrid[96] study suggests that radial grid connections in general make sense up to 50 km distance from their connection points onshore. For larger distances (in the range of 50-150 km) from shore, the concentration of wind farms is a determining factor for the benefits of clustering. Above 150 km distance, offshore grid hubs are considered as typical solutions. In countries where such hubs can easily be defined, the connection costs of offshore wind farms could be reduced by up to 34%[97]. The OffshoreGrid study has calculated that, assuming strong offshore wind development, the cost reduction for the North Sea area as a whole could be around 17% by 2030[98].

Regarding integrated "wind farm connection and interconnector" solutions, these are beneficial in terms of infrastructure investments, as there is always a cost reduction. However, the cost savings have to be compared to the increased system costs that are the result of the constraints for electricity trading, which underlines the need for coordinated approaches involving developers, regulators and TSOs to identify optimal solutions.

Currently available designs

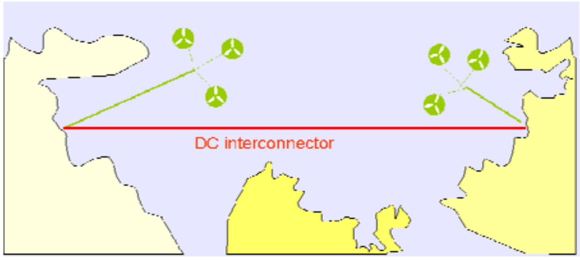


Radial connection using alternating (AC) or direct current (DC) technology



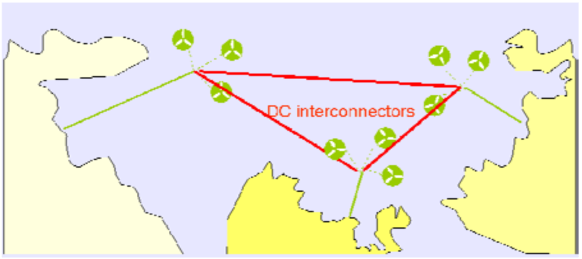
Radial AC or DC connection of clustered offshore wind power plants

[96] Financed by the Intelligent Energy Europe (IEE) programme has made a quantitative assessment of the costs and benefits of different design options in order to identify how much anticipatory investment would be needed while avoiding stranded costs. More information can be found at: www.offshoregrid.eu
[97] Cost reduction calculated for Germany.
[98] According to the OffshoreGrid study, offshore grid infrastructure development would cost 32 billion euros until 2020 and 90 billion euros until 2030 considering radial connections. Clustering offshore wind farms at offshore hubs could reduce this investment need by 15 bn € between 2020 and 2030. Further investment need reductions could be gained by clustering wind farms before 2020 and by integrating wind farm hubs with interconnectors. According to the case study about the Great Britain / Norway / continental Europe area, an integrated solution could require 70-80% less grid investment, but would present constraints for the use of interconnectors between countries. However the net benefits are estimated to be significantly higher in this geographic area.



Radial AC or DC connection of wind park clusters with point-to-point international interconnector

Target design



Meshed international offshore grid based on multi-terminal scheme

Source: ENTSO-E / OffshoreGrid study

ANNEX 5: INPUT DOCUMENTS

This impact assessment builds on the following general inputs:

- Current framework for Trans-European Energy Networks (TEN-E)[99] and its impact assessment[100]
- Green Paper "Towards a secure, sustainable and competitive European Energy Network"[101] and its public consultation[102] in the period November 2008 – March 2009.
- Implementation Report[103] on the TEN-E guidelines and TEN-E financial regulation
- European Energy Plan for Recovery[104]
- Priority Interconnection Plan 2007[105]
- Third internal energy market package[106]
- Climate and Energy package[107]
- Directive 2009/28/EC on renewables energies[108] and National Renewable Energy Action Plans[109]
- Directive 2009/31/EC on the geological storage of CO2
- Directive 2008/114/EC on the identification and designation of European critical infrastructures and the assessment of the need to improve their protection
- Regulation concerning measures to safeguard security of gas supply and repealing Directive 2004/67/EC, impact assessment and accompanying documents[110]
- Communication on Offshore Wind Energy[111]
- Political Declaration of the North Seas Countries Offshore Grid Initiative[112]
- Declaration of the Budapest V4+ Energy Security Summit 24 February, 2010[113]

[99] Decision 1364/2006/EC and Regulation 680/2007 of the European Parliament and of the Council
[100] SEC(2003) 742
[101] COM(2008) 781
[102] http://ec.europa.eu/energy/strategies/consultations/2009_03_31_gp_energy_en.htm
[103] COM(2010)203 and SEC(2010)505
[104] Regulation (EC) N°663/2009 of the European Parliament and of the Council of 13 July 2009 establishing a programme to aid economic recovery by granting Union financial assistance to projects in the field of energy (OJ L 200, 31.7.2009)
[105] COM(2006) 846 final/2
[106] http://ec.europa.eu/energy/gas_electricity/third_legislative_package_en.htm: see notably Directives 2009/72/EC and 2009/73/EC and Regulations (EC) 713/2009, 714/2009 and 715/2009
[107] OJ L140 of 5.06.2009
[108] Directive 2009/28/EC OJ L140 of 5.06.2009 p. 16
[109] Available at: http://ec.europa.eu/energy/renewables/transparency_platform/transparency_platform_en.htm
[110] COM(2009) 363, SEC(2009) 979, SEC(2009) 977
[111] COM(2008) 768
[112] http://www.benelux.be/pdf/pdf_fr/act/act0170_NorthSeasCountriesOffshoreGridInitiativePoliticalDeclaration.pdf
[113] http://visegradgroup.eu/main.php?folderID=859&articleID=27720&ctag=articlelist&iid=1

The impact assessment also builds on the results of the following studies:

1. *General studies*

- *EU Energy Trends to 2030: Update 2009* (Baseline 2009 and Reference scenario 2009)
- *World Energy Outlook 2009*. IEA
- "The revision of the trans-European energy network policy (TEN-E)", impact assessment study by COWI, Cambridge Econometrics and KEMA for the European Commission. October 2010
- "Energy Infrastructure Costs and Investments between 1996 and 2013 (medium-term) and further to 2023 (long-term) on the Trans-European Energy Network and its Connection to Neighbouring Regions with emphasis on investments on renewable energy sources and their integration into the Trans-European energy networks, including an Inventory of the Technical Status of the European Energy-Network for the Year 2003" (TEN-Energy-Invest), study by Centro Elettrotecnico Sperimentale Italiano, Instituto de Investigación Tecnológica, Mercados Energeticos and Ramboll for the European Commission. October 2005

2. *Studies concerning fossil fuels*

- Ten Year Network Development Plan by ENTSOG[114]
- "Methodologies for Gas Transmission Tariffs and Balancing Fees in Europe", study by KEMA. December 2009
- "Feasibility of Europe-wide CO2 infrastructures", study by Arup for the European Commission. To be published by end 2010
- "Evolution of size and cost of a trans-European CO2 pipeline network", study by the Joint Research Centre (JRC) of the European Commission. 2010
- "Technical aspects of variable use of oil pipelines coming into the EU from third countries", feasibility study by ILF and Purvin & Gertz for the European Commission (expected to be completed by autumn 2010)
- "Model-based Analysis of Infrastructure Projects and Market Integration in Europe with Special Focus on Security of Supply Scenarios", study by EWI Institute of Energy Economics at the University of Cologne. May 2010
- "Study on natural gas storage in the EU", study by Ramboll Oil and Gas. October 2008

3. *Studies concerning the power sector*

- Ten-Year Network Development Plan, ENTSO-E. 2010[115]
- "2009 Technology Map of the European Strategic Energy Technology Plan (SET-Plan) – Part I: Technology Descriptions", Chapter 12, JRC-SETIS Work Group. 2009
- "The European Electricity Grid Initiative (EEGI): Roadmap 2010-2018 and Detailed Implementation Plan 2010-2012", ENTSO-E and EDSO. 25 May 2010
- *System Adequacy Forecast 2010-2025*, ENTSO-E. 2009
- *Power Choices*, Eurelectric. 2009

[114] http://www.entsog.eu/download/investment/ENTSOG_TYNDR_MAIN_23dec2009___.pdf
[115] https://www.entsoe.eu/fileadmin/user_upload/_library/SDC/TYNDP/TYNDP-final_document.pdf

- *Roadmap 2050: A Practical Guide to a Prosperous, Low-Carbon Europe*, European Climate Foundation. 2010
- *Renewables 24/7: Infrastructure Needed to Save the Climate*, Greenpeace/EREC. 2009
- *Transforming Europe's Electricity Supply*, EASAC. 2009
- OffshoreGrid study[116], consortium coordinated by 3E. July 2010
- *European Wind Integration Study (EWIS)*, final report. March 2010
- *Pure Power: Wind energy targets for 2020 and 2030*[117], EWEA, December 2009
- *Oceans of Opportunity*, report on offshore wind energy[118], EWEA, September 2009
- Reports produced under SUSPLAN, REALISEGRID and IRENE 40 projects financed under FP7. Forthcoming
- "Influence of National and Company Interests on European Electricity Transmission Investments". Study by Matti Supponen, Helsinki University of Technology. Draft version dated 1 August 2010

4. Studies concerning smart grids

- "Impacts of Information and Communication Technologies on Energy Efficiency"[119], Bio Intelligence Service Final Report, September 2008. Supported by the European Commission DG INFSO
- "Smart 2020: Enabling the low carbon economy in the information age"[120] by The Climate Group on behalf of the Global eSustainability Initiative (GeSI)
- "The Green Grid: Energy savings and carbon emissions reductions enabled by a smart grid", Electric Power Research Institute (EPRI), Palo Alto, California, United States, June 2008 http://www.smartgridnews.com/artman/uploads/1/SGNR_2009_EPRI_Green_Grid_June_2008.pdf
- Findings of the High-Level Advisory Group on ICT for Smart Electricity Distribution Networks: "ICT for a low carbon Economy – Smart Electricity Distribution Networks", July 2009. Supported by the European Commission, DG for Information Society and Media http://ec.europa.eu/information_society/activities/sustainable_growth/docs/sb_publications/pub_smart_edn_web.pdf
- "Electricity Storage: Making Large-Scale Adoption of Wind and Solar Energies a Reality". Cornelius Piper, Holger Rubel, Boston Consulting Group. March 2010

[116] Deliverables are available at: www.offshoregrid.eu
[117] http://www.ewea.org/fileadmin/ewea_documents/documents/publications/reports/Pure_Power_Full_Report.pdf
[118] http://www.ewea.org/fileadmin/ewea_documents/documents/publications/reports/Offshore_Report_2009.pdf
[119] http://cordis.europa.eu/fp7/ict/sustainable-growth/studies_en.html
[120] http://www.smart2020.org/_assets/files/02_Smart2020Report.pdf

Energising Europe

A new energy infrastructure for a 21st Century Europe

Europe's energy networks are in need of refurbishment and modernisation. The enlarged European Union (EU) has inherited poor west-east and north-south connections and the focus has been on national markets rather than balancing supply and trade across borders in a single internal market. For a truly European system we need to make sure energy from renewable sources can be absorbed into networks and that supplies are secure wherever you live. The European Commission has therefore tabled a new initiative to develop an integrated European energy network fit for today's challenges.

The binding targets set by the EU's Energy Policy for Europe and the challenges outlined above can only be met by the complete modernisation of our energy infrastructure. This means implementing supply corridors across the EU, turning networks into intelligent grids and ensuring supply of gas when and wherever needed.

Building an energy infrastructure that is fit for purpose

In its Communication 'Energy infrastructure priorities for 2020 and beyond – A Blueprint for an integrated European energy network', the Commission puts forward a new way of getting the infrastructure we need, by identifying the key projects of European interest, obtaining EU wide agreement for these projects and making sure that they are built with the same level of commitment in all Member States involved.

20-20-20 – the Energy Policy for Europe

This policy states that by 2020 renewable sources have to contribute 20% to our final energy consumption, greenhouse gas emissions have to be reduced by 20% and energy efficiency gains should deliver a 20% reduction in energy consumption.

Directorate-General for Energy
EUROPEAN COMMISSION

THE COMMISSION SETS OUT **A SERIES OF ENERGY INFRASTRUCTURE PRIORITIES** FOR 2020 AND BEYOND.

ADDRESSING THE 2020 ENERGY POLICY CHALLENGES

To make our electricity grid fit for 2020 by establishing:

- Offshore grids in the Northern Seas and connections to Central Europe – from production capacity in the Northern Seas to centres of consumption in Central Europe.
- Connections of renewables in South Western Europe.
- Connections in Central Eastern and South Eastern Europe – to assist market and renewables integration.
- The Baltic Energy Market Interconnection Plan (BEMIP) – to integrate the Baltic States within the European market, strengthening interconnections with Finland, Sweden and Poland, and to reinforce the Polish grid and interconnections east and westward.

To diversify gas supplies through an integrated network by implementing:

- The Southern corridor – to diversify sources and bring gas in from the Caspian Basin, Central Asia and the Middle East.
- The BEMIP and the North-South corridor in Central Eastern and South Eastern Europe – to link the Baltic, Black, Adriatic and Aegean Seas.
- The North-South connections in Western Europe.

To ensure the security of oil supply by:

- Reinforcing the interoperability of the Central Eastern European pipeline network – to remove bottlenecks, enable reverse flows and ensure uninterrupted crude oil supplies to landlocked EU countries and take pressure off transportation by tankers in the Baltic Sea and Turkish Straits.

To roll out smart grid technologies by:

- Providing the necessary framework and incentives for rapid investment in an intelligent network infrastructure – to give real choices for savings, efficiency, and integration of renewables, and accommodate new demand such as electric vehicles.

PREPARING THE LONGER TERM NETWORKS

Over the longer term, in order to drastically reduce greenhouse gas emissions, the EU has to start now to design, plan and build the networks of the future. The Commission therefore also sets out priorities for longer term networks.

To establish European Electricity Highways by:

- Establishing a modular development plan – to allow the commissioning of the first Electricity Highways by 2020 which will accommodate rapidly increasing renewables generation in the EU and neighbouring countries.

To establish a CO_2 transport network by:

- Examining and agreeing on the technical and practical modalities of a CO_2 transport network – to build on the results of the European Industrial Initiative for CO_2 capture and storage launched under the SET-Plan.

How best to turn the priorities into reality

First identify the projects...

Agreed and transparent criteria are the key to finding and supporting the projects that will make these priorities a reality on the ground.

Projects shall be examined according to these criteria to ensure consistency across the EU and ranked by levels of urgency. Those meeting best these criteria would be awarded the label of Project of European Interest.

Then help them get off the ground...

Dedicated regional platforms should identify concrete projects, draw up investment plans and monitor their implementation, as this method is now being demonstrated by the North Seas Countries' Offshore Grid Initiative (NSCOGI) and the Baltic Energy Market Interconnection Plan (BEMIP) initiative.

Faster and more transparent permitting procedures are vital to enable the implementation of the Projects of European Interest which are needed to meet our climate and energy objectives. This will be done by maintaining the high standards of environmental protection and better involving the public in the decision-making process.

> Current permitting procedures are a barrier to implementation. A power line can take 15 years from planning to operation. Such delays jeopardise a large part of the investments needed by 2020.

Finally, support them by…

Leveraging private financing sources through improved cost allocation via right tariff setting by the regulators, according to the 'user pays principle'.
Currently, tariff setting remains national and does not take into account wider European benefits, and very often it does not cover major technological changes such as the connection of offshore sources or wider reverse flow benefits of gas pipelines. In 2011, the Commission will take action with the regulators to address these shortcomings.

Optimising the leverage of public and private financing sources by mitigating investors' risks. This will be done on two fronts. Firstly, the EU will strengthen its partnership with international financial institutions, search for synergies within existing financial instruments and adapt them to the energy infrastructure sector. Secondly, the Commission will propose a new instrument which will combine financial mechanisms tailored towards the specific financial risks and needs faced by projects at the various stages of their development.

> About €200 billion must be invested in smart transmission networks and storage until 2020 in order to meet the energy and climate policy objectives. However, it is estimated that, mainly due to non-commercial benefits and high risks, only little over half of these would be completed by 2020, leaving a gap of €100 billion. If permitting issues are resolved, an estimated gap of €60 billion will remain. If we want to have the infrastructure built in time, we have to fill the gap, alleviate the constraints faced by investors and mitigate project risks.

The benefits

The Blueprint puts forward practical ways to meet the 20-20-20 energy and climate policy targets by making it easier for energy from renewable sources to get onto the grid and targeting CO_2 capture and storage issues.

Optimising for the benefits of all European citizens the multiple renewable sources of energy in Europe, drawing on the best water, wind and sun locations, requires an integrated European network.

Such a network will ensure secure supply of electricity and gas for all EU citizens at affordable prices, irrespective of the country they live in.

It will enable the EU to deliver a properly functioning internal market, with positive effects on the EU's competitiveness and the faster emergence of a low-carbon energy system.

Through the realisation of investments, new jobs will be created, with positive growth effects for the wider European economy.

It puts forward ways to move towards intelligent grids, which will facilitate transparency and enable consumers to control appliances at their homes to save energy, facilitate domestic generation and reduce cost. New technologies will also help to boost innovation and technological leadership of the European industry, including SMEs.

The Blueprint proposes a more transparent permitting process in which citizen feedback is welcomed and incorporated, in which administrations at national, regional and local levels have clear guidance on the procedures and deadlines to respect, and in which businesses benefit from less uncertainty and risk when realising their investments.

Industry will benefit from support to mitigate the risk of investment in cutting-edge technologies and through financial leveraging and political backing.

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EUROPEAN COMMISSION

Brussels, 17.11.2010
SEC(2010) 1398 final

COMMISSION STAFF WORKING PAPER

ON REFINING AND THE SUPPLY OF PETROLEUM PRODUCTS IN THE EU

Accompanying document to the

COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS

Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network

{COM(2010) 677 final}

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

1. Falling demand in petroleum products in the EU in the last few years at a time of stable levels of refining capacity has in turn affected refining margins, which in 2009 were at their lowest levels in the last 15 years.

2. The EU petroleum product market is a mature market. On top of long-lasting effects of the global financial and economic crisis, EU regulations to tighten fuel specifications, reduce emissions from refineries and cars as well as to provide support for the development of non-fossil fuels point towards a future of diminishing demand for petroleum-based products.

3. The demand for certain products, in particular middle distillates such as jet fuel, kerosene and gasoil, including marine gasoil, is however expected to continue to grow for a few more years. On the other hand, gasoline demand in the EU is widely expected to fall further.

4. In 2008, net imports of gasoil/diesel amounted to 20 million tonnes, equivalent to 6.9% of EU gasoil/diesel consumption while net exports of gasoline amount to 43 million tonnes, equivalent to 31% of EU gasoline production. If net imports of kerosene and jet fuels are taken into account, the EU shortfall in middle distillates amounts to upwards of 35 million tonnes of net imports per year.

5. In order to contain or reduce these trade deficits, the EU refining industry would have to invest significantly in additional refinery conversion capacity to produce more middle distillates, and it would have to reduce gasoline-focussed refinery capacity.

6. The additional units needed to produce increasing amounts of middle distillates are more energy intensive, and emit more CO2 than other types of units. The EU refining sector, which is included in the EU Emissions Trading Scheme, will therefore have to pay more for the CO2 emissions from (more complex) refineries producing more of the products which the EU requires (i.e.: middle distillates)

7. Overall, known planned/actual divestments and shutdowns in EU refining capacities since the start of the crisis in 2008 extend to 18 out of 104 refineries in the EU, representing some 134 million tonnes per year/2.7 million bbl/day of crude capacity, equivalent to 17% of total EU refining capacity. Only two of these facilities have been sold, others have been put up for sale for some time but have found no buyers, others yet have been shutdown for extended maintenance until market conditions recover. It is not known how many employees these 'vulnerable' refineries represent.

8. While the industry employs directly some 100,000 people in the EU, it is estimated that perhaps as much as 400,000 to 600,000 Europeans in total are directly dependent on the EU refining industry for their livelihood. This does not include other dependent industries, the largest of which, the petrochemical industry, employs 778,000 staff in the EU.

9. EU refining capacity upgrading is expected to lead to quite significant reductions in exports of (excess supply of) gasoline by 2030, while it is expected that the import dependence of the EU in gasoil/diesel will continue to increase by 2030.

10. Even under a scenario of increasing EU dependence in gasoil/diesel, the industry will be faced with necessary investments in European refining capacity upgrades in order to cope with further growth in demand for middle distillates (including as a result of changing sulphur fuel specifications for ships).

11. Depending on assumptions on the development of the crude diet in Europe between 2005 and 2030 and taking into account adopted and implemented EU policies, investments required to upgrade European refining capacities in that period could amount to between 17.8 and 29.3 billion Euros, of which between 3.3 and 11.7 billion Euros alone will account for future marine sulphur fuel specification changes to be transposed into EU regulation by the end of 2010.

12. It is estimated that the amount of investments that the refining industry in Europe has already committed to spending (in what it calls firm projects) between 2010 and 2020 is of the order of 13.3 billion Euros.

13. In spite of projections of declining demand for fossil fuels, processing intensity in refining will increase as a result of more stringent product specifications, in particular as a result of new IMO changes. One possible consequence is that refinery CO2 emissions will increase between 2005 and 2030, by around 6% (and increasing by 12% between 2005 and 2020), mainly as a direct result of the needs for hydrogen in refinery units geared towards producing higher proportions of new IMO compliant fuel.

14. Significant falls in the projected EU demand for transport gasoline by 2030 according to PRIMES (20.7% in the Reference scenario) point to the need for gasoline-focussed refinery plant restructuring, with up to a third of necessary capacity reductions, depending on the type of unit.

2. INTRODUCTION

In November 2008, the Commission announced in the Second Strategic Energy Review[1] (SER2) that a Communication on Refining Capacity and EU Oil Demand would be prepared in 2010. SER 2 focussed on energy security and, given the EU's dependence on oil imports and also on the exports and imports of petroleum products, highlighted both the need to improve the level of transparency of the demand-supply balance for refining capacity as well as concerns regarding the potential availability of diesel fuel in the future.

Since November 2008, the concern has shifted from being mainly one of security of supply to considering also how the EU refining industry's adaptation to a changing business environment is likely to impact the EU and on how EU policies to decrease the EU's dependence on fossil fuels will further add pressure on the EU refining sector. In light of these developments, it was decided that a factual study, in the form of a Staff Working Document, would be prepared instead of the Communication announced in SER2.

[1] COM(2008) 781.

This Document accompanies the Communication on the energy infrastructure priorities for 2020 and 2030 in which the continued contribution of oil to the EU energy mix and to the transport sector up to 2030 is underlined and where it is highlighted that the future shape of crude oil and petroleum product transport infrastructure will also be determined by developments in the European refining sector. In that context, the focus of this document is to provide some light specifically on the refining activity and the supply of petroleum products in the EU, and as such to highlight and explain key current and future challenges of the EU refining industry as well as to report some initial quantification of a number of those challenges in terms of the impacts by 2030 of PRIMES EU petroleum product demand projections. It also contains a detailed, factual account of the characteristics of the EU refining industry and some comparisons to other parts of the world in order to provide the necessary background and context for these challenges and impacts.

3. Overview of refining and the supply of petroleum products in the EU

3.1. Key facts on EU refining and trade in petroleum products

- In May 2010 there were 104 refineries operating in the European Union. The EU's crude refining capacity currently represents 778 million tonnes per year (or 15.5 million barrels per day), equivalent to 18% of total global capacity;
- The EU is the second largest producer of petroleum products in the world after the United States;
- There are refineries in 21 Member States with the exceptions of Cyprus, Estonia, Latvia, Luxembourg, Malta, and Slovenia;
- The global financial and economic crisis that began in 2008 has impacted margins in all regions of the world. If average annual margins are compared, North-West Europe has however fared rather better than other regions in comparison in the last three years;
- The average utilisation rate[2] in OECD Europe in 2009 amounted to 79%, compared to 85% the previous year. So far in 2010, utilisation rates averaged 76%, showing a continuing downward trend. This needs to be put in the context of previous utilisation rates for the EU close to 90% as recently as 2005;
- Looking at the evolution of the petroleum product demand mix in the EU, the share of jet fuel and kerosene has increased between 1990 and 2008 from representing 5.5% to 9.4%; the share of gasoil (including diesel but not heating oil) from 17.7% to 31%; the share of gasoline from 22.7% to 16.1% and the share of heavy fuel oil from 16.3% to 6.4%;
- The two key trade petroleum products in the EU in terms of volume have been gasoline and gasoil/diesel (include heating oil), gasoil/diesel being the main petroleum product imported into the EU while gasoline is the main product exported from the EU. The EU is also very import-dependent on jet fuel and kerosene;
- Russia is the biggest supplier of gasoil/diesel to the EU, followed by the United States, while the United States is the largest recipient of gasoline from the EU. In the case of kerosene/ jet fuels imports, the third largest traded product, the EU mainly relies on a number of Middle Eastern countries.

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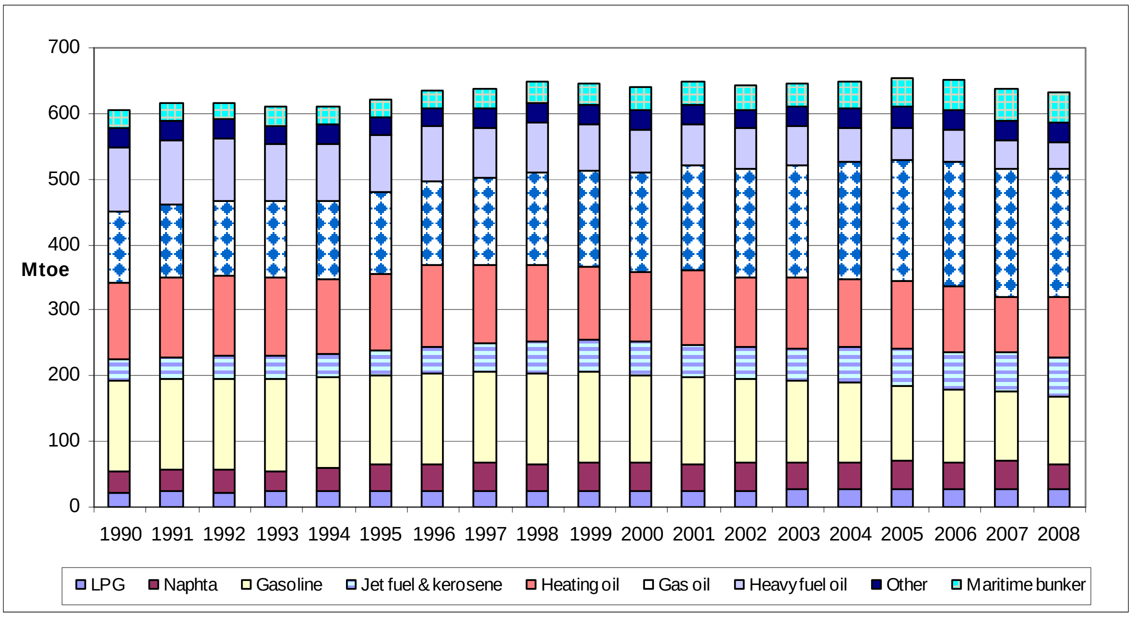
[2] Based on crude throughput as a proportion of operable refining capacity.

3.2. Current and future key challenges of the EU refining sector

3.2.1. The evolution of demand

It is widely considered that the EU petroleum product market is a mature market which has more than likely already hit its peak. Between 1990 and 2008, EU demand for petroleum products grew by an average of only 0.2% a year, recording its highest level in 2005 after which it fell every year, registering a 3% fall between 2005 and 2008.

EU 27 Petroleum product demand evolution, 1990-2008



Source: EUROSTAT/PRIMES

Analysing the progression of demand in individual petroleum products reveals very different trends. Between 1990 and 2008, jet fuel and kerosene consumption almost doubled; consumption in gasoil[3] registered a steady and sustained growth; demand for naphta registered an initial increase and then a fall; demand for gasoline and heating oil fell quite sharply, while demand for heavy fuel oil[4] fell significantly.

Projecting forward towards the short-to-medium term, what is relatively certain is that the fall in heavy fuel oil will continue, given the gradual eradication of the use of such products due to regulation on the specification of petroleum fuels towards cleaner, less polluting fuels.

With regard to the evolution of middle distillates[5], it is expected that heating oil should continue to fall as more efficient and environmentally friendly district heating systems continue to replace traditional oil burners. Gasoil evolution will depend on a number of variables, such as whether EU support to promote the wider use of non-fossil fuels is successful; whether tighter marine fuel specifications will lead to a broad switch from residual

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[3] Unless otherwise specified, gasoil refers to transport diesel fuel, of which over 90% is used in road transport.

[4] Heavy fuel oils other than bunker fuels are used in medium to large industrial plants and power stations in combustion equipment such as boilers and furnaces.

[5] Middle distillates include heating oil, diesel, kerosene and aviation/ jet fuel. Heating oil is mainly used in domestic heating, while diesel is used as a motor fuel and also as a fuel in agricultural vehicles, small boats and trains. Jet fuel and kerosene are used to power airplanes and kerosene is also sometimes used in domestic heating.

fuel to marine gasoil rather than desulphurised residual oil; and, to a lesser extent, whether the EU-wide tax differential between road diesel and gasoline[6] is maintained[7]. Kerosene/ jet fuel demand is however expected to continue to grow until large scale use of suitable renewable fuels in airplanes.

Equally, the direction of growth of the demand for light distillates (LPG, gasoline and naphta), will depend on a number of considerations. In particular, the development of demand for gasoline will depend on the growth and success of alternative fuel vehicles and energy taxation (as for gasoil), as well as developments in the penetration of sustainable, renewable fuels in the US (see section 3.2.2.) and gasoline engine efficiency.

Other than economic developments, the two factors most likely to impact future demand for petroleum products in the EU are the forthcoming revision of the Sulphur Content in Liquid Fuels Directive (SCLFD) to integrate tighter international regulations on the sulphur content of marine fuel[8] as well as recent legislation to reduce CO2 emissions from new cars and transport fuels[9].

The requirement to supply future marine fuel with a maximum sulphur content of 0.1% in the Baltic Sea and the North Sea & English Channel could amount to an increase in demand for middle distillates of around 15 million tonnes per year from 2015 (which represents close to 8% of EU gasoil demand in 2008).

This very much depends on how the new changes are dealt with. There is the possibility that ships will widely opt to continue using high sulphur fuel oil after having installed on-board scrubbers to remove sulphur from fuel oil.

Notwithstanding the fact that ship owners switching to gasoil will likely have to pay more for their fuel than if they continued to use fuel oil[10], a key advantage for ships from scrubbing is

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6 According to June 2010 figures from the Commission Oil Bulletin, while pre-tax consumer prices of premium unleaded gasoline are lower than for diesel in all but 1 of the EU 27 Member States (Malta), higher taxes and duties on gasoline means that the price of diesel is cheaper at the pump in 26 of the 27 EU Member States (with the exception of the United Kingdom). See more details in annex.

7 A future revision of the Energy Taxation Directive may address this differential, but even if it proposed changes which would lead to the disappearance of this differential across the EU, it would take a while to have an impact given 10 to 15 year replacement cycles for cars and given that most diesel is still used by commercial vehicles where the possibility to switch to gasoline is more limited.

8 The 2008 revised International Maritime Organisation MARPOL Annex VI regulation on sulphur restrictions in marine fuels provides for a shift to low sulphur fuel for maritime transport first within the European Emission Controlled Areas (the current fuel sulphur limit of marine fuels would be reduced from 1.5% to 1.0% by 2010 and then to 0.1% by 2015) and in a second phase, globally where the maximum permitted sulphur level would be reduced from 4.5% to 3.5% by 2012 and then to 0.5% by 2020 (with an alternative date of 2025 if suitable fuel is not available, to be decided by 2018). The European Emission Controlled Areas are the Baltic Sea and the North Sea & English Channel.

9 Adopted in April 2009 along with the climate and energy package, it requires reductions in the average fuel consumption of new cars, with binding targets of 130g/km (from 140g/km) by 2010 and 115g/km by 2020. The Fuel Quality Directive amended at the same time further tightens fuel specifications and introduces a requirement to lower life cycle GHG intensity of transport fuels by 6% by 2020.

10 The key deciding factor will probably be the eventual price of low sulphur marine fuels. According to Purvin & Gertz, bunker fuel for use in the emissions control areas would be expected to cost in the range of $250 to $300 per tonne more for the 0.1% maximum sulphur content quality than the 1.5% maximum sulphur content quality. This represents an increase in the cost of the fuel of 60% to 75%. They estimate that 0.5% maximum sulphur content bunker fuel is expected to cost in the range of $120 to $170 per tonne more than the current high sulphur quality. This represents an increase in the cost of bunker fuel in the range of 30% to 50%. Purvin & Gertz conclude that stack scrubbing is economically attractive for fuel cost price differentials well below $100 per tonne, and that stack scrubbing is likely to be very attractive economically compared to the price differentials above.

that it would allow them to meet sulphur cap requirements wherever the ship trades. There is however some scepticism on this option given that many ships have held back from making the necessary investments to prepare for compliance with the existing EU requirement in the SCLFD of the use of marine fuels used by ships on inland waterways and at berth in any EU ports containing no more than 0.1% of sulphur by January 2010[11].

While sulphur fuel specifications could represent a source of increasing demand for (marine) transport fuel from EU refiners, it is expected that CO2 emissions legislation will contribute to improved efficiency of vehicles such as through increased penetration of hybrid vehicles, thereby reducing the demand for transport fossil-fuels such as gasoil and gasoline. It is expected that this regulation will lead to a penetration of conventional hybrids equivalent to 27% of the total passenger fleet by 2030[12].

3.2.2. Demand & supply imbalance and dependence on trade

3.2.2.1. EU refining supply out of step with evolving demand

Two trends which have characterised the growth in demand for petroleum products in the EU since 1990 have been the continued, strong growth in middle distillates such as jet fuel and kerosene and gasoil on the one hand and the parallel strong falls in demand for gasoline on the other.

Between 1990 and 2008, demand for middle distillates (including heating oil) grew by 35% (and demand for jet fuel/kerosene and diesel increased by 82%), while demand for gasoline fell during that same period by 26%. In parallel, EU supply of middle distillates between 1990 and 2008 grew by 28%, while gasoline supply only fell by 4%.

These developments resulted in a supply/demand imbalance in the EU with regard to such products which has led it to be dependent on trade in order to balance out demand and supply.

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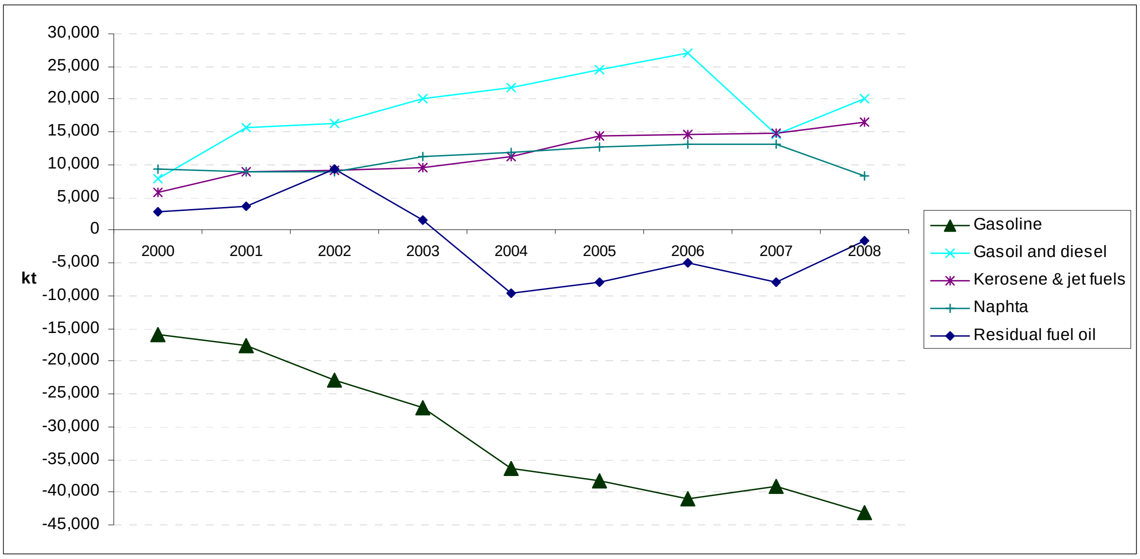
11 This led to a Recommendation by the Commission to Member States to request from ships that have failed compliance by that date to provide detailed evidence of the steps they are taking to ensure compliance, including a contract with a manufacturer and an approved retrofit plan to be completed by no later than 1st of September 2010.

12 As contained in the PRIMES Reference scenario.

Evolution of EU net imports in key petroleum products, 2000-2008



Source: EUROSTAT

By 2008, gasoil/diesel (including heating oil) was the main petroleum product imported into the EU, reaching 20 million tonnes of net imports, equivalent to 6.9% of EU gasoil/diesel consumption. In contrast, the main product exported from the EU was gasoline, with net exports of 43 million tonnes in 2008, equivalent to 31% of EU gasoline production.

With regard to gasoil/diesel imports, Russia is by far the largest supplier of the product into the EU, having exported 13.7 million tonnes of gasoil/diesel in 2008 to the EU. Though this amount only represents 4.8% of total EU demand of 288 million tonnes of gasoil/diesel for that year, it amounts to 35% of total gasoil/diesel imports. With regard to gasoline, the EU exported 18.7 million tonnes of excess gasoline to the US that same year, which was equivalent to 13.6% of EU gasoline production (of 137 million tonnes) and 37% of total EU gasoline exports in 2008.

If net imports of kerosene and jet fuels are taken into account, the EU shortfall in middle distillates amounts to upwards of 35 million tonnes of net imports per year, imports of kerosene and jet fuel coming mainly from several Middle Eastern countries.

3.2.2.2. Growing trade deficits

Should EU demand for middle distillates continue to grow (which is generally expected), and should the current structure of EU refining remain unchanged, it will mean processing more crude and obtaining more middle distillates but also more gasoline, thereby leading to a widening of the EU supply/demand imbalance for diesel and gasoline.

So far the US has served as a convenient outlet for excess EU gasoline but it is widely predicted to reduce its consumption of gasoline going forward. While the US vehicle stock will continue to be dominated by gasoline in the foreseeable future, it is suspected that the demand for it has already peaked as more efficient vehicles are produced and as the proportion of biofuels (mainly ethanol) progressively grows to represent a greater proportion of US vehicle fuel use[13].

13 In its Annual Energy Outlook 2009 reference case, the US Energy Information Administration projects falls in the growth of motor gasoline consumption in the US equivalent to -8.4% between 2010 and

But should there be other potential markets to which the EU could export its surplus gasoline production, keeping the status quo (in terms of refining capacity) could be an option for the industry. The most obvious markets are Africa and the Middle East as these are the closest to Europe and both are expected to experience growing demand in gasoline going forward. However future gasoline trade deficits in both these regions are likely to be well short of current EU gasoline export levels.

In terms of increasing imports of gasoil/diesel, while Russia has been a reliable source of supply to date, it could prove difficult for it to meet any substantial increases in EU demand for diesel imports given that Russian refinery capacity today remains at the same level as it was in the late 90's[14] and also taking into account relatively modest developments in capacity expected in the near future.

On the other hand, it can be expected that the situation which currently prevails in Russia which leads its refiners to process more crude than is required for domestic consumption in order to export the excess will remain in the foreseeable future. This situation is largely the result of the current tax regime which taxes crude exports more highly than product exports. Russian oil export tariffs on light oil products are typically 70% of export tariffs on crude oil, and export tariffs on heavy oil products represent only around 40% of crude export tariffs[15]. Thus it can be expected that Russia will continue to run a trade surplus in diesel in the forthcoming years.

Other countries like China, India or Saudi Arabia have greatly expanded diesel capacity in recent years and could be relied upon to supply the EU market (with the farthest locations still being open to debate, as mentioned in the global competition section). This being said, demand for diesel is expected to grow significantly across the globe, with the Asia Pacific region in particular foreseen to be running a large diesel deficit going forward as diesel experiences the fastest growing demand of refined products in the region. And while North America is currently the second biggest supplier of diesel to the EU, running a surplus in diesel capacity of upwards of 30 million tonnes, it is expected that it will run only a slight diesel surplus from 2015 as it becomes the fastest growing refined product in demand there, reflecting increasing volumes of road freight and some dieselisation of the private car fleet[16].

In conclusion, should the refining industry opt for the status quo in an environment of growing demand for middle distillates, the EU's import deficit in middle distillates will extend further. This is not only a problem for the EU in terms of growing import dependence for such products, it is also a problem for the EU refining industry in terms of growing pressures to

2020 and -5.2% between 2020 and 2030 (equivalent to a fall of -13.1% between 2010 and 2030). Upcoming emission standards as well as the passing of the 2007 US Energy Independence and Security Act which promotes the use of biogasoline represent key influences on future US demand for gasoline. In addition, the Obama administration has brought forward a requirement for better vehicle fuel consumption. By 2011, the Corporate Average Fuel Economy requirement on car-manufacturers will shift from an average consumption of 27.3 miles per gallon from the current requirement of 35.5 miles per gallon.

14 According to Russian oil refining capacities contained in the BP Statistical Review of World Energy 2009. Note however that in his report to the State Duma on the 2nd of December 2009, the Russian Energy Minister announced that between 1.2 to 1.4 trillion roubles (32 billions Euros) would be invested into upgraded refinery capacity in Russia.

15 The Russian Ministry of Economic Development has recently prepared amendments to customs tariffs which provides for more equal export tariffs for light and heavy products.

16 Projections by Wood Mackenzie, as part of its work evaluating the impact of biofuels on the EU refining industry for the European Commission.

export excess gasoline supply to other markets, which is not evident given expected future developments in world demand for gasoline and diesel.

3.2.3. Supply challenges

3.2.3.1. Falling productions of North Sea Crude and variations in crude quality

North-Sea crude production (from Norway, UK, Denmark) fell from 6.4 to 4.3 million barrels per day between 2000 and 2008. Over the same period, the supplies to Europe of heavier, sourer/more sulphurous, crudes from Russia and Africa have been growing. The result has been an increase in the proportion of heavy and sulphurous crudes coming into EU refineries, as well as a higher dependence on oil imports from third-party countries which represented 80% of EU crude refinery intake in 2008 against 75% in 2000.

The impact on the EU refining industry of lighter crude being replaced by heavier crude has varied according to region, with North-Western European (NWE) refineries being especially concerned[17]. Conversely, in Central Europe, refineries are often located on the Druzhba pipeline, and the great majority of their intake is Urals crude. In the Mediterranean area, the larger proportion is Arabian Gulf, which is again heavier than Urals crude, with similar API[18] but higher sulphur content, followed by Urals crude.

Falling productions of North-Sea crude in an environment of growing demand for lighter distillates represents a major concern for the NWE refining industry. Lighter crude oils such as North-Sea crude produce a higher share of more valuable, light products that can be recovered with simple distillation, while heavier crude oils produce a greater share of lower-valued products (such as fuel oil) with simple distillation and therefore require additional processing to produce higher value products.

North-Sea crudes have an additional attractive property, in having low sulphur content. Higher sulphur crudes are naturally less valuable in an environment of lower sulphur fuel specifications, such as in the EU. In addition, the impurities in heavy, high sulphur crudes, such as nitrogen and metal, generally increase as the crude becomes heavier and further increase the processing severity required to convert the heavy crudes to light products.

The quality of crude oil thus dictates the level of processing and re-processing to achieve the optimal mix of product output, with a trend towards heavier and more sulphurous crudes leading to a more complex, and costlier, refining process, such as via the use of deep conversion and/or desulphurization units, also leading to higher CO2 emissions.

Going forward, it isn't clear how Europe will be affected by the changing global crude diet. In the short term, according to the IEA, the average crude density may slightly lighten with a marginal decrease in the sulphur content until 2014 mainly due to the impact of growing condensate[19] volumes produced by OPEC countries. Lighter supplies from Russia, Africa and the Middle East are also expected to increase according to the IEA, partly offset by expected Canadian crude mix, where new production from heavy oil sands is mostly sour.

In the longer run, it is expected that NWE crude intake from the Urals, the Caspian region and the Middle East will gradually come to represent growing proportions. This trend may

[17] Nearly 100% of the crude refinery intake in Ireland and Denmark is North-Sea originated, followed by the UK (80%), Sweden (57%), Germany (27%), France (21%), Finland (17%), the Netherlands and Belgium (14%).

[18] API expresses a crude's relative density, with the higher the API gravity, the lighter the crude.

[19] Condensate is a very light, liquid hydrocarbon stream that is recovered from the processing of gas and the gas from oil reservoirs and can be regarded as almost identical to a light sweet crude.

become a key challenge for refiners in that region, pushing them towards investments for the adaptation of their plants in order to refine the changing flow of crude.

3.2.3.2. Adapting supply to regulation

The impact of biofuels[20]

In the EU, it is expected that much or all of the growth in motor-fuel supply, which represents the biggest use of processed crude oil, will be in biofuels in the next twenty years.

A key driver of the supply of biofuels in the EU will be the Renewable Energy Directive which sets a 10% target for the use of renewable energy in the transport sector by 2020, the majority of which is expected to be contributed from biofuels, which have to meet certain specific sustainability criteria.

The increasing use of biofuels will have an impact on EU refiners in terms of a reduced need for the supply of conventional fossil transport fuels. In the case of biodiesel, it has the potential to reduce the growing pressure on the need for diesel..

On the other hand, increasing the share of biogasoline blendstocks such as ethanol in the European gasoline pool could reduce further the market for refinery-produced gasoline, which would be problematic to refiners given that there is already an excess of gasoline-producing refinery capacity in Europe, as noted earlier.

Tightening marine sulphur fuel restrictions & increasing supply of middle distillates

The future marine sulphur fuel specification requirements mentioned above are likely to pose difficulties to the industry in supplying the resulting demand. While supplying 1% sulphur fuel should not pose significant problems for refiners – blends can simply be modified to redistribute the higher sulphur components - the real challenge will be the changes to 0.1% sulphur content and 0.5% respectively for the ECAs and the rest of the world, as these will likely require the conversion of bunker fuels to diesel[21]. This will require investment in desulphurisation or conversion capacities.

However, the production of additional gasoil, whether for the marine sector or in order to meet current EU demand, poses an additional problem for the EU refining sector as it implies further cracking/breaking up of the heavier remaining products. Complex refineries are more energy intensive, and emit more CO2 than simple refineries. Every additional cracking process and every additional desulphurisation step needs energy and thus increases CO2 emissions. Thus, increasing gasoil production in the context of ever tighter sulphur specifications will lead to an increase in CO2 emissions by the EU refining sector[22].

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20 A detailed analysis of the impact of the use of biofuels on EU oil refining will be published by the European Commission in the Autumn of 2010.

21 Current technology cannot achieve reductions in the sulphur content of residues to 0.1% unless a very low sulphur feed is used. If it was possible, it is questionable whether refiners would not rather prefer to focus instead on converting residual fuel to other lighter, more valuable fuels, and decide to stop supplying the bunker market altogether.

22 2009 estimates of the costs of changes in marine sulphur fuel specifications by Purvin & Gertz for the European Commission, are for 7 million tonnes per year of extra carbon dioxide emissions by 2015 (due to changes to 0.1% sulphur content), representing an increase of 5% versus Baseline carbon dioxide emissions of 142 million tonnes in 2015. Including the change to 0.5% globally, total increases in CO_2 emissions by 2020 could reach 11.8 million tonnes per year.

The EU refining sector, which will be required either to purchase permits to emit CO2 or to improve the CO2 emission efficiency of its plants[23], will therefore have to pay more for the CO2 emissions from (more complex) refineries producing the products which the EU requires (i.e: middle distillates). For the same reason, careful consideration of the impact on refineries needs to be given when designing the implementation measures to reduce fuel life cycle Green House Gas (GHG) emissions (contained in the Fuel Quality Directive).

This leaves the EU with the dilemma of on the one hand becoming more heavily reliant on imports of petroleum products into the EU or on the other hand, hoping that the EU industry will produce more of the required products, even if (all else being equal) it means emitting more CO2, and therefore having to pay for it.

The future price of carbon in the ETS scheme is therefore a crucial issue to the industry and to the EU, as the higher it is, the more the risk that it exceeds the freight costs that an importer of refined products such as diesel would incur from shipping the product from abroad, with no overall benefit in terms of CO2 emissions.

According to the refining industry, it would have to buy about 25% of its allowances to maintain activity which, inclusive of the additional costs of CO2 in purchased electricity, should cost the sector over 1 billion Euros a year based on a price of 30 Euros per ton[24].

3.2.4. The profitability of the EU refining industry

Falling demand for petroleum products at a time of stable levels of capacity have in turn significantly affected refining margins[25]. The impact of the recent crisis on refining margins has been particularly significant, as the chart below shows, with both simple (hydroskimming) and complex (cracking) margins hitting 15 year lows in 2009.

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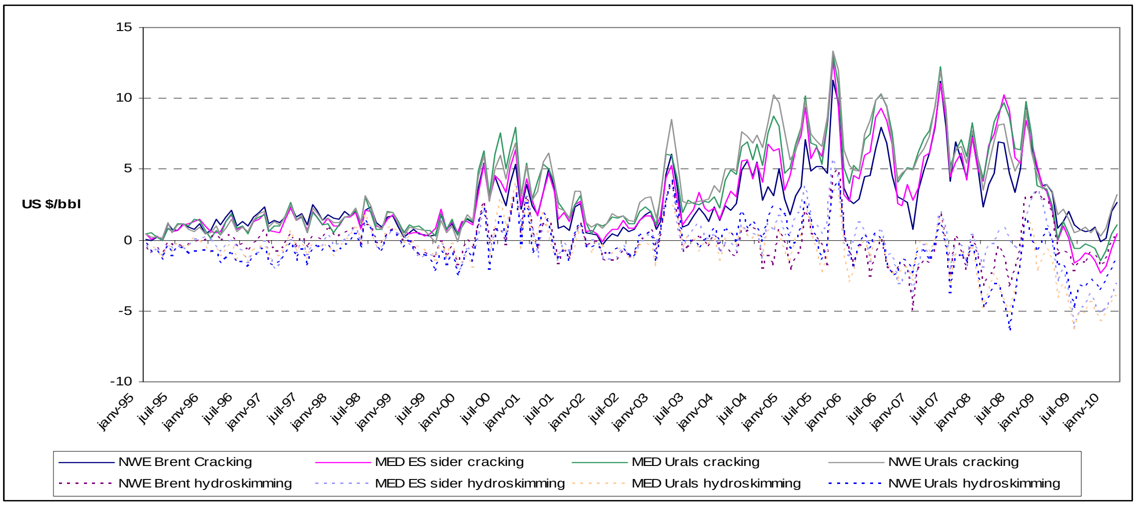
[23] As the EU refining industry is included in the EU Emissions Trading Scheme (the ETS). Note that the EU refinery industry has been recognised as being at risk of carbon leakage, on the grounds that crude oil and derived products are moved around the world in a very open market in which there is complete exposure to worldwide competition, which will allow the industry to obtain free permits for the first two years of the third phase of the EU emissions trading scheme (2013-2014). Free allowances will in principle be allocated based on product-specific benchmarks for each relevant product. The starting point for the benchmarks is the average of the 10% most efficient installations, in terms of greenhouse gases, in a sector or sub-sector in the Community in the years 2007-2008. The use of such benchmarks is to ensure that the allocation takes place in a manner that gives incentives for reductions in greenhouse gas emissions and energy efficiency efficient techniques. Furthermore, given that the benchmarks will be stringent, only the most efficient installations will have any chance of receiving all of their needed allowances for free.

[24] It is however worth noting that the carbon price in the EU Emissions Trading Scheme has been trading at prices much below 30 Euros per ton, a combination of the crisis, higher than expected energy prices and the build up of considerable buffer of unused freely allocated allowances, which can be carried over into phase three (2013-2020) of the ETS. The ETS carbon price in the PRIMES Reference scenario in 2030 is 19 Euros per tonne of CO_2, much lower than the PRIMES Baseline (of 39 Euros) due to the achievement of the renewables targets and additional efficiency measures, which decrease electricity demand and emissions.

[25] The refinery margin is the profitability that results from processing a barrel of crude oil. It reflects the difference between the market value of the combination of products produced by the refinery and the cost of buying the crude at market price as well as the operating costs incurred in the refining process.

Refining margins for simple and complex refiners Jan 1995 – Feb 2010



Source: IEA

Going forward, there are divergent views on when the sector will experience a recovery in margins, and to what extent. While acknowledging a recovery in margins at the start of 2010 due to a drawdown in oil product inventories and recovering demand, the IEA[26] predicts that the construction of refineries globally over the past two years and a massive contraction in oil consumption during the recession have led to a glut of capacity at the global level. It thus maintains a bearish short-term outlook for the industry globally.

Looking further ahead, the combination of the prospect of increasing demand for middle distillates – including widespread global dieselisation (as mentioned above) – with consequent increases in low-sulphur fuel/middle distillates[27] prices as well as rising crude prices[28] lend support for a recovery in complex margins in the coming years in the EU[29].

3.2.5. Global competition coming to the EU

Asia and the Middle East have been building new, larger, more cost effective and generally more complex refining units in recent years, such that they are becoming key players in global refining markets.

In spite of the crisis, Asia and the Middle East have added 1.6 million bbl/day of new crude distillation capacity in 2009, and at least a further 600,000 b/day is expected in 2010. In terms of expected refining projects in the next five years, the two regions combined will add nearly three quarters of all additional capacity in the world (see annex 5 for more details).

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26 January 2010 Oil Market Report.

27 According to Purvin & Gertz, tightening sulphur marine fuel sulphur specifications would lead to increases in the prices of bunker fuels of between 30% and 75% in the Emission Controlled Areas by 2015.

28 Hydrocracking margins tend to be highest when crude prices are high and there is a wide price difference between light and heavy crudes, as hydrocrackers can take lowest-cost heavy crude and sell products into a high price market.

29 As part of its work evaluating the impact of biofuels on the EU refining industry for the European Commission, Wood Mackenzie presented projected NWE Urals cracking margins (more relevant going forward than Brent cracking margins) to reach \$3.45/bbl in 2010 compared to \$2.62/bbl 2009 and \$4.62/bbl in 2008. According to the consultant, margins should continue to rise slowly, reaching levels of \$5.13/bbl in real (2010) terms by 2015.

Given the closeness of the region to Europe, expectations are that the Middle East will likely become a key provider of refined products, especially of middle distillates, to Europe. European imports of kerosene and jet fuels already mainly originate from that region. The region is currently planning some 1.7 million bbl/day of additional capacity which is expected to come on stream by or around 2015. New projects include several large export-focussed refineries which are being co-financed by European-based oil majors such as Shell and Total.

For some, the idea of even importing refined products from places as far from Europe as Asia is not far-fetched, with the view that operators of large refineries there could prove able to deliver products to the EU at prices competitive with home production[30]. While this may be true, the extra freight and logistics costs of importing from such distant places could mean that the price of end-products will rise, to the disadvantage of end-users. Admittedly, freight and logistics costs could also go down going forward, should the size of vessels employed to import refined products increase[31].

In practice, Asian oil firms are already eyeing the EU market. India's Essar has been expanding its home refinery at Vadinar with the aim to export to Europe, and it has been negotiating with Shell for a number of months on the acquisition of three of its Europe-based refineries (Stanlow in the UK and Heide and Hamburg-Harburg in Germany) with the intention to close these refineries and turn them into import terminals. PetroChina has also been in talks with Ineos over an investment in its Grangemouth refinery in Scotland.

Additionally, state subsidies are supporting some refineries in such countries, with the example of Chinese refiners which have been running record high throughputs in 2009 due in part to guaranteed margins. For instance Sinopec, a state-controlled refiner, is subsidising its refineries to export products, thereby encouraging them to maintain high throughputs[32].

The industry believes that with limited domestic demand for high-quality fuels, Indian and Middle Eastern refiners will seek to use the EU market as a temporary outlet for excess production until local markets grow sufficiently to absorb production. It warns that over time, the combination of domestic market growth and tightening product specifications could then see such players refocus on their domestic markets, with consequences for a more import-dependent Europe[33].

3.2.6. Investments in upgrading the EU refining sector: increasing middle distillates capacity

As mentioned previously, a growing trade gap is avoidable should EU refiners decide to invest heavily in upgrading existing capacities to make them more complex and thus able to skew the production mix towards more diesel and less gasoline.

According to the industry, in order to fill an annual gap in demand of 30 million tonnes of gasoil and jet fuel (in 2008, EU net imports of gasoil/diesel and kerosene/jet fuel amounted to 36.7 million tonnes), the EU refining sector would need to build about 20 large hydrocrackers at a cost of more than 8.5 billion Euros[34].

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30 View expressed in April 2010 article of the Petroleum Economist "Downstream depression".

31 Until now, logistics have favoured transporting crude rather than refined products as the transportation of crude is less costly, due to larger vessels being employed to transport crude, than refined products.

32 Oil Market Report, March 12 2010.

33 White Paper on EU refining, Europia, May 2010

34 Ibid, 33.

As was already highlighted, an additional 15 million tonnes per year of low sulphur gas oil/diesel is expected from marine sulphur fuel restrictions being lowered from 1% to 0.1% by 2015. Producing an additional 15 million tonnes of gasoil a year would require investment of more or less 4.5 billion Euros, representing 10 upgrading projects, according to the industry[35]. This would come on top of the 20 projects cited previously.

Taking also into account the further costs that would need to be incurred to meet the proposed MARPOL global specification changes from 3.5% currently to 0.5% sulphur content globally by 2020[36], additional costs associated with the full changes in sulphur fuel specifications could run into as much as 23 billion Euros by 2020 in the EU[37].

According to the industry, capital expenditure associated with previously announced projects to be built in the EU within the next six to eight years was in the order of 34 billion Euros. However, in a context of low refining margins, many of these projects may not be implemented and the latest estimate is that only some 14 billion Euros of investments might be spent improving the European refining system in the next six to eight years, again depending on economic conditions[38].

Good and stable economic conditions – ensuring high and stable margins - are important for investment in new refining and conversion capacity to occur, as a number of years can come to pass between the decision to build a refinery and the start of production. Yet as has been said before, though margins are trending upwards again, they are still low and there is some uncertainty as to how they will develop.

Even if prospects were more positive however, there would be no guarantee that the EU refining industry would make the necessary investments to meet the shortfall in the supply of middle distillates. Tightening fuel specifications as well as the demand focus on diesel are not new phenomena in Europe, and yet the industry has been slow to adapt. This is because until now, there has been a market for the excess gasoline produced by refining units in the EU, such that the industry could opt not to carry out all of the investments required for more hydrocracking units[39] to produce more middle distillates and deep conversion units such as cokers and residue cracking installations to produce low sulphur marine fuel.

Also, while the European refining industry has been faced with dramatic reductions in demand for fuel oil since the 1980's, at the same time the rapid development in North Sea

35 Ibid, 33.

36 Which would require an additional 100 hydrocracking projects globally in the next decade at a cost of 46 billion Euros (White Paper on EU refining, Europia, May 2010).

37 Estimates by Purvin & Gertz for the European Commission, 2009. These assume that 20 million tonnes of marine bunker fuel would need to be produced to a maximum of 0.1% sulphur content by 2015, rising to 24 million tonnes per year by 2020. Investments in delayed coking and hydrocracking are assumed to be needed to meet the new SECA specifications. In addition, middle distillate streams produced from delayed coking require additional hydrotreating before they can be used for the production of diesel or gasoil. Additional hydrogen plant capacity is also needed to produce hydrogen for the hydrocracking and hydrotreating units and sulphur recovery units are needed to handle the additional sulphur removed.

38 Historically, according to Europia (White Paper on Refining), European refiners have invested an average of around 5 billion Euros each year over the past 20 years in desulphurisation capacity of distillates and gasoline, the upgrading of production facilities and processes and the installation of emission abatement equipment and energy savings.

39 One alternative approach to dealing with increasing demand for diesel and falling demand for gasoline would be to implement changes to the catalytic-cracking process (rather than develop hydrocrackers), such that these units could process heavy residues into diesel. One example of a specialist heavy residue cat-cracker in existence is a unit at Shell's Pervis, Netherlands, refinery.

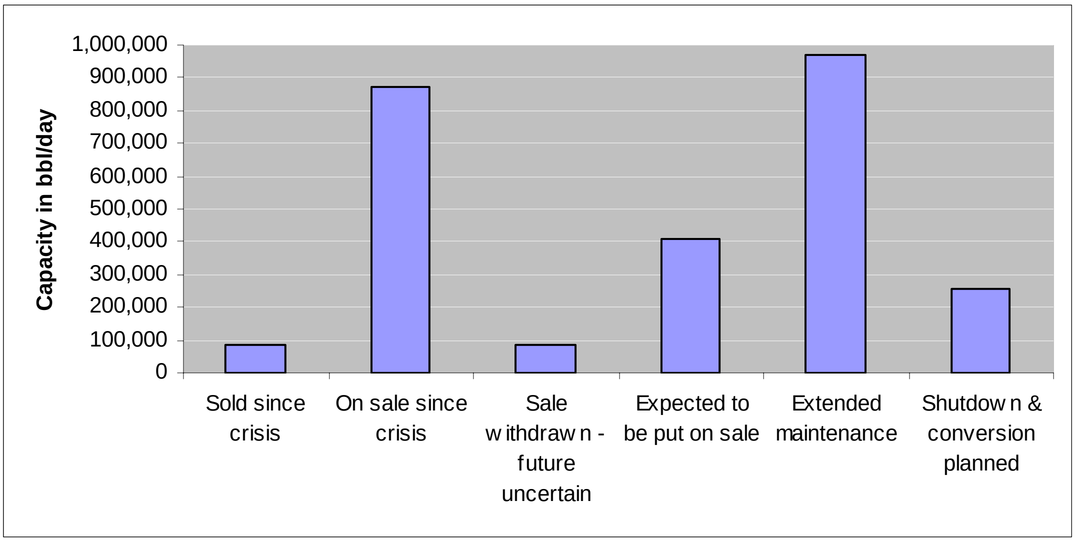
crude production, along with increasing demand for bunker fuel, allowed especially coast-based North Western EU refiners to avoid fuel oil conversion investments.

Last but not least, while the EU refining industry has suffered on a number of occasions in the past as a result of economic downturns and oil shocks, there have always been prospects of recovery and continued growth in demand which eventually did take place. In this instance, future EU demand prospects are bleak, especially if put in the context of growth prospects in other regions of the globe such as the Asia Pacific and the Middle East.

In conclusion, while there is a considerable need for further investments by the EU refining industry, and in the case of falling gasoline exports, a real incentive for the EU industry to invest, there are many developments which put together make such investments unlikely, not least the growing costs of refining in the EU, the falling supply of North-Sea crude and uncertain prospects in terms of refining margins.

3.2.7. Impacts of restructuring of the sector: reducing gasoline capacity

Summary of EU refineries planned/actual divestments and shutdowns since 2008



Source: European Commission. Note: This information has not been confirmed by the EU refining industry and is contained here for illustrative purposes.

Overall, known planned/actual divestments and shutdowns in EU refining capacities since the start of the crisis in 2008 extend to 18 out of 104 refineries in the EU, representing some 134 million tonnes per year/2.7 million bbl/day of crude capacity, equivalent to 17% of total EU refining capacity. Only two of these units have been sold, others have been put up for sale for some time but have found no buyers, others yet have been shutdown for extended maintenance until market conditions recover.

The most vulnerable types of units are either small to medium-size and/or gasoline-oriented refineries, which are less adapted to current demand patterns. The industry however warns that restructuring of gasoline capacity could also affect diesel production if, instead of divesting only of gasoline units such as Fluid Catalytic Converters (FCCs) or catalytic reformers, EU refiners opt to shut down entire refineries altogether[40].

[40] White Paper on EU refining, Europia, May 2010.

Assets which have been put on sale since the crisis and are still awaiting buyers amount to close to 900,000 bbl/day. It is expected that at least another 400,000 bbl/day of capacity is likely to be formally put on sale in the foreseeable future as a result of the crisis.

In addition, refining capacity that is known to have been temporarily shutdown as a result of the crisis amounts to some 900,000 bbl/day. These units could either be restarted or eventually also be put on sale, depending on market conditions.

Note that no complete shutdowns have been announced by EU refiners. Since the beginning of the crisis, uneconomic assets that have not been put on sale have generally been subject to extended maintenance/temporary shutdowns, while assets that have been formally 'shut down' are in fact being converted to depots/storage facilities (equivalent to 258,000 bbl/day, to date).

Opinions on the amount of capacity that needs to be shut-down in the EU abound. These range from between 640,000 to upwards of 2 million bbl/day, equivalent to between 4% and 15% of total EU capacity, with the view that such decreases are necessary for a return to acceptable margins and in order to prevent further increases in the volumes of gasoline supplies going forward.

If 2009 utilisation rates for OECD Europe (calculated as a proportion of product consumption to total capacity) of 79% is a good guide of the likely long run utilisation rate for the EU industry, then it could be argued that there is 21% excess capacity. This exceeds the total capacity of the 18 refineries in question.

It is not known how many employees these 'vulnerable' refineries represent, and estimates are imperfect as indicators such as capacity, utilisation and complexity cannot by themselves provide an accurate guide. In addition, while the number of direct employees is known for some refineries, there are a number of additional indirect employments which depend on a refinery for their livelihood, whether as sub-contractors working on-site or as providers of products/ services either to the refinery or to employees of the refinery. The number of dependent indirect employments as a multiple of direct employments for a refinery can be of the order of 3 to 5, according to representatives of the industry.

Thus while the industry itself employs directly only 100,000 people in the EU, it can be considered that as much as 400,000 to 600,000 jobs are directly dependent on the EU refining industry[41].

The gradual disappearance of the refining activity in the EU would also have consequences for the industries for which a local refining presence is important. The EU petrochemical sector, which employs 778,000, is perhaps the best example of such an industry.

There are 58 steam crackers[42] in the EU, 53 of which are currently in operation, while 77% of the feedstock of those 53 crackers in operation comes from refineries. Of the 58 steam crackers in existence, 41 are directly integrated refinery/steam crackers.

According to the petrochemical industry, having refinery and interdependent industry on the same site brings a number of synergies in terms not only of the supply of energy but also in terms of support services and product exchanges[43]. The relationship is therefore mutually

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[41] Not included in this number are the further 600,000 jobs in logistics and marketing.

[42] Which crack naphta/LPG feedstock into lighter olefins such as ethylene - one of the most important raw materials of the organic chemical industry - and propylene - used in the manufacture of resins, fibres and plastics.

[43] Over 5.3 M/tons of products from crackers are sent back to refineries, equivalent to 12.5% of total refinery transfers to steam crackers. This includes hydrogen, which is produced in excess by the crackers and which refineries are normally short of and which is used by refineries in hydrocrackers in

beneficial, though integrating refineries and steam crackers is not the strategy employed by all the oil majors, and while Total as well as ExxonMobil are highly integrated (upwards of 74%), BP and Shell have relatively lower levels of integration (24% and 39% respectively).

The degree of integration with the petrochemicals industry is also only one of several factors that will influence how vulnerable a refinery is to being closed down. Other key aspects will likely include how clean and efficient (in terms of CO2 emissions and pollutants) the refinery is and its flexibility and fit in terms of meeting market demand. The cost of access to crude oil is another factor.

3.2.8. Long-term – 2050 and beyond: Preparing for a "decarbonisation era" in the EU

Looking beyond the next twenty years, up to and as far as 2050, the key challenge for the EU refining industry on the basis of current EU ambitions with regard to the environment and climate change is less one of partial restructuring and adaptation/upgrading of refining capacity and more of a paradigm shift with a radical departure from oil being used as the main transport fuel or as a key source of energy.

The energy and transport sectors are the targets of the vision to a move towards a low carbon, resource efficient and climate resilient economy by 2050, and as an energy-intensive industry supplying mainly fossil-based fuels to the transport sector, the EU refining industry will be concerned by developments to implement such a vision.

Transport in particular has been the sector most resilient to efforts to reduce CO2 emissions due to its strong dependence on fossil energy sources. Currently, the sector is responsible for about a quarter of EU CO2 emissions and also contributes significantly to reduced air quality and related health problems, particularly in urban areas. While energy and transport efficiency as well as effective transport demand management can all contribute to reducing emissions, the ultimate solution to near full decarbonisation of transport is the substitution of fossil sources by CO2-free alternative fuels for transport.

Such a vision is guided less by idealistic ambition than practical as well as moral imperatives:

(1) Oil, the main energy source for transport overall, supplying nearly 100% of road transport fuels, is expected, with present knowledge, to reach depletion by 2050. Substitution of oil therefore needs to start as soon as possible and increase rapidly to compensate for declining oil production, expected to reach its peak within this decade. Climate protection and security of energy supply objectives would therefore both benefit from building up CO2-free and largely oil-free energy supply to transport with a time horizon of 2050[44].

(2) By 2030, the global car fleet is predicted to grow from 800 million to 1.6 billion vehicles and to 2.5 billion by 2050. This will be accompanied by an increasing scarcity and cost of energy resources. These trends will have to be addressed by a step change in technology to ensure the sustainability of mobility in the long-term[45].

As the EU progressively decarbonises the transport sector, it is inevitable the sector must directly consume less fossil energy since it is unlikely ever to be viable to capture CO2 emissions on vehicles.

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order to upgrade heavier fractions into lighter products, such as diesel, naphta and kerosene. It also includes butanes and gasoline.

44 Report of the European Commission Expert Group on Future Transport Fuels, forthcoming.

45 Communication on a European strategy on clean and energy efficient vehicles.

While the oil industry does not foresee the end of oil as a major energy source by 2050, a number of its companies have already made significant investments to move away from dependence on oil and offer some examples of how some of the actors present in the EU refining market are looking at the longer-term.

4. IMPACTS OF FUTURE DEMAND DEVELOPMENTS ON THE REFINING INDUSTRY BY 2030

4.1. Demand projections according to implemented and adopted policies

This chapter provides a quantitative assessment of the medium-term impacts of expected demand developments in EU petroleum products on the EU refining industry.

It presents the results of running the PRIMES 2009 Baseline [business as usual] and PRIMES 2009 Reference [policy] scenario petroleum product demand projections on the OURSE refining module of the POLES energy model[46] in order to estimate the impacts of evolving demand in terms of:

1. Capacity requirements and capital investment requirements for additional process capacity or upgrade of existing capacity;

2. Production levels;

3. Levels of CO2 emissions;

4. EU import and export levels of petroleum products.

PRIMES projections were also run separately in the CONCAWE refining model[47], and results have also been reported below, for comparison with OURSE outputs.

The PRIMES 2009 Baseline demand projections result from developments in the assumed absence of new policies beyond those implemented by April 2009. It is not a forecast of likely developments, given that policies will need to develop. Therefore, there is no assumption in the Baseline that national/overall green-house gas (GHG) or renewable energy sources (RES) targets are achieved, nor of non-ETS (EU Emission Trading System) targets; CO2 emissions and RES shares are modelling results.

In contrast, the PRIMES Reference scenario reveals the effects of agreed policies, including the achievement of legally binding targets on 20% RES and 20% GHG reduction for 2020.

More details on both the PRIMES 2009 Baseline and Reference scenarios can be found in annex 3.

The impacts of the PRIMES demand projections are reported with a variation on the assumptions of the refining model with regard to future marine sulphur fuel specifications which are expected to be transposed into EU regulation. The impacts of such changes are reported separately due to the important investments that they will require by the EU refining

[46] The POLES (Prospective Outlook for the Long-term Energy System) model simulates the energy demand and supply for 32 countries and 18 world regions. Further details on the OURSE refining module of POLES can be found in annex.

[47] CONCAWE is the oil companies' European association for environment, health and safety in refining and distribution. The CONCAWE EU refining model simulates the EU (incl. Switzerland and Norway) refining system. More information on the model can be found on the internet site of the association (www.concawe.be).

industry if it decides to produce shipping fuel that meets the new specifications. Specifically, the variations in fuel specification changes that are modelled here are as follows:

Case A: assumes a change in maximum permitted sulphur content in marine fuel for Emission Controlled Areas (ECAs) in the EU (the Baltic Sea and the North Sea & English Channel) from 1.5% to 1% by 2010 and then down to 0.1% by 2015; and for the rest of the world: from 4.5% to 3.5% in 2012 and then down to 0.5% from 2020[48].

Case B: assumes no changes in maximum permitted sulphur content in marine fuel beyond 2012, i.e: ECAs remain at 1% and the rest of the world remains at 3.5%.

Note that in comparing a case including future IMO changes to one excluding them, in the latter case the changes to 1% and 3.5% respectively for the ECAs and the rest of the world have been taken for granted. As was explained previously in this document, this is because it is generally regarded that such changes will not pose significant problems for refiners – blends can simply be modified to redistribute the higher sulphur components - while the real challenge will be the changes to 0.1% sulphur content and 0.5% respectively for the ECAs and the rest of the world, as these will likely require the conversion of bunker fuels to diesel[49]. This will require investment in desulphurisation or conversion capacities.

The context for the impacts on the EU refining industry which are reported below in terms of key additional outputs from the OURSE model, is as follows:

(1) Production of petroleum products: the production levels of EU refineries during the period 2005 to 2030 is projected to fall by 14%, similar to the projected fall in demand in the PRIMES Reference scenario over that period[50];

(2) Trade flows: it is expected that Russia will have sufficient refinery capacities in middle distillates during the projection period to continue to supply the EU, while North-America will not continue to absorb the excess gasoline that the EU is projected to produce, such that new markets will have to be found. According to the OURSE model, by 2030, the EU net exports of gasoline will total 19.4 mtoe, equivalent to 18% of EU gasoline production for that year while EU net imports of gasoil/diesel will be 37.7 mtoe, equivalent to 15% of EU diesel/gasoil demand in 2030. In comparison, OURSE numbers for 2005 show that the EU net exports of gasoline amounted to 32.4 mtoe, equivalent to 21.5% of its gasoline production in 2005, and gasoil/diesel net imports were equivalent to 28.2 mtoe, amounting to 9.7% of EU gasoil/diesel demand in that year[51]. In short therefore, the OURSE model projects resultant trade flows for the economically optimal capacity required to satisfy the PRIMES reference demand which amount to falling gasoline exports and increasing gasoil/diesel imports by 2030 compared to 2005.

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48 The CONCAWE EU refining model makes the same assumptions as OURSE with regard to the timing and nature of the fuel specification changes in the ECAS, while for the rest of the world it assumes that the change from 4.5% to 3.5% already occurs in 2010.

49 Current technology cannot achieve reductions in the sulphur content of residues to 0.1% unless a very low sulphur feed is used. If it was possible, it is questionable whether refiners would not rather prefer to focus instead on converting residual fuel to lighter, more valuable fuels, and decide to stop supplying the bunker market altogether.

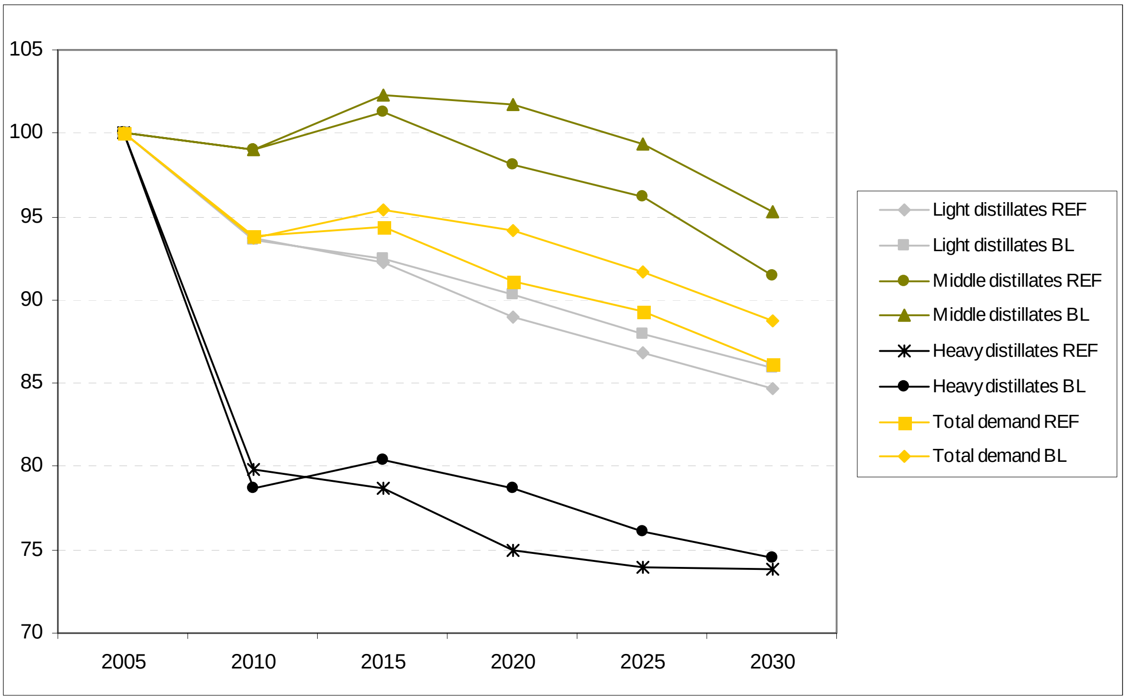
50 The CONCAWE model supply growth projections reveal an 11% drop in the 2005-2030 period.

51 The CONCAWE European refining model is run with fixed imports and exports outside the EU, and therefore keeps the trade situation constant over time. The sensitivity of the model to trade flows was however tested by changing the assumptions made with respect to the volumes of exports and imports to reflect the trade situation projected by the OURSE model as described above.

A key assumption of the OURSE model is with regard to the evolution of the EU crude diet. Globally, it assumes that by 2030, the API degree of conventional crude oil will have slowly decreased while sulphur content should increase slightly. However, it is expected that this will be balanced by an increasing share of condensates used in refinery production and the availability of upgraded crude oil from extra-heavy oil. In the case of the EU, the OURSE model assumes relative stability between 2005 and 2030, both in terms of the API degree and sulphur content of refineries supply, as along with an increasing share of condensates, the assumption is included of an expected doubling of the share of high medium distillate yielding crudes[52] .

Note in addition that the OURSE model treats the EU27, Switzerland, Norway and Turkey together as forming the region of Europe, broken down into two zones: Z3 (Northern Europe) and Z4 (Southern Europe). Impacts are therefore reported for the EU27 + these three countries. While it cannot be easily estimated what amount of the investments and CO2 emissions are EU27 specific, it is useful to note that IFP simulate EU27 demand into the OURSE model by using topping unit[53] capacity proportions. By that measure, Norway and Switzerland represent 4% of Z3 capacity and Turkey, 12.5% of Z4 capacity.

EU petroleum products demand projections, PRIMES 2009 Baseline and Reference scenarios compared



As the chart above reveals, whether business as usual or policy targets beyond April 2009 are assumed makes little differences in terms of the demand projections in petroleum products for the EU. The general trends in both cases can be summarised as follows:

(1) A general fall in the level of consumption of petroleum products;

(2) The continued gradual erosion of demand for high sulphur residual inland fuel and marine bunkers (which make up heavy distillates);

52 The CONCAWE model assumes no change in crude mix over time.

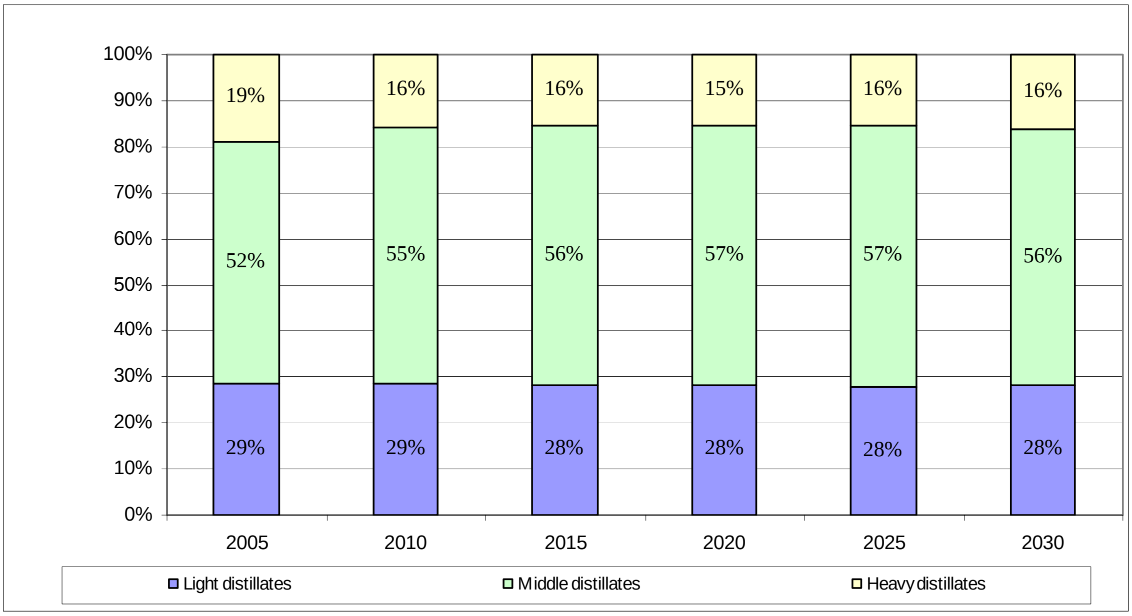
53 Topping refining is the simplest configuration of refining, and a part of the distillation process. It thus involves no treating or conversion.

(3) An initial increase in demand for middle distillates (including gasoil, heating oil, kerosene and jet fuel) followed by an eventual and overall fall, mainly resulting from a decrease in road diesel demand due to regulation to restrict CO2 emissions from cars becoming effective[54] as the car parc is gradually renewed and due also to the spill over effects from more efficient car engines to those of trucks (truck diesel consumption stabilises between 2020 and 2030);

(4) A continued fall in the demand for gasoline (included in light distillates, along with naphta). Note that the PRIMES demand projections do not assume a change in the current taxation regime in the EU, which differentiates between diesel and gasoline in favour of the former.

It is important to note that in both scenarios, the proportion of middle distillates in total demand increases quite significantly between 2005 and 2010, after which it remains fairly stable.

PRIMES Reference scenario EU demand projections split by type of product



4.2. The impact of demand projections on the EU refining industry

4.2.1. Impacts in terms of refining investments

According to the OURSE model, the impacts of the Reference scenario in terms of the investments required to upgrade EU+3 refining capacities amount to 17.8 billion Euros between 2005 and 2030, of which 3.3 billion Euros account for IMO changes[55].

54 The CO2 from cars regulations included in the PRIMES Baseline and Reference scenarios require strong reductions in the average fuel consumption of new cars. Binding targets are 130g/km by 2010 and 115g/km by 2020. (it should be noted that the Regulation contains a provisional goal of 95g/km for 2020)

55 Note that the differences between demand projections under the Baseline scenario and the Reference scenario are not significant enough to make any notable difference in terms of investments according to the OURSE model outputs.

This results primarily from investments in extra gasoil hydrodesulfurisation units which will be in short supply on the basis of both the Baseline and Reference Scenarios projections. The chart below shows the volumes that will be needed to meet demand in the Reference scenario, though there is little difference between the two scenarios (Baseline demand will require slightly more investments in all of the same types of units, excepting cokers[56]). Note that the new IMO regulations will require 14.3 million/t year of extra capacity by 2030 (the difference between case A and case B in the chart below), mainly in terms of extra hydrocraking[57] units (amounting to 6.6 million t/year), hydrodesulphurisation of residuals (amounting to 5.4 million t/year) and hydrotreating of vacuum gasoil[58] (4.2 million t/year).

Thus, the levels of investments required in order to supply initially rising (but over the whole period, falling) levels of middle distillates is quite considerable, and even with such investments, imports are projected to rise further.

One variation that has been undertaken on the OURSE model runs of the PRIMES Reference demand projections is with regard to crude oil supply projections. As was highlighted above, the OURSE model projections assume a balanced crude diet between 2005 and 2030 in Europe, which along with an increasing share of condensates relies on a doubling of the share of high medium distillate yielding crudes. Simply keeping the share of such crudes constant during that period (with the consequence of an important increase in the overall sulphur content) in the OURSE model however results in total investments between 2005 and 2030 of 29.7 billion Euros of which 9.3 billion Euros alone account for IMO changes.

Running the PRIMES Reference scenario projections on the Concawe model while keeping trade levels between 2005 and 2030 constant would require 29.2 billion Euros of investments in that period, of which 13.3 billion Euros would have to be spent due to the new IMO changes. The same demand projections combined with an augmentation in the importation of gasoil/diesel between 2005 and 2020 from 20 Mt/year to 40 Mt/year (and staying at that level every year thereafter to 2030) will however require total investments of 25.8 billion Euros between 2005 and 2030, of which IMO changes alone amount to 11.7 billion Euros.

Concawe estimates that the amount of investments that the refining industry in Europe has already committed to spending (or what it calls firm projects) between 2010 and 2020 is of the order of 13.3 billion Euros.

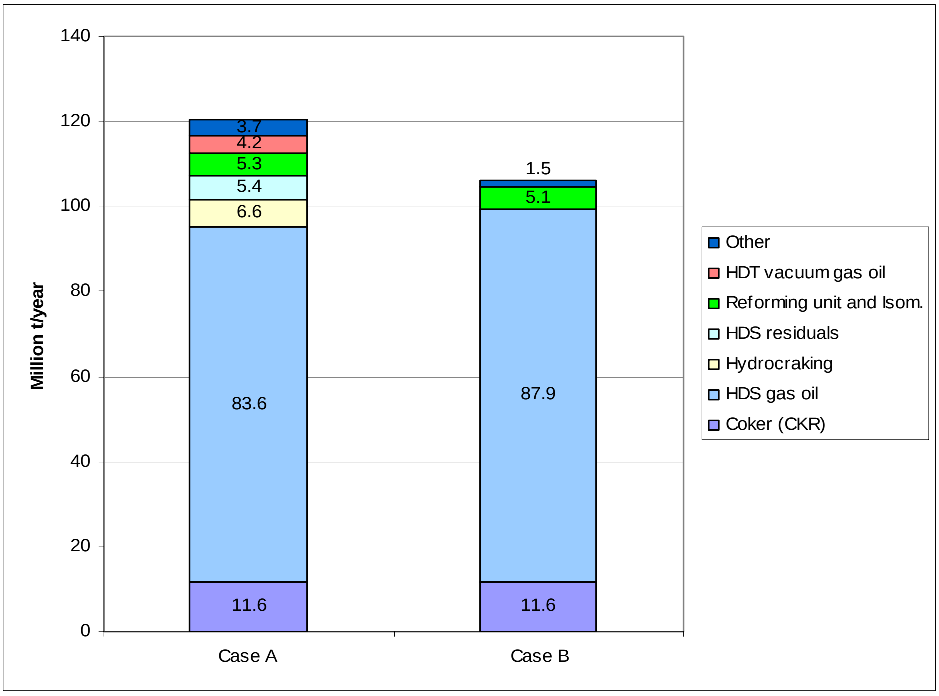
Note in addition that according to the Concawe model results, cumulative refining investments between 2005-2020 are higher than for 2005-2030, a reflection of falling demand in petroleum products according to the PRIMES demand projections. This highlights a particular dilemma faced by refiners of investing early in capacity that will only be partially utilised at a later point in time in the non too-distant future.

[56] Delayed coking units are a type of deep conversion unit, which are the most sophisticated refining units. Cokers crack residual oil hydrocarbon molecules into coker gas oil and petroleum coke.

[57] The process whereby hydrocarbon molecules of petroleum are mainly broken into jet fuel and diesel oil components by the addition of hydrogen under high pressure in the presence of a catalyst

[58] Hydrotreating of vacuum gasoil is a process that removes sulfur and nitrogen from vacuum gasoil, which is the product recovered from vacuum distillation.

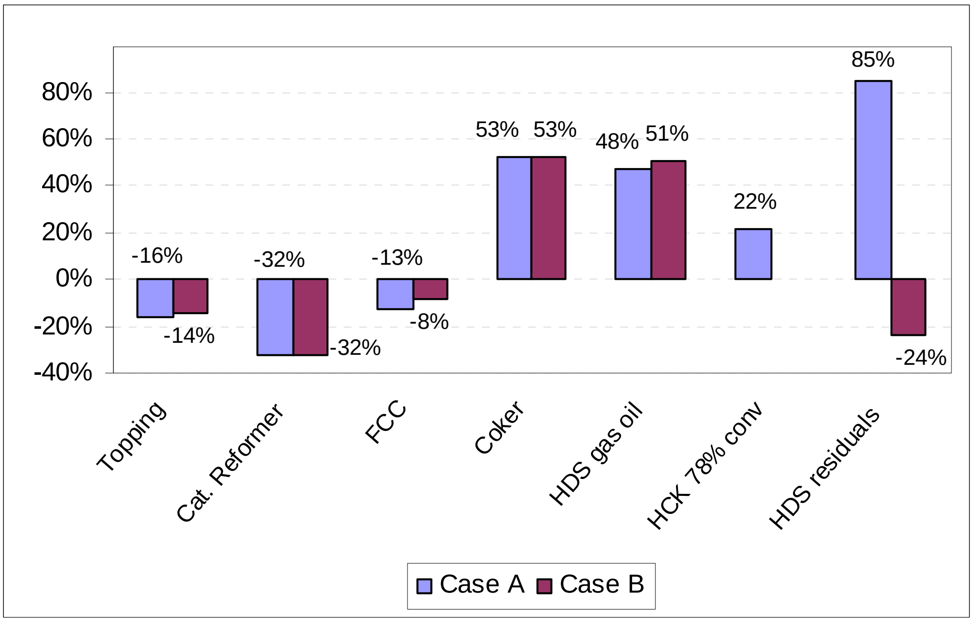
OURSE model investments in refining capacity in EU+3, 2005-2030, on the basis of the Reference demand projections, split by type of unit



4.2.2. Utilisation of refining units

According to OURSE model results, in terms of changes in refining capacity from 2005 levels by 2030, whether new IMO regulations are assumed or not, similar reductions in the use of simple refining capacity can be expected to occur, while similar increases in the use of cokers and hydrodesulphurisation units should result. In addition, assuming IMO changes will require significant increase in the use of residual hydrodesulphurisation and some 22% increase in the use of hydrocracking units. Note again that there is very little difference between the PRIMES Baseline and Reference cases in terms of the demand projections in petroleum products for the EU as there is little difference between the two in terms of the demand projections in petroleum products for the EU.

Necessary changes in refining capacity use in EU+3, 2005-2030, on the basis of the reference demand projections



4.2.3. CO2 emissions

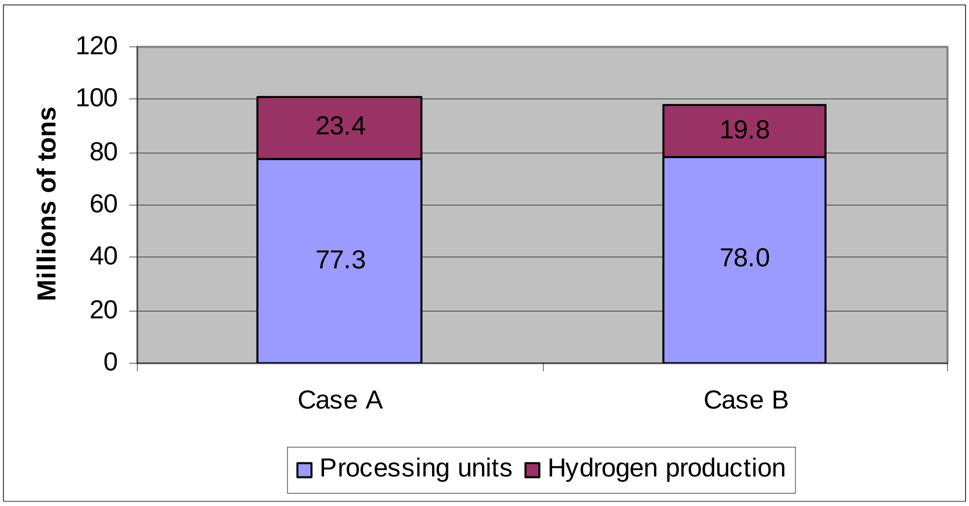
Whether IMO changes are assumed or not in the OURSE model makes little difference in terms of CO2 emissions from EU+3 refineries by 2030, which are projected to emit around 100 million tonnes of CO2. This compares to 118.5 million tonnes of CO2 in 2005[59], the fall in emissions resulting from falling production of petroleum products. Note however that in both cases, a growing proportion of the CO2 emissions will come from the needs for hydrogen in refineries (hydrocracking units uses hydrogen to upgrade heavier fractions into lighter products while hydrodesulphurisation units use hydrogen to chemically remove the sulphur), such that by 2030, 20% of all CO2 emissions from EU refineries will come from hydrogen production, compared to only 14% in 2005. Specifically, CO2 emissions due to the IMO changes amount to 3.3 million tonnes of CO2 in the reference case, essentially as a result of the extra emissions from hydrogen use.

Changing the crude supply assumptions towards an increase in the sulphur content of the EU crude diet (by keeping the proportion of high middle distillate yielding crudes, as explained above) would however result in a level of CO2 emissions of 110.3 million tonnes in 2030, 5.6 million tonnes as a direct result of new IMO changes.

In contrast, the Concawe refining model results reveal that in spite of declining market demand for fossil fuels, processing intensity in refining increases as a result of more stringent product specifications, particularly in the case including IMO changes, and consequently that refinery CO2 emissions will increase somewhat between 2005 and 2030, by around 6% (and increasing by 12% between 2005 and 2020).

59 IFP estimations of EU refineries CO2 emissions. In comparison to 118.5 million tonnes of CO2 emitted in 2005. Note that this does not include emissions related to petrochemical activities.

OURSE model CO2 emissions of EU refineries by 2030 in EU+3, on the basis of the Reference demand projections



4.2.4. Summary: impact of demand projections on the EU refining industry

EU refining capacity upgrading is expected to lead to significant reductions in exports of (excess supply of) gasoline by 2030, while it is expected that the import dependence of the EU in gasoil/diesel will continue to increase by 2030.

Depending on assumptions on the development of the crude diet in Europe between 2005 and 2030 and taking into account adopted and implemented EU policies, investments required to upgrade European refining capacities in that period could amount to between 17.8 and 29.3 billion Euros, of which between 3.3 and 11.7 billion Euros alone will account for future marine sulphur fuel specification changes to be transposed into EU regulation by the end of 2010. These figures result from a scenario of increasing import dependence in gasoil/diesel.

It is estimated that the amount of investments that the refining industry in Europe has already committed to spending (in what it calls firm projects) between 2010 and 2020 is of the order of 13.3 billion Euros.

In spite of projections of declining demand for fossil fuels, processing intensity in refining will increase as a result of more stringent product specifications, in particular as a result of new IMO changes. One possible consequence is that refinery CO2 emissions will increase between 2005 and 2030, by around 6% (and increasing by 12% between 2005 and 2020), mainly as a direct result of the needs for hydrogen in refinery units geared towards producing higher proportions of new IMO compliant fuel.

Significant falls in the projected EU demand for transport gasoline by 2030 according to PRIMES (of 20.7% in the Reference scenario) point to the need for gasoline-focussed refinery plant restructuration, with necessary capacity reductions by up to a third, depending on the type of unit.

1. ANNEX 1: REFINING AND APPLICATIONS OF REFINING PRODUCTS

1.1 Introduction to refining

An oil refinery represents one link in the chain of an integrated business that provides oil products to Europe's consumers. From exploration and production through to crude oil trading and refining to distribution, finished products trading and sales to end-consumers.

The role of refineries in the supply chain of the petroleum industry is to process crude oils into the finished products that are needed by the market. Refineries can use a variety of processes and can have very different configurations.

Essentially, refining breaks crude oil down into its various components, which are then selectively reconfigured into new products such as fuels and lubricants for automotive, ship and aircraft engines. Refining by-products can then be used in petrochemical processes to form materials such as plastics and foams.

Crude oil can be used in many different ways because it contains a broad mix of hydrocarbons (i.e. molecules made of hydrogen and carbon atoms which range from very light to very heavy) of varying molecular complexity: different masses, forms and lengths. Such various structures mean differing properties and thereby uses. These hydrocarbons must be separated and refined prior to commercial use.

1.2. Refined products

Refined products are commonly split into light, middle and heavy distillates and specialty products.

Light distillates include gasoline, which is mainly used as a motor fuel, LPG (liquid petroleum gas) which is commonly used as a fuel in heating appliances and vehicles, and naphta, used as feedstock in the production of petrochemicals such as plastics and fibres.

Middle distillates include gasoil, diesel, kerosene and aviation/ jet fuel. Gasoil is mainly used in domestic heating, while diesel is used as a motor fuel and also as a fuel in agricultural vehicles, small boats and trains. Jet fuel and kerosene are used to power airplanes and kerosene is also sometimes used in domestic heating.

Heavy distillates are composed of bunker fuels for large ship engines and heavy fuel oil for industrial installations such as power stations and boilers.

Specialty products include bitumen (used to make road asphalt and roofing materials), waxes (including polishes, candles, food paper), lubricants and greases for automotive and industrial applications, coke for specialty applications like electrodes and hydrocarbon solvents, primarily used in specialty industrial applications.

Most refineries are known as 'fuels refineries' and usually produce a mix of the main products, which are diesel, gasoline, heating gasoil, jet fuel and heavy gasoil as well as LPG. Other refineries, known as 'specialty refineries', specialise in one or a combination of the specialty products above.

1.3. Refinery processes

The processes used by refineries can be classified into three categories: separation, treating and conversion.

1.3.1. Separation

The first process of any refinery is the separation or fractionation of crude into different fractions by distillation, known as atmospheric distillation.

Separation is achieved by raising temperature of the input crude to circa 360°C. This vaporises individual fractions of the crude feed which then condense and separate out according to the varying boiling points and densities of petroleum products. Lighter fractions such as LPG, naphta and kerosene have lower boiling points, lower carbon content and higher hydrogen content than heavier factions such as vacuum gasoil and vacuum residues.

This process is known as simple distillation, also referred to as topping or hydroskimming when done in the presence of hydrogen. The use of a vacuum enables the products to vaporise at lower temperatures, which is known as vacuum distillation.

1.3.2. Treating

Treating improves the quality of petroleum fractions distilled in order to meet the specifications of finished products. Hydrotreating processes use hydrogen (a by-product of the reforming process) and catalysts to remove sulphur and other contaminants such as salts, nickel, vanadium and nitrogen oxides. Examples of hydrotreating processes include hydrogenating, hydrofining and hydrodesulphurisation.

1.3.3. Conversion

Cracking, visbreaking and coking processes break down (convert) large, less valuable, hydrocarbon molecules into smaller, more valuable, lighter ones.

In a cracking refinery, atmospheric residue (an output from distillation) is further distilled under vacuum conditions to recover vacuum gasoil (VGO). A vacuum residue also results from vacuum distillation. VGO is then fed into a cracking unit that converts part of it into a mix of hydrocarbons that boil in the atmospheric distillation range. The most common crackers are fluid catalytic crackers (FCCs) and hydrocrackers.

Conversion refineries such as FCCs and hydrocrackers usually contain all the processing units of a hydroskimming refinery to which a number of conversion units are added. Conversion refineries would typically require more energy per unit of crude intake compared to hydroskimming refineries. They would therefore also generate more Green House Gases (GHG) per unit of crude oil intake.

Deep conversion units are the most sophisticated types of refineries. They convert vacuum residue into lighter products. Such refineries are becoming more and more the norm, with the increasing demand for lighter, cleaner products and the rapidly declining use of heavy residual fuels. Deep conversion refineries are even more energy intensive than conversion units and as a consequence generate more GHG emissions per unit of crude oil intake.

1.4. Types of refinery units

The **topping** unit is the simplest configuration, with no conversion or treating. It is able to produce a number of products suitable for direct use in the end-market such as LPG, kerosene (which can be used directly as a heating fuel or can be upgraded to jet fuel) and heating gasoil, if produced from very low sulphur crudes. However, no crude oil can produce gasoil that meets current EU diesel quality specifications without desulphurisation, therefore topping refineries cannot produce diesel for the EU market. Topping also produces naphta, fuel gas (which is used as a fuel for the refinery) and residue. The atmospheric residue is a fuel oil with a quality that varies according to the quality of the crude processed.

Hydroskimming units upgrade naphta to gasoline and gasoil to diesel and heating oil. Such refineries are equipped with astmospheric distillation, naphta reforming and the necessary treating processes. Note that hydroskimming refineries must normally produce some gasoline in order to have the hydrogen needed to produce diesel, which limits the possibilities to optimise gasoline and diesel production independently. These units generally do not contain catalytic conversion processes and therefore their product distribution reflects closely the composition of the crude oil processed.

Hydrotreating units use hydrogen (a by-product of the reforming process) and catalysts to remove sulphur and other contaminants such as salts, nickel, vanadium and nitrogen oxides. Examples of hydrotreating processes include hydrogenating, hydrofining and hydrodesulphurisation.

Isomerisation and reforming units are used to rearrange the structure of petroleum molecules to produce higher-value molecules of a similar size. These new molecules could have a higher octane number than the original ones and are therefore a more valuable gasoline blending component[60]. For example, **catalytic reforming units** are used to convert low octane petroleum refinery naphtha into high-octane liquid products called reformates which are components of high-octane gasoline.

A **fluid catalytic cracker** (FCC) uses catalysts and high temperature to crack/break down vacuum gasoil or residue into mainly gasoline and a small volume of (poor quality) gasoil. The proportion of gasoline and gasoil produced by an FCC refinery is relatively fixed. The ability to change yields and reduce gasoline production is limited by a number of constraints. FCC units were the main choice of European refineries in the 1970s and 1980s when there was a strong growth in demand for gasoline.

A **hydrocracker** uses catalysts, hydrogen, high pressure and high temperature to crack vacuum gasoil or residue into mainly (good quality) gasoil and jet fuel. Note that hydrogen produced from reforming is insufficient to feed a hydrocracker, such that a hydrocracking unit needs an additional dedicated hydrogen supply. Hydrocracking refineries can be designed with a greater ability to vary the relative yields of diesel and gasoline, resulting in increased refinery flexibility. In the 1990s, when EU demand began to switch from gasoline to diesel, gradually more investment went into hydrocracking units, although catalytic crackers are still the dominant configuration in Europe.

A **coker** unit converts vacuum residue or residue into low molecular weight hydrocarbon gases, naphtha, light and heavy gas oils, and petroleum coke. The process thermally cracks the long chain hydrocarbon molecules in the residual oil feed into shorter chain molecules.

Examples of **deep conversion** units are residue FCCs, which is an FCC unit designed to crack residue as well as VGO; residue hydrocracking, which cracks residue rather than VGO and delayed coking which is a very high-severity form of thermal cracking. Deep conversion capacity accounts for less than 3.5% of crude distillation capacity.

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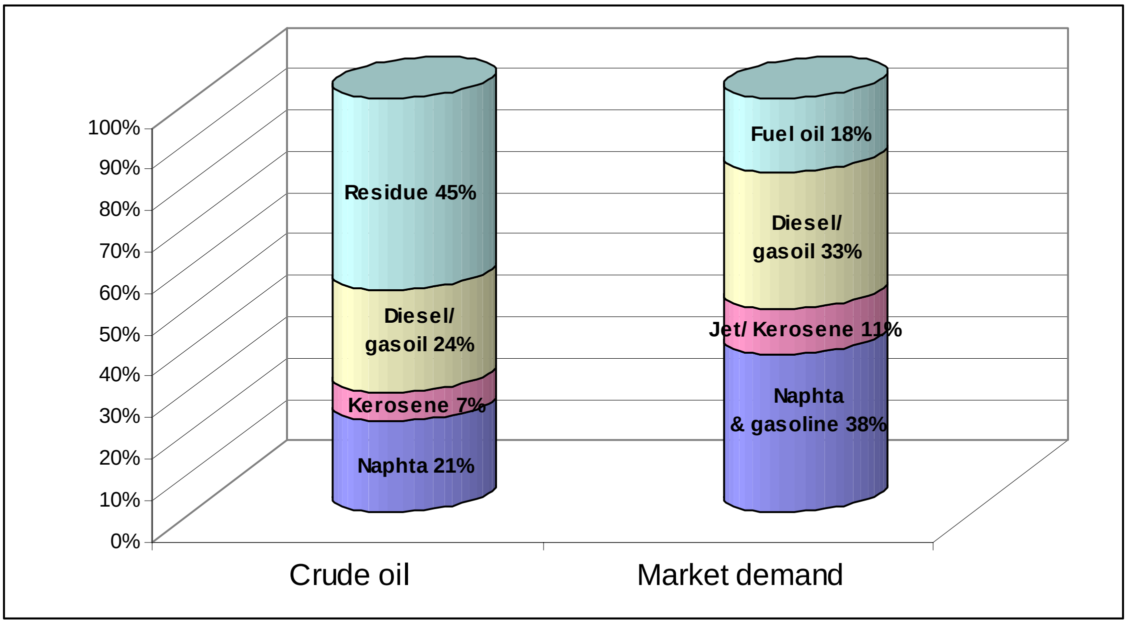
[60] The octane rating of gasoline is an indicator of how much the fuel can be compressed before it spontaneously ignites. When gas ignites by compression rather than because of the spark from the spark plug, it causes 'knocking' in the engine, which can damage an engine. Lower-octane gasoline can handle the least amount of compression before igniting.

1.5. Refinery yield

The yield from a refinery will depend on the processes that it has and the type of crude oil that it processes.

Once a refinery has been built with a certain configuration and designed for a certain type of crude, there is little it can do to change its yield structure significantly without major investment in new processes.

Comparison of average yield of crude distillation and market demand



Source: Purvin & Gertz

The average yield obtained from crude distillation does not match the proportion of products demanded by the market. To rectify this, refiners use different combinations of conversion and treating processes to produce lighter products from residue. For comparison, a hydroskimming refinery designed to process North Sea Crude would achieve a fuel oil yield of approximately 33% of total finished products. An FCC refinery processing the same crude would have a fuel oil yield of only 13% of finished products while the fuel oil yield of a hydrocracking refinery would be similar to that of an FCC refinery with the additional advantage that a greater proportion of the yield would be made up of middle distillates and a smaller proportion of the yield would be gasoline.

The costs of building FCC and hydrocracking refineries are comparable and much more expensive to build than hydroskimming refineries.

2. ANNEX 2: CHARACTERISTICS AND EVOLUTION OF THE EU REFINING SECTOR

2.1. Description of the EU refining sector

2.1.1. Capacity

In May 2010 there were around 104 refineries operating in the European Union. The EU's crude refining capacity currently represents 778 million tonnes, equivalent to 18% of total global capacity. The EU is the second largest producer of petroleum products in the world after the United States. There are refineries in 21 Member States with the exceptions of Cyprus, Estonia, Latvia, Luxembourg, Malta, and Slovenia.

Over half of the refining capacity in the EU is in North Western Europe (NWE), slightly more than a quarter in the Mediterranean region (MED) and the rest in Central and Eastern Europe (CEE)[61]. These regional groupings are based on the state of infrastructure and geographical accessibility to different crude streams and transportation routings. Usually, the crude intake in NWE is mainly a mix of North Sea crude, followed by Urals, which has a lower API[62] and higher sulphur content. Conversely, in Central Europe, refineries are often located on the Druzhba pipeline, and the great majority of their intake is Urals crude. In the Mediterranean area, the larger proportion is Arabian Gulf, which is again heavier than Urals crude, with similar API but higher sulphur content, followed by Urals crude.

EU refineries by region, by number and capacity

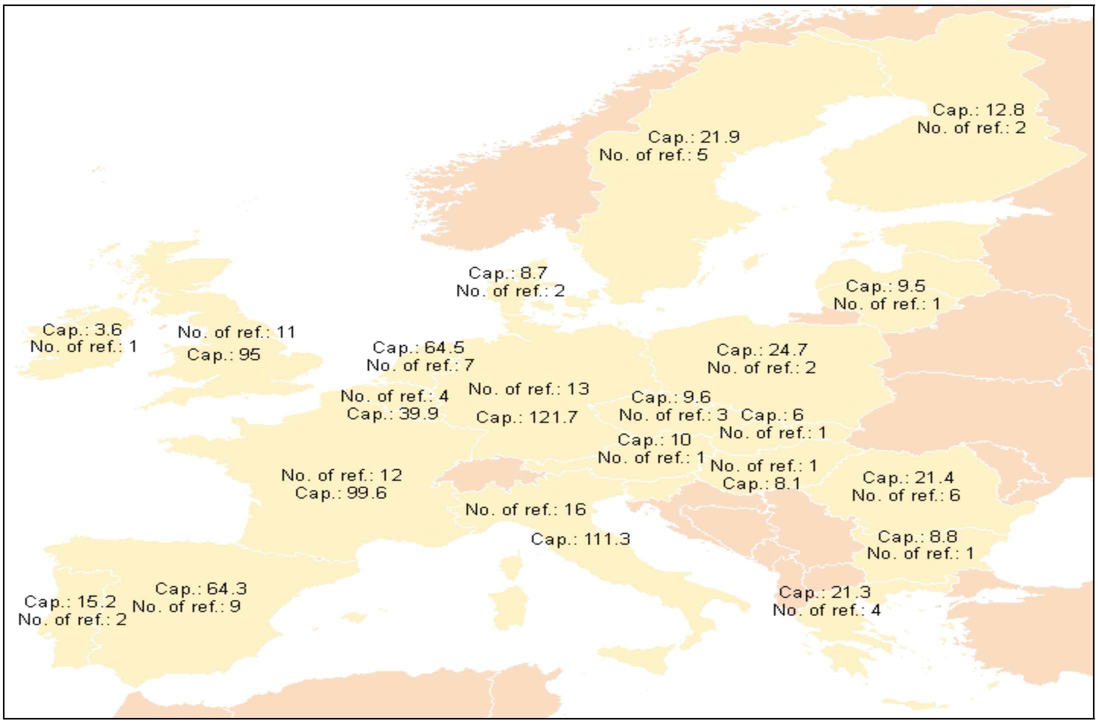
REGION	NUMBER OF REFINERIES	CAPACITY MT/YEAR	CAPACITY MBBL/DAY	CAPACITY %
North West Europe (NWE)	56	465	9.3	60
Mediterranean (MED)	31	212	4.2	27
Central and Eastern Europe (CEE)	17	101	2	13
Total	104	778	15.5	100

Source: European Commission. Note: capacity refers to crude processing capacity.

[61] NWE: Austria, Belgium, Denmark, France, Germany, Ireland, Netherlands, Sweden, UK. MED: Greece, Italy, Portugal, Spain. CEE: Bulgaria, Czech Republic, Finland, Hungary, Lithuania, Poland, Romania, Slovakia.

[62] API expresses a crude's relative density, with the higher the API gravity, the lighter the crude.

EU refinery numbers and capacity, in million tonnes per year, by Member State



Source: European Commission

EU refinery numbers and capacity, by Member State

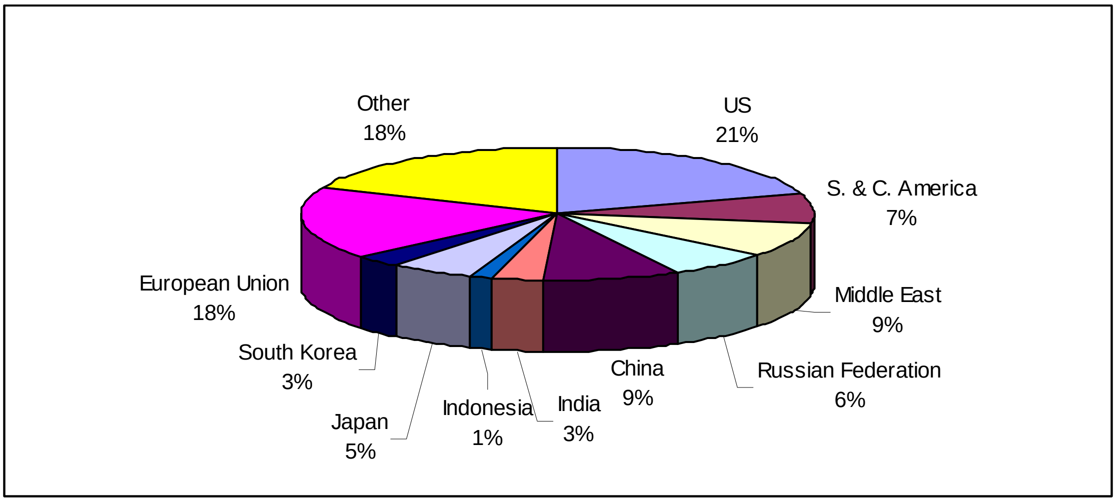
Country	Number of refineries	Crude refining capacity	
		kt/Year	bbl/day
Austria	1	10,006,852	200,000
Belgium	4	39,907,326	797,600
Bulgaria	1	8,806,030	176,000
Czech Republic	3	9,606,577	192,000
Denmark	2	8,680,944	173,500
Finland	2	12,783,752	255,500
France	12	99,578,190	1,990,200
Germany	13	121,743,365	2,433,200
Greece	4	21,264,560	425,000
Hungary	1	8,055,516	161,000
Ireland	1	3,552,433	71,000
Italy	16	111,333,164	2,225,600
Lithuania	1	9,506,510	190,000
Netherlands	7	64,534,191	1,289,800
Poland	2	24,666,891	493,000
Portugal	2	15,210,416	304,000
Romania	6	21,388,497	427,525
Slovakia	1	6,004,111	120,000
Spain	9	64,315,961	1,282,500
Sweden	5	21,864,972	437,000
United Kingdom	11	94,990,049	1,898,500

Total EU	**104**	**777,800,307**	**15,542,925**

Source: European Commission

EU capacity in the global context

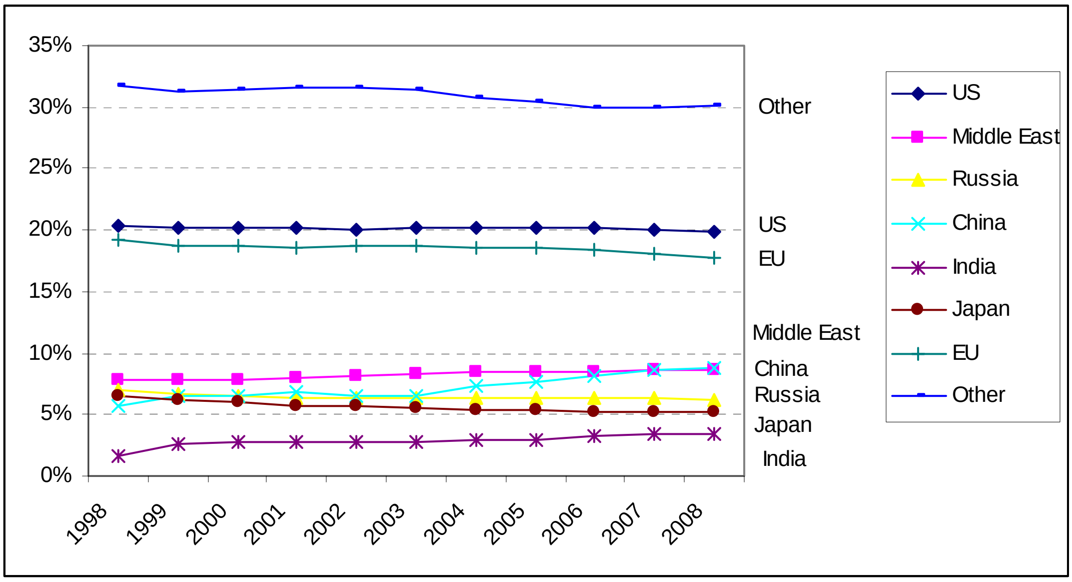
World crude processing capacity split, 2008



Source: BP Statistical Review of World Energy 2009

As the chart below providing world trends in crude processing capacity shows, in the last ten or so years, the proportions of refining capacity in mature markets such as the EU, the US and Japan have trended downwards while emerging economies such as the Middle East, China and India have progressively been building up capacity.

World trends in crude processing capacity, 1998-2008



Source: BP Statistical Review of World Energy 2009

2.1.2. The players in the EU refining market

Total S.A. has the greatest refining capacity, and together with two other International Oil Companies (IOCs) (Shell and ExxonMobil), account for around half of total capacity in the NWE region. In the MED region, the company with the greatest capacity is Eni, while the three companies with the greatest capacity - Eni, Repsol and ExxonMobil - account together for over a third of capacity in that region. In the CEE region, the biggest player is PKN, with about a third of capacity. PKN, MOL and Neste together account for around two thirds of total capacity in the CEE region.

Overview of EU players active in refining crude oil

Type of player	Description	Example
International Oil Companies (IOCs)	Vertically-integrated with supply chain operations from exploration and production through to refining and retail marketing.	Shell, BP, ExxonMobil, Chevron, ConocoPhillips and Total
National Oil Companies (NOCs)	Often began as state-owned/controlled companies with significant operations within their national borders, but some have undergone transformation to publicly quoted entities with a wide share ownership.	PKN (Poland), MOL (Hungary), Eni (Italy), OMV (Austria), Rompetrol (Romania), KPC (Kuwait) and PDVSA (Venezuela)
Pure-Play Refiners	Specialise in refinery operations alone where they refine crude oil for other market players. Their business model involves an open market for wholesale products.	Ineos and Petroplus
Refiner and Marketers	Refinery operations are integrated with retail fuel marketing.	SARAS
Niche Refineries	Specialist refinery with specific processes such as bitumen plants.	Nynas

Source: Econ Pöyry AB

2.1.3. Refining margins

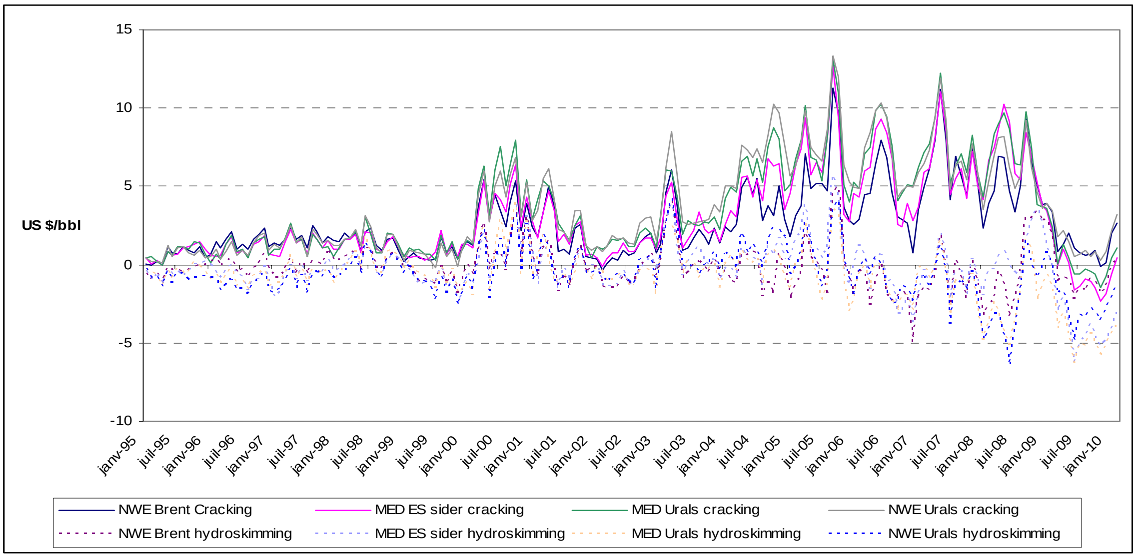
The refinery margin is the profitability that results from processing a barrel of crude oil. It reflects the difference between the market value of the combination of products produced by the refinery and the cost of buying the crude at market price as well as the operating costs incurred in the refining process.

Refining margins will generally rise if there is insufficient capacity to cover the demand needs, and will fall if the reverse is true. In Europe in the 90's, years of underinvestment in capacity in combination with high and growing oil demand kept refining margins high.

The charts below detail the trend in refining margins for simple hydroskimming refineries and complex cracking refineries for various crudes in NWE and the MED in recent years.

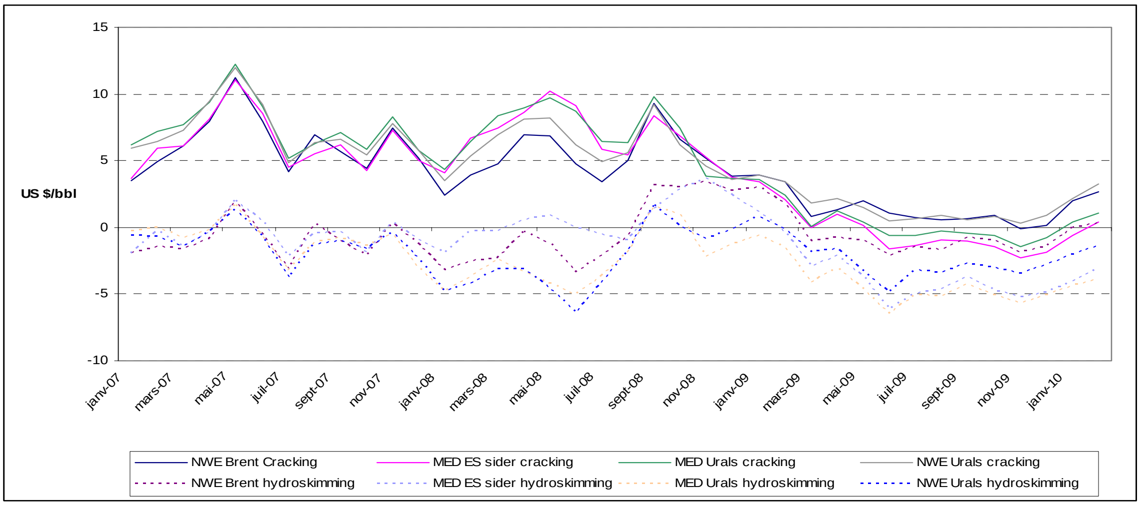
Looking at refining margins displayed in the next chart reveals more clearly the recent evolution of European refining margins. While a depression in margins can clearly be observed over the course of 2009, a pickup can also be seen at the end of the year, continuing into 2010.

Refining margins for simple and complex refiners in the EU, Jan 1995 – Feb 2010



Source: IEA

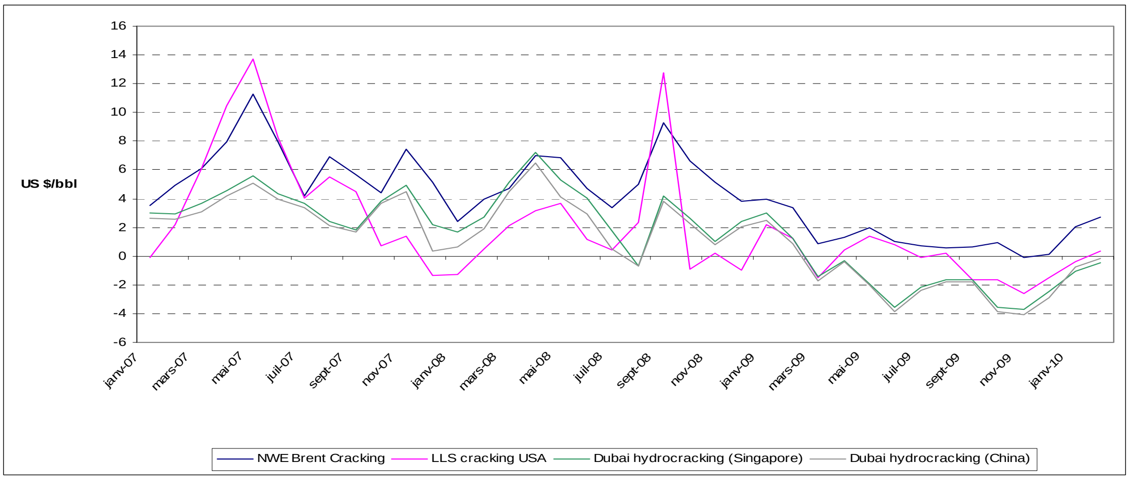
Refining margins for simple and complex refiners Jan 2007 – Feb 2010



Source: IEA

EU margins in the global context

Refining margins for complex refiners Jan 2007 – Feb 2010, comparison of world regions



Source: IEA

The chart above clearly shows that the crisis has impacted margins in all regions of the world. If average annual margins are compared, North-West Europe has even fared rather better than all other regions in comparison in the last three years (table below).

Average annual margins (in $/bbl)

YEAR	NWE BRENT CRACKING	LLS CRACKING USA	DUBAI HYDROCRACKING (SINGAPORE)	DUBAI HYDROCRACKING (CHINA)
2007	6.3	4.6	3.6	3.1
2008	5.2	1.9	3.1	2.4
2009	1.3	-0.2	-1.5	-1.8

Source: IEA

Margins outlook

In its January Oil Market Report the IEA explained that while refining margins rebounded this winter due to a drawdown in oil product inventories and recovering demand, the construction of refineries over the past two years and a massive contraction in oil consumption during the recession have led to a glut of capacity at the global levels. It thus maintains a bearish short-term outlook for the industry.

According to Wood Mackenzie consultancy, expectations in the EU are for continued negative simple margins, but for a recovery in complex margins to occur already in 2010. Wood Mackenzie project NWE Urals cracking margins[63] to reach $3.45/bbl in 2010

63 Given the increasing relevance of Urals crude in Europe (and falling relevance of Brent crude), it is more useful to look at Urals cracking margins going forward.

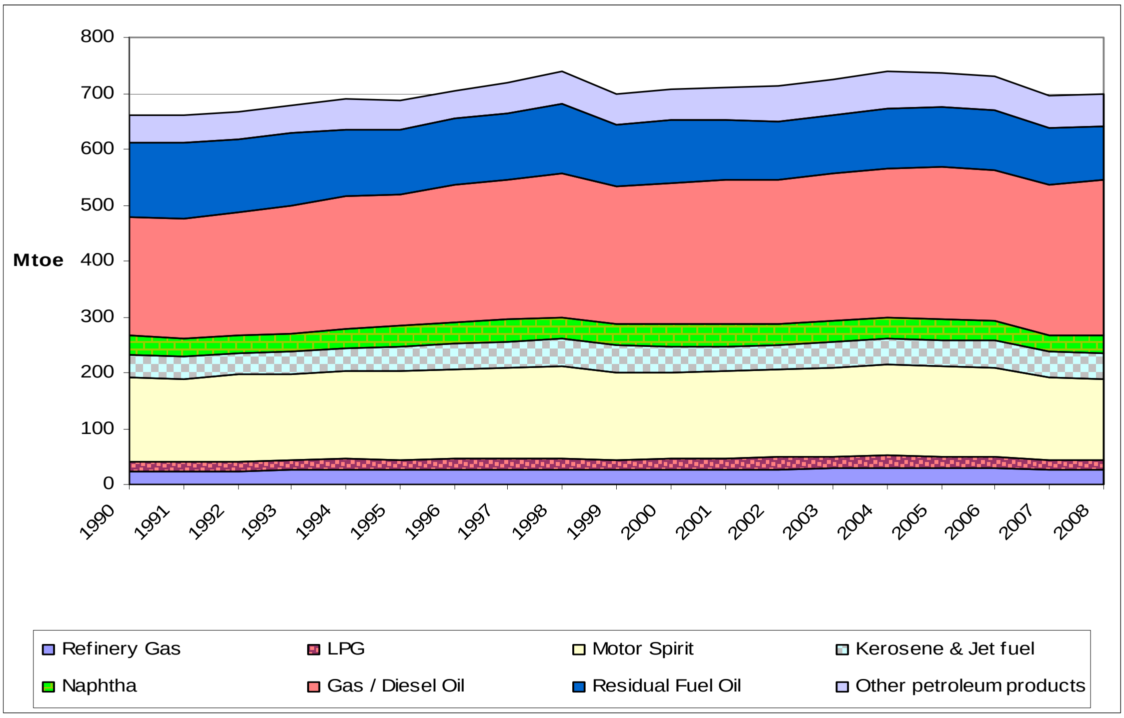
compared to $2.62/bbl 2009 and $4.62/bbl in 2008. According to the consultant, margins should continue to rise slowly, reaching levels of $5.13/bbl in real (2010) terms by 2015.

According to the IFP, complex margins from $3.4/bbl are "perfectly satisfactory from a refiner's perspective"[64]. On this basis, should Wood Mackenzie expectations be realised, complex refining in the EU should return to 'satisfactory' levels of returns before the end of the year.

2.2. Role of the EU refining sector in the supply of petroleum products

2.2.1. Output of the EU refining sector

EU refining sector production[65] evolution, 1990-2008

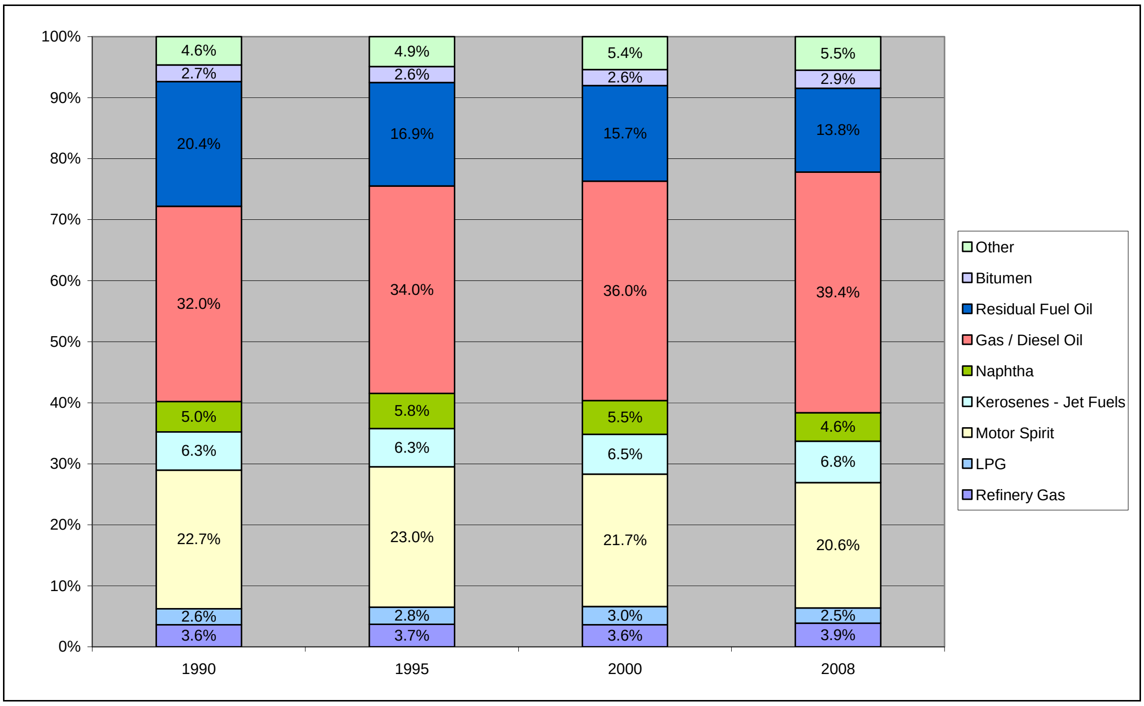


Source: Eurostat

64 Panorama 2009 "A look at refining", IFP.

65 EU refining production data shown here is equivalent to net transformation output of refineries, which excludes consumption in refineries.

EU refining sector production split, 1990-2008

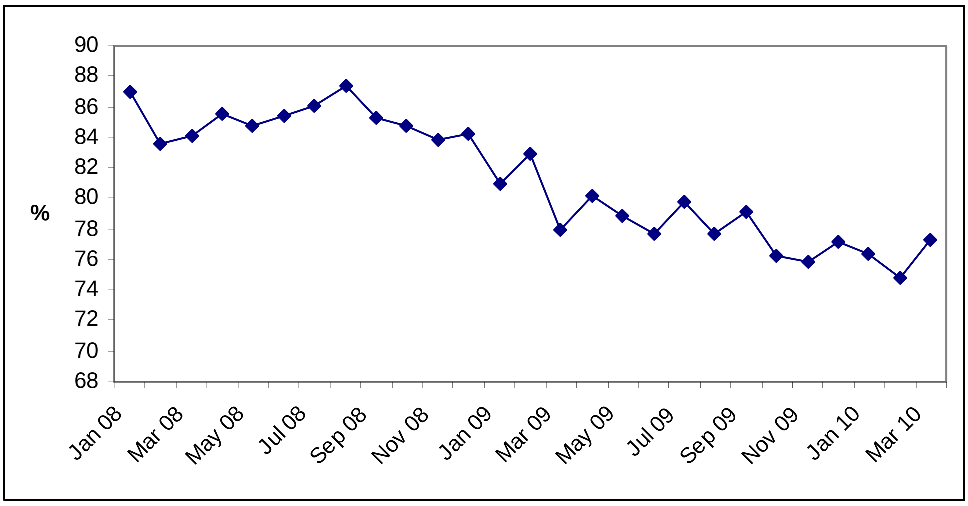


Source: Eurostat

Since 1990, EU refinery sector production has increased by 0.3% per year. In that time, fuel oil production was significantly reduced, while motor spirit (gasoline) production decreased by 4.2%. Gas/diesel oil production increased by 30.4% during that period, and it went from representing 32% of total production in 1990 to 39% by 2008.

2.2.2. Utilisation rates

Utilisation rates, OECD Europe



Source: IEA

Utilisation rates, OECD Europe

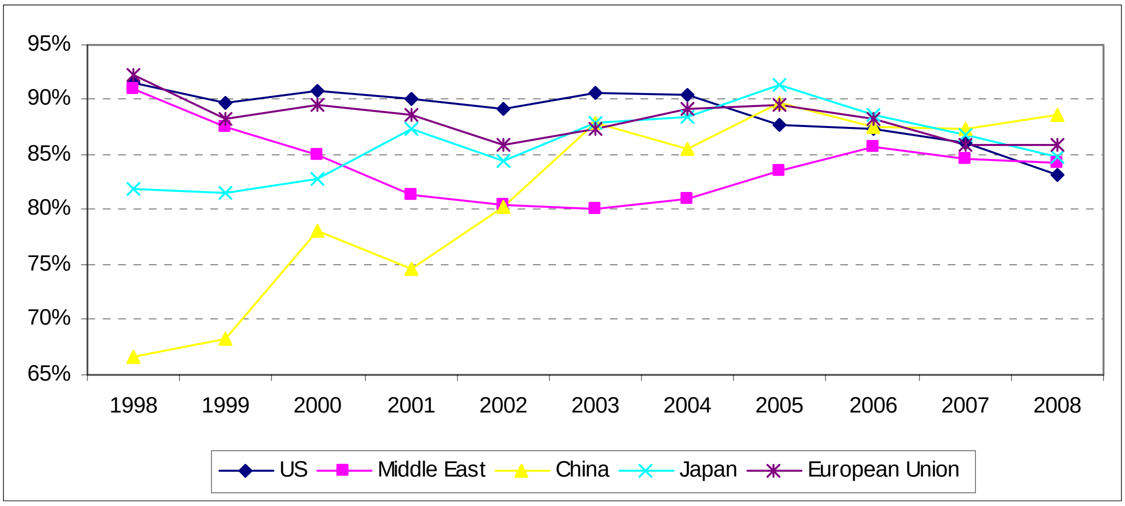
Year	2008	2009	2010 (3 MONTHS)
Average of monthly rates	85.2	78.7	76.2

Source: IEA

The average utilisation rate[66] in OECD Europe in 2009 amounted to 79%, compared to 85% the previous year. In the first three months of 2010, utilisation rates averaged 76%, showing a continuing downward trend. This needs to be put in the context of previous utilisation rates for the EU close to 90% as recently as 2005.

EU utilisation rates in the global context

Comparison of utilisation rates, different regions, 1998-2008



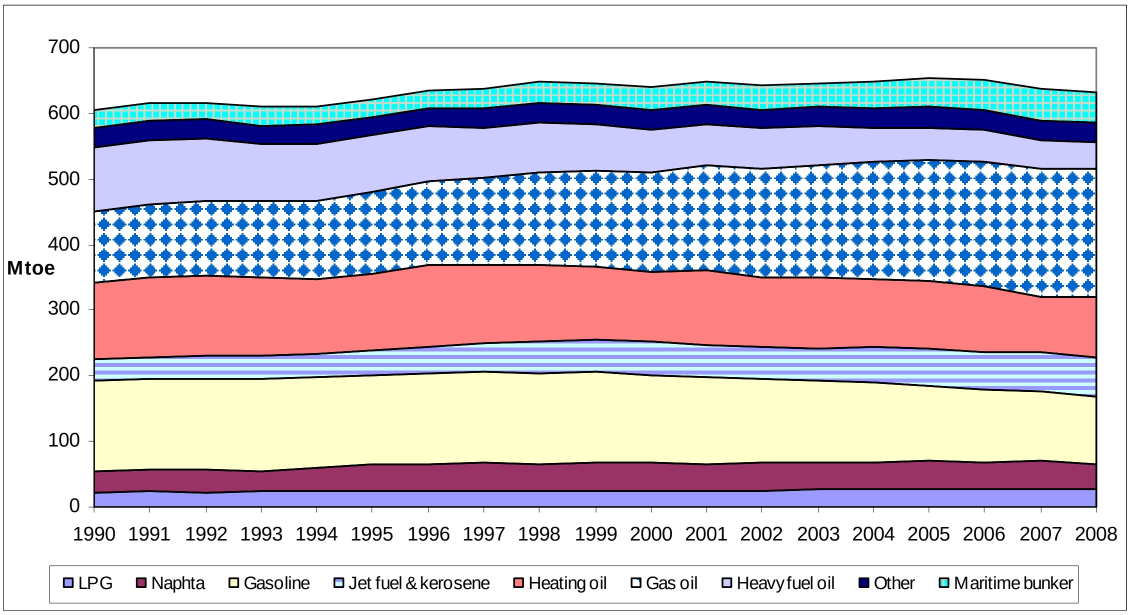
Source: BP Statistical Review of World Energy 2009

In comparison to a selection of other major refining nations, the chart above reveals that utilisation rates in the EU since 1998 have generally been high compared to the rest of the world. US utilisation rates were more constant than the EU in the first part of the last decade, though have trended downwards in the latter part. Mature markets such as the US, EU and Japan have registered falls in utilisation rates in the more recent years as China's has continued to increase, registering the highest utilisation rate in 2008, while in the Middle East, crude capacity utilisation has been relatively stable since 2006.

66 Crude throughput/production as a proportion of operable refining capacity.

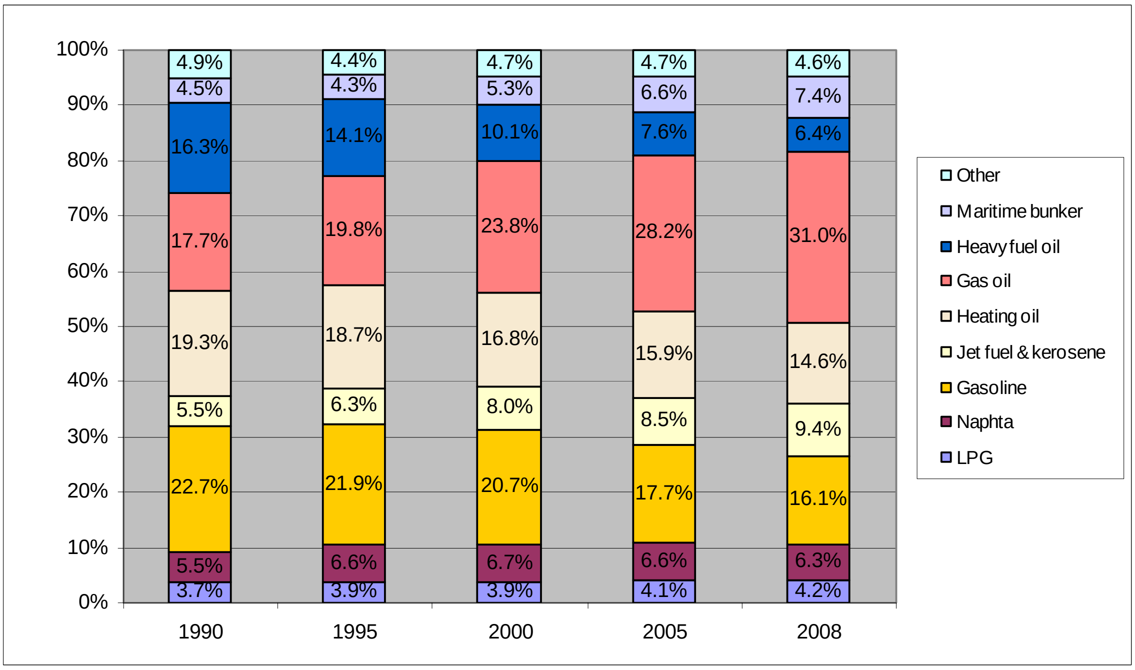
2.2.3. EU demand for petroleum products

EU 27 Petroleum product demand evolution, 1990-2008



Source: Eurostat/Primes

EU 27 Petroleum product demand mix, 1990-2008



Source: Eurostat/Primes

EU27 demand in petroleum products increased relatively steadily until 2005, after which it fell every year until 2008. This has been the result of opposing trends in key products, with, at one extreme, jet fuel and kerosene consumption almost doubling during the period; consumption in gasoil registering steady and sustained growth; demand for naphta registering an initial increase and then a fall; sustained falls in demand for gasoline and heating oil, and quite significant falls in demand for heavy fuel oil.

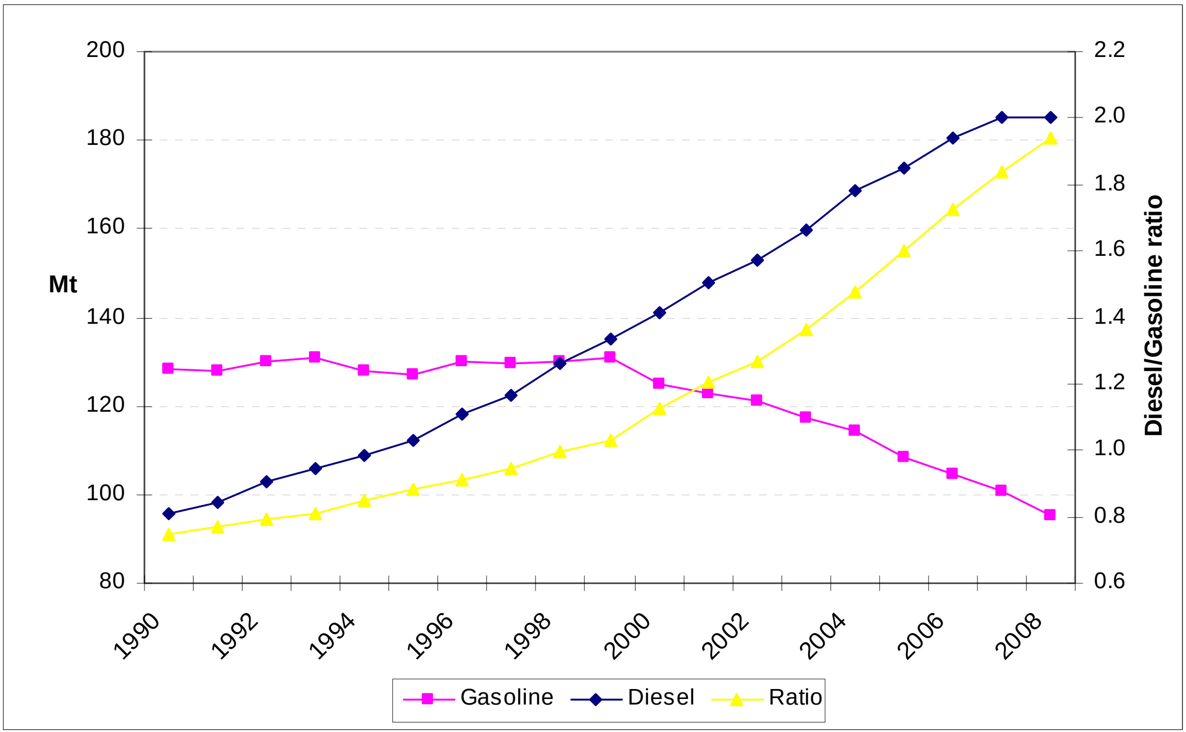
This has therefore meant if one looks at the evolution of the petroleum product demand mix in the EU, that the share of jet fuel and kerosene has increased between 1990 and 2008 from representing 5.5% to 9.4%; the share of gasoil from 17.7% to 31%; the share of gasoline from 22.7% to 16.1% and the share of heavy fuel oil from 16.3% to 6.4%.

Note that almost two thirds of the total demand for petroleum products comes from the transport sector (industry use makes up 25%, while household & services use is only 13%), and therefore that the evolution of the use of transport fuels is a vital element for the EU refining industry.

Gasoil (diesel use in the transport sector) demand represents by far the largest single component of EU demand for petroleum products. Gasoil use in the transport sector (excluding bunkers, which are shown separately in the demand charts above) can be further broken into three uses: road, rail and inland navigation. Road diesel represents the vast majority of gasoil demand (96% in 2008).

Key to understanding the important growth of gasoil since 1990, and to appreciating the importance of this product to the EU consumer, is therefore an understanding of the evolution of the demand for road diesel. To complete the picture, the evolution of the demand of gasoline as a road fuel is plotted against the evolution of demand for road diesel in the diagram below, in order to appreciate the relative evolution of these two key road fuels.

EU 27 transport diesel and gasoline demand evolution 1990-2008



Source: Eurostat

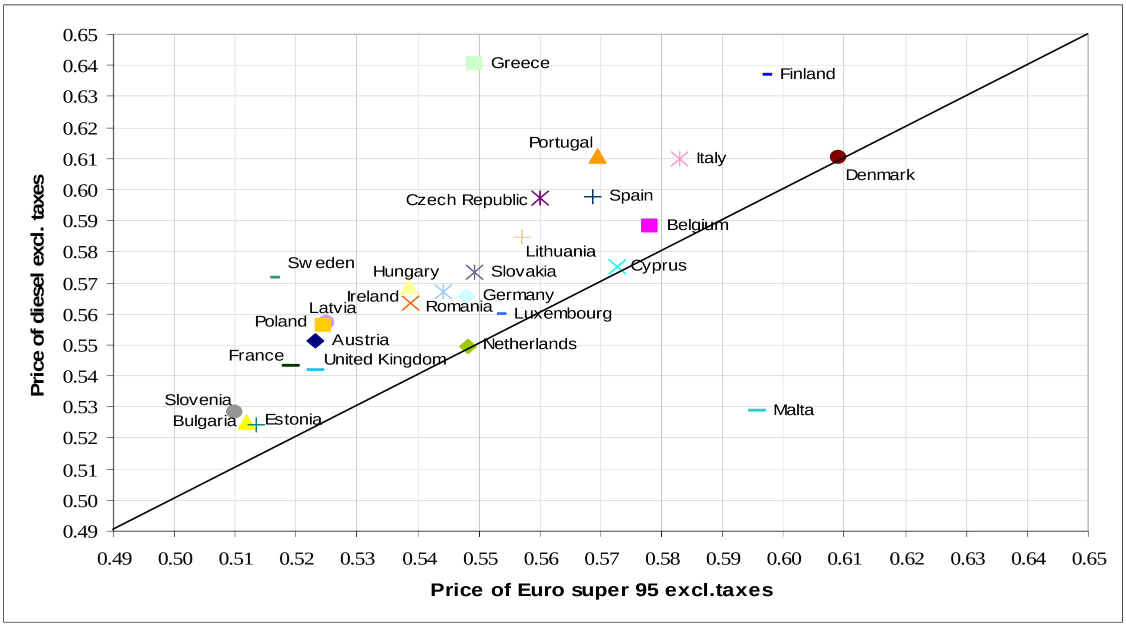
It can clearly be seen that the evolution in diesel demand as a road fuel has been at the expense of gasoline.

One factor which has driven the demand for road diesel in the EU is the higher efficiency of diesel engines, which has meant that car consumers in the EU have tended to purchase diesel vehicles in increasing proportions, despite their higher initial price.

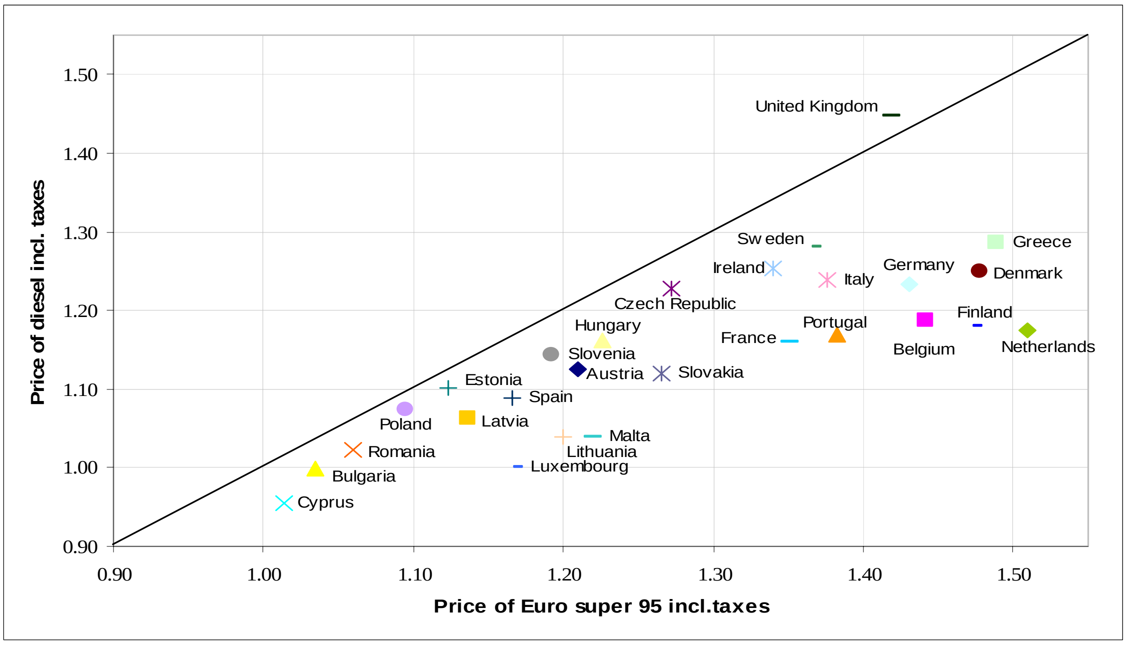
Demand for road diesel in the EU has also been growing constantly partly as a result of a tax differential between diesel and unleaded gasoline for vehicle use which has long favoured the former against the latter.

As an illustration, June 2010 figures[67] show that while pre-tax consumer prices of premium unleaded gasoline are lower than for diesel in all but one of the EU 27 Member States (Malta), higher taxes and duties on gasoline means that the price of diesel is cheaper at the pump in 26 of the 27 EU Member States (with the exception of the United Kingdom).

Vehicle diesel and unleaded gasoline tax differential, excluding and including taxes, prices as at 14/06/2010



67 European Commission Oil Bulletin, 14th of June 2010.



Source: European Commission Oil Bulletin

2.2.4. *Imports and exports of petroleum products to/from the EU*

Evolution of EU net imports/ exports in key petroleum products, 2000-2008

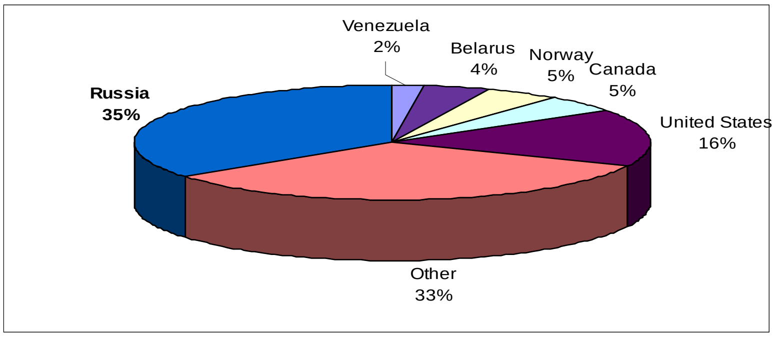
Source: Eurostat

In the last few years, the two key trade petroleum products in the EU in terms of volume have been gasoline and gasoil/diesel (include heating oil), gasoil/diesel being the main petroleum product imported into the EU while gasoline is the main product exported from the EU. Looking back at the chart showing the evolution of demand in diesel and gasoline in transport, it is interesting to note that the general trend in net imports of gasoil/diesel has been towards increasing import dependence as the demand for diesel in transport has been growing which, confirming the evolution of growth in demand and supply of gasoil/diesel and gasoline, shows that the industry has not been able to meet the growing demand for diesel[68].

68 One important thing to note with regard to the evolution of gasoil/diesel imports: 2007 net imports of gasoil/ diesel were significantly below the preceding year and constituted a significant break from the

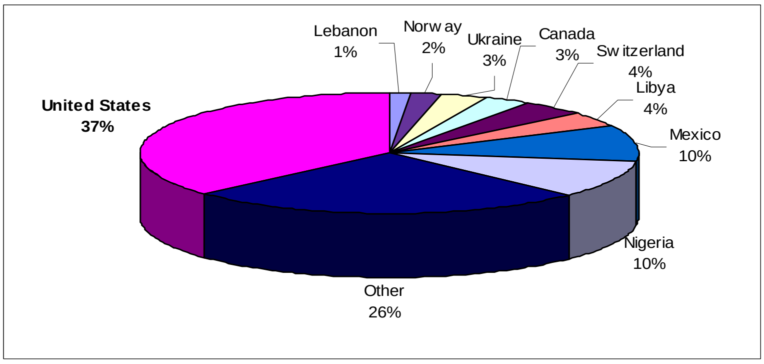
The charts below provide some details of the countries from which the EU imports its middles distillates (gasoil/diesel and kerosene/ jet fuels) and to where the EU exports gasoline. The import dependence of Russia for gasoil/diesel and the export dependence of the United States for gasoline can quite clearly be seen. In the case of kerosene/ jet fuels, the import dependence is more evenly spread out though the reliance on Middle Eastern countries is high.

Volume breakdown of gasoil/ diesel imports into the EU, 2008



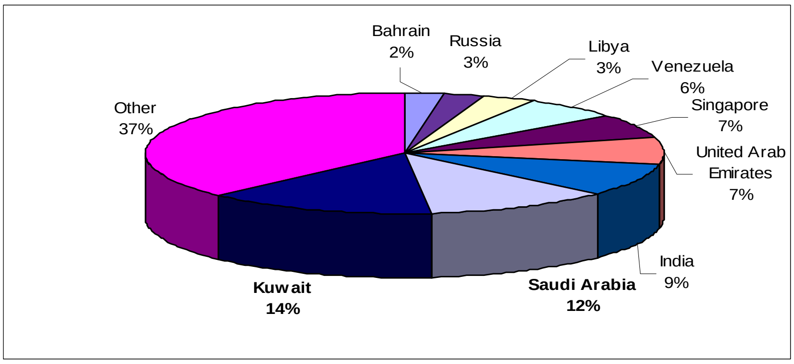
Source: Eurostat

Volume breakdown of EU gasoline export destinations, 2008



Source: Eurostat

Volume breakdown of kerosene/jet fuel imports into the EU, 2008



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trend of increasing levels of net importation in the last few years. This was a one-off event, resulting from quite significant falls in the level of total gasoil/ diesel imports into the EU (while exports remained relatively constant) due mainly to much lower gasoil/ diesel imports into Germany in 2007, resulting from reduced households consumption of heating oil that year. Germans purchased much of their heating oil needs for 2007 in 2006, ahead of an anticipated VAT increase on the 1st of January 2007.

Source: Eurostat

There are other important things to note in observing these figures denoting trade dependence:

- The EU was also quite significantly reliant on the US for gasoil/diesel imports in 2008. However, this was not so in 2007 (US only exported 5.4% of gasoil/ diesel), while EU dependence on Russia in 2007 was much more significant (47%);

- Judging from 2007 and 2008 data, the only country to which the EU exports a significant proportion of its gasoline supply is the US (In 2007, the EU exported 32% of its gasoline production to the US; the next country was Mexico, to which it exported only 6% of its gasoline production);

- The 'other 'element is significant for all products, revealing that the EU trades small proportions of petroleum products with a multitude of nations.

3. ANNEX 3: DESCRIPTION OF SCENARIO ANALYSIS AND MODEL ASSUMPTIONS

3.1. PRIMES demand projections

3.1.1. Description of main assumptions in the PRIMES 2009 Baseline and the Reference scenario

The PRIMES 2009 Baseline (BL) demand projections result from projections of developments in the assumed absence of new policies beyond those implemented by April 2009. It is not a forecast of likely developments, given that policies will need to develop. Therefore, there is no assumption in the BL that national/overall green-house gas (GHG) or renewable energy sources (RES) targets are achieved, nor of non-ETS (EU Emission Trading System) targets; CO2 emissions and RES shares are modelling results.

The PRIMES Reference (REF) scenario reveals the effects of agreed policies, including the achievement of legally binding targets on 20% RES and 20% GHG reduction for 2020.

Macroeconomic projections in the BL and the REF reflect the recent economic downturn, followed by sustained economic growth resuming after 2010, but the downturn is expected to have long lasting effects leading to a permanent loss in GDP (GDP level in 2030 is assumed to end up 10% lower than before the crisis). Average annual economic growth of 1.7% per annum is assumed over the period 2005-2030 in both the BL and REF.

Oil prices are expected to reach $88/barrel in 2020 and $106/barrel in 2030, expressed in 2008 prices, in both the BL and REF. In nominal terms, this amounts respectively to $112/barrel in 2020 and $164/barrel in 2030, assuming 2% inflation per annum.

ETS carbon prices are lower in the REF than the BL due to the achievement of the RES targets and additional efficiency measures, which decrease electricity demand and emissions. Thus ETS carbon prices (in real terms, 2008 prices) in 2030 are 39 Euros per tonne of CO2 in the BL and 19 Euros per tonne of CO2 in the REF.

Non-ETS carbon values in the REF are low due to relatively low energy demand (as a result of the crisis), policy measures (incl. for cars) and the currently inexpensive opportunities in non-CO2 GHG abatement. Non-ETS carbon value in 2008 prices is 0 Euros per tonne of CO2 in the BL and 5 Euros per tonne of CO2 in the REF in 2030.

All policies implemented by April 2009 were included in the BL. This includes the effects of measures of the current Energy Efficiency Action Plan that have already been implemented, e.g. the five Ecodesign implementing measures adopted by April 2009. The recast of the Energy Performance of Buildings Directive is not included in the assumptions, but implemented national measures on e.g. building codes are reflected.

The BL also includes legislation to reduce CO2 emissions from new cars and transport fuels which was adopted in April 2009 along with the climate and energy package. The legislation sets emission performance standards for new passenger cars as part of the Community's integrated approach to reduce CO2 emissions from light-duty vehicles. It requires significant reductions in the average fuel consumption of new cars, with binding targets of 130g/km by 2010 and 115g/km by 2020. This leads to a penetration of hybrids, equivalent to around 30% of the passenger fleet by 2030, which is a policy outcome in PRIMES, as opposed to a constraint.

Policies beyond April 2009 were also included in cases where there was very little uncertainty about how they will evolve. Thus, the ETS Directive and its full implementation were included in the BL given that clear market conditions were already established in the directive and that structures and caps for ETS were agreed before April 2009; where issues were pending (e.g. carbon leakage) a conservative approach was followed excluding auctioning for most branches for modelling purposes. Similarly, a conservative view was taken on CDM credits and banking (allowing for the maximum possible) as well as regarding future specific CO2 emissions for cars (not yet assuming fully the indicative target for 2020).

Regarding the non-ETS sectors, the BL does not impose the achievement of the agreed targets for 2020 as, similar to the targets in the Renewables (RES) directive, the achievement depends on the forthcoming policies and measures in the individual Member States. Pending the implementation of vigourous policies in the Member States, only a minimal decline of non-ETS emission by 2020 result in the BL.

With regard to the RES directive, it requires Member States to submit a National Renewable Energy Action Plan (NREAP) to the European Commission by 30 June 2010. Therefore, only the RES measures that had been already implemented at national level have been included in the BL, showing that Member States need to step up their efforts to reach their RES targets. Similarly to the RES Directive, the Effort Sharing Decision is only reflected through policy measures that have already been implemented. Specifically, the BL achieves 15% of RES share in final energy demand in 2020 instead of the 20% target, with the RES share in transport amounting to only 7% by 2020 instead of the 10% target.

Specifically, the BL projects a penetration of diesel biofuel as a proportion of final transport diesel demand of 4.3%, 7.5% and 9.2% respectively for 2010, 2020 and 2030 and gasoline biofuel penetration as a proportion of final transport gasoline demand of 3.0%, 5.8% and 7.6% respectively for 2010, 2020 and 2030.

In addition, the overall 20% reduction (below the 1990 level) target for GHG is not achieved, the BL only achieving an 8% reduction for energy related CO2 (-14% for all GHG).

The REF mirrors achievement of 20% RES and 20% GHG reduction targets for 2020, as set in the energy and climate package, which includes the achievement of national RES targets and the RES transport sub-target, as well as the respect of the ETS cap and the achievement of non-ETS national targets (GHG Effort Sharing Decision). However, energy demand declines significantly in the REF but not enough to reach the indicative 20% energy savings objective.

With regard to RES transport targets, the REF projects a penetration of diesel biofuel as a proportion of final transport diesel demand of 4.3%, 10.1% and 12.6% respectively for 2010, 2020 and 2030 and gasoline biofuel penetration as a proportion of final transport gasoline demand of 3.0%, 8.0% and 10.2% respectively for 2010, 2020 and 2030[69].

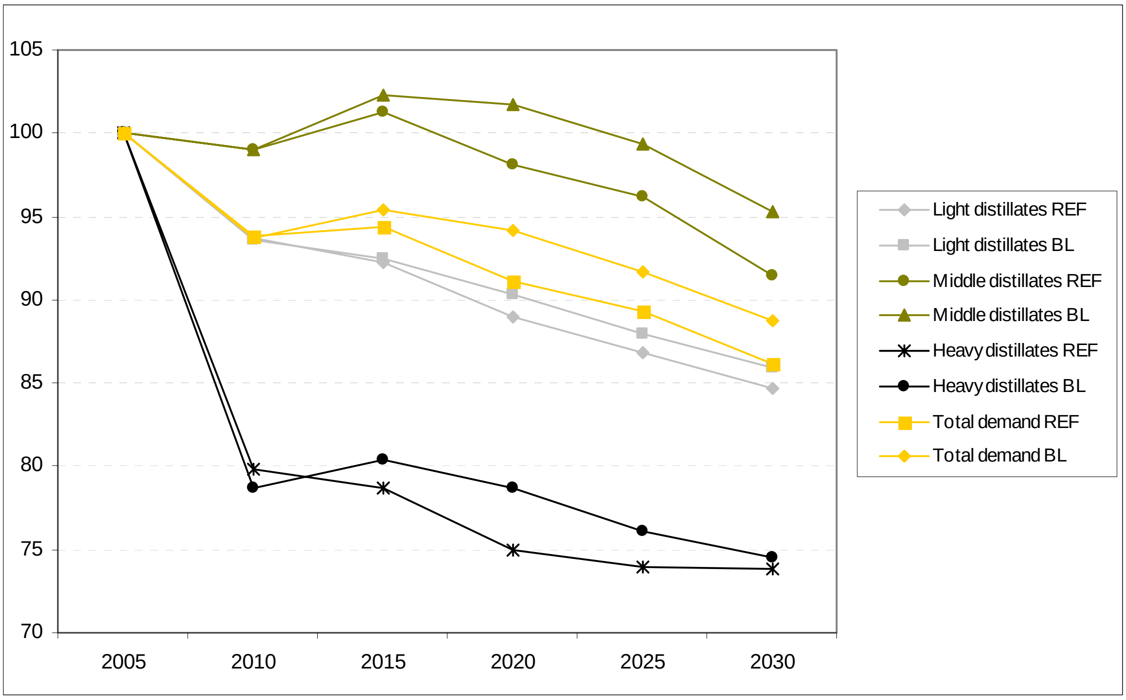
The penetration of hybrids as a proportion of total passenger car fleet in the REF is equivalent to 27% of the passenger fleet by 2030.

Other policies which the REF takes into account includes legislation adopted between April and December 2009, i.e: the four Eco-design measures, the recast of the building Directive and the labelling of tyres.

[69] Note that the total renewables target of 10% in the transport sector by 2020 is met in the reference case, with the breakdown of the 10% being split as follows: diesel biofuel 6.6%, gasoline biofuel 2.6% and green electricity accounting for 0.8%.

3.1.2. *PRIMES petroleum products demand projections*

EU petroleum products demand projections, PRIMES 2009 Baseline and Reference scenarios compared



Source: European Commission

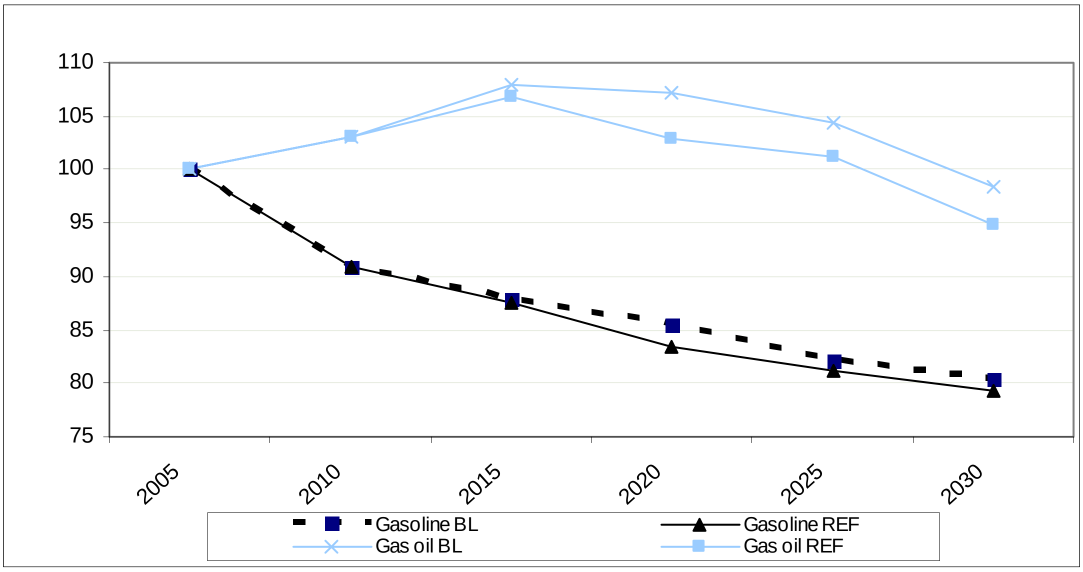
Overall petroleum product demand is projected to decline by 13.8% in the REF compared to 11.3% in the BL between 2005-2030. Both the BL and the REF project a continuation in observed historical trends in a number of products, including the continued significant falls in demand for heavy fuel oil; continued sustained falls in demand for gasoline and heating oil; a continued slow decrease in the demand for naphta. Both the BL and the REF project a break from recent trends in the growth for other petroleum products including continued but slower growth in demand for jet fuel and kerosene; and an initial but small increase in diesel, followed by a slow decline, leading to an overall fall.

As noted already in this document, one of the main challenges faced by the EU refining industry going forward would be in terms of continued growth in demand for middle distillates parallel to a fall in demand for gasoline, which poses a problem to EU refiners given the current EU refining configuration which cannot produce more middle distillates without also increasing the supply of gasoline.

If a comparison of the BL demand projections for middle distillates for different years is made, it reveals that while 2010 volumes end up slightly below 2005 levels, by 2015 demand for middle distillates is projected to grow by 2.3% from 2005 levels, after which it will gradually fall to a level in 2030 below that of 2005 (-4.7%). Note that 2015 is the turning point for the demand of gasoil, while the demand for jet fuel/kerosene is expected to continue growing to 2030. In the REF case, the trends are exactly the same, with the key differences that by 2015, demand for middle distillates will grow by less than the BL (only 1.2%), and the fall thereafter will be greater, (by 8.5% from 2005-2030).

The trend for transport diesel in the BL is for an overall fall by 2030 from 2005 levels of 1.7% compared to 5% in the REF case. In comparison, the BL projects gasoline demand to fall by 19.6% in comparison to a projected fall of 20.7% in the REF case.

PRIMES Baseline and Reference transport diesel and gasoline projections comparison



Source: European Commission

Key differences between the BL and the REF cases are in terms of the assumed penetration of renewables and the use of alternative fuel vehicles in the transport sector[70].

The Baseline projects a penetration of diesel biofuel as a proportion of final transport diesel demand of 4.3%, 7.5% and 9.2% respectively for 2010, 2020 and 2030 and gasoline biofuel penetration as a proportion of final transport gasoline demand of 3.0%, 5.8% and 7.6% respectively for 2010, 2020 and 2030.

In contrast, the Reference scenario projects a penetration of diesel biofuel as a proportion of final transport diesel demand of 4.3%, 10.1% and 12.6% respectively for 2010, 2020 and 2030 and gasoline biofuel penetration as a proportion of final transport gasoline demand of 3.0%, 8.0% and 10.2% respectively for 2010, 2020 and 2030[71].

Note in addition that the penetration of hybrids as a proportion of total passenger car fleet (assumed to be equivalent to 30% of the passenger fleet by 2030 in the Baseline and 27% of the passenger fleet by 2030 in the Reference Scenario) contributes significantly towards meeting the requirements of the CO2 from cars regulation.

The penetration of electric vehicles is insignificant in both the Baseline and Reference scenarios.

70 Note that the demand projections shown above and used in the OURSE model are net of biofuel demand.

71 Note that the total renewables target of 10% in the transport sector by 2020 is met in the reference case, with the breakdown of the 10% being split as follows: diesel biofuel 6.6%, gasoline biofuel 2.6% and green electricity accounting for 0.8%.

3.2. Description of OURSE refining module of the POLES energy model

The objective of the OURSE model is to represent the refining activity at a world scale level. It is included in the POLES (Prospective Outlook for the Long-term Energy System) model.

Because the model designed to represent the world-wide refining industry must have a limited number of equations, a representative refinery has been defined for a restricted number of regions in the world (corresponding to the POLES nomenclature). Moreover the crude oil supply has been aggregated (the size of the model is directly linked to the number of crude oil which are introduced in the model). Finally, as the model has to represent the oil product exchanges between the main regions in the world, a multi-refinery approach is considered.

The main inputs of the model are (i) the oil product demand (in terms of both quantities and specifications), (ii) the crude oil availability, (iii) the CO_2 emissions restrictions and taxes. The main output are (i) the refineries throughput (activity level), (ii) the products blending, (iii) the products trade, (iv) the investments (technology dynamic of the refining processes), (v) the marginal costs of oil products (supply prices), and (vi) the pollutant emissions.

All the relevant techno-economic characteristics of the oil refining industry (technical processes, investment and operating costs, pollutant emission factors...) are included in the model.

The refining model of POLES is able to simulate the consequences of:

– changes of oil product demand such as a modification of the share of the automotive fuels (gasoline and diesel)

– changes of specification of oil products (sulphur content of oil products for instance)

– carbon emissions regulation (bounds and taxes)

– adoption of alternative type of policies.

As the model permits exchanges of petroleum products between the main regions in the world, the refining industry has been split into several geographical areas. In each refining area, it is assumed that the crude oils are processed together and that there is only one investment variable for each unit. Moreover the model implicitly allows intermediate product exchanges inside each area.

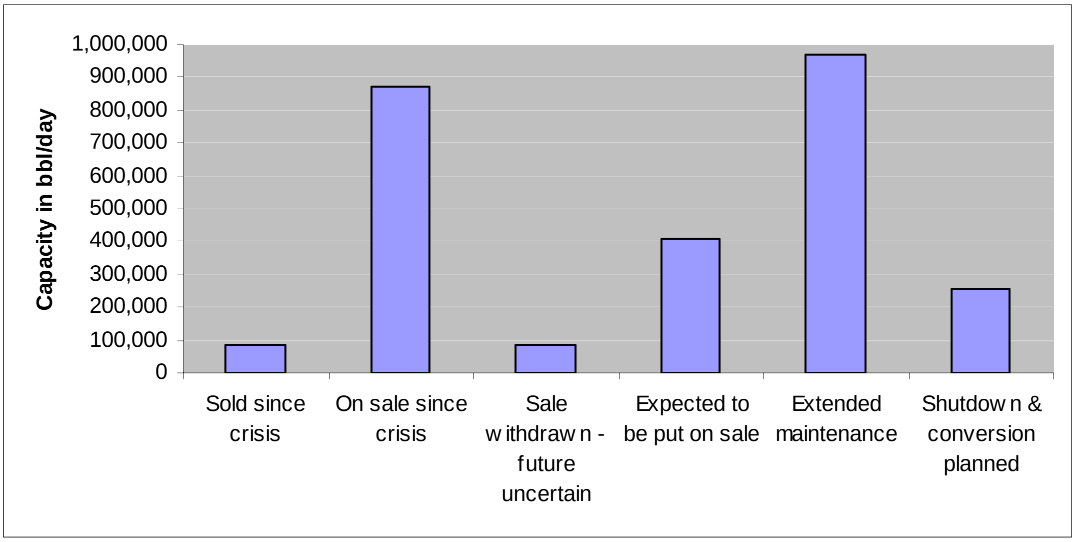
The geographical considerations upon crude oil supply and petroleum product demand, and the technical analysis of the refineries lead to nine refining areas being defined in the world:

Area 1 - Z1	North and Central America : Canada, USA, Mexico
Area 2 - Z2	Latin America,
Area 3 - Z3	North Europe : all Europe except South Europe
Area 4 - Z4	South Europe : Italy, Greece, Portugal, Spain, Turkey, Croatia, Slovenia, Former Yugoslavia
Area 5 - Z5	Former Soviet Union (CIS)
Area 6 - Z6	Africa
Area 7 - Z7	Middle East
Area 8 - Z8	China
Area 9 - Z9	Other Asia

The general denominations "Latin America", "Former Soviet Union", "Africa", "Middle East" are those which are used by the International Energy Agency (IEA) in its statistical yearbooks (energy balances).

4. ANNEX 4: SUMMARY OF KEY PROJECTS & PLANNED/ACTUAL DIVESTMENTS IN THE EU REFINING SECTOR

Summary of EU refineries planned/actual divestments and shutdowns since 2008



Source: European Commission. Note: This information has not been confirmed by the EU refining industry and is contained here for illustrative purposes.

- Known planned/actual divestments and shutdowns in EU refining capacities since the start of the crisis in 2008 extend to 18 out of 104 refineries in the EU, representing some 2.7 million bbl/day/134 million tonnes per year of crude capacity, equivalent to 17% of total EU refining capacity.
- Actual deals have been few and far between, with the exception of the sale of a small processing facility in Belgium by Petroplus and part of a Dutch plant by Total.
- In general, both planned and actual divestments have been of simple refining plants of mainly small capacity.
- Assets which have been put on sale since the crisis and are still awaiting buyers amount to close to 900,000 bbl/day. It is expected that at least another 400,000 bbl/day of capacity is likely to be formally put on sale in the foreseeable future as a result of the crisis.
- All of the known potential/actual buyers of assets on sale are non-Europeans. Other than the Russian Lukoil, willing acquirers of EU refining assets include India's Essar and Reliance and China's PetroChina though no deals have been concluded yet. Swiss oil trading firm Vitol bought Petroplus's processing unit in Antwerp last year (21,000 bbl/day) while American refiner Valero has expressed interest in purchasing Chevron's Pembroke refinery (202,000 bbl/day).
- While interest in acquiring stakes in the EU refining market by oil companies located in neighbouring countries such as Lukoil is to secure outlets for their crude production, the interest of PetroChina stems from the wish to grow their global presence in refining, and they see the current environment of low margins, and therefore low prices, as opportune. Though not from a neighbouring country, India's Essar sees the acquisition of EU assets as an opportunity to turn them into import, storage and distribution centres for its refined products produced at its home refinery in Vadinar.

- Refining capacity that is known to have been temporarily shutdown as a result of the crisis amounts to over 900,000 bbl/day. These units could either be restarted or eventually also be put on sale, depending on market conditions.
- The numbers employed in the refineries represented by these capacities are not known and are not formally communicated by refiners.
- Note that no complete shutdowns have been announced by EU refiners. Since the beginning of the crisis, uneconomic assets that have not been put on sale have generally been subject to extended maintenance/temporary shutdowns, while assets that have been formally 'shut down' are in fact being converted to depots/storage facilities (equivalent to 258,000 bbl/day, to date).
- There have also been reports of planned investments in extra diesel capacity/ hydrodesulphurisation/coker capacity at medium to large, more complex plants, as follows:

ExxonMobil

- The company announced plans in December 2008 to invest $1 billion in extra diesel capacity expansion (by 143,000 bbl/day) in three of its refineries (two in the US, one in Belgium: Antwerp). The Antwerp refinery has a capacity of 305,000 bbl/day.

Repsol

- Repsol was granted a Euro 400 million loan from the European Investment Bank for the construction of a coker unit at its 220,000 bbl/day Petronor refinery in Bilbao, Spain. The project consists of a 2 million tonne/year coker unit and related treatment units. The coker plant, which will cost a total Euro 780 million, will convert heavy fuel oils into diesel, gasoline, propane and butane;

Royal Dutch Shell

- Shell is planning on continuing to invest in larger integrated refining and chemical sites, including a $500 million investment in a new hydrodesulphurisation unit at the firm's 406,000 bbl/day Pernis plant.

Total

- Earlier in the year, Total announced its intention to restructure its refining output to reduce its production of gasoline and increase its production of diesel. This would include investing 800 million of Euros in adapting its French Gonfreville (338,000 bbl/day) refinery to change its output in favour of diesel.

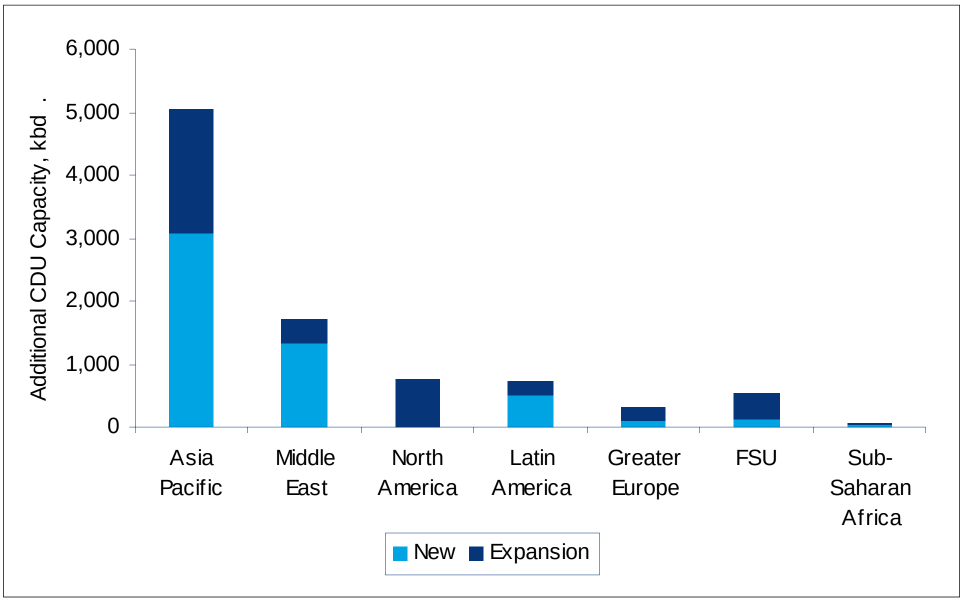
5. ANNEX 5: NON-EU REFINING CAPACITY DEVELOPMENTS & DIVESTMENTS

The IEA reported in May 2009[72] that the impact of the financial and economic crisis on the global refining sector amounted to 1.6 million barrels/day of postponement or cancellation of new refining capacity (by April 2009). In addition, according to the IEA some 800,000 bbl/day of refining projects have been delayed for 18 months or more.

The crisis has certainly hit all parts of the globe, with falling refining margins and utilisation rates recorded in many regions (more details in annex 2).

Future prospects in terms of additional refinery capacity are however for some 9 million bbl/day between 2008 and 2015, according to Wood Mackenzie, equivalent to a 10% increase in total world refinery capacity.

Expected additional refinery capacity by region, 2008-2015



Source: Wood Mackenzie

According to the above data, 59% of world new refinery capacity between 2008 and 2015 (amounting to 3 million bbl/day) will be in the Asia Pacific region, while 50% of world capacity expansion will come from that region (2 million bbl/day). The Middle East will contribute 26% of world new refinery capacity during that period, and 10% of world capacity expansion. In comparison, Europe is expected to contribute 2% of world new refinery capacity during that period, and 5.6% of world capacity expansion, amounting in total to 322,000 bbl/day of additional capacity.

North-America

North-America, which includes the US, Canada and Mexico, has total refinery capacity of 21 million bbl/day, equivalent to 24% of total world refining capacity.

In spite of the challenging climate and its impact on the industry in that region, it is expected that close to 800,000 bbl/day of additional capacity will come on stream between now and 2015 in North-America.

[72] Impact of the Financial and Economic Crisis on Global Energy investment, IEA, May 2009.

Middle East

The Middle East consisting of Iran, Iraq, Jordan, Kuwait, Oman, Qatar, Saudi Arabia, UAE and Yemen has 7.6 million bbl/day of refining capacity, equivalent to 9% of world refining capacity.

By 2015, the region is expected to add 1.7 million bbl/day of refinery capacity, amounting to almost a quarter of current capacity in the region.

Asia-Pacific

The Asia Pacific region consists of China, Asia, South Korea, Indonesia and Japan along with many other smaller refining countries. The region has capacity of 25 million bbl/day, amounting to 28% of world refining capacity.

As highlighted above, the biggest expectations for additional refinery capacity in the world in the next five years are in the Asia Pacific region. It is expected to add five million bbl/day of additional capacity by that date, amounting to 56% of total additional world capacity and amounting to increasing existing capacity in that region by 20%.

A number of EU oil majors are attempting to establish a refining presence in China, such as BP, which is in talks with state company Sinopec on a new refining joint venture there, while Total is known to be in talks with Sinochem and China Petroleum & Chemical about a number of refining projects also in China.

Other regions

- South and Central America which includes Brazil, Argentina and Venezuela as well as other small refining countries has 6.6 million bbl/day of refining capacity, equivalent to 7% of total world refining capacity. Around 500,000 bbl/day of new refining capacity is expected in that region between 2008 and 2015, and some 200,000 bbl/day of capacity upgrades of mainly coking and hydrocracking, mainly in Brazil and Venezuela.

- The former Soviet Union region, which includes Russia, Ukraine, Belarus, Georgia among others, has 8 million tonnes of refining capacity, equivalent to 9% of total world refining capacity. An additional 500,000 bbl/day of new and expanded capacity is expected to come on stream in that region by 2015.

- Africa has 3 million bbl/day of refining capacity, amounting to 3.6% of world refining capacity. Only very small capacity additions are expected in the next ten years, amounting to less than 100,000 bbl/day.