Energy files during the third quarter of 2013

On 19-20 September, Vilnius hosted an informal meeting of Energy Ministers in preparation to the next Energy Council of 12 December 2013. The meeting put on its agenda the key energy priorities of the Lithuanian Presidency of the Council of the EU, including completion of the EU energy internal market in 2014 and the strengthening of the external dimension of EU energy policy. Discussions were held on how the extension of the energy acquis *beyond the borders of the EU could ensure a level playing field for EU power producers vis-à-vis producers outside the EEA. The Commission also presented the results of the public consultation on the Green Paper "A 2030 framework for climate and energy policies", in view of the Commission's upcoming strategy framework for 2030. Broad consensus was reached on greenhouse gas emission reduction but no agreement on the form of new renewable targets. As to the implementation of the energy efficiency Directive, results will be published next June.*

On 9 October, the Commission will adopt the final list of projects of common interest (PCIs) eligible for EU funding (including the Connecting Europe Facility). This list is required by the TEN-E Regulation (EU) No 347/2013 which lays down guidelines for the development and interoperability of priority corridors and areas of trans-European energy infrastructure. The list of 248 projects will be submitted to the European Parliament in the form of a delegated act for examination over two - maximum 4 - months. The selected PCIs concern predominantly electricity and gas projects, each of them connecting to one of the 12 European priority corridors. The Lithuanian Council Presidency will also organise a high level conference on the future of EU energy infrastructure, with particular focus on the implementation of the first European list of projects of common interest, on 4-5 November 2013 in Vilnius.

Regarding the external aspects of European energy policy, the European Commission has published a review of the main achievements since 2011. The report issued on 13 September (COM(2013) 638 final) addresses the challenges of the diversification of external energy sources (such as the Southern Corridor) due to the increased demand for energy, the competitive advantage of the US' unconventional oil and gas production, and the inter-governmental agreements potentially incompatible with EU law. The first EU list of PCIs will also include some links to non-EU countries, and interconnection capacities with third countries will continue to be a high priority in view to establish a pan-European energy market.

The European Parliament shall endorse the multiannual budget of the EU and its implementing programmes for the period 2014-2020 at its plenary session between 21 and 24 October. The energy policy objectives of the European co-legislators now remain to finalise ongoing legislative dossiers under the *current legislature. These legislative priorities include the "carbon market fix" proposal, the notification of investment projects in energy infrastructure and the amendment of legislation on biofuels.*

INTERNAL MARKET

European Emissions Trading System

In its carbon market report 2012 from last November, the Commission called on the Council and the Parliament to enable the amendment of the Auctioning Regulation to change the auctioning timetable for carbon allowances related to the transition to the third trading period (2013-2020) of the ETS.
Due to the allocation of too many emission allowances by EU Member States, and because firms had actually reduced their emissions in the first two years of the first phase, carbon prices have gradually dropped since 2005. To remedy this, the Commission is proposing to withhold future-dated emission allowances worth 900 million euro in the current trading period, which would be re-introduced to the market in the next auctioning phase.
The price of emission permits fell again to 2.81 euro/tonne after the opinion-giving ITRE committee opposed the "carbon market fix" or "trading fix" proposal on 24 January 2013 and then reached a historical record low of 2.46 euros in April, when the Parliament returned the file to the ENVI committee for further discussion.
According to a new compromise reached on 19 June between the EPP, the Socialists and the Liberals, the Commission would only have the right to delay auctions of carbon permits in exceptional circumstances and just once during the 2013-2020 trading period, provided an impact assessment shows the sectors concerned will not face "significant risk" of companies relocating outside the EU. MEPs also capped the number of credits to be frozen at a maximum of 900 million, and auction revenues worth 600 million permits shall be earmarked for innovation projects.

Procedure
The compromise proposal (2012/0202(COD), rapporteur Mr. Matthias Groote (S&D, DE) was adopted by Parliament in July. Negotiations in view of an agreement between Parliament and the Member States are expected to be conducted under the Lithuanian Presidency.

ENERGY INFRASTRUCTURE

Investment projects in energy infrastructure

The proposed Regulation establishes a common framework for the notification to the Commission of data and information on investment projects in energy infrastructure. Member States are required to notify the Commission every two years of data and information on investment projects concerning the production, storage and transport of oil, natural gas, electricity (including electricity from renewable sources), biofuels and the capture and storage of carbon dioxide. Investments to be notified to the Commission include: (i) projects both planned and under construction; (ii) transformation of existing infrastructure as well as (iii) decommissioning projects of a certain size, on a five-year horizon, in the territory of Member States, including interconnections with third countries.

Parliament's Energy committee proposes to extend the scope of the proposed Regulation by lowering the threshold of the size of installations to include, for instance, also infrastructure in the coal, carbon capture, nuclear, and district heating and cooling sectors. Other amendments aim at minimising the administrative burden related to reporting and at reinforcing provisions relating to the confidentiality of information and data security.

Procedure
Parliament's ITRE committee has adopted its report (2013/0082(COD), rapporteur Adina-Ioana VĂLEAN (ALDE, RO) on 26 September. The rapporteur will enter into negotiations with the Council represented by the Lithuanian Presidency mid-October.

ENERGY EFFICIENCY

Biofuels Directive (indirect land-use change)

In 2010, the Commission carried out a review of the impact of indirect land-use change (ILUC) on greenhouse gas emissions, that is the conversion of formerly non-agricultural land (forests) to food production and the diversion of agricultural land from food to biofuel production. It acknowledged that ILUC can reduce the greenhouse gas emissions savings associated with biofuels and bioliquids in comparison to the fossil fuels they replace. Therefore the Commission proposed in October 2012 to amend the Fuel Quality Directive (98/70/EC) and Renewable Energy Directive (2009/28/EC) to promote, on the one hand, a transition to "advanced" biofuels that deliver substantial greenhouse gas savings and, on the other hand, to limit the proportion of "conventional" biofuels produced from food crops (with potential ILUC emissions) to 5% within the EU's current 10% renewable energy target for 2020 for the transport sector. It also proposed an increase to 60% of the minimum greenhouse gas saving threshold for biofuels and bioliquids produced in new installations, with effect from 1st July 2014, and the introduction of the reporting of estimated emissions from carbon stock changes caused by indirect land-use change.

Member States generally supported the aim to address indirect land-use change. However, many national delegations are concerned with a policy shift towards advanced biofuels, on grounds that it could jeopardise existing investments in conventional biofuel production and render the achievement of the existing EU renewables objectives more costly and challenging.

Procedure
The parliamentary report (2012/0288(COD) of MEP Corinne Lepage (ALDE, FR) was put to the vote in Parliament on 11 September. According to the amendments adopted by Parliament, the share of conventional (first generation) biofuels should be capped at 6% of the total energy consumption in the transport sector, whereas advanced biofuels (sourced from seaweed or certain types of waste) should represent at least 2.5% by 2020. Parliament endorsed the 2020 target to take into account ILUC emissions when calculating the greenhouse gas emission savings required under the sustainability criteria set out in the Fuel Quality and Renewable Energy Directives. However, Parliament removed the numerical reference to the estimated greenhouse gas emissions caused by ILUC.
Due to a tight vote, the rapporteur, Ms. Lepage was two votes short of receiving a mandate to negotiate with member states. The Council will therefore adopt its position independently from Parliament, and if it will differ from Parliament's first reading text, a second reading will be required. The red line for Parliament's rapporteur is not to go above a 6,5% share of first generation biofuels and the introduction of the ILUC factor as of 2020. European Ministers for Environment will next meet on 14 October.

Swiss Supreme Court
Nuclear Security

ECJ T-465/11
Globula v European Commission

The Swiss Supreme Court was recently called to decide whether the time cap imposed on the operating license of one of nuclear power plants in Switzerland as a precautionary measure to enhance nuclear security was grounded in law. In a majority (4 to 1) decision (Docket 2C_347/2012 and 2C_357/2012 of 28 March 2013, <http://www.bger.ch/fr/index.htm>, published in the Supreme Court Reporter Volume 139 part II page 185), Switzerland's highest court held that the responsibility to ensure compliance with the nuclear security prerequisites lied primarily with the licensing authority. The Court also pointed out that the Swiss conception of nuclear security was not absolute but included core security measures as necessary prerequisite to the operating licence being granted or renewed, and additional risk-reducing measures subject to other financial, economic and operational considerations.

Facts

Operational since the early 1970s, Mühleberg nuclear plant (Mühleberg NPP) it the only of the five operating nuclear power plants (NPP) in Switzerland subject to a time-limited operating license; such limitation was imposed following identification of certain technical problems in the commissioning phase. The initial operating licence was extended on several occasions for additional limited time-periods, the last time until 31 December 2012. Its operator Bernische Kraftwerke Energie AG (BKW) successfully sought the removal of the time-cap from the ministerial department in charge of delivering said authorisation (the Federal Department of the Environment, Transport, Energy and Communications or DETEC) on the ground of it being (a) discriminatory against BKW, and (b) based on pure political considerations devoid of any legal grounds and justified by no security considerations.

A group of local residents challenged that decision before the Swiss Administrative Court (the Administrative Court) invoking security concerns (cracks in the nuclear reactor core shroud, lack of alternative cooling system, untested resistance to seismic exposure). Incidentally, to substantiate their case, the applicants requested full access to Mühleberg NPP's application file, including nuclear security reports, as part of the applicants' core right to prepare and argue their case. Partial access was eventually granted, with restrictive conditions for those internal documents containing confidential commercial information, exclusive any security sensitive information, for which the public interest to preserve secrecy was deemed to prevail over the applicants' individual interest to argue their case (Docket A-667/2010, interim decision of 8 December 2010; all Administrative Court's decisions quoted hereafter are available on its website <http://www.bvger.ch/>). The Administrative Court declined, however, to consider the applicants' motion for the immediate closure of Mühleberg NPP (Docket A-667/2010, interim decision of 31 May 2011).

The Administrative Court partly admitted the appeal and imposed a time-cap on the operating licence until 28 June 2013 (Docket A-667/2010, final decision of 1 March 2012). In summary, the Administrative Court held that such time-limit was justified by law pending the elimination of security-related concerns and other operational deficiencies, a full withdrawal of the operating licence being deemed, in such case, out of proportion. It also instructed the BKW to submit, in support of its formal application to extend the operating licence beyond June 2013, a comprehensive maintenance program detailing the investments contemplated to remedy the shortcomings and secure safe operation over the estimated residual operating life of the Mühleberg NPP. The operator BKW, and DETEC challenged this decision before the Swiss Supreme Court, leading to the commented decision.

Finding

The Supreme Court upheld the challenge and annulled the Administrative Court's decision, effectively restoring the DETEC's decision to extent the operating license of Mühleberg NPP without any time-cap thereto. It considered, *inter alia*, that the Administrative Court had no authority to impose such time-cap based on the legal allocation of responsibilities between licensing authorities and monitoring authorities (*infra 1*) and procedures (*infra 2*), and that by all means the imposition thereof proceeded from misconstruction of nuclear security as prevailing under Swiss law (*infra 3*) .

Licensing authority versus monitoring authority

The Swiss Supreme Court drew a clear line between the competence of the licensing authority and those of the monitoring authority (Supreme Court's 28 March 2013 decision, ground 9). Until 2008, the Principal Nuclear Safety Division (HSK) within the Swiss Federal Office for Energy (itself part of the operating licensing authority DETEC) was in charge of monitoring nuclear safety and the security of nuclear installations. As from 2009, such technical specialized competences were transferred to a fully independent regulatory body, the Swiss Federal Nuclear Safety Inspectorate (IFSN). Consequently, the operating licensing authority, whilst not exempted from proceeding to a critical appraisal of the IFSN security assessment, may not substitute its own appreciation to the IFSN's unless for compelling conclusive reasons (as determined if required with the technical support of the Swiss advisory Commission for Nuclear Security).

These fundamental principles extend to the Administrative Court when requested to review the licensing authority's decisions in challenge proceedings: said Court should not depart, at its own discretion, from the prior assessment of the specialized authority in charge, but should only do so for conclusive reasons. Likewise, it should not impose additional operating restrictions unless they are imposed by law and require no prerequisite technical clarifications.

Relationship between the licensing, supervision and license withdrawal procedures

Following the same line of reasoning, the Swiss Supreme Court clarified the interaction between licensing, monitoring and licence withdrawal procedures (Supreme Court's 28 March 2013 decision, ground 10).

An operating license is granted, usually for an indeterminate period of time, when all the prevailing legal security prerequisites are met; the onus lies with the DETEC to verify this through the licensing procedure. Upon the issuance of the operating licence, the responsibility lies with the license holder, under the constant monitoring of the IFSN, to ensure that the installations and equipments remain in "good state" during their entire operating life, and to take all the measures required by the experience, the state of the equipment and considering new technologies, to further enhance the nuclear security. The operating license is withdrawn when the legal security prerequisites for granting it are no longer met, or should the license holder fail to proceed to the security improvements required to adapt to enhanced legal requirements and/or science and technology evolution notwithstanding being formally invited to do so.

The security assessment of a NPP is thus a continuous process, and constant additional security checks, queries and investigations and improvements are standard practice; hence by no means should an operating license be denied because the state of the installations at the time the license application might no longer meet some requirements that will presumably be imposed in the future. The licensing authority may set a time-limit to the operating license, only when it anticipates with a sufficient degree of certainty that legal security prerequisites will no longer be satisfied at a later stage and that the constant monitoring will not suffice to guarantee the proper maintenance of the installations.

In the case at hand, the Supreme Court considered that the security concerns regarding the Mühleberg NPP are appropriately addressed through the constant monitoring of IFSN, hence that the Administrative Court's decision to restore a time-cap was both materially unjustified and proceeded from a misapprehension of the legal allocation of responsibilities between the licensing and monitoring authorities. In effect, considering that the maintenance proposal approval process before the DETEC could not realistically be completed by June 2013, the time cap amounted to an unjustified temporary denial of the operating license beyond June 2013.

Nuclear security under Swiss law

More generally, the Swiss Supreme Court clarified the Swiss law notion of nuclear security, setting a limit as to how much precaution could be realistically required in that area (Supreme Court's 28 March 2013 decision, ground 11).

Borrowing from approach prevailing *inter alia* in environmental law, the Supreme Court developed a two-tier approach to nuclear security, namely:

- A first tier, comprising those core legal security prerequisites, which based on the experience and the state of science and technology, are indispensable and therefore must imperatively be satisfied regardless of any financial considerations. These are the mandatory security prerequisites to all operating license hence subject to the determination by the licensing authority through the licensing process.
- A second tier, including all those additional, precautionary, risk-reducing measures which are to be taken insofar as they compatible with others aspects (technical, financial, and operational) of the installations (so-called As Low As Reasonably Achievable or ALARA principle). These are the additional security enhancement measures that can be ordered by the monitoring authority throughout the monitoring process but which, as such, constitute no sufficient ground to either deny or impose a time-cap on an operating license.

Swiss law therefore provides for a high degree in security, but not a zero risk and absolute security, that would be unrealistic in the field of nuclear energy. It set forth core legal security prerequisites, prescribes additional security precautions as required by monitoring authorities to contain the risks and consequences of their materialization to an acceptable degree, and assumes the residual minimal risk as an 'acceptable risk'.

In the case at hand, the Supreme Court held that a June 2013 time-limit would be justified had it been considered that, beyond that date, the IFSN's constant monitoring of the installations and equipment would no longer suffice to guarantee compliance with the legal security prerequisites and required maintenance. Such time cap is not justified when the outstanding issues concern additional security precautions in the ALARA area or to adjustment to new technologies or enhanced security demands. The Supreme Court concluded that the identified outstanding security concerns did not relate to legal security prerequisites hence did not justify a time-cap.

Comment

Much publicised when the decision was taken at a public hearing, largely misunderstood in the midst of Switzerland's flimsy attempt to emancipate from nuclear power, this decision has attracted surprisingly little attention when

the fifty-page reasoning was made public few months later, in July 2013. Yet this leading decision does not do what it appears to say on the box: it is no endorsement of nuclear energy.
In effect, in a separate proceeding, some of the Applicants obtained that the operating license authority DETEC re-examine whether the legal security prerequisites to the operating licence attribution were still satisfied. The Swiss Supreme Court upheld, only weeks after the noted decision, the Administrative Court's decision that alleged security concerns were sufficiently concrete and convincing to require such immediate re-examination independently from the constant supervision of the IFSN (Docket 2C_860/2012, decision of 14 May 2013, confirming the Administrative Court's decision Docket A-6030/2011, decision of 30 July 2012).
Rather, this decision is a firm and cautiously crafted restatement of who does what in the complex web of nuclear energy, an acknowledgment of the inexorable nuclear risk, and a gentle remainder of the fundamental principle of the separation of powers in a democratic society.

By Dr Isabelle Fellrath
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Globula v. European Commission
In February 2011, the Czech authorities had notified to the Commission their decision to exempt Globula partially from the obligation to provide third party access to an underground gas storage facility in Damboøice. In June the Commission ordered the Czech Republic to withdraw their decision, applying the procedure of the Third Gas Directive which had entered into force in the meantime in March 2011.
By its judgment of 06.09.2013 the General Court annuls the Commission Decision.
The Court does not contest that new procedural rules – contrary to substantive rules – are generally held to apply to all proceedings pending at the time when they enter into force. However, the Court estimates that the procedural changes of the Third Gas Directive cannot be considered in isolation from the substantive changes. The Court also emphasizes the significant role that ACER, the European Agency for the Cooperation of Energy Regulators, now plays as a new actor in the procedure to be followed by the national authorities. The Court concludes that the procedural and substantive changes introduced by the Third Gas Directive – both on European and on national level – form an indivisible whole, with the result that the entirety of those provisions may not be accorded retroactive effect.
The European Energy Journal will try to analyze the subtleties of the judgment in its next issue.

EU Law and the Development of a Sustainable, Competitive and Secure Energy Policy

Author Bram Delvaux
Reviewed by Helmut Schmitt von Sydow

This book is the result of several years and experience culminating in the author's doctoral dissertation in Leuven, which he has now edited, updated and revised. So it is over 400 pages thick, with 40 pages of documentation and 1348 footnotes.

The first hundred pages explain the objectives of the European energy policy and present the secondary legislation; that is useful even if there are no striking news. The central chapter fills 200 pages and examines the principles of EU law and the legal bases prior to the Lisbon Treaty; that looks epic and may appeal mainly to academics and historians, but it helps to prepare the two final chapters (100 pages) on Union competences after the adoption of the Lisbon Treaty and on future options for the European energy framework. That is the part lawyers and politicians will jump to.

On Lisbon in general, the new categories of Union competences, the revised Protocol on subsidiarity and proportionality and the relevant changes concerning Articles 122, 191, 270 and 352 TFEU are well explained. On Article 194 establishing a specific energy competence, the author scrutinizes the text paragraph-by-paragraph, sentence-by-sentence, trying to uncover their meaning and scope. He even looks into the relation between Article 194 and the Gas Security Regulation of 2010. But as many scholars, he fails to look at the genesis of Article 194: The decisive parts of Article 194 were not written at Lisbon but during the Intergovernmental Conference in 2004 and were already outdated when Lisbon rushed through them avoiding any substantive discussion. The new energy policy does not stem from the Lisbon Treaty but from the conclusions of Heads of State and Government starting with the informal meeting of 2005 at Hampton Court upon the initiative of British Prime Minister Tony Blair, as the author correctly mentions on page 16. Outsiders may have difficulties to access confidential papers on the negotiations, but your European Energy Journal, in its very first issue, has published a synopsis of the official conference documents, showing in particular that the two parts of Article 194 paragraph 2 form an indivisible whole. Ignoring the background, the author remains on the surface and consequently concludes that the legal base of Gas Security Regulation is incorrect. In real life, the mantra of Member States' completely free choice of energy sources has been overtaken by the needs and facts concerning a common policy on security of supply, on renewables and on other looming challenges.

As cautious, even shy, the author's interpretation of Article 194 may seem, he fully recognizes that "urgent, decisive and immediate action is required" beyond the wording of Article 194;

hence his last chapter on future options where he explores the possibilities for enhanced cooperation, Schengen-like cooperation, functional and regional cooperation. As these options do not seem very promising, he then suggests a number of amendments not only to Article 194 of the Treaty on the Functioning of the EU, but also to Articles 122, 191, 192, 170-171 TFEU and to Article 13 of the TEU. Finally, he examines the feasibility of a completely new, energy-specific Treaty that should be a "very attractive option" in particular for Member States, which have already cooperated voluntarily under regional initiatives. In order to overcome the legal and institutional difficulties to draft such a Treaty, the author proposes to draw inspiration from the institutional framework of the Energy Community Treaty from South East Europe (p. 390). Here the author fails to recall that the EU – with all its Member States is already part of the Energy Community (p. 83), and that it would be a paradox that (part of) the EU should copy a Treaty which itself is a fragmentary copy of the EU Treaty.

In conclusion, this book excels by its wealth of information, documentation and ideas. However the update is not as complete as it could have been, and instead of repairing the bad and outdated wording of Article 194 by a more dynamic interpretation, the author tries to solve the urgent problems by proposing lengthy and uncertain negotiations on Treaty amendments or even an entire new Treaty.

Intersentia, Cambridge-Antwerp-Portland, 2013
ISBN 978-1-78068-064-4

Kampf um Strom: Mythen, Macht und Monopole

Author Claudia Kemfert
Reviewed by Helmut Schmitt von Sydow

Meet Claudia Kemfert, a familiar face on the German energy scene. She is professor at the Hertie School of Governance in Berlin, participates regularly in round table discussions, and each time German television needs a comment on energy news they will surely ask Mrs Kemfert for some sound bites - because she conveys profound knowledge and well-weighed reasoning in plain and concise language.

Her latest book on the "Battle for Electricity" is a perfect example. On 130 pages without any footnotes but with a lot of facts and occasional anecdotes, she scrutinizes the myths that powerful monopolies oppose to recent German energy policy, from the feasibility of a nuclear opt out by 2022 and of long term planning for 2050 to the risk of blackouts and surging prices. Will Germany's single-handed initiatives isolate the country internationally and prejudice its industry? The reader may not always agree with the author's messages but surely will better understand the issues of the energy debate in Germany - and elsewhere.

Murmann, Hamburg, 2013
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Addressing the financial barriers to energy efficiency investment

By **Joseph Curtin**
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1. Introduction

There is sufficient cost-effective energy savings potential available in the EU (across the built environment, transport, energy supply, and industry sectors) to meet the EU's 20 per cent target for energy savings.[1] What we mean by "cost effective" in this context is potential energy savings investments, which are attractive from a life cycle perspective, using discount rates in line with government bond rates.

A number of barriers exist, however, which influence investors' perception of what is cost-effective, and lead them to higher "implicit discount rates" when considering energy efficiency opportunities. Studies have consistently found that businesses and householders do not consider the full future benefits of investing in energy efficiency. The implicit discount rates applied to such investments have been found to range from 25 per cent to over 100 per cent, using a variety of methodologies.[2] As a result of these barriers, there is a shortfall in energy efficiency investment within the EU. If additional investment cannot be galvanized, the EU will not meet its 20 per cent energy saving target for 2020.[3]

In this chapter we explore the financial barrier to energy efficiency investment, which constrains the level of capital that is available to businesses and consumers. This financial barrier, however, cannot be considered independently from compounding barriers on the demand side and in the regulatory environment with which it interacts. These are therefore also briefly set out. The following sections describe and assess the effectiveness of EU level interventions to address the financial barrier in three broad categories: grand-aided funding; the use of innovative financial instruments; and the role of international financial institutions. A brief conclusion follows.

2. Barriers to Energy Efficiency Investment in the EU

The effective pricing of carbon is a key element of least-cost policy mix to respond to climate change. A number of barriers and market failures, however, prevent investors from making cost-effective investments in energy efficiency. A carbon price therefore

1 See: Eichhammer, W. et al.: Study on the Energy Savings Potentials in EU Member States, Candidate Countries and EEA Countries. 2009; and Wesselink, B. et al.: Energy Savings 2020 – How to triple the impact of energy saving policies in Europe. Report to the European Climate Foundation, 2010.

2 Gillingham, K, Newell RG and Palmer, K (2009) *Energy Efficiency Economics and Policy*. NBER Working Paper No. 15031. Cambridge: MA.

3 EC (2011) Commission Staff Working Document: Impact Assessment. COM (2011) 277, final.

needs to be flanked by supplementary energy efficiency policies as part of a cost-effective policy mix.[4]

In this section we explore the types of barriers that exist with a particular focus on the financial barrier to investment, which is covered in the first section. The following two sections cover barriers on the demand side and regulatory barriers respectively.

2.1. The Financial Barrier

Barriers on the supply side render banks and financial institutions reluctant to provide credit for energy efficiency investment. Blumstein *et al* (1980) first described the financial barrier, suggesting that "liquidity constraints" discouraged investment in energy efficiency.[5] According to the International Energy Agency (IEA), the term "financial barrier" encapsulates the "initial cost barrier, risk exposure, the debates on appropriate discount factors, the nature of the financier, and controversial evaluation methods".[6]

The financial barrier to energy efficient investment revolves around the high up front investment costs. Many households and businesses have limited access to credit, a problem exacerbated by the financial crisis. This is partly attributable to an information deficit within banks and other financial institutions, which in turn arises to some extent from a lack of *ex post* data and case study evidence on the impacts of many kinds of energy efficiency investments.[7]

This data deficit was emphasized by the financial sector and institutional investors in their response to a European Commission consultation on financial support for energy efficiency in buildings. The sector emphasized the need for more objective and reliable performance information (e.g. payback periods, return on investment, default rates) in relation to energy efficiency projects, technologies and services.[8]

Even where data exists, calculating the risk exposure is made difficult when the repayment stream is reliant, to some extent, on future benefits. These in turn are dependent on behavioral factors, energy prices, weather, occupancy patterns and other uncertainties.[9] Financiers will therefore not generally accept future energy savings as collateral, and energy savings-backed securities do not exist. In many financial institutions there is also a lack of familiarity and experience with, and information about, business models that rely on future energy savings to repay up front costs, such as Energy Service Companies (ESCOs) that use energy performance contracting. This factor is compounded on the demand side (for example, within public sector organisations) where procuring an ESCO contract can be challenging, and requires in-house knowledge and expertise. These factors hinder the emergence of energy efficiency-tailored financial products and business models.

Furthermore, banks generally have limited balance sheets, and depend on borrowing from the capital markets to finance projects. Loans with terms of five to seven years and quick returns are generally preferred for this reason. Longer loans must be safe and asset-backed (with debt generally limited to 70-80 per cent of marketable asset value) if they are to be securitised in due course.[10] Changes to the Basel and Solvency frameworks, as well as the general credit constraint associated with the fi-

4 See, for example, Ryan, L., S. Moarif, E. Levina, and R. Baron (2011), *Energy Efficiency Policies and Carbon Pricing*, IEA/OECD: Paris, or: OECD (2009) *The Economics of Climate Change Mitigation*, OECD, Paris

5 See: Blumstein C, Kreig B, Schipper L, York C. 1980. *Overcoming Social and Institutional Barriers to Energy Efficiency*. Energy 5: 355–72

6 De T'Serclaes, P (2007) *Financing Energy Efficient Homes: Existing policy responses to financial barriers*. IEA: Paris.

7 De T'Serclaes, P (2007) *Financing Energy Efficient Homes: Existing policy responses to financial barriers*. IEA: Paris.

8 EC (2012) Public Consultation: "Financial Support for Energy Efficiency in Buildings". Available: http://ec.europa.eu/energy/efficiency/consultations/20120518_eeb_financial_support_en.htm

9 De T'Serclaes, P (2010) *Money Matters: Mitigating risk to spark private investments in energy efficiency*. IEA: Paris.

10 See: Curtin, Joseph and Maguire, Josephine, *Thinking Deeper: Financing Options for Home Retrofit,* Institute of International and European Affairs, Dublin, Ireland, September 2011.

nancial crisis, have tended to exacerbate these factors within the EU.[11] These considerations disadvantage energy efficiency investments with a positive net present value but longer payback periods.

The relatively small size of many projects compared to other investments also increases the transaction costs for banks. Efforts to bundle energy efficiency investments into packages to achieve economies of scale exist within the EU, but are in their infancy. Respondents to a Commission stakeholder consultation identified the bundling of energy efficiency projects to create larger investment opportunities as a key priority in promoting the use of financial instruments to fund energy efficiency projects.[12]

Banks may also fail to factor in the increase in customers' credit capacity which investment in energy efficiency offers. One study found that factoring in this enhanced credit capacity allows for greater numbers of loans to be approved.[13]

While some of these arguments are somewhat theoretical, empirical evidence also supports the existence of a financing barrier that works against business investment in energy efficiency. Enterprises frequently cite the lack of capital available for energy efficiency as a key barrier. Energy efficiency investments tend to come from savings rather than from borrowings, with finance instruments only playing a subordinate role.[14] Studies have also found that householders are similarly reluctant to borrow to finance energy efficiency investments in their home, and rely or savings and government grants.[15]

11 EC (2012) Public Consultation: "Financial Support for Energy Efficiency in Buildings". Available: http://ec.europa.eu/energy/efficiency/consultations/20120518_eeb_financial_support_en.htm.

12 *ibid*

13 Cited in: De T'Serclaes, P (2007) *Financing Energy Efficient Homes: Existing policy responses to financial barriers*. IEA: Paris, p19

14 Brüggemann, A. (2006) KfW survey on disabling and enabling factors in corporate energy efficiency. KfW Bankengruppe, Economics department: Frankfurt-am-Main.

15 See, for example. SEAI (2010) *Bringing Energy Home: Understanding how people think about energy in their homes*. SEAI: Dublin.

The evidence suggests, therefore, that the financial sector plays a somewhat limited role in financing energy efficiency investments, and that instruments which aggregate investments, or rely on future energy savings as collateral, are in their infancy.

2.2. Demand Side Barriers

There are a number of barriers on the demand side, which compound the supply side financial barrier described above, and result in lower demand for finance than would otherwise be the case. The most prominent in the literature are the split incentive/principal-agent problem, imperfect information and behavioural factors.

The principal-agent problem describes a situation where one party (the principal), such as a builder or landlord, decides the level of energy efficiency in a building, while the other party (the agent), such as the purchaser or tenant, has to pay the energy bills. In these cases (such as in rented dwellings or business premises) investment in energy efficiency will be suboptional.

> For many consumers energy efficiency is not a major concern. In the office space market in London energy costs represent only 1 to 2% of rental costs.

Incomplete information hinders investment in energy efficiency in various ways. For example, complex pricing structures for energy make costs and benefits difficult to calculate for building owners and occupiers. In any case bills are only salient once a month, and householders by and large tend to be unaware of their energy bills. It is not surprising, then, that consumers do not pay much attention to fluctuations in energy prices,[16] nor that energy use declines where energy prices are well understood.[17] In many instances, energy efficiency is not a major concern for consumers or firms because energy costs are relatively low compared to many other cost factors (such as labour costs). For example, in the office space market in London, energy costs are equivalent to only 1-2 per cent of rental costs. [18]

Even if consumers had perfect information about energy prices and could make a true cost-benefit calculation, behavioral economics tells us that consumers may deviate from "rationality" in their decision making because of various psychological limitations.[19] Research findings from cognitive and behavioral psychology suggest, for example, that consumers manifest a status quo bias, and may use rules of thumb to estimate prices and calculate bills,[20] and are less responsive to price signals as a result. On the other hand, social influence and behavioral 'nudges' which utilize insights from cognitive psychology may be more effective in galvanizing behavior change, and even investment decisions.[21]

16 Seligman, C and Darley, JM (1977). Feedback as a Means of Decreasing Residential Energy Consumption, *Journal of Applied Psychology*, vol. 62, no. 4, pp. 363–68; Abrahamse, W (2005). A Review of Intervention Studies Aimed at Household Energy Conservation, *Journal of Environmental Psychology*, vol. 25, no. 3, pp. 273–9.

17 Kempton, W and Montgomery, L (1982). Folk Quantification of Energy, *Energy*, vol. 7, n 10, pp 817 – 27.

18 Guertler, P., J. Pett and Z. Kaplan. 2005. "Valuing low energy offices: the essential step for the success of the Energy Performance of Buildings Directive." Proceedings of the 2005 ECEEE Summer Study on Energy Efficiency. Paris: European Council for an Energy-Efficient Economy. pp. 295-305. Cited in EUROPEAN COMMISSION Consultation Paper: FINANCIAL SUPPORT FOR ENERGY EFFICIENCY IN BUILDINGS, Feb 2012.

19 There are three main concepts from behavioral economics relevant in this respect: prospect theory, bounded rationality, and heuristic decision-making. See, for example, Gillingham, K, Newell RG and Palmer, K (2009) *Energy Efficiency Economics and Policy*. NBER Working Paper No. 15031. Cambridge: MA.

20 Congdon, WJ, Kling, JR and Mullainathan, S (2011). *Policy and Choice: Public Finance Through the Lens of Behavioural Economics, Brookings Institution Press.*

21 The concept of 'nudging' was first described in: Richard Thaler and Cass Sunstein (2008) *Nudge: Improving Decisions about Health, Wealth and Happiness*. Yale University Press, 2008.

2.3. Regulatory Barriers

The regulatory framework constitutes a further barrier to varying degrees in EU Member States. Energy market prices do not always reflect all environmental and social costs, for example those related to pollution, greenhouse gas emissions, resources depletion or geopolitical dependency. In other cases, an unpredictable or changeable policy backdrop, including frequent changes in the legal framework and financial support programmes, and a lack of a long-term vision, result in an uncertain investment climate. Furthermore, policies that allow energy suppliers to increase their profits by selling more electricity or natural gas create a disincentive to the deployment of energy efficiency programs by these utilities. [22]

Low ambition levels and lack of enforcement of building energy codes within some Member States also hampers efforts to increase the energy efficiency of buildings. And the often decentralised nature of the institutional competences in the building sector, with national, regional and local authorities playing different roles (in building code enforcement, support programme, or regulatory and tax policy) is another challenge, which sometimes results in sub-optimal support for energy efficiency in buildings. [23] Grant schemes can also induce market distortions, and in some cases constitute a barrier for private financing.

In conclusion, the financial barrier interacts - and is compounded by - barriers on the demand side, and by barriers created by the regulatory framework. The interaction of these barriers results in underinvestment in energy efficiency across the EU than would be economically rational.

3. Grant-based approaches to addressing the financial barrier

The EU's role in energy efficiency policy is pri-

22 Carter, S. 2001. Breaking the Consumption Habit: Ratemaking for Efficient Resource Decisions. The Electricity Journal 14:66-74.

23 Carter, S. 2001. Breaking the Consumption Habit: Ratemaking for Efficient Resource Decisions. The Electricity Journal 14:66-74.

marily concerned with setting the framework conditions (e.g. long-term outlook and targets, removing unhelpful rules, monitoring compliance) and facilitating implementation (e.g. sharing best practices between Member States etc.). Many of its interventions, discussed in previous chapters, (such as, for example, the EPBD) are focused on addressing informational and other barriers to energy efficiency investments.

It is for Member States, for the most part, to address financial barriers. Having said that, the EU has at its disposal a number of important instruments and funding streams, which can be used directly to address the financial barrier, and that are aimed at complementing existing Member State supports and provoking new policy interventions. In this section we focus on grant-based instruments, and in particular on grant funding provided under cohesion policy and Intelligent Energy Europe.

3.1. Grant-based cohesion policy funding

The overall objective of cohesion policy in the 2007 – 2013 period is to deliver smart, sustainable and inclusive growth. Both the European Regional Development Fund (ERDF) and the Cohesion Fund aim to strengthen economic and social cohesion in the EU by correcting regional and local development imbalances through investment. The ERDF has specifically targeted improvements in energy efficiency in the built environment sector. The Cohesion Fund, aimed at Member States whose Gross National Income (GNI) per inhabitant is less than 90 per cent of the Community average, may also be used for projects in the energy sector, as long as they clearly present a benefit to the environment, including improved energy efficiency.[24]

In total an estimated €4.6 billion of cohesion funding has focused on improving energy efficiency between 2007 and 2013, which accounts for approximately 1.3 per cent of the overall cohesion policy budget. The majority of this total came from the ERDF, and was provided in grant form to co-finance energy efficiency improvements in Member States,[25] to overcome the high up front cost of these investments.

EU Cohesion Policy will place an even greater focus on energy efficiency in the next programming period. The Multi-annual Financial Framework (MFF) for the EU was broadly agreed in February 2013, to cover the EU budget for the 2014 – 2020 period.[26] In more developed regions, at least 20 per cent of total ERDF resources at national level should be allocated to the low-carbon economy, with a corresponding figure of 6 per cent for less developed regions. Less developed regions are therefore permitted greater flexibility in the way they spend their funds.

In addition, allocations from the Cohesion Fund can also be made towards sustainable energy. Based on the overall MFF amounts put forward by the Commission, this would represent some €17 billion for sustainable energy (see Table 1 below).[27]

Cohesion Policy 2007-2013	Cohesion Policy 2014-2020	Minimum % allocation to EE/RE
Convergence	Less developed regions (GDP per capita <75% of EU27 average)	6%
Convergence phasing out	Transition regions (GDP per capita between 75% and 90% of EU27 average)	20%
Regional competitiveness and employment phasing in		
Regional competitiveness and employment	More developed regions (GDP per capita 90% of EU27 average)	20%

Fig. 1- *New classification of regions and proposed ERDF minimum shares for Energy Efficiency and Renewables (Source: European PPP Expertise Centre, 2013)*

24 Council Regulation (EC) No 1084/2006 of 11 July 2006 establishing a Cohesion Fund and repealing Regulation (EC) No 1164/94 See: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32006R1084:EN:NOT

25 Donnelly, M (2013) Financing Energy Efficiency: the role of the regulatory framework, Power Point Presentation, available: http://www.buildup.eu/publications/26802

26 At the time of writing it has yet to be adopted by the European Council and European Parliament.

27 European PPP Expertise Center (2013) European Commission Cohesion Policy Proposals for 2014-2020. Available: http://www.eib.org/epec/ee/documents/05-eccpp-for-2014-2020.pdf

The European Court of Auditors has criticized the way in which cohesion funds were spent on energy efficiency. The Court found that the projects selected by Member State authorities did not have rational objectives in terms of cost-effectiveness, i.e. projects were not selected for their potential to produce financial benefits through energy savings. Their audit demonstrated that average pay back periods of investments exceeded 50 years (and reached 150 years in some cases). Buildings were regarded as being 'ready' for funding if they were in need of refurbishment, and if documentation provided complied with requirements. None of the projects had an analysis of the energy savings potential in relation to investments, in order to justify the measures selected. On this basis the Court argued that energy efficiency was at best a secondary concern.[28]

The Court recommended that funding for energy efficiency be subject to a proper needs assessment, regular monitoring, the use of comparable performance indicators as well as the use of transparent project selection criteria and standard investment costs per unit of energy to be saved, with a maximum acceptable simple payback period.

It should be noted, however, that the audit has itself been criticized for not take into account the importance of 'co-benefits' of energy efficiency investment, including returns in tax from increased employment, and societal benefits such as improved health and the resultant reduction in health spending. Using strict cost-effectiveness guidelines (such as a maximum accepted simple payback) may also preclude deeper retrofits, which are required in the long term to achieve a zero carbon buildings sector.[29]

The recast EPBD requires the Commission to present an analysis on, *inter alia*, the effectiveness and appropriateness of the level of structural funds that were used for increasing energy efficiency in buildings. Based on this analysis, the Commission has committed to developing guidelines for the selection and evaluation of energy efficiency projects in the context of cohesion policy funding, to establish a more standardised approach in 2013.[30] Balancing strict cost-effectiveness criteria with the needs of long-term decarbonization constitutes a considerable challenge.

3.2. Grants Under Intelligent Energy Europe (IIE)

Grants available under EU cohesion policy are supplemented by grants available under other funding streams. The IEE is part of the EU's Competitiveness and Innovation Framework Programme. It is aimed at delivering on the ambitious climate change and energy targets that the EU has set for itself, and is managed by Executive Agency for Competitiveness and Innovation (EACI). Under the programme €730 million of funds was made available between 2007 and 2013 for Intelligent Energy. Of this total, around 50 per cent has been allocated to energy efficiency projects. Funding covers up to 75 per cent of the eligible project costs. The projects selected in 2009-2011 are estimated to have triggered cumulative investment in sustainable energy of more than €1.5 billion.[31]

The European Court of Auditors has criticized the way in which cohesion funds were spent on energy efficiency

28 ECA (2012) Cost Effectiveness of Cohesion Policy Investments in energy, Special Report No. 21. Available: http://eca.europa.eu/portal/pls/portal/docs/1/19614746.PDF

29 EurActive (2103) Bulk of EU energy efficiency funds misused, says auditor. Available: http://www.euractiv.com/energy-efficiency/90-eu-energy-efficiency-funds-mi-news-517041

30 EC (2013) Financial support for energy efficiency in buildings Brussels, SWD (2013) 143 final. Available: http://ec.europa.eu/energy/efficiency/buildings/doc/report_financing_ee_buildings_com_2013_225_en.pdf

31 EC (2013) Financial support for energy efficiency in buildings Brussels, SWD 143 final. Available: http://ec.europa.eu/energy/efficiency/buildings/doc/report_financing_ee_buildings_

3.3. Limitation of Grants

A grant-based approach to addressing the financial barrier to energy efficiency is perhaps inherently limited for a number of reasons. Grants rely on direct exchequer funding, and therefore place demands on scarce public budgets at a time when theses budgets are shrinking. Public funding alone will never be sufficient in any case, to galvanize the level so investment necessary to meet EU targets. Furthermore grant programmes are in competition with other areas for continued funding, and these programmes at EU and Member State level can be withdrawn at short notice, resulting in boom-bust investment cycles. Furthermore, grants only target the financial barrier indirectly, without addressing underlying issues (such as, for example, unfamiliarity with ESCO contracting in financial institutions or public sector organisations). For these reasons the European Commission has been exploring alternative approaches to addressing the financial barrier.

4. Innovative Financial Instruments to address the financial barrier

The European Commission has stressed that the bulk of energy efficiency investment should be made by the private sector, and that efforts should be made to ensure that public funding complements and leverages private investment, rather than crowding it out.[32] Grants, it has argued, should be used primarily to address market failures or to support innovative technologies and investments going beyond cost-efficient energy efficiency performance.[33]

There are several options for creating value for energy savings through market mechanisms, which alleviate the need for grants. Financial instruments, such as revolving funds and guarantee schemes, can offer significant new financing streams for strategic investments with evident commercial potential. These types of instruments have the potential to be more effective than grants because they can leverage private capital, and can stretch the impact of EU funding further by facilitating and attracting other public and private financing to projects.

The EU's approach to promoting the use of financial instruments is set out in this section. It explores the promotion of these instruments under JESSICA, IEE and the EU Energy Efficiency Fund.

4.1. Cohesion funds to promote financial engineering instruments/JESSICA

In the 2007 – 2013 period the Commission began using Cohesion Policy funding to promote the creation and use of financial engineering instruments (FEIs). These are financial instruments aimed at overcoming the financial barrier to energy efficiency, which have the potential to be self-sustaining.

Four joint initiatives in this sphere were developed by the European Commission in co-operation with the European Investment Bank (EIB) group and other financial institutions. Of particular relevance to energy efficiency promotion is JESSICA (the Joint European Support for Sustainable Investment in City Areas). This is an initiative of the European Commission developed in co-operation with the EIB and the Council of Europe Development Bank. It supports sustainable urban development and regeneration, including energy efficiency improvements, through the use of financial instruments.

Funds under JESSICA are dispersed to managing authorities, which can blend JESSICA monies with funding from other sources. Managing authorities may decide to channel funds through Holding Funds, which are generally established to invest in numerous projects. This offers managing authorities the option of delegating some of the tasks required

com_2013_225_en.pdf

32 EC (2012) Commission Staff Working Document: Elements for a Common Strategic Framework 2014 to 2020, Available: http://ec.europa.eu/regional_policy/sources/docoffic/working/strategic_framework/csf_part1_en.pdf

33 European Commission (2012) Commission Staff Working Document 61: Elements for a Common Strategic Framework 2014 to 2020. Available: http://ec.europa.eu/regional_policy/sources/docoffic/working/strategic_framework/csf_part1_en.pdf

in project selection to expert professionals. Investments can take the form of equity, loans and/or guarantees, which can be tailored to the specific needs of particular countries, regions and projects.

The ultimate objective is that returns from investments are reinvested in new projects. By recycling funding, and through leveraging private investment (and other public funds) JESSICA is intended to maximize the impact of public funding and to offer a more sustainable alternative to the assistance traditionally provided through grants.

FEIs can also act as a powerful catalyst for the establishment of partnerships between countries, regions, cities, the EIB, other banks, and various investor classes. This was particularly the case with JESSICA, where the EIB promoted networking platforms, and knowledge and best practice exchange.

Establishing FEIs has not transpired to be straightforward. Significant delays have been attributed to their 'newness', their complexity and a lack of awareness of funding opportunities among potential beneficiaries. The financial engineering and expertise required to establish an appropriate structure capable of drawing down funding, represents a barrier to take up in public sector and other agencies. Drawing down funding through FEIs has required a steep learning curve and cultural change in agencies more used to applying for grants. Reporting requirements also tend to be onerous. A lack of awareness about funding opportunities is also responsible for uptake problems, especially at regional and local levels. Other implementation issues have related to the difficulties associated with attracting private sector co-investment.[34]

Despite the challenges experienced since 2007, FEIs for energy efficiency and renewable energy in buildings constituted €345 million (€250 million of which came from structural funds) of support. Twelve initiatives across five Member States (the UK, Germany, Italy, Greece and Estonia) have been piloted.

One example is the London Green Fund, which is a JESSICA holding fund established in late 2009. EIB funding was matched by funding from the London Development Agency and the London Waste and Recycling Board. The London Green Fund in turn established two separate funds, one of which is the Energy Efficiency Urban Development Fund. This fund attracts finance from the private sector, and lends money to urban retrofit projects within the greater London area.

The Commission has stated its intention to focus to a greater extent on FEIs in the programme period 2014-2020. There is a need to be realistic about the complexity of such projects and the time and structures involved to make investments happen. Based on experience, it has taken up to two years to set-up FEIs focused on energy efficiency. There was also a significant amount of resources required for marketing and awareness-raising campaigns to reach targeted groups. Capacity building is particularly necessary among target groups,

Challenges notwithstanding, indications are that this thematic area will grow. The Commission published a report outlining recommendations for how financial support for energy efficiency in buildings could be improved in the coming period.[35] One outcome is that the Commission will launch a study in 2013 to obtain a comprehensive overview of the financial support for energy efficiency in the Member States, addressing, *inter alia*, the lack of information on the impact of financial measures.

4.2. Intelligent Energy Europe (IEE)

IEE also provides project development assistance (PDA) under five separate funding

34 European Commission/EIB (2013) Financial Instruments: A Stock-taking Exercise in Preparation for the 2014-2020 Programming Period. Available: http://ec.europa.eu/regional_policy/thefunds/instruments/doc/fls_stocktaking_final.pdf

35 EC (2013) Financial support for energy efficiency in buildings, 143 final. Available: http://ec.europa.eu/energy/efficiency/buildings/doc/report_financing_ee_buildings_com_2013_225_en.pdf

streams to public authorities, public bodies and financial institutions. Provision of technical assistance is seen by stakeholders as very important for the further uptake of financial instruments.

ELENA (European Local Energy Assistance) was launched by the European Commission and the EIB in December 2009. In total €49 million of funding has been made available under ELENA, with an ultimate objective of supporting more than €1 billion of energy efficiency and renewable energy projects. Funding is available under four different facilities: KfW-ELENA, EIB-ELENA, CEB-ELENA and EBRD-ELENA.[36] A fifth facility (MLEI-PDA) is the overseen by the Executive Agency for Competitiveness and Innovation (ECAI), and directed to smaller projects.

Funding covers a proportion of the cost for technical support that is necessary to prepare, implement and finance the investment programme. Eligible costs for ELENA support correspond to any technical support that is necessary to prepare, implement and finance the investment programme. This technical support may be of different types, including: feasibility and market studies, structuring of programmes, business plans, energy audits, preparation of tendering procedures and contractual arrangements and project implementation units. The EU contribution can cover up to 90 per cent of eligible costs.

The aim is to generate bankable investment projects that can attract outside finance, for example, from local banks or other financial institutions such as the EIB. Eligible projects are therefore generally at least €30-€50 million in size. Although not a prerequisite to receive EIB funding, ELENA assistance may facilitate access to EIB funding.

A key target area for ELENA assistance is energy performance contracting implemented by ESCOs.[37] The Commission's Energy Efficiency Plan emphasizes the central role it sees for ESCOs. Its commitment to continue promoting ESCO activity in the coming period is underscored by the Commission's campaign to promote and build capacity for energy performance contracting and ESCOs throughout Europe.[38]

In addition to PDA and direct project support, the IEE programme supports a range of other initiatives, such as the European Build Up web portal for energy-efficient buildings, the ManagEnergy information service for local and regional authorities and energy agencies, the ELTIS portal on urban transport and mobility, and the annual EU Sustainable Energy Week. In the coming programme period the Commission will investigating whether the information provided at EU level could be improved (mainly through the Build UP web portal).

4.3. The European Energy Efficiency Fund (EEEF)

The European Energy Programme for Recovery (EEPR) was established in 2009 to address both Europe's economic crisis and European energy policy objectives. Almost €4 billion was assigned to co-finance EU energy projects that would boost the economic recovery, increase the security of energy supply and contribute to the reduction of greenhouse gas emissions. A part of this programme, in July 2011, the European Commission launched an innovative public-private partnership, the EEEF. The EEEF was allocated €146 million from the EEPR (3.7 per cent of the total EEPR envelope).

Of this total, €125 million was invested as risk capital in the EEEF (the junior tranche), thereby partly assuming the economic risks associated with the investment projects. The European Investment Bank committed €75 million in the mezzanine tranche, and in senior shares. Further commitments came from the Cassa Depositi e Prestiti (CDP), which con-

36 For more details see: http://ec.europa.eu/energy/intelligent/getting-funds/project-development-assistance/index_en.htm

37 Where the service providers fund a project, guarantee future savings made on energy bills, and loan is repaid through the savings achieved.

38 EC (2013) Financial support for energy efficiency in buildings, SWD (2013) 143 final. Available: http://ec.europa.eu/energy/efficiency/buildings/doc/report_financing_ee_buildings_com_2013_225_en.pdf

tributed €60 million also in mezzanine and senior shares, and €5 million contributed to the mezzanine tranche by Deutsche Bank (who will also act as investment manager of the fund). The Fund ultimately aims to attract a total of approximately €800 and is seeking further investment partners.

The EEEF aims to provide market-based financing, rather than concessional funding. Financing may come in the form of debt, mezzanine or equity, as well as leasing structures and forfeiting loans for specific industry partners. The interest rate depends on the risk structure of the investment.

The EEEF aims to overcome barriers to energy efficiency investment in the public sector, such as budget restrictions or lack of experience with this kind of investment. Projects are aimed at fostering public-private partnership, in particular on smaller scale investments by local authorities or ESCOs (acting on behalf of public sector organisations), thereby complementing the larger scale finance that the EIB already offers for energy efficiency investments throughout the European Union. Eligible projects are energy efficiency and renewable energy projects, particularly in urban settings, which achieve at least a 20 per cent energy saving. 70 per cent of the investment will be targeted towards energy efficiency. The Fund can invest up to a maximum of €25 million per project.

The outstanding €21million of the Commission's allocation will be made available as grants for project development services related to technical and financial preparation of projects. The technical assistance offered under the new facility targets investment projects that may be financed by the fund. Like ELENA, technical assistance can be provided to cover up to 90 per cent of all eligible costs. The overall size of eligible projects should generally be less than €50 million (thereby complementing ELENA which provides investments of greater than €50 million).

No data is publically available about the performance of the fund to date, nor concerning the amount of projects it has supported. It is thought that the fund has encountered difficulties identifying suitable projects.

4.4. Key Challenges

A key challenges remains the need for the provision of much more accurate and standardised information on the energy and economic performance of improvement measures, and energy efficiency projects, through wider sharing of successful projects and practices. There is also a need to promote greater awareness of funding options, and the development of expertise in drawing down funding and procuring ESCO contracts etc.

This process of information building and readiness in Member States will be enhanced by the introduction of the Energy Efficiency Directive (Chapters 3 and 4). Under Art. 20 Member States are required to facilitate the establishment of financing facilities, or use of existing ones, for energy efficiency improvement measures to maximize the benefits of multiple streams of financing.

The Commission is required to assist Member States in setting up these facilities and to provide technical support where necessary. Where appropriate, it can deploy the expertise of European financial institutions, such as the EIB to this end. The Commission is also required to facilitate the exchange of best practice between the competent national or regional authorities or bodies.

The EED (Chapter 3) encourages Member States to set up National Energy Efficiency National Funds, although they are not required to do so. The establishment of national energy efficiency funds has the potential to link efforts to provide funding at EU level with the demand for and awareness of funding opportunities in Member States. National funds have the potential to attract funding from national exchequers, from the EIB or other EU funding streams (and potentially also from obligated energy suppliers, in fulfilment of their obligations under Art 7 of the EED).

Indeed some Member States have already established national energy efficiency funds, and they are likely to become more common across the EU. They and have the potential to promote greater levels of ESCO activity in the public and private sectors, as well as promoting knowledge and best practice around establishing funds within Member States. The experiences garnered at national level may be mirrored at regional level, or among other competent national authorities.

5. International Financial Institutions (IFIs)

There are three IFIs which actively promote investment in energy efficiency within the EU. These are the EIB, The European Bank for Reconstruction and Development, and the Council of Europe Development Bank.

The EIB is the bank of the European Union and is owned by the 27 Member States. It aims to support sound investments that further EU policy goals. Since 2010, the EIB has given the highest priority to renewable energy and energy efficiency projects. Its extensive role in blending funding from EU programmes (such as ELENA and the EEEF) to unlock further financial flows has been described above.

The EIB's traditional lending instruments are constantly being redefined to focus more on the energy sector, in line with changing EU priorities. Between 2008 and the end of 2012, €42.5 billion of dedicated overall loan amount (€283 billion) went to the energy sector. Of this total, energy efficiency received €4.8 billion of funding within the EU, of which €1.7 billion was in the building sector. [39]

The EIB's energy efficiency portfolio has seen a decrease in the share of investment loans from 100 per cent to 35 per cent from 2000 to 2011, more or less corresponding to an increase in the share of global and framework loans from zero to some 60 per cent in 2011. The latter types of grouped financing are particularly suitable to finance demand-side energy efficiency investments (e.g. building refurbishment), which are individually small and scattered, hence limiting EIB's possibilities to address them through direct individual loans.

An assessment of the EIB's performance over the past decade in galvanizing energy efficiency investment found that the it has adapted and elaborated its project selection criteria through revision of its eligibility rules, in order to reflect the increasing policy focus on energy efficiency. In particular in 2007 it developed a lending policy that prioritizes energy efficiency investments, and established specific eligibility criteria to select projects with a clear contribution to efficiency.

The review found that the EIB's organisational structure had significantly evolved over the previous decade. The emergence of new instruments and organisational units, however, remained fragmented to some extent, and has so far not been embraced by a coherent strategy. It recommended that the Bank should devise an integrated energy efficiency lending strategy, and establish an appropriate management structure to implement it; that tighter criteria could be developed for assessing effectiveness; and that innovative financing approaches to energy efficiency should be trialed and evaluated.[40]

It is clear that the relevance of energy efficiency to the EIB loan book will grow during the next programming period (2014-2020).

The European Bank for Reconstruction and Development (EBRD), and the Council of Europe Development Bank (CEB), also increasingly operate their own investment instruments for energy efficiency within the EU. The EBRD is part owned by EU member States, the EU and the EIB. Since 2002, it has provided loans and equity to 104 energy efficiency projects in the EU, amounting to €1.8 billion. The total fund-

39 EC (2013) Financial support for energy efficiency in buildings SWD 143 final, Brussels. Available: http://ec.europa.eu/energy/efficiency/buildings/doc/report_financing_ee_buildings_com_2013_225_en.pdf

40 EIB (2012) Evaluation of EIB's Energy Efficiency (EE) Financing in the EU from 2000 to 2011: How did the Bank respond to the EE challenge in the context of a reinforced EU EE policy? EIB: Luxembourg.

ing mobilised on the market during this period amounts to €14.9 billion which indicates a leverage of approximately 1:7. For its part, the CEB, which is owned by 40 member countries including most of the members of the EU, has approved a total of approximately €2.4 billion to projects at least partially concerning energy efficiency within the EU since 2001.[41]

6. Conclusions

A number of barriers prevent optimal levels of investment in energy efficiency within the EU. The focus of this chapter has been the financial barrier, which is multi-faceted, and compounded by barriers on the demand-side, and in the regulatory system.

Traditional approaches to overcoming the financial barrier to energy efficiency investment have focused on grant support for investment projects. The large majority of grant funding was provided under the EDRF fund, a cohesion policy instrument. The extent to which this grant-aided funding was effectively targeted at energy efficiency has been questioned. Nonetheless, grant-aided funding which targets energy efficiency will continue to grow in the coming budgetary period, albeit under new project eligibility criteria that are being developed. Balances the need for cost-effectiveness with the needs of long-term decarbonization in the development of new criteria is a considerable challenge.

Grant-aided support has a number of limitations - not least the level of public funding available, the increased competition for increasingly scarce public resources, and the potential for grants to result in market distortions.

For these reasons, the European Commission is increasingly promoting measures that create value for energy savings through market mechanisms. FEIs have the potential to put investments in energy efficiency on a more sustainable footing.

41 EC (2013) Financial support for energy efficiency in buildings SWD (2013) 143 final, Brussels. Available: http://ec.europa.eu/energy/efficiency/buildings/doc/report_financing_ee_buildings_com_2013_225_en.pdf

FEIs that have been piloted include revolving funds under the Structural Funds programms. Various technical assistance packages have also been developed under ELENA, which attempt to create a pipeline of investor-ready energy efficiency investment opportunities. A key object of these instruments is to promote greater levels of ESCO activity. The establishment of several funds and guarantee systems (with EU-level funding being used as a 'first loss' guarantee to de-risk the investments) such as the EEEF is fundamental for attracting private capital and stimulating the ESCO and energy performance contracting market.

Efforts to establish and promote these instruments have not always been entirely successful. Difficulties have included the complexity and financial engineering skills required to establish funds, the time they take to establish, and the unfamiliarity with funds compared to grants among potential clients.

Due to this information and expertise deficit on the demand side, the supply or availability of funding alone is not a sufficient condition for overcoming the financial barrier to energy efficiency. The provision of information and development of expertise in relevant Member State authorities via the EIB and other institutions, is therefore of considerable importance.

An overview of the evolution of the European unbundling process in the electricity sector: The cases of France, the UK and Belgium

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About twenty years ago, the European Union (EU) started the liberalisation process of the energy sector. The aim was to create a single European energy market that could provide more competitive energy prices and benefit European consumers. The said liberalisation would apply to both the electricity and gas markets.

One of the cornerstones of this liberalisation process has been the unbundling of transmission system operators (TSOs) from their historic mother companies: the vertically integrated generation companies. The liberalisation process has been implemented in several phases with a gradual increase of the level of unbundling.

The first step towards unbundling was introduced by the 1st Electricity Directive. It referred to *accounting and management unbundling* of the network activities. A further step was taken with the adoption of the 2nd Electricity Directive, which reinforced the separation between generation and transmission activities of vertically integrated companies by imposing *legal unbundling*. Nevertheless, practical experience showed that even after the implementation of legal unbundling, possible conflicts of interest remained an obstacle to competition, carrying negative repercussions on market functioning and investment incentives.

To solve these inefficiencies, the 3rd Electricity Directive introduced *three different unbundling models*, while particularly advocating for the so-called "ownership unbundling", which is considered the most effective way to ensure a well-functioning internal electricity market.

This article will provide a short overview of the three EU Electricity Directives and the evolution of the unbundling process through their contributions. It will then focus on three EU Member States used as case studies - France, the United Kingdom (UK) and Belgium - and illustrate how the said Directives were transposed into national law in each of these countries. These countries illustrate interesting implementations of the unbundling principles. This focus will be useful to analyse the types of challenges involved in moving from a vertically integrated undertaking (VUI) model to an unbundled transmission operator model. For each case, it will be demonstrated that the choice of the unbundling model was largely influenced by national circumstances, including political objectives of the government, positioning of some key stakeholders and their respective level of involvement.

1. The evolution of the EU unbundling legislation

The 1st Electricity Directive

In line with the EU's overall ambition to create a single European market, the principle of creating a single energy market has gradually come forward. The opening of the European electricity market to competition began effectively with the adoption of the 1st Electricity Directive in 1996[1]. The European Commission (EC) has consistently argued that liberalisation would increase the efficiency of the energy sector and the competitiveness of the European economy as a whole. At EU Member State level, governments have advocated that ultimately an open gas and electricity market would reduce energy costs for industry and the consumers.

The 1st Electricity Directive (Article 7) provides for clear language that EU Member States must designate, for undertakings which own a transmission system, a system operator responsible for "operating, ensuring the maintenance of, and, if necessary, developing the transmission system in a given area and its interconnectors with other systems, in order to guarantee security of supply". In addition, the 1st Electricity Directive stipulates that the TSO "shall not discriminate between system users or classes of system users, particularly in favour of its subsidiaries or shareholders" and that "unless the transmission system is already independent from generation and distribution activities, the system operator shall be independent at least in management terms from other activities not relating to the transmission system".

Moreover, discussions leading to the first Directives and Regulations for the internal gas and electricity markets were strongly influenced by the power deregulations that were at that time taking place in the UK and Norway. Increasing efficiency by introducing new entrants in generation, trading and sales, and welcoming more power exchanges between EU Member States were initially the main goals contemplated. Cogeneration and combined cycle gas turbines were making their first appearance in the generation mix, while renewable energy sources were in a prototyping stage. Reducing CO_2 emissions was not yet an issue for industry or policy makers.

The 1st Electricity Directive refers to "unbundling" mainly with respect to internal accounting and single buyers[2]. In particular, Article 14(3) of the said Directive states that "integrated electricity undertakings shall, in their internal accounting, keep separate accounts for their generation, transmission and distribution activities, and, where appropriate, consolidated accounts for other, non-electricity activities, as they would be required to do if the activities in question were carried out by separate undertakings, with a view to avoiding discrimination, cross-subsidization and distortion of competition". Furthermore, according to Article 15 of the said Directive, "Member States which designate as a single buyer a vertically integrated electricity undertaking or part of a VIU shall lay down provisions requiring the single buyer to operate separately from the generation and distribution activities of the integrated undertaking"[3].

The 2nd Electricity Directive

Supported by *inter alia* a report from the EC that showed insufficient progress towards an internal gas and electricity market[4], a 2nd Electricity Directive[5] was adopted in 2003 in order to accelerate the completion of opening up the electricity market to competition, while maintaining high standards for public services and public service obligations.

The 2nd Electricity Directive imposed clear unbundling requirements on TSOs that are part of a VIU. For those TSOs, it was required to be independent "at least in terms of its legal form,

1 Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity.

2 As per Article 2(22), single buyer means "any legal person who, within the system where he is established, is responsible for the unified management of the transmission system and/or for centralized electricity purchasing and selling". [3] The "single buyer" concept was put forward by France.

3 The "single buyer" concept was put forward by France.

4 Among the reasons were insufficient independence from TSOs (favouring their mother companies, barrier to new entrants, lack of data exchange between TSOs, etc.).

5 Directive 2003/54/EC of the European Parliament and of the Council of 6 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC.

organisation and decision-making from other activities not relating to transmission. These rules shall not create an obligation to separate the ownership of assets of the transmission system from the VIU" (Article 10(1)). This concept was needed to ensure a reasonably fast approval of the legislation by all key EU countries, given the intensive lobbying from several VIUs as well as from some large EU Member States.

According to the 2nd Electricity Directive, markets for all non-household electricity customers were to be liberalised by July 2004 and, for private households, by July 2007., A competition inquiry in the electricity sector launched in 2005 (Inquiry Report) and closed two years later showed however that in 2007 there were still "malfunctioning markets" for industrial consumers[6].

Among the main findings of this Inquiry Report, the EC noted that at the wholesale level, the electricity market remained national in scope,

The ISO model (Independent System Operator) has only been implemented in two out of 28 Member States

and maintained in general the high level of concentration of the pre-liberalisation period. Furthermore, the level of unbundling of network and supply interests had negative repercussions on market functioning and on incentives to invest in networks. Among the fundamental deficiencies in the competitive structure of the electricity market, the EC highlighted the structural conflicts of interest caused by insufficient unbundling of networks from the competitive parts of the sector, generation and supply.
It was therefore considered necessary to reinforce the level of unbundling. This would also in turn facilitate cooperation among network operators. Economic evidence showed that full ownership unbundling appears to be the most effective way to provide market choices for energy users and encourage investment, mainly because independent network companies are not influenced by overlapping supply/generation interests as regards investment decisions. It was also considered that "the independent system operator approach would improve the status quo, but would require more detailed, prescriptive and costly regulation and would be less effective in addressing the disincentives to invest in networks"[7].

The 3rd Electricity Directive
The 3rd Electricity Directive[8] was adopted in 2009 to remedy the problems identified in the above-mentioned Inquiry Report. It went "one step" further in the unbundling process and introduced three possible models for operating the transmission system. With this choice, the EC aimed at ensuring full support for and, hence, swift approval of the legislation by all key EU countries.

The 3rd Electricity Directive contains new and more detailed unbundling provisions, according to which any TSO in the EU has to opt from the three following models:
- Full Ownership Unbundling (FOU);
- Independent System Operator (ISO); or
- Independent Transmission Operator (ITO).

The initial draft from the EC only mentioned the FOU and ISO options. The ITO option was introduced at a later stage at the initiative of France[9].

6 DG Competition report on energy sector inquiry, Brussels, 10 January 2007, SEC(2006) 1724.

7 *Ibid*, p. 14.

8 Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC.

9 On 29 January 2008, France, Germany, Austria, Bulgaria, Greece, Luxembourg, Latvia and the Slovak Republic submitted a letter including proposals for a 'third option' for energy liberalisation: http://www.euractiv.com/energy/eu-states-oppose-unbundling-tabl-news-219274

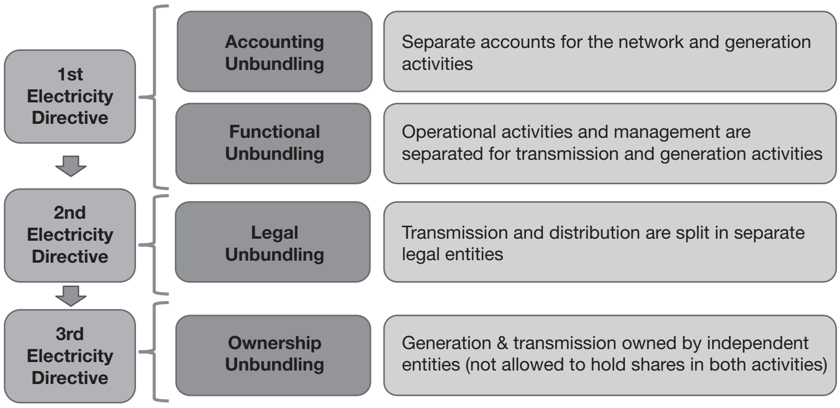

Figure 1: *How unbundling has evolved in the EU*

The **FOU model** can be seen as the model that foresees the strictest unbundling criteria (Article 9):

1. Each undertaking which owns a transmission system must act as a TSO;
2. A same person cannot have a cross-control over a TSO on the one hand and undertakings performing generation and/or supply activities on the other hand;
3. A same person cannot appoint members of the supervisory board, the administrative board or bodies legally representing the undertaking, of a TSO or a transmission system, and directly or indirectly exercise control or exercise any right over an undertaking performing generation and/or supply activities; and
4. A same person cannot be a member of the supervisory board, the administrative board or bodies legally representing the undertaking, of both an undertaking performing generation and/or supply activities and a TSO or a transmission system.

However, for TSOs that belonged to a VIU on 3 September 2009, EU Member States may also opt for the ISO or ITO model, as set out below[10].

In the **ISO model,** the VIU retains the ownership of the grid, while the operation of the network is performed by and independent operator. Provisions are set to protect the independence of the ISO and to ensure that the owner will develop the network. However, in practice this could appear to be rather difficult, as the VIU may not (always) have a real incentive to develop the grid if as a result of it, its market power will be reduced. As a result, this model has only been implemented in 2 out of the 28 EU Member States.

According to the **ITO model,** the VIU is preserved and corresponding national regulation is put in place to ensure that the network operator is effectively independent. Additional conditions include:

- Increased barriers to the exchange or common use of personnel, IT systems, premises and communications between the ITO and the energy companies of the group to which the ITO belongs;
- The corporate identity of the ITO should be visibly different from that of the group;
- The personnel policy of the ITO should be subject to the control of a partially independent Supervisory Body (to prevent remunerations and careers to be de facto linked to the profitability of the group).

In the implementation of the "Unbundling Directive", the ITO solution has been preferred by many large VIUs. However, critics of the ITO model generally argue that the guarantees of "real" full independence of the TSO under the ITO model are not yet sufficient.

Although the FOU model was considered the most effective solution for unbundling, the ISO and ITO models were finally also included in the EU legislation as a compromise

10 More precisely, the Member State concerned may designate an ITO in accordance with Article 13 of the Directive, or opt for the ITO model as established under Chapter V of the Directive.

solution, following intense negotiations during the adoption of the 3rd Energy Package, which includes the 3rd Electricity Directive and new or amended Electricity Regulations.

Besides these unbundling requirements, the 3rd Electricity Directive also required the TSOs to be certified (Article 10). Now with this new Directive, before an undertaking is approved and designated as a TSO, it must be certified by the National Regulatory Authority (NRA), as having complied with the requirements of Article 9 of the Directive.

2. The unbundling process in France

France chose to implement the ITO model as unbundling regime for its electricity and gas TSOs.

The French electricity TSO, Réseau de Transport d'Electricité (RTE), is currently entirely controlled by the French Republic, through is controlling shareholding of Electricité de France (EDF), which in turn controls the TSO. RTE is a limited liability corporation, known in France as a *société anonyme* and has, in accordance with the provisions of the 3rd Electricity Directive, been certified by the appropriate bodies upon advice of the French NRA.

Under French law, the current main texts governing electricity activities are:

- The Ordinance codifying the legislative part of the French energy code of 10 May 2011 (the Energy Code)[11];
- The New Organisation of the Electricity Market, passed on 7 December 2010 (the NOME Law)[12];
- The Decree n°2005-1069 of 30 August 2005 approving the status of the company RTE EDF Transport (the Decree)[13];
- The Law n°2004-803 of 9 August 2004 related to the gas and electricity public service and to gas and electricity undertakings (the 2004 Law)[14];
- The Law n°2000-108 of February 2000 related to the modernization and the development of the public service of electricity (the 2000 Law)[15].

2.1. *Evolution of France's unbundling process*

Prior to the 2000 Law, electricity activities were carried out by EDF as a national vertically integrated company.

The 2000 Law transposed the 1st Electricity Directive and brought a *partial* liberalisation of the production activity and definition of a restricted category of eligible clients. Concerning transmission, it provided that the management of the transmission system should be entrusted by EDF to an autonomous service, which would initially not constitute a separate legal entity. The 2000 Law put in place provisions aiming to ensure the independence of the electricity TSO and created the CRE. RTE was created on 01 July 2000 as an internal division of EDF, with independent finance, management and accounting.

> In France, the networks with voltage level higher than 63 kV are classified as transmission and therefore are operated by RTE

It is to be noted, that, in France, the networks with voltage level higher than 63 kV are classified as transmission and therefore are operated by RTE. Networks with voltage level below 63 kV are operated by the DSOs.

11 Code de l'énergie.

12 Loi n° 2010-1488 du 7 décembre 2010 portant nouvelle organisation du marché de l'électricité (1).

13 Décret n°2005-1069 du 30 août 2005 approuvant les statuts de la société RTE EDF Transport.

14 Loi n° 2004-803 du 9 août 2004 relative au service public de l'électricité et du gaz et aux entreprises électriques et gazières.

15 Loi n° 2000-108 du 10 février 2000 relative à la modernisation et au développement du service public de l'électricité.

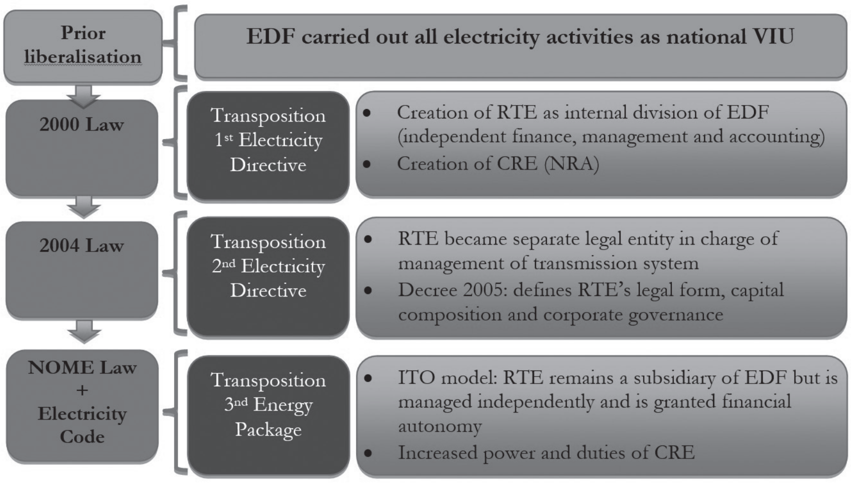

Figure 2: *How unbundling has evolved in France*

The 2004 Law transposed the 2nd Electricity Directive into French law and stated that the system operator, RTE:

- Retains responsibility for maintaining, operating and developing the electricity transmission system;
- Becomes the owner of its industrial assets;
- Is a company whose capital continues to be held entirely "by EDF, the State or other companies or institutions *belonging to the public sector*".

It also ensured the transposition of the EU legal unbundling requirement applicable to TSOs, providing for the creation of a separate legal entity (distinct from the legal entity taking care of generation and supply), entrusted with the management of the transmission system.

The by-laws of RTE were approved in 2005 (by the Decree). Among other things, the Decree specifies the legal form, name and purpose of the new company, the composition of its capital and its method of corporate governance (see below). As a limited liability company and subsidiary of the EDF Group, RTE saw its legally entrusted missions reaffirmed with the new electricity laws and regulations.

An inquiry launched in 2005 by the EC identified some shortcomings in the French electricity and gas markets as well as an "inadequate" level of unbundling between network and supply interests. The EC considered this created negative effects on the market and level of investments. Consequently, under the 3rd Energy Package, priority was given to achieve more effective unbundling of network and supply activities.

Consequently, a new electricity act, the NOME Law, was adopted as well as the Energy Code, aimed to mark the end of the transposition process of the 3rd Energy Package into the French legislation. The new law significantly increased CRE's duties and powers, notably its control over the TSO, including when it comes to the approval of future grid development plans.

The ITO Model France has chosen to comply for the unbundling for TSOs is referred to in Article 9(8)(b) of the 3rd Electricity Directive. Under this Article, a VIU may own a significant percentage of the shares of the TSO and the ITO model will then be applied. Therefore, according to the 3rd Electricity Directive, a TSO may remain the subsidiary of a VIU, provided that:

1. The TSO is managed independently from its shareholders:
    a. RTE's top management is appointed by the French government;
    b. The compensation of the management is not decided by EDF, the generation company/shareholder;
    c. EDF has no control on operational decisions of RTE.

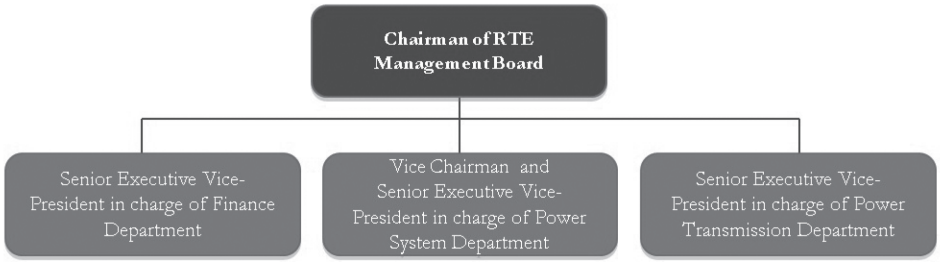

Figure 3: *Structure of RTE Management Board*

2. RTE is granted an economic and financial autonomy:
   a. All relevant charges are covered through a transmission tariff;
   b. RTE's investments are approved by the CRE;
   c. RTE may issue financial instruments.

2.2. RTE Governance

In terms of governance, RTE is a limited liability company with a Management Board and a Supervisory Board.

The Management Board

Under the terms of the Decree[16], which approved RTE's Articles of Association, the RTE Board of Management is the "only [body] competent to implement operations that contribute to the operation, maintenance and development of the public electricity transmission system".

The Management Board consistsis made up of four members, each appointed for a period of five years:

- The Chairman of the Management Board;
- The Vice-Chairman of the Management Board, Senior Executive Vice-President in charge of RTE's Power System Department;
- The Senior Executive Vice-President in charge of RTE's Finance Department;
- The Senior Executive Vice-President in charge of RTE's Power Transmission Department.

The Chairman of the Management Board is appointed by the Supervisory Board, with the agreement of the French Minister for Energy.

16 Décret n°2005-1069 du 30 août 2005 approuvant les statuts de la société RTE EDF Transport

The other members of the Management Board are also appointed by the Supervisory Board, on the recommendation of the Chairman of the Management Board. The Supervisory Board may not remove the Chairman or any other member of the Management Board, without first consulting the Commission de Régulation de l'Energie (CRE).

To confirm their independence, articles L 111-30 to L 111-33 of the Energy Code stipulate that RTE's senior executive officers are required to abide by strict deontological rules. As such, they are not permitted to hold other responsibilities within the vertically integrated company either before or after their terms of office. Nor are they permitted to hold other such responsibilities during the course of their terms of office, or to hold any stakes or interests in the same vertically integrated company. In addition, the professional interests of employees in management positions at RTE are guaranteed by measures set forth in article L 111-29 of the Energy Code.

RTE also appoints a chief compliance officer, who is an employee of the company. He is subject to the competencies attributed to him by CRE and is tasked with ensuring that the company's practices are compliant with obligations requiring it to be independent from the other companies of the VIU. His appointment must be approved by CRE. The chief compliance officer is responsible for overseeing compliance with the commitments set out in the code of practice, ensuring that all of the provisions guaranteeing RTE's independence are properly implemented, and producing a report for CRE. To carry out his appointed tasks, he attends meetings of RTE's various management bodies, and receives copies of their agendas, preparatory files and minutes, for meetings of relevance. CRE receives a report on the implementation of RTE's code of practice, drafted by the chief compliance officer.

CRE certifies that RTE has complied with its obligations under the rules on independence governing its status as part of a VIU. As such, RTE implements any new or additional organizational measures that may be needed in order to guarantee its independence within the vertically integrated organisation, and the chief compliance officer reports on these measures.

Every year, the Chairman of the Management Board submits RTE's investment programme to CRE for official approval.

The tariffs charges for using the transmission system are determined by CRE and approved by the French Minister for Energy.

The Supervisory Board

The Supervisory Board oversees the RTE's Management Board at all times, notably to ensure its economic supervision. It carries out all checks and controls deemed necessary. The Supervisory Board also deliberates key strategic, economic, financial or technological decisions. However, it may not issue any instructions concerning day-to-day management or decisions relating to the construction or modernization of transmission installations, provided they do not exceed the scope of the financial plan it has itself approved.

The Supervisory Board is composed of 12 members, each appointed for a five-year mandate:

- Four members appointed by the French government;
- Four by EDF; and
- Four elected by RTE's employees.

The chief compliance officer oversees the work of the Board and attends its meetings.

3. The unbundling process in the United Kingdom

The UK's energy case is quite exceptional. Numerous studies on EU electricity markets rightfully point out that the UK is the pioneer in energy market liberalisation[17]. The UK legislation for energy market liberalisation precedes the corresponding EU Energy Directives by 7 years in the case of electricity and by 12 years in the case of gas. It is therefore not surprising that National Grid, who owns and operates the electricity transmission network in England and Wales and the gas transmission network throughout Great Britain (GB), is the oldest TSO operating under a FOU model.

In Scotland, National Grid has been operating the electricity transmission network under the ISO Model. However it is our understanding this situation is not ideal for the operator as National Grid has mentioned it would like the EC "to hold its nerve and go for complete unbundling, with independent ownership of transmission networks"[18].

The independent operation of TSOs is perceived as paramount in the UK. It is felt that in the absence of ownership links to generators or to suppliers, TSOs have no incentive or reason to discriminate between market participants.

National Grid is a public limited company. Its shares, which were first owned by the 12 English and Welsh regional monopolies or "Area Boards" (see below), were listed in 1995 on the London Stock Exchange, with not more than one year later almost all of them being disposed by the "Area Boards".

National Grid has been certified as a TSO-FOU by the appropriate authorities.

17 Sources: http://arno.uvt.nl/show.cgi?fid=120962, http://www.unecom.de/documents/presentations/Ehlers_Insights_into_Energy_Market_Unbundling_070509.pdf

18 In one of its statements, National Grid also pointed out that since 1990, over £5.5 billion has been invested in the "unbundled" electricity transmission network in England and Wales – around double the investment seen before privatisation/liberalisation. Network reliability has averaged 99.9998% – around five times higher than continental Europe. A study from the University of Cambridge states that the creation of an independent TSO has caused a fall of 30% in real transmission charges between 1993 and 2005).

The current key texts governing electricity activities in the UK include:

- The 1947 Electricity Act[19];
- The 1957 Electricity Act[20];
- The 1989 Electricity Act[21];
- The 2000 Utilities Act[22];
- The 2004 Energy Act[23];
- The licenses[24].

3.1. Evolution of UK's unbundling process

Before entering into more details, it is important to be aware of the fact that there are two separate regimes in the UK: one covering Great Britain (GB) and one for Northern Ireland. This paper will focus on the case of GB only.

The GB energy market was one of the world's first fully deregulated markets. The electricity industry was considerably reorganised in the 1990s under the 1989 Electricity Act[25]. This reorganisation took place a few years after the UK privatised its gas sector and could therefore benefit from the lessons learned from this early experience.

Prior to the liberalisation, and following the Second World War, the UK had 560 electricity suppliers, of which approximately one-third were privately owned. Under the 1947 Electricity Act[26] and the 1957 Electricity Act[27] the electricity industry in England and Wales was reorganised with the aim to nationalise the electricity grid, as well as numerous privately owned electricity generation and supply utilities in GB. The structure of the electricity sector was the following:

- The British Electricity Authority (BEA), established by the 1947 Electricity Act, was a public corporation responsible for the generation and transmission of electricity. The BEA was under the duty "to develop and maintain an efficient, coordinated and economical system of supply of electricity in bulk for all parts of England and Wales, and for that purpose to generate or acquire supplies of electricity and to provide bulk supplies of electricity for the Area Boards for distribution by those Boards". The BEA Board consisted of seven to nine members appointed by the Minister of Power. In 1954, the BEA was renamed the Central Electricity Authority (CEA);
- Regional monopolies (12 in England & Wales and 2 in Scotland), called the Area Boards, were responsible for distribution and supply. The Area Boards, which were also created by the 1947 Electricity Act, were each responsible for a closed geographical area;

From 2001 onwards, the duty to supply all customers was replaced by a duty to connect and to maintain the connection

- Following the adoption of the 1957 Electricity Act, further reorganisations took place. In England and Wales, the CEA was replaced by a state owned company, called the Central Electricity Generating Board (CEGB) that was responsible for generation and transmission activities. Accountable for the bulk supply to the "Area Boards", the CEGB was in control of the system with the "Area Boards" subordinate.

In sum, the pre-privatisation structure of the electricity industry in GB was characterised by extensive vertical integration of generation, transmission, distribution and supply. The structure of the nationalised industry in England and Wales was dominated by one large generation and transmission company: the CEGB.

19 UK Electricity Act 1947.
20 UK Electricity Act 1957.
21 UK Electricity Act 1989 as amended.
22 UK Utilities Act 2000.
23 UK Energy Act 2004.
24 E.g. National Grid's Licence Agreement: http://www.nationalgrid.com/uk/Gas/Charges/Tools/Calc/license.htm
25 Electricity Act 1989.
26 Electricity Act 1947.
27 Electricity Act 1957.

With the introduction of the 1989 Electricity Act in 1990, the electricity sector was unbundled into separate units for generation, transmission and distribution & supply, following which privatization could take place. Additionally the 1989 Electricity Act introduced a system of independent regulation. The situation changed as follows:

- In England and Wales CEGB was unbundled in phases:
  - Generation was separated into three components: two privately owned fossil-fuel generators companies, Powergen (34% of generation capacity) and National Power (52% of generation capacity), and one nuclear generation company, Nuclear Electric (14% of generation capacity). Nuclear Electric was kept under public ownership, primarily due to its less efficient economic nature;
  - Ownership and operation of the high voltage transmission system was transferred to the newly created National Grid Company plc. (National Grid). The shares, which were first owned through a holding company "National Grid Group plc." by the 12 English and Welsh regional monopolies or "Area Boards", were in 1995 listed on the London Stock Exchange;
- The 12 English and Welsh and the 2 Scottish "Area Boards" were replaced by Regional Electricity Companies (RECs), which were then privatized as 14 Public Electricity Suppliers (PESs). Distribution and supply activities were not legally unbundled, but accounts had to be separated. This implied that the PESs were still having their monopoly distribution right as well as the supply monopoly to consumers within their authorised areas;
- Furthermore, the 1989 Electricity Act established a new regulator: the Director General of Electricity Supplies (DGES). With the support of the Office of Electricity Regulation (OFFER) the DGES had to regulate the newly privatized electricity industry and to promote competition within the industry;
- An electricity pool was established as a wholesale market mechanism through which electricity was traded in England and Wales. The pool was operated by National Grid, which administered the pool's settlement system on behalf of pool members (wholesale buyers and sellers of electricity).

It was not until the 2000 Utilities Act[28] that the legal separation of distribution and supply was effectively imposed. Going further than the principle of accounting unbundling, the 2000 Utilities Act introduced a licensing regime that required separate licenses for supply and for distribution activities, which had to be held by different legal entities, thus implementing effective legal unbundling. This implied that the concept of PESs was removed along with the concept of geographically exclusive areas. From 2001 onwards, the duty to supply all customers was replaced by a statutory duty to connect and to maintain the connection. The Distribution Network Operators (DNOs), as they were called from then on, were no longer permitted to hold a supply license. This would enable them to focus on their obligation to ensure fair and non-discriminatory access to the distribution networks.

Two different forms of licenses were introduced in the electricity sector:

- The electricity transmission license to be held by National Grid and by the two Scottish electricity transmission network owners;
- The electricity distribution license to be held by the DSOs, which own and operate local electricity distribution networks within their geographical areas.

In other words, the 2nd Electricity Directive was implemented in the UK legislation through a licensing regime. The conditions that companies have to comply with, when requesting such a license, also meet the unbundling requirements under the 2nd Energy Directive (legal unbundling).

With regard to the institutional framework and electricity market, the following changes intro-

28 Utilities Act 2000.

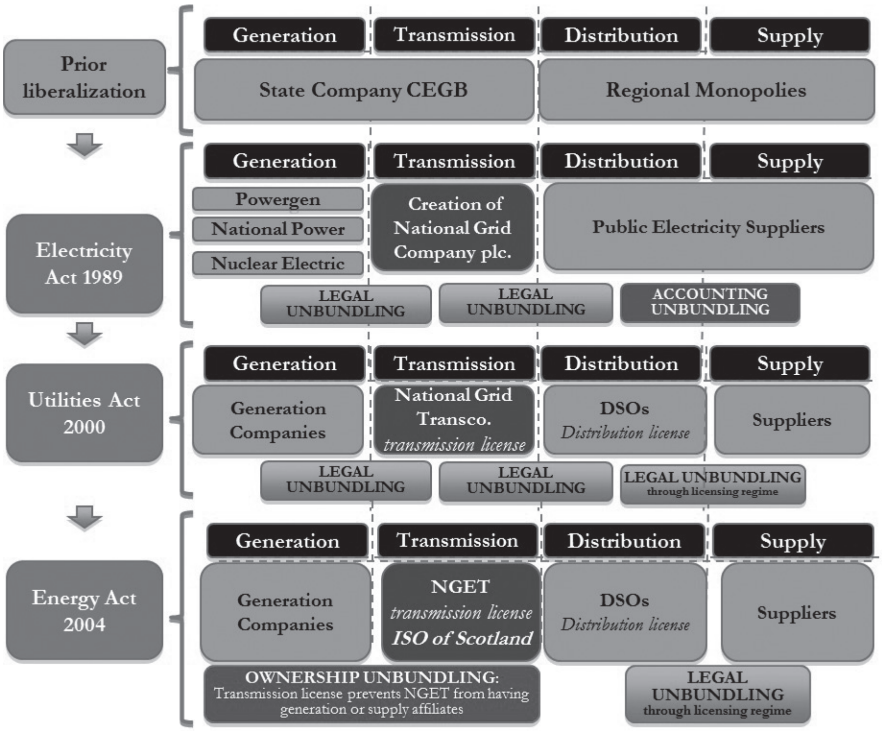

Figure 4: *How unbundling has evolved in Great Britain*

duced by the 2000 Utilities Act are noteworthy:

- DGES (individual regulator) was replaced with a regulatory board, the Gas and Electricity Market Authority, which was given new powers. A provision was also introduced to merge the gas and electricity regulators to form the non-ministerial Office of Gas and Electricity Markets (OFGEM). OFGEM is nowadays the NRA in the UK, responsible for the day-to-day operations and implementation of the policy;
- To solve the lack of competition identified, as a consequence of deficiencies in the pool system, a new electricity trading arrangement (NETA) was introduced to replace the pool. Under NETA, the bulk of electricity was traded in forward, futures and short-term markets through bilateral contracts. Participants were obliged to notify their contract volumes and final physical position to National Grid who was responsible for the Balancing Mechanism.

The licensing regime was further changed by the 2004 Energy Act[29]. The 2004 Energy Act expanded the NETA into the British Electricity Trading and Transmission Arrangements (BETTA)[30] and introduced Scotland into the market. Novelties included: a single system operator and a set of rules for trading energy and for access to and use of the transmission system. As a result, National Grid became the sole operator of electricity transmission in GB, extending the independent operation of TSOs to Scotland, where previously there had been two VIUs operating the transmission systems at the same time they were having generation and supply interests. The two Scottish transmission systems and the English and Wales system were from then on operated as one system, balancing electricity supply and demand across GB [31]. Moreover, Condition B6 of the license prevented National Grid from having generation or supply activities, so that is has no incentive towards favouring its own upstream or downstream business. The new rules also ensured that those seeking access to the grid would be able to obtain it on non-discriminatory terms.

29 Energy Act 2004.

30 British Electricity Trading and Transmission Arrangements.

31 Ownership of the transmission system remained fragmented all over UK, with National Grid for England and Wales and Scottish Power and Scottish and Southern Energy for Scotland.

The Transmission License places numerous obligations on National Grid with respect to the development and operation of the transmission system. These obligations include:
Having in force and complying with:
  - Balancing and Settlement Code; and
  - Connection and Use of System Code;
- Preparation of and compliance with the Grid Code;
- Publication of the Charging Statements;
- Preparation and publication of the Seven Year Statement, which aims at assisting National Grid Electricity System users in assessing the opportunities available to them for making new or additional use of the transmission system in the competitive electricity market;
- Requirement to offer terms for Connection to and Use of the System;
- Requirements in respect of interconnectors;
- Requirement to comply with defined security standards for planning and operation of the transmission system.

Operational decisions being taken by a strictly independent TSO have been considered as a key development for effective unbundling. This concept was pushed forward five years later by the EU as one of the unbundling models under its 3rd Electricity Directive.

The 2004 Energy Act further removes the restriction that prevents the OFGEM from granting more than one transmission license in any given geographical area. It further allowed OFGEM to alter, with the consent of the license holder, the geographical scope of the license and it allows for license conditions that can restrict the activities of the transmission license holder.

3.2. National Grid Governance

As mentioned above, National Grid owns and operates the national grid high-voltage electricity transmission network in England and Wales, and since 1 April 2005 – as the BETTA changes came into effect – it also operates the electricity transmission network in Scotland (although this is still owned by Scottish Power and Southern Energy).

Since 2000, the holding company National Grid Group started pursuing some major mergers and acquisitions in the United States (US). In 2002, National Grid Group merged with Lattice Group plc, owner of Transco – the UK gas distribution business, which had demerged from BG Group in 2000. Because of the merger, National Grid Group became National Grid Transco. In 2005, National Grid Transco finally changed its name into National Grid plc. National Grid Company was renamed National Grid Electricity Transmission (NGET) and Transco was called National Grid Gas plc.

Besides US activities, interconnectors have become an important part of National Grid's portfolio. In what follows, we will discuss the overall management structure of National Grid plc, instead of NGET solely.

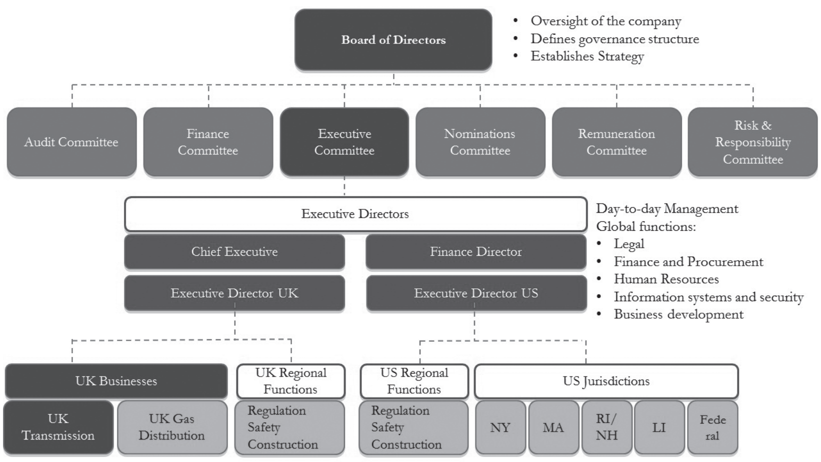

Figure 5: *National Grid management structure (in 2011)*

Management structure

In April 2011, an important reorganisation took place within National Grid, in order to have the company more closely aligned with local responsibilities as well in the US as in the UK.

Regional functions were created to take responsibility of the operations in the different countries. However, certain functions, such as finance, human resources and procurement, continue to have global responsibilities. The diagram above represents the new management structure as was in 2011 (note to the reader : recent changes to the said structure may have occurred since the drafting of this paper, inter alia the creation of a "Disclosure Committee" in support of the Chief Executive and Finance Directors).

National Grid's Board

The Board of National Grid Group decides upon those matters that impact the strategic direction and effective oversight of the company and its businesses. It maintains overall responsibility for the company's system of internal control and reviews the effectiveness of the framework annually. Examples of responsibilities of the Board include:

- Corporate governance;
- Strategy, financial policy and approval of the budget and business plan;
- Director/employee issues such as Director succession planning, with input and recommendations from the Nominations Committee; and
- Stock exchange and listing requirements such as dividend approval/recommendation and approval of results announcements, interim management statements and the Annual Report and Accounts.

> Currently, National Grid plc. has a primary listing on the London Stock Exchange and is a constituent of the FTSE 100 index

The Board currently consists of:

- A Non-executive Chairman;
- Five Executive Directors; and
- Seven Non-executive Directors determined by the Board to be independent.

In order to operate efficiently and to give appropriate attention and consideration to matters, the Board has delegated authority to several committees (see Figure 5), among which:

1. The Executive Committee, led by the Chief Executive, is responsible for day-to-day management of National Grid and for the execution of the company's strategy, business objectives and targets as approved by the Board;
2. The Risk Committee monitors and reviews the company's non-financial risks and interfaces with the Audit Committee. In this context, it is responsible for reviewing the strategies, policies, targets and performance of the company;
3. The Audit Committee has oversight of the company's financial reporting, and internal controls and their effectiveness, together with the procedures for the identification, assessment and reporting of risks;
4. The Finance Committee sets policy and grants authority for financing decisions, bank accounts, credit exposure, control mechanisms for hedging, etcetera;

1. The Nominations Committee is responsible for considering the structure, size and composition of the Board and for identifying and proposing individuals to be Directors and executive management reporting directly to the Chief Executive, together with establishing the criteria for any new position; and
2. The Remuneration Committee determines remuneration policy and practices, aligned to the company's strategy with the aim of the recruitment of Executive Directors and other senior employees to deliver value for

shareholders and high levels of customer service, safety and reliability.

National Grid's shareholders
As mentioned previously, National Grid plc. was first listed on the London Stock Exchange in 1995 – five years after the transmission activities of the CEGB were transferred to the company. The 12 RECs who first owned the company, had disposed most of their interest no later than the following year. Currently, National Grid plc. has a primary listing on the London Stock Exchange and is a constituent of the FTSE 100 Index. With regard to its US business activities, it has a secondary listing on the New York Stock Exchange.

As of 31 March 2013, the most important shareholders were The Capital Group Companies (10,91% of all voting rights), Black Rock, Inc. (5,21% of all voting rights), Crescent Holding GmbH (4,18% of all voting rights) and Legal and General Group plc. (3,99% of all voting rights). Other shareholders hold less than 3% of all voting rights.

The Board is responsible for overseeing the relations with institutional investors. This oversight is primarily managed by the Chief Executive, Finance Director and Director of Investor Relations. The latter, together with his team, meets regularly with current and prospective investors to discuss the company's strategy, performance, financing and other developments; and reports back to the Board. Depending on the subject, also other board members can meet with institutional investors. Engagement with individual shareholders (representing more than 95% of all shareholders) is managed by the Company Secretary & General Counsel.

4. The unbundling process in Belgium
In Belgium, the liberalisation process of the electricity market started effectively in 1999, with the transposition of the 1st Electricity Directive into national law. Belgium opted for the full ownership unbundling model for its TSO, undertaking the transition in several steps.

Under Belgian law, the current main texts governing electricity activities are:
- Law of 29 April 1999 relating to the organization of the electricity market (the 1999 Electricity law) [32];
- Royal Decree of 19 December 2002 establishing a technical regulation for the operation of the electricity transmission network and the access to it;
- Law of 1st June 2005 amending the Law of 29 April 1999 relating to the organization of the electricity market; and
- Law of 8 January 2012 amending the Law of 29 April 1999 relating to the organization of the electricity market and the Law of 12 April 1965 relating to the transmission of gaseous products and others by pipeline.

4.1. Evolution of Belgium's unbundling process
Before the adoption of the 1999 Electricity law, the Belgium power sector was rather a complex market, even though there were not many players. It was organized as follows:
- Electricity transmission was dominated by a rather complex monopolistic structure: a company called CPTE, created in 1995 by both Electrabel (a vertically integrated privately owned utility) and SPE (a producer in public hands). It was in charge of "coordinating" the efficient operation of the energy assets in Belgium. Various assets, including transmission, of the two market players, Electrabel and SPE were brought together under the umbrella of the said CPTE;
- Electrabel dominated the market with a market share of more than 90%. SPE's share represented about 6.5%. Some market shares were in the hands of a couple of small independent producers and industrial auto-producers;
- The supply and distribution of electricity were in the hands of municipal and intermunicipal controlled companies, while Electrabel and SPE were effectively in charge of ensuring the supply to clients directly connected to the grids.

32 Law of 29 April 1999 relating to the organisation of the electricity market.

It is to be noted that in Belgium the transmission of electricity (networks with a voltage higher than 70kV) is a federal competence, whereas the distribution (networks with a maximum voltage of 70kV) is regulated at regional level[33, 34]. This paper will focus on the unbundling process of the transmission sector only.

From the very beginning of the EU energy liberalisation process, Belgium placed itself as a front-runner in the unbundling process. It aimed to go further than what the European Directive(s) required regarding unbundling. For example, instead of limiting itself to the separation of accounts as required by the 1st Electricity Directive, Belgium decided to push ahead with legal unbundling, meaning that the transmission activities had to be fully dissociated from the other activities and placed in a separate and dedicated "network" entity.

The three main changes introduced by the 1999 Electricity law were the following:

- The electricity producers were required to have a license before they could start their activities;
- The electricity transmission became a legal monopoly and had to be legally separated and independent from generation and supply. As a result, and in order to achieve the objective of legal unbundling, CPTE created in 2001 a subsidiary called "Elia" which would later give birth to the current Belgian TSO, Elia System Operator (which obtained a 20 year renewable license in 2002 from the government). The transmission assets and activities had to be brought into the said Elia companies; and
- The independent federal regulator, the Commission for the Regulation of Electricity and Gas (CREG) was created, as well as regional regulators (as the Regions are in charge of distribution). Various tasks were given to this NRA, among which:
  - Controlling and supervising the application of the laws and regulations in the energy sector[35];
  - Controlling the national TSO;
  - A large tariff competence; and
  - Advising the government with regard to the organisation and operation of the electricity market.

As Electrabel and SPE were no longer allowed to coordinate their joint activities in the sector of electricity generation nor to own transmission assets, CPTE was liquidated and Electrabel and SPE became the initial owners of Elia System Operator's.

The concept of legal unbundling was introduced at EU level in 2003 by the 2nd Electricity Directive. However, as mentioned above, this type of unbundling was already in place in Belgium since 1999. Consequently, the new EU legislation did not bring major amendments to the Belgian law in this area. Indeed, it only foresaw unbundling provisions for TSOs that were part of a VIU, which was not effectively the case for Elia System Operator.

A series of laws and royal decrees[36] were enacted in order to implement the EU unbundling requirements. Most of these provisions were also enacted in the Belgian TSO's articles of association and/or internal by-laws as well as in shareholders' agreement(s). This entire legal framework was structured in preliminary protocols intervened between the Belgian Government, the "historic" shareholders of Elia (Electrabel and SPE) and the Belgian municipalities, which ought to become the TSO's main shareholder.

33 The federal competences in the energy sector included generation, transmission, tariffs, long-term planning and competition issues, while the regional competences dealt essentially with the distribution of electricity, the rational use of energy and renewable energy. The split of energy competences are currently under legal review by the Belgian government.

34 The full market opening for customers took place on 1 July 2003 in the Region of Flanders and in 2007 for both Wallonia and Brussels-Capital.

35 Between 1999 and 2003, there were two federal regulators: the CREG for liberalised markets and the Control Committee for Electricity and Gas for captive markets. This last was abolished in 2003.

36 The main law transposing the 2nd Electricity Directive into national law being the "Loi du 1er juin 2005 portant modification de la loi du 29 avril 1999 relative à l'organisation du marché de l'électricité".

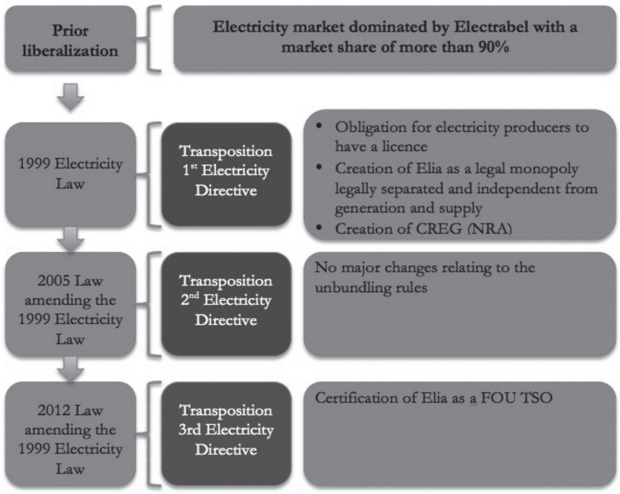

Figure 6: *How unbundling has evolved in Belgium*

The 3rd Electricity Directive became also in Belgium a new cornerstone in the evolution of the unbundling process, as it has been in most of the EU Member States. The new text aimed at reinforcing the TSOs' independency vis-à-vis electricity producers and/or suppliers, by including strict unbundling provisions for both VIU and non-VIU. In this respect, the new certification process by the NRA, and to be "confirmed" by the EC, became a *sine qua non* condition to be designated (or conformed, as the case may be) as a TSO.

The 3rd Electricity Directive was transposed into Belgian law through the law of 8 January 2012 amending the 1999 Electricity Law[37].

On 11 April 2012, Elia System Operator submitted its application to the CREG in order to be certified as a transmission system operator.

Since the Belgian legislator opted for the full ownership unbundling model, conditions to be fulfilled by Elia System Operator were the following:

1. The obligation for the owner of the transmission system to act as a TSO;
2. Measures prohibiting cross-control over a TSO on one hand and undertakings performing generation and/or supply activities on the other hand;
3. Measures prohibiting the same person to appoint members of the supervisory board, the administrative board or bodies legally representing the undertaking, of the TSO and directly or indirectly to exercise control or exercise any right over an undertaking performing generation and/or supply activities; and
4. Measures prohibiting the same person to be a member of the supervisory board, the administrative board or bodies legally representing the undertaking, of both an undertaking performing generation and/or supply activities and the TSO.

On the 06 December 2012, the CREG granted the certification to Elia. Such certification implies that Elia System Operator fully complies with the unbundling provisions introduced by the 3rd Electricity Directive.

4.2. Elia Governance

<u>Elia's shareholders</u>

Belgium imposed for the historic shareholders to withdraw gradually from shareholding of the TSO. It took over 10 years over different phases for it to happen, during which Electrabel and SPE were proportionally selling their shares in Elia to a municipal holding company created in 2001, Publi-T. Publipart, which also represents interests of several Belgian munici-

37 Loi du 8 janvier 2012 portant modifications de la loi du 29 avril 1999 relative à l'organisation du marché de l'électricité et de la loi du 12 avril 1965 relative au transport de produits gazeux et autres par canalisation.

palities, holds also a significant percentage of shares in the company. The Belgian municipalities are, directly or indirectly, Elia's core shareholder. A significant percentage of shares are listed on the Euronext stock exchange and Elia is a member of the BEL 20 Index.

According to Belgian company laws, Belgian "societies anonymes" as Elia may have mainly two types of general meetings of shareholders:

- Ordinary General Meetings, which occurs ever year on a specific date; and
- Extraordinary General Meetings, convened by the Board of Directors as often as deemed necessary in the interest of the company. Furthermore, shareholders who together represent at least 1/5 of the share capital may also request a General Meeting to the Board of Directors, which is must convene it within three weeks upon reception of such request.

The topics submitted to the Ordinary General Meetings for decision mainly relate to:

- the nomination of the members of the Board of Directors;
- the discharge of Directors and Commissioners regarding the performance of their tasks during the past financial year;
- the approval of the annual accounts; and
- the decision on the allocation of the results of the company.

The topics submitted to the Extraordinary General Meetings for decision mainly relate to:

- the modification of Elia's corporate scope;
- a significant change in Elia's governance (e.g. which has an impact on the statutes); and
- significant capital changes.

Besides the specific sector laws and royal decrees and besides the Elia's articles of association, shareholders agreements were also an essential part of the Elia "unbundling" process.

Elia's Corporate Governance

As the Belgian generators Electrabel and SPE remained shareholders of the TSO for a couple of years, and were as such allowed by Belgian corporate law to be represented on the Elia Board of Directors, it was essential that the Board powers of the said generators' representatives were appropriately limited or strictly delimited.

To this end, the Belgian electricity law, various Royal Decrees, the Elia articles of association, the Elia shareholders' agreement and a series of other implementing documents were drafted in such way that the effective management of the Belgian TSO for all matters regarding the Belgian grid was legally transferred to an independent senior management team, the Elia Management Committee ("Comité de Direction/ Directiecomité"). The CREG, the Belgian NRA, exercises some control on this Team (especially regarding its independence). Independent directors nominated on Elia's Board of Directors (see below) have also the task to verify the said Management Committee acts independently from any specific market player's interests. Advisory Board Committees to the Board, such as the Corporate Governance Committee, the Audit Committee and the Remuneration Committee, were also created by the same legal documents.

The Board of Directors is the ultimate decision-making body of Elia, except for matters reserved by the law or the statutes to the shareholders or to the Management Committee.

The Board of Directors is at least responsible for the following competences:

- the definition of Elia's general policy, values and strategy;
- the exercise of the powers conferred to it by the law and by the statutes;
- the power to accomplish all the acts necessary ore useful to the realisation of Elia's corporate object, except for those reserved by the law or the statutes to the General Meeting of Shareholders or delegated to the Management Committee; and
- the supervision of:
  - the Management Committee's performances and the realisation of Elia's strategy;
  - the efficiency of the advisory Board committees;

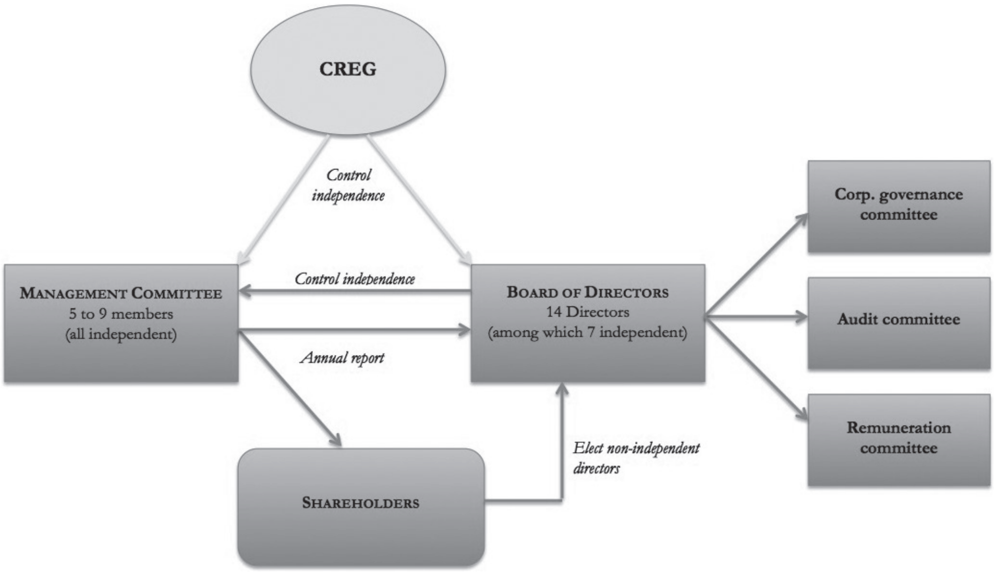

Figure 7: *Elia's Corporate Governance*

- the integrity of the meaningful information communicated to the shareholders;
- the internal control and risk-management framework; and
- the auditors' performances and the internal audit function (the General Meeting of Shareholders must elect two auditors from the members of the Belgian Institute of Company Auditors for a period of three years, subject to CREG's approval).

In order to guarantee that the decisions are taken in the interest of the company, at least half of the Directors have to be independent from any ties with the generation companies. These "independent directors" are proposed by the Corporate Governance Committee and elected by the Ordinary General Meeting of Shareholders, subject to CREG's prior approval. The "non-independent directors" are proposed and elected by the Ordinary General Meeting of Shareholders.

Members of the Board of Directors are elected for a period of six years. They in turn elect a president and one or several vice-presidents. The president opens, closes and presides over the meetings and discussions. He works in close collaboration with the CEO. The vice-president (or, if they are several, the dean of vice-presidents) assumes the tasks of the president when the latest is absent from a meeting. The Board of Directors also elects a secretary, who gives their advice to the Board on all the governance related issues. The secretary is not necessarily a member of the Board.

As already mentioned, in order to perform its tasks and responsibilities efficiently, the Board of Directors established three advisory committees: the Corporate Governance Committee, the Audit Committee and the Remuneration Committee. The Board of Directors has the possibility to create, if necessary, other ad hoc committees.

The advisory committees make recommendations to the Board of Directors about specific matters for which they have the necessary expertise. However, decision-making remains exclusively in the hands of the Board (the advisory committees only provide some advices but do not take any decisions).

Each advisory committee is composed of at least three directors. The members of each committee are elected by the Board and choose among themselves their president.

The Elia Management Committee operates in a fully independent way the electricity transmission network. It is also responsible for the daily management.

More precisely, the Management Committee is at least responsible for the following competences:

- the operation of Elia System Operator, which includes all the technical, financial and social matters related to this operation;
- the establishment of internal controls in order to identify, assess, manage and monitor the financial risks of the company and other kinds of risks;
- the submission to the Board of Director of an exhaustive, reliable and accurate plan of the annual accounts;
- the preparation of the publication of Elia's annual accounts and meaningful information;
- the submission to the Board of Directors of an objective and understandable assessment of Elia's financial situation;
- the provision in due time to the Board of Directors of all the information necessary to the accomplishment of its obligations;
- the responsibility to the Board of Directors and the report to it on the performance of its functions; and
- the exercise of the competences delegated to the Management Committee by the Board of Directors, it being understood that such delegation cannot relates to the Company's general policy or to any act reserved to the Board of Directors by the law.

In all three countries it has taken several years to move to a more or less unbundled transmission operator model

The members of the must all be independent from market players, including generators. They are elected by the Board of Directors, subject to the Corporate Governance Committee's prior approval, that may also revoke them.

The Elia Management Committee reports annually on the exercise of its powers to the Elia Board of Directors and to the Ordinary General Meeting of Shareholders. Its president and vice-president may, together or individually, participate ex officio in an advisory capacity to the Board meetings.

5. Conclusions

According to the European (and EU Member States') energy legislation, there are several possibilities to implement the unbundling process requirements at TSOs level.

The practical examples of the France, UK and Belgium demonstrate that in all cases it has taken several years to move from a VIU model to a more or less unbundled transmission operator model, which can ensure non-discriminatory access to the grid and be attractive for investments into the sector.

It is acknowledged by many stakeholders that full ownership unbundling between generation and transmission activities remains the most effective way to ensure the independence of the TSO. The FOU model can solve the inherent conflict of interest between producers and the TSO and is a tool to promote investments in infrastructure, transparency and non-discriminatory access for new market entrants. However, where strong vertically integrated companies exist, its practical implementation seems to remain difficult to fully achieve.

Given the major issue raised by the lack of investments in generation, some EU Member States are taking steps to achieve more control over their energy mix, the regulation and the TSO activities. It seems that today, the need of full TSO independence appears, for some, less crucial today than it was until recently. However, for the time being, the EC does not appear to contemplate in a positive way any request to water down the independence requirements towards TSOs and NRAs.

The example of Belgium shows the experience of a country which opted for a full ownership

unbundling model however implemented in several steps. This case attests that there is an intermediary solution between the case studies of France and the UK.
Elia, the Belgium TSO, was originally owned by the VIUs that dominated the market. As the liberalisation process advanced, Belgium imposed the VIUs to gradually withdraw from the shareholding of Elia. This withdrawal, which took place in several phases over a period of almost a decade, has lead to the creation a fully unbundled TSO, which is independent from other activities of the electricity sector.
Essential to the “Elia case” was the effective “independence” of the Management, which was guaranteed through various laws and corporate documents. This independence was there from the “very first day”, including when the TSO was not yet fully unbundled but was some kind of ITO even before the concept of ITO was developed.

This period where the company was not yet an FOU shows that even with representatives of generators present at the Board (and/or at Equity level), if appropriate rules are applied at the level of corporate documentation and/or in the applicable legislation, and with the appropriate control mechanisms, a TSO can nevertheless be fully independent.

Now that Elia is a certified TFO, this is of course still the case.

Clearly, the choice between the different models largely depends on the particular situation of each country and on some of the political goals defined by the concerned government. And *in fine*, this will to a large extent be tributary of the quality of the men and people managing and directing the TSO…

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The Geopolitics of Energy in the Eastern Mediterranean

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New energy findings in the eastern Mediterranean have ratcheted up tensions in a region already mired in instability. Their discovery is spurring a major geopolitical realignment in the region as neighbouring countries stake their claims to help achieve energy independence, sustained economic growth and job creation derived from energy production and access to lucrative export markets.

As policy makers, industry participants and various analysts search for ways to overcome challenges precipitated by rising global energy prices, the reportedly vast hydrocarbon deposits in the eastern Mediterranean continue to command significant attention. Emerging challenges were made clearly evident in the March 2013 European Council Conclusions which stated that, *"it remains crucial to further intensify the diversification of Europe's energy supply and develop indigenous energy resources to ensure security of supply, reduce the EU's external energy dependency and stimulate economic growth*."[1]

Within this context, the issue of east Mediterranean gas gains ever more traction.

In August 2013, the United States (U.S.) Energy Information Administration (EIA) stated that offshore natural gas discoveries in the eastern Mediterranean sea have the potential to significantly alter energy security dynamics in the region, as countries including Cyprus, Israel, Jordan, Lebanon, and Syria begin to satisfy their domestic consumption through home-grown resources, while also increasing their potential to export natural gas in the coming decade. Israel and Cyprus have so far led the way in terms of exploration and production. The former is already benefiting from gas coming from its Tamar[2] field, while also pushing forward with its plans to capitalize on its Leviathan[3] deposits; whereas the latter has confirmed gas in its Block 12 offshore area, and is already working with major U.S. and Israeli resource companies to appraise the deposits before forging ahead with extraction.

Taken together, natural gas discovered in the east Mediterranean sea has divided foreign policy and energy analysts over what transport routes would be most productive and efficient, and how countries can work together to extract resources and create a new energy corridor in Europe's southeast. However, the region remains plagued by instability and tension, with recent developments in Egypt and Syria contributing to a further increase in global oil and natural gas prices. Higher prices impact import markets such as the European Union, in particular, because Member States traditionally buy their gas subject to long-term

1 http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/137197.pdf

2 Proven resources: 10tcf

3 Noble owns 39.66% of the Leviathan field and Delek Group owns 15% and the proven gas resources amount to 19tcf

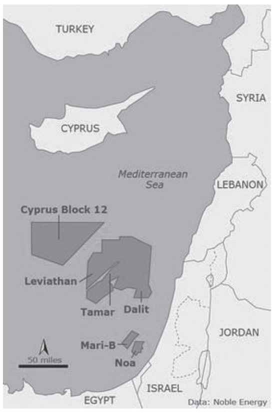

Fig. 1 *– Emed deposits*

contracts. In addition, ongoing uncertainty in Libya and North Africa, in general, continues to exacerbate potential security threats and territorial disputes over Exclusive Economic Zones (EEZs).

The balance of power between the key players in the east Mediterranean is progressively shifting and transforming relations in the region. The prospect of astonishing mineral wealth is stirring both current and dormant conflicts, as well as shaping new, mutual interest alliances in Europe's South. As the tectonic plates shift, Cyprus sees itself playing an integral role in a regional energy triangle involving Israel and potentially Greece, where exploration is about to get underway in the Ionian Sea and South of Crete. Meanwhile, the balance of power is counterweighted as Turkey carves out a niche as a dominant regional player. These developments are not without geopolitical consequences as they generate new challenges for both the European Union (EU) and the U.S.

Potential transport routes for east Mediterranean gas

The small island of Cyprus is moving ahead with its plan to extract resources in cooperation with Israel and U.S.-based Noble Energy, which has confirmed 7 trillion cubic feet (tcf) in the country's Block 12 offshore concession. The 2010 U.S. Geological Survey estimated that Block 12[4] could, in fact, hold more than 10 tcf of recoverable natural gas, with the entire Levant Basin containing nearly 122 tcf. That makes it one of the world's richest deposits, albeit in one of the most politically intractable geographic areas. Lebanon, Cyprus, Israel, Turkey, the Palestinian Authority and Syria are all staking claims to profit from these new energy findings. To be sure, the discovery of hydrocarbons in Cyprus' EEZ would be a boon for a country that is highly dependent on energy imports. After a devastating explosion in July 2011 that knocked out the island's largest power station in Vasiliko, Cyprus desperately needs energy.

Cyprus remains committed to sparking economic growth, creating jobs and increasing productivity, especially after an EU bank bailout in March 2013 exposed cracks in its economy. Indeed, extracting, refining and exporting natural gas could be real game-changer for Cyprus. The country has already confirmed its commitment to build an onshore liquefaction capacity to refine its own resources, some of which will be destined for Europe and other global export markets. Feasibility studies have been carried out in Cyprus for LNG pipeline infrastructure that would connect it to Israel, including a floating liquefied natural gas plant (FLNG) as back-up plan. The Cypriot Minister for Energy, George Lakkotrypis, recently confirmed that negotiations between Cyprus, Noble Energy and Delek Energy, its Israeli counterpart, for a liquefaction capability[5] have entered a substantive phase.[6] Noble is also considering working with other "strategic partners" – such as Australian oil and gas company Woodside, whose expertise is liquefaction and downstream marketing, and who also retains links to global markets and established relations with customers. Woodside are also keenly awaiting an Israeli court decision later this year before completing a deal to invest in the Leviathan natural gas project.[7] The Israeli high

4 Commonly referred to as 'Aphrodite'

5 Reports suggest that an agreement will be reached by the end of 2013, yet it remains to be seen if such an ambitious timeline can be reached.

6 See http://www.financialmirror.com/news-details.php?nid=30637, Accessed on: 16 August 2013

7 For more information: http://www.bloomberg.com/news/2013-08-21/woodside-awaits-israel-court-decision-before-completing-gas-deal.html. Accessed on: August 22 2013

court is expected to reach a decision later this year on whether the Israeli cabinets decision to approve 40% gas exports requires approval by the Knesset.

For its part, the European Investment Bank (EIB) stated that it would consider investing in the proposed Liquefied Natural Gas (LNG) terminal in Cyprus. The Cyprus National Hydrocarbons Co. estimates the first phase of the LNG facility, including infrastructure and as many as five production lines, or trains, will cost more than €9 billion.[8] Cypriot authorities are said to be looking at different options, including possibly using LNG sales agreements as collateral for loans.[9] According to the EIBs screening and assessment criteria, the EU's lending arm would finance the extraction of hydrocarbons if opportunities arise which are technically, financially and economically justified, while also taking into account environmental[10] and social impacts.[11] Expectations are that construction of the onshore LNG facility and production lines will start in early 2016, with international exports reported to begin as early as 2020. If all goes according to plan, this could help Cyprus meet its bailout commitments, spark economic growth and generate returns worth having, both financial and political.

Working together with Israel, Cyprus has the potential to become an important energy exporter on the global market – the EU's east Mediterranean energy hub in the making. It is widely believed that Cyprus will need less than 10% of its offshore gas for domestic use, leaving significant quantities for export.[12] Natural gas is expected to flow to local markets by the end of 2018 or early 2019, and the LNG facility is expected to be operational by the end of 2019, thereby raising the prospect for LNG exports to Europe and other parts of the world.[13]

In order for Cyprus' energy hub aspirations to be realised, investors will need certain reassurances. More certainty over the quantities of gas in the region is required, and there needs to be a political agreement with Israel. Noble Energy, which owns 70% of Block 12, has already begun appraisal drilling, and this will

Cyprus will need less than 10% of its offshore gas for domestic use, leaving significant quantities for export

help confirm both the technical and commercial viability of the gas field's future production. In addition, two European companies, Total and ENI, and South Korea's Kogas, have already received licenses for exploration and production of Cyprus' other offshore blocks. As Cyprus' plans begin to crystallise, more and more companies will be willing to invest once the resource base in the east Mediterranean is proven and quantities have been confirmed.[14] Beyond Europe, resource companies in Russia and China have also expressed interest.

The geopolitics of energy

In an Arab dominated region, Israel is also investing serious political and financial capital

8 http://www.bloomberg.com/news/2013-07-12/cyprus-studies-lng-export-expansion-beyond-12-billion-terminal.html, Accessed on: 14 July 2013

9 See "EIB says would consider backing Cyprus LNG terminal", http://www.reuters.com/article/idUSL5N0EB2D620130530?irpc=43, Accessed on: June 2 2013

10 It is also mentioned that any fossil fuel power plant with a specific emission in excess of the Emission Performance Standard can only be financed where it contributes to security of supply on isolated energy systems such as small islands with no feasible mainland energy connection

11 Delivering Growth, Security and Sustainability, EIBs Screening and Assessment Criteria for Energy Projects, 25 July 2013

12 Sir Michael Leigh, A Recovery Strategy for Cyprus, Cyprus Weekly, 8 June 2013

13 Dr. Charles Ellinas, Cyprus and the energy developments in the Eastern Mediterranean, South Europe Studies, St. Anthony's College Oxford, Cyprus National Hydrocarbons Company 17 May 2013, p.19

14 Cyprus has so far leased 6 blocks. Noble owns the rights to Block 12; ENI/KOGAS have blocks 2,3 and 9; TOTAL has blocks 10 and 11

Fig. 2 – *USGS CYP blocks*

to help achieve energy independence. There has already been speculation about where Israel will export its gas after it has sufficiently satisfied domestic consumption. Following the severe disruptions to the Egyptian pipeline to Israel and Jordan caused by militia bombings in the Sinai, Israel and Jordan entered discussions to secure an agreement over exports of natural gas. However, this deal has not materialised despite debilitating gas shortages in Jordan. In response to the breakdown in discussions, former Israeli ambassador to Amman, Oded Eran, recently pointed out that, "*Israel's failure to supply Jordan with gas is part of policymakers' broader failure to use the country's energy resources for political and strategic purposes*."[15] He also underscored that offshore hydrocarbons could be used as a source of mutual interest between Israel and their Lebanese neighbours, including Hezbollah.[16] Eran's statements also raise several important questions related to the east Mediterranean energy discoveries: To what extent can these resources be used as fuel for cooperation and de-escalating historic rivalries in the region? How can we ensure that more fuel is not thrown onto the fire? Could these resources also be used in negotiations to reconcile Israel with its Palestinians neighbours?

In recent years, Israel's relations with Turkey have been strained as a result of Israel's decision to delimit its EEZ together with Cyprus, as well as the Mavi Marmara incident in May 2010, which set fire to bilateral relations. This has resulted in weakened diplomatic ties between the two countries as well as end Turkey's involvement in annual joint-military exercises in the east Mediterranean with Israel and the U.S. Consequently, the U.S. and Israel agreed to continue with the annual exercise and to invite the Greek navy to participate in place of Turkey. The 2012 exercise involved resistance to an unarmed enemy force, with capabilities similar to those of the Turkish navy, and focused on the protection of offshore drilling platforms of the kind that may be structured off the Israeli coast.[17]

The U.S. administration considers that Israel and Cyprus are within their legal rights to develop energy resources in their EEZs, yet Washington would prefer to keep an open door policy to Turkish involvement in future projects, whenever political circumstances permit.[18] In fact, ever since the breakdown of relations between Israel and Turkey, the U.S. has been trying vigorously to reconcile the two sides, culminating in Israeli Prime Minister Netanyahu's "apology" to Turkey in March 2013

15 http://www.haaretz.com/business/.premium-1.528810?block=true, Accessed on: 15 June 2013

16 Ibid

17 Jeffrey Mankoff, Resource Rivalry in the Eastern Mediterranean: The View from Washington, German Marshall Fund Mediterranean Policy Program, June 2012, p.4

18 See "East Mediterranean Gas Politics: A Third Corridor?" Natural Gas Europe, March 2012 http://www.naturalgaseurope.com/east-mediterranean-gas-third-corridor.

over the Gaza flotilla incident. U.S. involvement in the affair has given rise to speculation concerning the construction of an Israel-Turkey pipeline. Various commentators presume that gas reserves would find their way to Europe through Turkey; yet the likelihood is high that it would be used mainly to feed Turkey's voracious domestic consumption.[19] Furthermore, the situation in Lebanon and Syria will make this pipeline very difficult to materialise as it will inevitably have to go through their territorial waters.

In contrast to Israel, Cyprus is a country that has historically maintained good relations with most players in the region, besides Turkey. The option of LNG gives more flexibility as opposed to being locked into pipeline politics. Peace pipelines start with good intentions, yet they are easily prone to disruptions caused by geopolitical complexities (e.g. the Egyptian pipeline). Moreover, the option of LNG in Cyprus would make more sense in terms of security, as the security threats in Cyprus are considerably less than those in Israel or Turkey. The LNG terminal in Vasiliko would reportedly have the capacity for three trains and could accommodate up to four or five in the future. It has also been suggested that one of the most economical solutions for east Mediterranean gas to arrive to markets would be through the construction a Cyprus-Turkey pipeline infrastructure. It is reported that the cost of gas piped through a Cyprus-Turkey pipeline[20] would cost about $7-8 per MMBTU. However, this option remains impossible as long as Cyprus remains divided. On the other hand, Cyprus could stick with the LNG option and have the ability to export both to Asia and Europe, with Asian markets being more profitable (the cost of gas is estimated between $13-16 per MMBTU). At the end of the day, low cost is not always what drives a project – it is primarily about commercially-driven, profit-oriented objectives, not unpredictable reconciliation projects.

> Low cost is not always what drives a project – it is mainly about profit-orientated objectives, not unpredictable reconciliation projects

The pressure is currently on Cyprus. If they want Israel to join them in this joint venture, Cyprus has to move fast on the LNG agreement with Noble Energy and others. Linking their adjacent gas fields and jointly exporting certain quantities could prove to be the most economically efficient and lucrative strategy for both Cyprus and Israel. If Cyprus does not move fast, Noble could move to its Plan B option of investing in an FLNG plant jointly with Israel. On the contrary, the establishment of an LNG plant in Cyprus would allow Israel and Lebanon[21] to liquefy their gas in Cyprus, making it possible to create world class LNG hub at Vasiliko in Europe's newest strategic frontier.[22]

The European Dimension: a new south eastern corridor

EU dependence on energy imports is expected to grow as indigenous production of oil and gas in the North Sea declines. Oil imports will reportedly increase to 95% of EU demand by 2030 and gas imports from 63% of demand in 2010 to 80% by 2030.[23] As reliance on non-nuclear energy increases post-Fukushima and following Germany's decision to phase out nuclear by 2022, the EU needs to find new sources of energy. In light of new discoveries in

19 The 6bcm from Azerbaijan is not enough for Turkey.

20 In its report Aphrodite's gift, International Crisis Group described this as the most economic option if political circumstances permitted it. See: http://www.crisisgroup.org/~/media/Files/europe/turkey-cyprus/cyprus/216-aphrodites-gift-can-cypriot-gas-power-a-new-dialogue.pdf

21 Lebanon gas reserves may be delayed as a result of spill over from Syria.

22 Dr. Charles Ellinas, Cyprus and the energy developments in the Eastern Mediterranean, South Europe Studies, St. Anthony's College Oxford, Cyprus National Hydrocarbons Company ,17 May 2013, p.23

23 Delivering Growth, Security and Sustainability, EIBs Screening and Assessment Criteria for Energy Projects, 25 July 2013

its Mediterranean near abroad, natural gas remains the perfect partner for renewable energy in Europe's total energy mix.

The recent decision by the Shah Deniz consortium to select the Trans Adriatic Pipeline (TAP) as the energy project of choice to move forward the Southern Corridor initiative presents a major milestone in EU energy policy. It is also an important stepping stone to more energy diversification and increased energy security in Europe's southeast corner. However, the Trans-Anatolian gas pipeline (TANAP) and TAP combined will only provide about 10bcm to Europe – hardly enough to meet European demand. By 2025, Cyprus could be in a position to export 35bcm per year, starting with 7bcm by 2020, which could rise to 50bcm per year if Vasiliko becomes an LNG hub for the region.[24] As a result, Cyprus could end up supplying 50% of the additional gas needs of the EU through this new corridor in Europe's southeast.

The onshore LNG plan could serve to complement the Southern Corridor project as well as the goals set by the meeting of the European Council on energy in March 2013. Not only in terms of exploring and extracting indigenous resources[25], but also helping to complete the internal energy market and developing more interconnections to help end energy isolation. First and foremost, it would help member states who are dependent on a single external supplier, while also giving Cyprus' economy a much-needed shot in the arm.

There is a strategic value in lowering dependence on traditional suppliers such as Russia. A new energy corridor would have a huge impact on southeast European countries[26] including Bulgaria, Greece and Slovakia, who each receive about 85% of their domestically consumed gas from Russia. In addition, if theeast Mediterranean gas rush were to be connected with any potential success story with hydrocarbons in Greece[27], a more competitive energy market could be established in Europe's southern peripheries. Both the LNG plant and a proposed pipeline linking Israel-Cyprus and Greece have been submitted as Projects of Common Interest (PCI)[28] for European funding, with the European Commission expected to make its decision on PCIs later this year.

A new Mediterranean energy hub

Cyprus currently finds itself in a unique situation. If the Cypriot administration moves forward with the right purpose they could provide win-win solutions for themselves, the EU and their neighbours. With a new government in place, there is a renewed hope for movement on reconciliation between the Turkish Cypriots and the Greek Cypriots. A bi-zonal, bi-communal solution would provide significant impetus for more constructive dialogue and cooperation on matters pertaining to energy in the east Mediterranean. Ideally, a regional energy consortium could empower the area, promote good relations between neighbours, achieve interdependence and increase regional stability to attract investment. As it stands, regional actors are not inherently cohesive — they are a collection of states that work together loosely when different areas converge. In an era of intense economic globalization, they must work together to thrive. An energy consortium could also revitalize efforts to unite the region, such as the Union for the Mediterranean.[29]

24 Dr. Charles Ellinas, Cyprus and the energy developments in the Eastern Mediterranean, South Europe Studies, St. Anthony's College Oxford, Cyprus National Hydrocarbons Company 17 May 2013, p.31

25 Both onshore and offshore,

26 Greece and Cyprus have the highest electricity prices in the EU and rising energy poverty. Energy accounts for 50% of household bills

27 Scientific evidence in Greece suggests that a wealth of hydrocarbons in the sea area south of Crete could generate huge revenues to the tune of $437bn and create 300,000 jobs. See Anthony Foscolos, Implementation of the Greek Exclusive Economic Zone and its Financial and Geopolitical Benefits, Technical University of Crete, June 2, 2011

28 See: http://ec.europa.eu/energy/infrastructure/consultations/20120620_infrastructure_plan_en.htm, for lists of proposed projects of common interest

29 Thus far, most neighbourhood initiatives have unsuccessfully tried to create synergies between EU states and rim countries, such as Egypt, Turkey, Syria and Lebanon.

The east Mediterranean gas reserves have clearly invigorated discussions concerning the development of a new energy corridor in Europe's south. At present, the option of LNG in Cyprus appears to be the best option as it provides the most flexibility and development opportunities. The east Mediterranean gas pipeline linking Israel-Cyprus-Greece does present an interesting option; however, expert opinion remains divided over that project's technical feasibility.

As global energy dynamics continue to evolve, the European Union needs to diversify its sources and routes. The Southern corridor project represents a step in this direction, but the EU needs yet more interconnections[30] and resources in order to meet its internal demand and to build up supply to support its increasingly ambitious renewables policy. In terms of diversification, the option of piping east Mediterranean gas to Turkey and then on to Europe could be seen as the easiest option. However, this would go against the very concept of diversification, and instead it would potentially create another transit monopoly. All things considered, the EU should support the creation of a new energy corridor in the east Mediterranean to provide more energy diversity and energy security for Europe and its peripheries.

> If European hydrocarbons were linked to future US gas exports, Europe could see the end of long term contracts priced according to the crude oil index

If the EU is serious about doing what it takes to exploit its own resources and diversify its routes and sources, it will eventually set its own gas prices. The new global energy landscape precipitated by the U.S. gas revolution can also benefit the European Union. If European hydrocarbons were linked to future U.S. gas exports, for instance, Europe could see the end of long term contracts priced according to the crude oil index and, as a result, a steady convergence of global gas prices. Additionally, the more we begin to see natural gas being used in the transport sector, the more likely it will be that Europe will be able to set its own prices according to spot markets and hub-based pricing, thereby paving the way for a more liberalised and competitive energy market.

30 The Greece-Bulgaria Interconnector (IGB) is the next important phase of the Southern Corridor as this pipeline would provide gas from the Southern Corridor onwards to the Balkans and to Central Europe

The role of the Russian federation in a globalizing gas market

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Introduction

The global gas industry has experienced over the last decade an extraordinary evolution. The shale gas revolution in the United States has reshaped the world energy outlook and the rapid expansion of LNG trade has redesigned the global natural gas dynamics. These two pressures are rapidly converging, paving the way for a progressive globalization of world's natural gas markets and creating new dynamics also in the European gas industry, as far as the EU security of gas supply architecture and the EU gas pricing mechanism are concerned. In this framework at some point, the Russian Federation may find strategically attractive to rethink its gas strategy, adjusting to new supply realities and pricing formulas. This article will thus discuss the globalization of natural gas markets, its impact on Europe and the role of the Russian Federation in this rapidly changing context, also proposing a vision on the future scenarios for Russia's gas strategy in a globalizing market[1].

1. The globalization of natural gas markets and its impact on Europe

1.1 The world's three natural gas markets and their structural differences

As far as gas is concerned, it is necessary to talk about "markets" rather than "market". In fact, while a unique global oil market exists, gas still remains a regional fuel. In 2012 about 70% of world oil consumption was traded internationally. In the same year only 30% of world gas consumption was traded internationally[2]. This is due to the fact that gas logistics are the crucial element in the industry. For this reason, although oil is globally more important than gas, gas is more "geopolitical" than oil. This regional structure has led to the creation of three key gas markets in the world: the US, Asia Pacific and Europe. These markets differ mainly on two points: supply-demand balance and pricing.

Let's have a look at the first structural difference: supply-demand balance. The world's gas demand is predominantly concentrated in three areas: the US, Asia Pacific (notably Japan, Korea, China, India) and Europe. However, only some of these gas consumption centers are self-sufficient: the European Union (EU) and Japan are heavily dependent on gas imports, and also China and India increasingly rely on imports

1 This paper contains some results of the research conducted within Basic research program 2013 at NRU HSE, Moscow as well as some results of the research conducted with the "Energy: Resources and Markets" program of the Fondazione Eni Enrico Mattei, Milan.

2 Unless otherwise stated, all gas statistics in this article refer to: British Petroleum (2013).

to meet their fast-growing gas demand. With regard to the US, the recent shale gas revolution has completely reshaped the fundamentals of the gas market, leading the country to a renewed self-sufficiency.

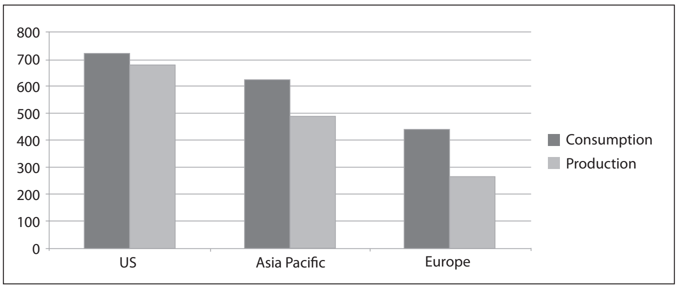

Fig. 1 *– Gas consumption and production in the world's three key markets (bcm) in 2012 (Source: Own elaboration on BP Statistical Review of World Energy, 2013)*

These different supply-demand balances generate different dynamics in terms of gas trade movements:
The US predominantly uses its domestic gas and thus transports the fuel on the vast domestic network of pipelines. In 2012 the US imported about 11% of its total gas consumption from Canada. Moreover, in the same year the US also imported minor volumes of gas via LNG from Trinidad and Tobago, Qatar, Egypt and Yemen. However, these imports are expected to decline in the near future because of robust US production. The US, and the North American sub-continent as a whole, is indeed expected to become a gas exporter;
Asia Pacific countries are mainly supplied via LNG from Malaysia, Australia and Qatar;
The EU imports gas mainly from Russia, Norway, Algeria, Qatar and Libya. Minor volumes are also provided from Nigeria, Trinidad and Tobago, and Egypt. The EU dependency on external suppliers, represented by the imports/consumption ratio, stood at 70% in 2012.
We are also to mark the growing impact of coal import from the US to EU in post-recession years due to low price shale gas. Intensive European efforts to reduce footprint and emission are being braked by painful recovery and cost considerations in the European energy industry.

The different endowment of gas resources and, consequently, the different gas supply architecture of the three markets considered have led to a second structural difference: the gas pricing mechanism. The US gas prices are increasingly decoupled from the international gas market, with Henry Hub prices stabilized at a level of USD 2,5/MBtu to USD 4/MBtu during 2012[3]. The Asia Pacific gas prices continue to be oil-linked, since price formation in

3 International Energy Agency (2013).

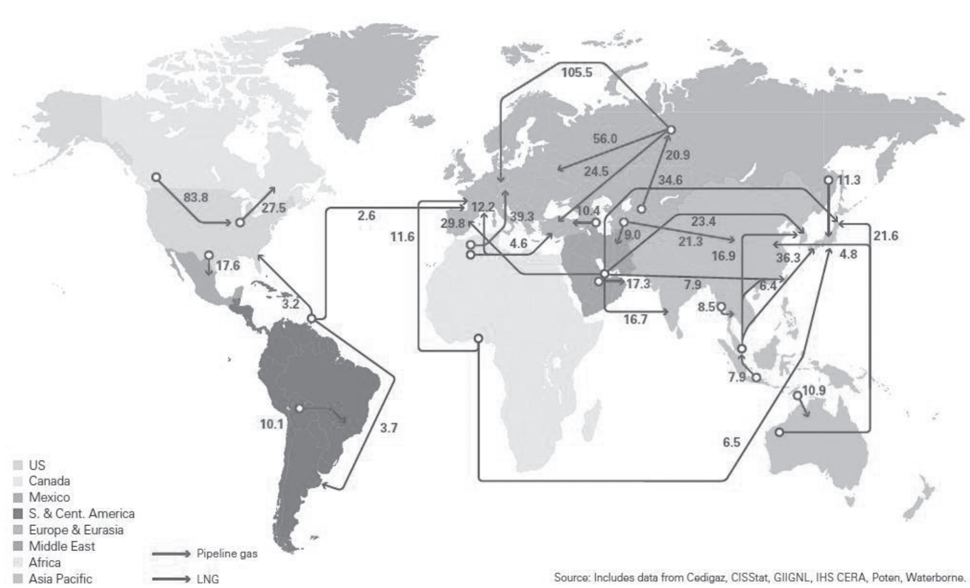

Fig. 2 *– Gas: major trade movements in 2012 (Source: BP Statistical Review of World Energy, 2013)*

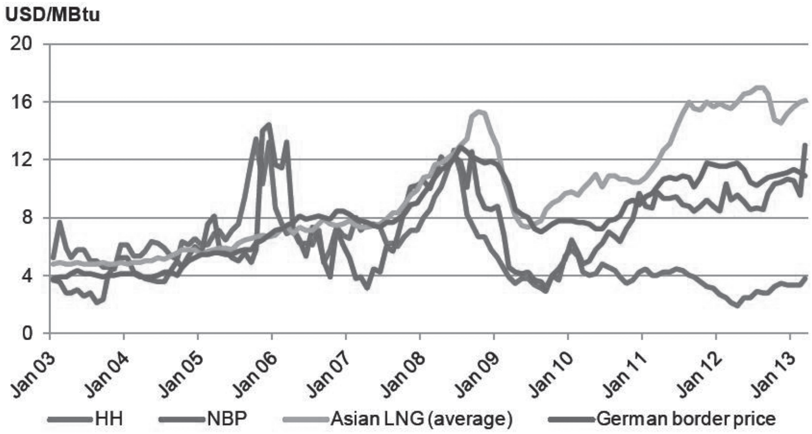

Fig. 3 *– Gas price developments in the three main regional markets 2003- 2013 (Source: International Energy Agency, 2013)*

their contracts continues to be dominated by oil indexation. The gap between Japanese LNG prices (at a level about USD 15-17/MBtu) and Henry Hub prices has widened enormously since 2011, because of the increase in LNG demand to accommodate for the unavailability of a significant part of Japanese nuclear generation capacity following the Fukushima accident[4]. In Europe, gas prices are market based in the UK while on the continent they continue to be influenced by oil price movements (at a level about USD 8-12/MBtu), although oil and gas prices are no longer as correlated as before 2009.

Globally, this results in a three-tier gas market with considerable scope for arbitration. However, infrastructure connecting the three areas continues to lag behind regional supply/demand realities. In fact, over the last two years not insignificant LNG amounts have been redirected from Europe to Japan, where prices were much higher. In the medium term, a possible increase in availability of LNG spot volumes and possible LNG exports from North America could provide energy traders with an increased toolset to pursue arbitrage opportunities.

1.2 LNG: the key driver of globalization of natural gas markets

The regional character of the global gas

4 Rogers (2012a).

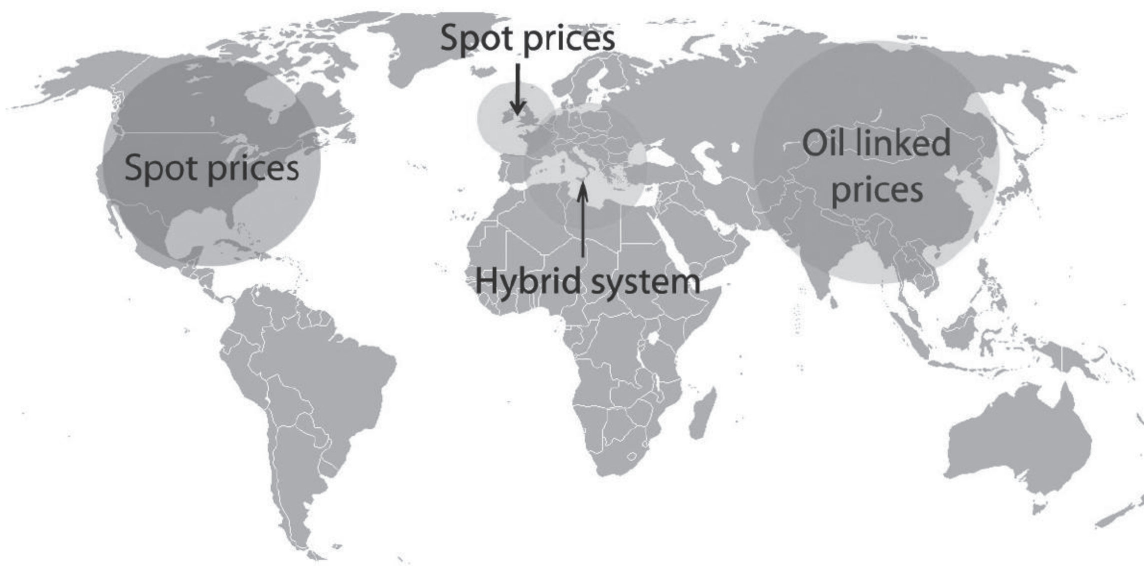

Fig. 4 *– The global gas pricing (Source: own elaboration, 2013)*

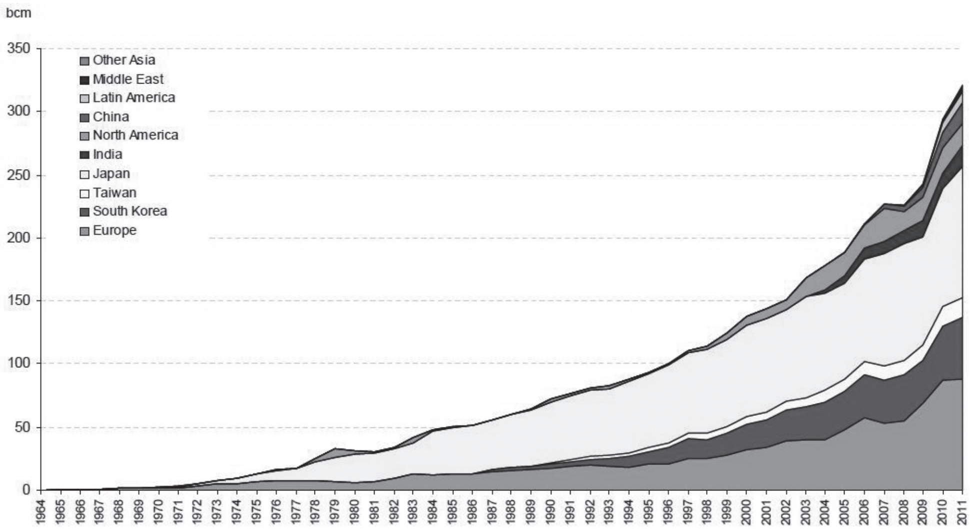

Fig. 5 *– Evolution of international LNG demand 1964-2011 (Source: Cedigaz, 2012)*

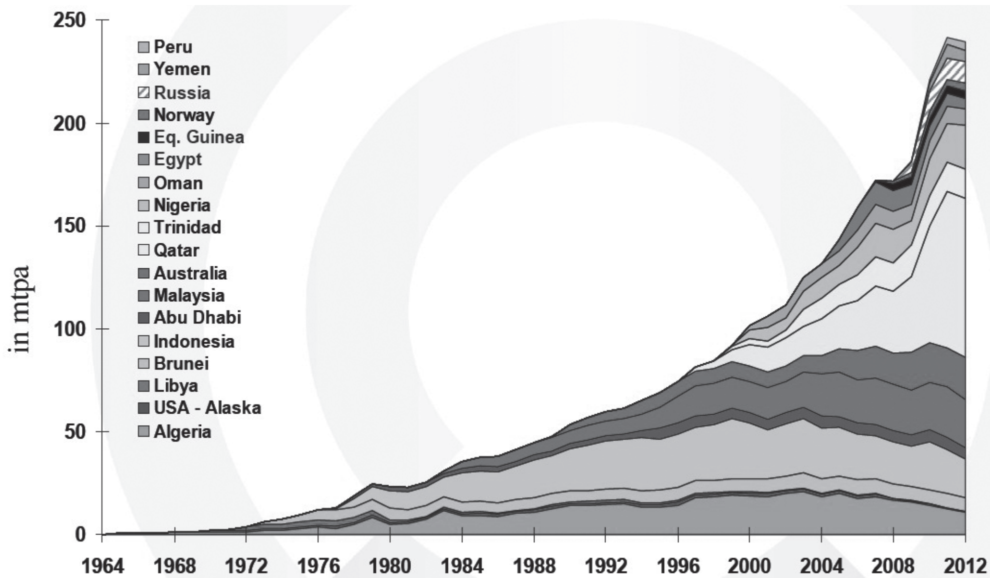

Fig. 6 *– LNG trade by exporters 1964-2012 (Source: Ledesma, 2012)*

industry has become less pronounced in recent years with the emergence of a sizeable inter-regional LNG business. This trade, which is projected to continue to grow strongly over the next decades, is increasing the price links between the main regional markets through the potential for arbitrage (though reduced import needs in North America is expected to weaken price links with other regional markets). The international LNG demand has grown constantly over time. However, it particularly surged over the last decade: from 137 billion cubic meters (bcm) in 2000 to 328 bcm in 2012, mainly because of the demand from Asia Pacific (227 bcm in 2012). In fact, Japan is the world's largest importer of LNG, followed by South Korea.

Since 1964 the international LNG supply has traditionally came from Indonesia, Algeria, Malaysia, Brunei, Libya, US-Alaska and Abu Dhabi. Australia entered the LNG market in the early 1990s, while Qatar arrived in the late 1990s. Since 2000 many other players have become part of the global LNG supply architecture: Trinidad and Tobago, Nigeria, Oman, Egypt, Equatorial Guinea, Norway, Russia, Yemen and Peru[5].

5 Cedigaz (2012).

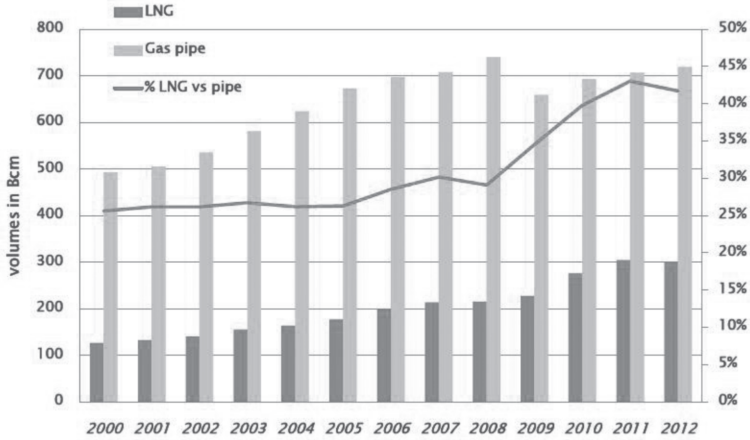

Fig. 7 *– Worldwide international gas trade: LNG vs. gas pipe (Source: GIIGNL, 2013)*

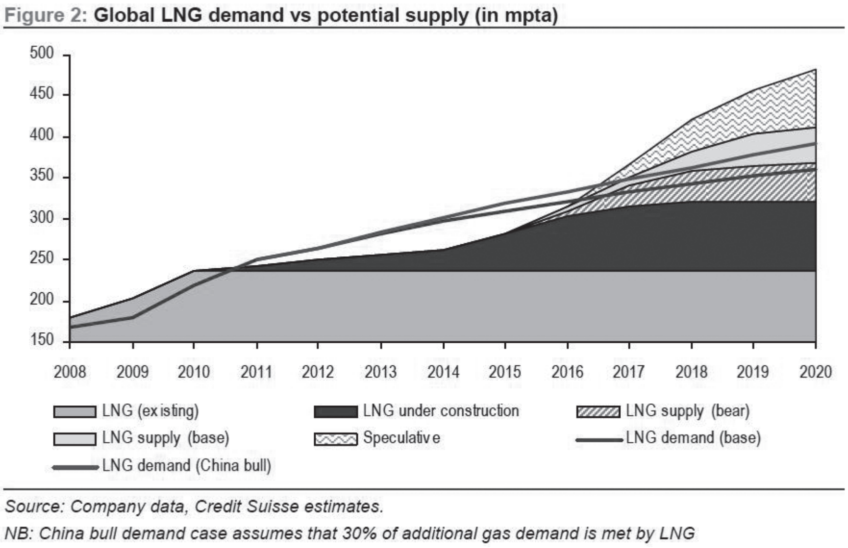

Fig. 8 *– Global LNG demand vs. potential supply,Mt/y (Source: Credit Suisse, 2012)*

The growth in LNG trade is forging linkages between the key regional gas hotspots, paving the way for the globalization of world's gas markets. A key feature is represented by the share of gas traded internationally via LNG, which has surged from 30% in 2008 to 42% in 2012[6].

This expansion of LNG trade has encouraged greater integration of regional gas markets, and has been accompanied by increased spot trade and by greater flexibility in the terms and conditions of long-term gas contracts. Such a trend is likely to continue over the near future, considering that as of May 2013, 13 LNG projects were under construction worldwide, representing a total capacity of 138.2 bcm/yr.

However, a truly global gas market, functioning in a similar way to the international crude oil market, remains today a long way off. A main obstacle to a real globalization of gas markets could be represented by the US shale gas revolution, a phenomenon that effectively de-linked the US from the rest of the world. The present divergence in price between the US, Europe and Asia Pacific has never been so marked. However, as the North American continent adds LNG export capacities, trade and arbitrage dynamics will inevitably seek to exploit such price differences and, in doing so, reduce them.

With regard to the global LNG supply/demand outlook, as the previous graph clearly shows[7],

6 GIIGNL (2013).

7 Credit Suisse (2012).

we have entered a tighter LNG in particular due to the strong LNG demand in Japan after the Fukushima nuclear accident and the subsequent closure of almost all nuclear plants in the country as well as the strong LNG demand in other East Asian countries in recent years. However, it could be that the pendulum will already swing back beyond 2015-2016 towards a loose market, as new sources of LNG supply from Australia, North America and East Africa will come online. The reason for these cycles, where the global LNG market goes from a situation of undersupply to oversupply and back to undersupply and so on, is due to the long lead times of developing new gas supply infrastructure. The latter cannot react quickly to changes in demand, especially when these changes are massive and very fast like in the case of the US shale gas revolution or the closing down of all 50 nuclear power plants in Japan between March 2011 and May 2012. This last point clearly exemplifies the uncertainty that characterize the LNG market, as the government of Shinzo Abe initially intended to restart the country's nuclear reactors (thus laying a major question mark on the country's LNG demand outlook), a hypothetic decision later delayed by the opposition of the public opinion, particularly after the radioactive water problems registered at Fukushima Daiichi during the last summer.

1.3 The role of the US shale gas revolution

Unconventional gas is rapidly reshaping the energy world. This energy revolution currently is at its initial steps and its full long-term implications are still difficult to discern. However, one thing is clear: the understanding of the gas resource base is shifting, with the immediate result that the potential time horizon of future gas supply is being radically extended. The industry has traditionally thought of gas supply as lasting 60 years, based on the narrow metric of proven reserves divided by current production (or consumption). But today, recoverable reserves of unconventional gas -including both shale and CBM- are estimated conservatively at 250 years of current consumption. And it is not simply that the gas resource base has expanded; it has also become more widely

> The US could strategically use its gas to help Europe wean itself off its dependence on Russian exports

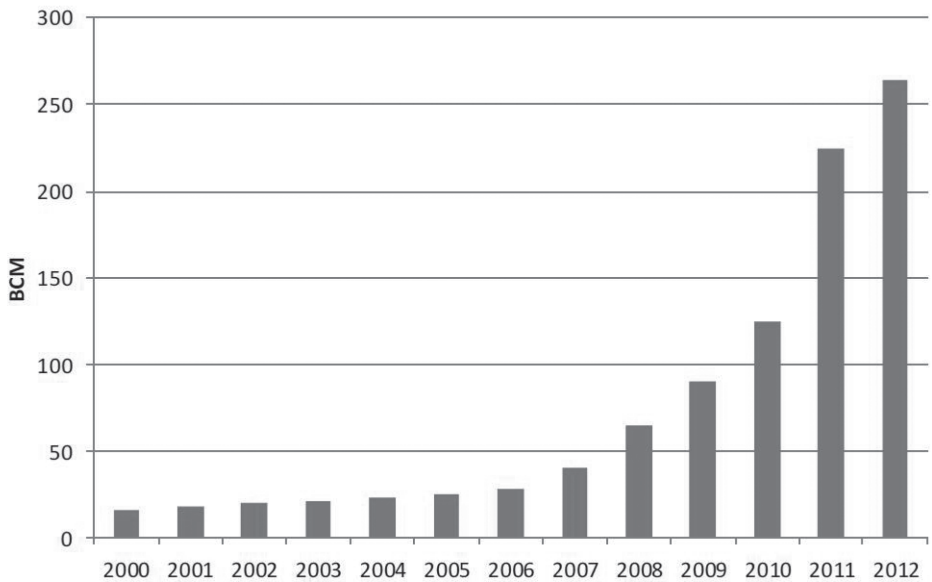

***Fig. 9** – US shale gas production, 2000-2012 (Source: own elaboration on International Energy Agency, 2013)*

distributed, with far-reaching implications for security of supply and geopolitics.
In the US, shale gas production began in the 1970s, when declining production potential from conventional gas deposits spurred the federal government to invest in R&D and demonstration projects that ultimately led to directional and horizontal drilling, micro seismic imaging and massive hydraulic fracturing. In the early 1990s the Department of Energy subsidized Texas gas company Mitchell Energy's first horizontal drill in the Barnett Shale in north Texas. Mitchell Energy utilized all these component technologies and techniques to achieve the first economical shale fracture in 1998 using an innovative process called slick-water fracturing. Since then, shale gas has been the fastest growing contributor to total primary energy in the US, with a production growing from 20 bcm in 2000 to over 260 bcm in 2012. Starting from small volumes in the early 2000s nd then growing progressively up, the US shale gas revolution had thus become reality[8].

The US experience of explosive growth in shale gas production has already changed the shape of the gas market in the country. Shale gas represents around 40% of US gas production in 2012, rising from 34% in 2011 and just 3% in 2002. In a period of five years (2007-2012), US shale gas production grew six fold, increasing from 45 bcm to around 264 bcm[9]. LNG imports, which had once been expected to provide a significant share of US gas supply by now, have declined to minimal levels. Instead the focus has switched to exports, and several LNG export projects are being launched. At this point the crucial question is: what's next for shale gas in the US? The EIA (2013) expects shale gas to lead growth in total gas production through 2040[10].

So, what about the export potential of this US shale gas? The possibility of US LNG exports is very attractive for gas producers,

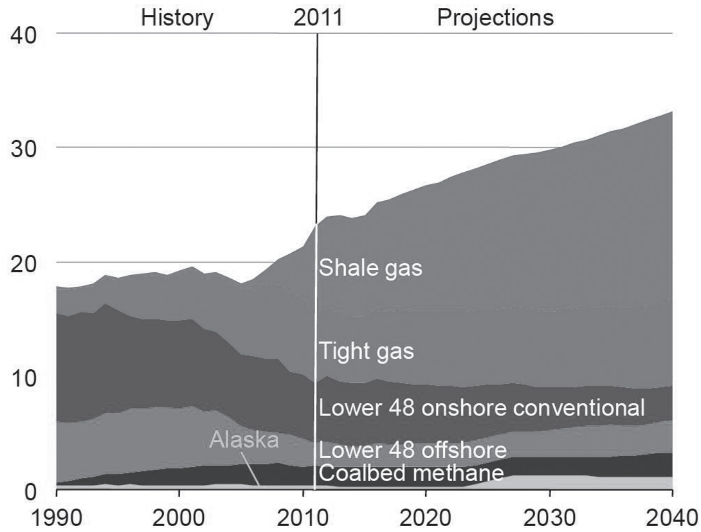

Fig. 10 *- US gas production by source 1990-2040 (Source: Energy Information Administration, 2013)*
Unit in Trillion Cubic Feet (tcf).
** 1 Tcf = 28 bcm*

LNG import terminals' holders and future potential importers due to the current high spread between US and other regional gas prices. It has led to an emerging debate on to what extent the US should export LNG or try to keep the benefits of cheap gas to enhance the competitiveness of the US economy. There is a fear that LNG exports would lead to increasing US domestic gas prices, hitting the competitiveness of the US energy-intensive industries. Gas-consuming American businesses, in the hope of keeping domestic gas prices ultra-low, are thus lobbying the government to block exports. Boosting natural-gas exports could have both pros and cons. On the beneficial side, the US could strategically use its gas to help Europe wean itself off its dependence on Russian exports or to help Japan in meeting its increasing gas demand. On the minus side, making US gas more expensive could also make it harder for the country to tackle climate change at home, considering that cheap gas is expected to displace some 9% of US coal demand by 2035.

1.4 The impact on the European market

The European gas markets are not isolated from what happens in the rest of the world. The new gas supply emerging globally -because of the increase in global LNG supply and the US shale gas revolution, as described in the

8 International Energy Agency (2012a).
9 International Energy Agency (2013).
10 Energy Information Administration (2013).

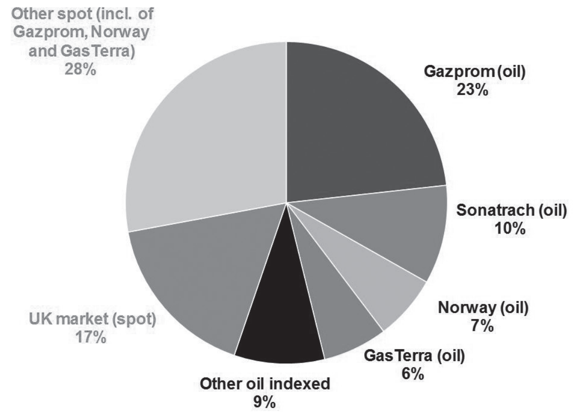

Fig. 11 *– Estimated split of European gas supply in 2012,55% oil-indexed (Source: Societe Generale Cross Asset Research, 2012)*

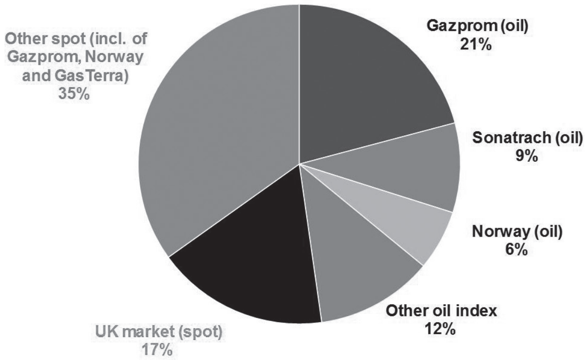

Fig. 12 *– Estimated split of European gas supply in 2013, 48% oil-indexed (Source: Societe Generale Cross Asset Research, 2012)*

previous sections- is causing an unprecedented shift in supply-demand balances, creating new dynamics in the European gas industry, with particular regard to the gas pricing mechanism. In particular, these dynamics are leading to the development of a new model for European gas markets: "hybrid pricing". As Stern and Rogers (2013) point out: "This model refers to the situation where long-term oil indexed contracts co-exist with traded gas hubs; the latter performing a role of short-term balancing"[11]. This model could be considered as a transition phase towards a fully spot and hub based market. In fact, the European gas markets seem to be inexorably going in this direction, as the empirical evidence suggests. In 2012 around 45% of gas sold in Europe was based on hub prices, and in 2013 more than half of Europe's gas is said to be priced in relation to hub and exchange prices[12].

As Bros (2012) pointed out: "Oil indexation is facing major challenges. The old system where oil-linked long-term contracts were signed to ensure both security of demand and security of supply and hub spot trading provided additional volumes, is facing a step change. It is estimated that by 2014 oil indexation pricing should represent the minority stake in European gas supply. In Europe, the rationale for oil indexation disappeared many years ago, so hub pricing makes more sense today"[13]. In the horizon 2015 it is possible to expect the European gas pricing to be increasingly based on trading at the spot level (particularly for the industrial sector), even if some long-term take-or-pay contracts will remain indexed to oil. The European gas markets will thus maintain some elements of inflexibility. The various market players should carefully measure this element, as it could cause a further drop in gas demand due to the fact that gas will not be competitive against coal. Over the last few years the natural gas demand in the EU has come under attack both by subsidized renewables and cheap coal from the US, as coal in this country was in turn displaced by cheap gas prices due to the shale gas revolution.

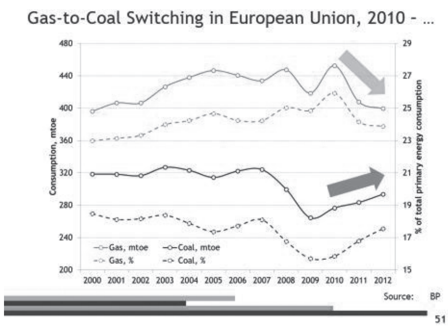

Fig. 13 *– Gas to coal switching in the EU, 2010 (Source: British Petroleum)*

11 Stern J., Rogers H. (2013).

12 Bros T. (2012).

13 Bros T. (2012).

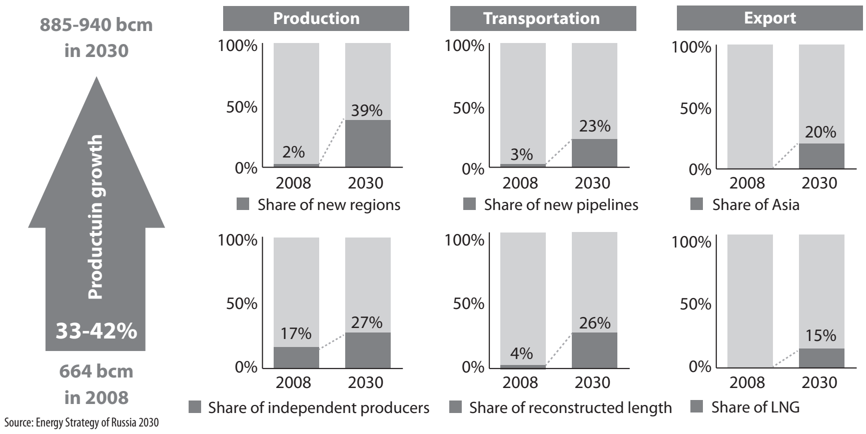

Fig. 14 *– Indicators for the Russian gas industry development according to the ES-2030 (Source: Ministry of Energy of the Russian Federation, 2009)*

2. The current Russian gas strategy

2.1 Introduction

Russia owns 45 tcm of gas reserves[14], an amount equal to the 25% of the world's total proven reserves. Around 70% of these reserves are located in on-shore Western Siberia and 10% in onshore European regions. Some 11% are located offshore on the Russian continental shelf, mainly in the Barents Sea. Around 40% of the Russian gas reserves are concentrated in hard-to-reach areas, thus making both exploration and production from the fields more technologically difficult and expensive.

Gazprom's leading position in global gas output is attributable to a handful of giant gas fields in the Nadym-Pur-Taz area in northern Tyumen Region, the shallow and compact reserves of which are easy to tap. In the 1980s and 1990s, in order to produce several hundred bcm of gas a year, it was sufficient to drill only a few thousand gas wells. These fields are largely in a declining phase obliging Gazprom to invest in new, more remote, difficult and expensive gas fields. In 1990-2004 the average annual decline in gas well flow rates was relatively stable at about 3%. The recent crisis and the following drop in gas demand explain a more substantial 3.5% decline in average gas well flow rates in 2005-2009.

Nowadays Russia is investing as never before in gas production. All large-scale projects are continuing despite the unfavorable market conditions since the 2009 crises. New markets are opening up in Asia and LNG became a State priority with huge tax exemptions and financial support, while the share of gas imports from Turkmenistan has dramatically decreased. The structure of the Russian gas balance is changing in favor of the domestic market, both in terms of supply and demand. Growing prices and growing demand increase the attractiveness of the domestic market.

2.2 The Russian Energy Strategy up to 2030

<u>Production outlook</u>

In 2009 the Ministry of Energy of the Russian Federation published the general scheme of the country's gas industry development: the Russian Energy Strategy up to 2030[15]. This document called for a strong increase in production, proposing a wide range of production targets: 870-977 bcm by 2030 (+33-42% compared to 2008). Since 2009, most experts have agreed that these targets need to be revised and in January 2013 the country's Ministry of Economic Development published a long-term projection for Russia's economic development to 2030, foreseeing gas production at 780 bcm by 2020 and 870 bcm by 2030[16].

The share of independent companies is continuously growing, decreasing the market

14 Cedigaz (2012).

15 Ministry of Energy of the Russian Federation (2010).

16 Ministry of Economic Development of the Russian Federation (2013).

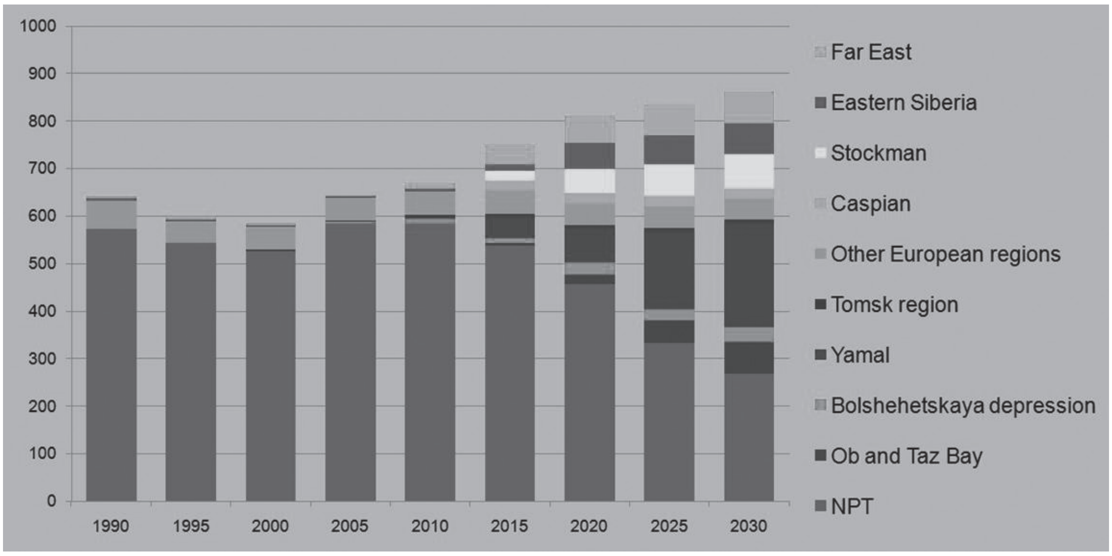

Fig. 15 – *Russian gas production outlook to 2030 by region (Source: Ministry of Energy of the Russian Federation, 2009)*

share of Gazprom. Among the independent producers, Novatek and Lukoil are the most dynamic. Independent gas companies have a huge potential for production increase, limited only by access to Gazprom`s Unified Gas Supply System (UGSS). In order to sustain and increase production, companies will have to move to more remote and challenging fields with significantly higher costs. The share of the new regions in the total gas production is expected to increase up to 40% due to the development of fields in Yamal, East Siberia and the Far East and the Shtokman field. At the same time, gas output will half in the "old" developed regions.

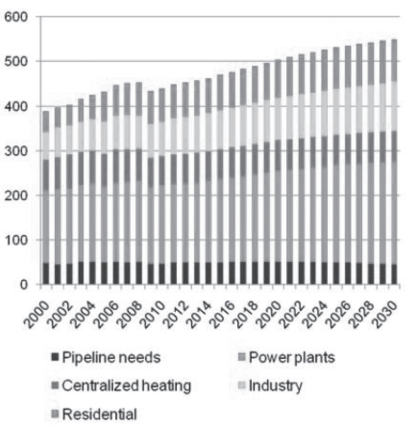

Fig. 16 – *Russian domestic gas demand forecast, Innovative scenario/bcm (Source: Ministry of Energy of the Russian Federation, 2009)*

Demand outlook

Russian domestic gas prices are rising to reach an equal profitability level with export prices (originally planned for 2011), but the speed of their growth will be subject for numerous reviews (due to the unpredictability of oil prices and European gas prices, changing domestic economic situation, etc.). Due to the crises and social pressure, the prices will probably reach European netback parity only in 2014. The following graph shows the Russian domestic gas demand projection. In 2009, due to the crisis, demand declined by 6%. It is expected that gas demand will recover to pre-crises levels after 2013.

Projected domestic demand is expected to grow strongly as price elasticity of the domestic gas demand is rather low and as alternatives to replace gas are limited. For gas producers, the domestic price increase is the most important source of additional revenues. In 2009 for the first time Gazprom`s profit from domestic gas sales reached US$ 70 billion. Increasing domestic gas prices are making domestic market more attractive and profitable for Gazprom and independent gas producers. In fact, since 2010 Gazprom reached a profitability on the domestic market. However, the slow economic growth in Russia in 2013 brought up again new debates on containing tariffs on transport, electricity and gas (like the so-called “gas pause” after the 1998 crisis). It is possible that tariffs will not be allowed to rise above the CPI rate, therefore substantially influencing the impact of the Russian energy policy.

External energy relations
Concerning Russian external energy relations, the key points of the Russian Energy Strategy of 2009 were: (i) Reflecting the Russian national interests in the international energy regulation system (“New Concept of international energy markets regulation”); (ii) Export markets diversification (share of the Asian region in the Russian energy export should increase up to 26-27% in parallel with sustained volumes of energy resources to Europe); (iii) Diversification of the energy export structure, increasing share of high value-added goods (LNG share in gas exports should reach 14-15% by 2030, the share of primary energy resources in total energy exports should not exceed 70%); (iv) Provide stable conditions on the export markets, including guaranteed demand and reasonable prices for Russian energy resources (long-term take-or-pay contracts, transit agreements, by-passing infrastructure, strategic oil reserve, oil exchanges with pricing in Roubles, Russian oil markers); (v) Strengthening positions of the Russian energy companies abroad (presence of one Russian energy company among 3 world leading energy companies and among 5 leading companies; presence of two Russian companies among 10 leading energy companies and 10 leading companies); (vi) Provide efficient international cooperation on risky and challenging projects in Russia (including offshore projects in Arctic).

A review of the Russian Energy Strategy up to 2035 or even to 2050 is expected in 2013-2014.

3. Rethinking the Russian strategy in a globalizing natural gas market

In this framework of progressive globalization of natural gas markets, also the Russian Federation might be forced to rethink its gas strategy, adjusting to new supply and demand realities as well as pricing formulas.

3.1 The need to improve the competitiveness of Russian gas exports in global markets

The first effect of the progressive globalization of natural gas markets on Russia is the need to improve the competitiveness of the country’s gas exports. There are two main options to achieve this goal: a reduction of state seizures and a reduction of companies’ costs throughout the chain of supply. At first sight, in order to counteract these threats, it would appear useful to reduce or even eliminate the duties on exports of natural gas, especially since other major market players do not use them and they are not approved by the WTO. Waiver of duties, of course, would increase the international competitiveness of Russian natural gas and increase the volume of exports, but it has a main negative aspect: it would lead to an increase in domestic prices for gas, which would curb economic development and reduce the added value of most type of economic activities, which in turn could slow down the country’s economy.

At first sight, it would appear useful to reduce or even eliminate the Russian duties on exports, especially since they are not approved by the WTO

3.2 The importance of improving the efficiency of Russian investment projects

Very important would also be the improvement of the efficiency of investment projects. In fact, a recent work done by Russian and foreign experts, who analysed the cost of domestic energy projects, has showed that they were typically several times more expensive compared to existing analogous projects found elsewhere, while those projects that were completed were underutilized for years. The main condition for increasing the efficiency of the Russian natural gas system is a radical improvement in the quality of public, and especially corporate, governance. The latter can play an important role in attracting foreign partners into the consortia engaged in resource development. If properly managed, it would enable the country to attract foreign investment and apply advanced technology, develop types of business activities with potential, ensure tight control over costs, facilitate access to logistics and adapt to the rules of international markets.

3.3 The need for a realistic view of the European gas market

The EU's import needs in the long-term remain a major question mark. The greatest uncertainty, as far as long-term gas prospects are concerned, relates more to demand security than to supply security. Major questions are: How seriously will Europe pursue and implement climate change policies? What will be the role of gas in this context? Will gas continue to be challenged by cheap coal? Will the ongoing trend of gas being squeezed by renewables on one hand and cheap coal on the other hand continue? Up to date the Russian Federation has had an optimistic view on the future outlook of the European gas demand, which justifies its numerous new pipeline projects. However, should the future European gas demand turn out to be lower than expected, profitability of these investments may result to be lower than expected by investors at the moment.

> The greatest uncertainty relates more to demand security than to supply security

3.4 The need to choose between volumes or prices

Russia's strategy is presently based on maximization of gas export volumes as well as on expected high gas prices based on oil indexation. High Russian gas prices compared to spot markets risk to reduce Russian market share. Russia should rather aim for the long-term profit maximization, as it is impossible to maximize both volumes and prices.

3.5 The quest to secure demand and to get additional margins in Europe

Europe is a highly solvable and well-placed market for Russian gas but it is already a mature market approaching plateau demand in the foreseeable future and the Russian goal should be to maintain the existing market share. A downstream strategy in order to secure demand and to get additional margins in Europe could have the following structure: (i) Development of marketing and trading activities (like Gazprom Marketing & Trading). Swap operations with WINGAS, DONG, Statoil and other companies in order to reach attractive North European markets, especially the UK; (ii) Swaps of assets with European companies (like WINGAS, EON, Gasunie etc.) in order to strengthen downstream positions; (iii) Power generation and direct access to the final consumers to guarantee security of demand and get additional margins; (iv) Underground storages to cover seasonal demand and increase margins.

3.6 The opportunity to diversify the gas export markets portfolio

Uncertainties surrounding the size of future European natural gas demand and the strong growth of Asian gas markets, coupled with the large gas resources available in the eastern part of Russia, are the key factors which should encourage the country to diversify its gas export markets portfolio. Considering that contract negotiations with China still have no clarity on price formula so far, and Turkmenistan is increasing deliveries to China, Russia should intensify talks with Japan and South Korea in order to anticipate the expected competition from Australian LNG to these markets. The diversification of the gas export markets portfolio should be encouraged together with the diversification of gas logistics, as LNG could provide a greater flexibility to Russian gas export.

3.7 The need to reinforce the EU-Russia gas partnership

While Europe has the right to develop its internal energy market in the way it wishes, it is important to take into account the constrains of its major partners and in particular the ones of Russia. However, the restructuring of the Russian gas industry should be left to the market and not to DG Competition. Gazprom will have to follow Statoil's lead and adjust to new supply realities and pricing formulas. If put under additional political pressure from Brussels, however, the Russians will likely rally around the flag and adopt a position that serves neither security of supply nor security of demand in Europe. Either each Party adapts its approaches in order to reflect other Party's interest – or it is not a strategic partnership.

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Norway

The common Swedisch-Norwegian market for electricity certificates

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Introduction

Norway and Sweden established a common Swedish-Norwegian market for trading of electricity certificates on 1 January 2012. After one and a half years of operation, interesting effects and tendencies can be observed.

The common certificates market is the principal support scheme of the two countries under the EU Renewables Directive[1] in order to increase the share of electricity production from renewable energy sources and provides important incentives for investing in new power production facilities based on renewable energy sources.

The electricity certificates market was established by way of a treaty, under which Norway joined the Swedish market for electricity certificates which had been in operation since 2003. The Swedish market was amended pursuant to the treaty to facilitate the supra-national dimensions, That is related to revised targets. Negotiations regarding a common market failed in 2006 when Norwegian officials expressed the view that a common market would be too expensive for Norwegian consumers and Norwegian industry. However, the launch of the Renewables Directive regarding promotion of the use of energy from renewable sources entailed increased challenges for Norway to develop a beneficial internal support scheme. Therefore, negotiations were reinitiated in 2007, leading up to the two countries making use of the directive's facility to establish a joint support scheme. Norwegian implementation of the EU Renewables Directive was a prerequisite for the common market to enter into force.

Directive 2009/28/EC – promotion of renewable energy sources

The Renewables Directive introduces a mandatory target of at least a 20 % share of use of energy from renewable sources by the EU in 2020. Based on this, each state is obliged to adopt national targets for its percentage share of use of energy from renewable sources in 2020. The national target for Sweden under the Renewables Directive has been set at 49 % by 2020 (up from 39,8 % in 2005)[2]. Norway has implemented the Directive as a part of the EEA-agreement and a national target has been set at 67,5 % by 2020 (up from 56 % in 2005).

One of the main elements to fulfil the goals of the Directive is to increase the share of power production based on renewable energy sources. The Directive provides for several alternative support schemes as incentives to increase renewable power production and accelerate investments in renewable energy technologies. Such support schemes include investment aid, tax exemptions or reductions, tax refunds, green certificates arrangements and direct price support schemes including feed-in tariffs and premium payments.

Various support schemes have been established in the EU Member States. Feed-in tariffs in different forms, which usually is a compensation rate provided to producers for the renewable electricity they produce, are established in several countries such as France, Germany and Italy. In other countries, including the United Kingdom and Sweden, market based schemes have been enacted. Prior to the establishment of the joint market for electricity certificates, the Norwegian support schemes were based on fiscal incentives.

The common market for electricity certificates

The certificate market is based on a demand for certificates created by law. The electricity certificates are issued to power producers for each 1 MWh produced using new renewable energy sources. The legislation establishes an obligation for the electricity suppliers to purchase electricity certificates

1 Directive 2009/28/EC.

2 The Swedish Parliament has set higher national targets, amounting to 50%, in the Swedish National Renewables Action Plan. These targets are, however, not legally binding under the mechanisms of the Renewables Directive.

from the producers and an obligation to deliver such certificates for annulment based on a yearly quota-requirement. This creates the demand for certificates, and in turn, a price formation based on market mechanisms. As a result, the system will generate revenues for the producers in addition to power sale. Thus, the increased revenues generated by the certificate market will give previously non-profitable projects an opportunity to be profitable. In the end it will be the end-users that provide the cash-flow for purchasing certificates by paying electricity bills.

The main aims of Sweden and Norway in entering into the treaty for a joint market have been to attract more players in the market, greater turnover volume, more competition and better liquidity compared to what could be obtained in national markets. This shall in turn result in better utilisation of the natural resources of the countries, especially when the duty to finance half of the support scheme does not affect how the benefit of the increase in production shall be divided by the countries. Market players in Norway and Sweden have long term experience with supra-national markets from the pan-Nordic electricity market which was established in 1996.

The goal of establishing the common market is to create 26.4 TWh new power production based on renewable energy in Norway and Sweden together by 2020. Each country is committed to financing 13.2 TWh through the certificate system. The growth of power production will be an important tool for the countries to achieve their national targets regarding the use of energy from renewable sources.

Effects of the market and national variations

In its "Progress Report" published in 27 March 2013, the European Commission gives an assessment of various alternative support schemes and expresses a clear preference for cross border mechanisms. The Renewables Directive clearly provides a basis for the development of such schemes, but so far very few supranational schemes are in place. The Commission highlights the benefits of the Swedish-Norwegian model: "*Many national reforms have had a negative impact on the investment climate. Most critical have been changes that reduce the return on investments already made. Such changes alter the legitimate expectations of business and clearly discourage investment, at a time when significantly more investment is needed. Thus there is a need for guidance on the reform process itself, to ensure support schemes are cost effective but not disruptive. The Commission also feels more action is needed to ensure convergence and the Europeanisation of energy: in addition to developing common approaches to supporting renewable energy, growing cross-border cooperation must occur. The current legal framework for such cooperation is the Renewable Energy Directive's cooperation mechanism framework. This includes joint projects, where common approaches can be developed based on specific renewable energy projects, technologies or regions as well as joint support schemes such as the Swedish-Norwegian scheme, feasible within well connected regional markets where consumers will also physically profit from renewable energy capacity installed in a neighbouring country. Such instruments provide the pathway to the European development of renewable energy, where resource development in a single energy market occurs on a common and cost effective basis. To this end, in addition to the forthcoming guidance on co-operation mechanisms, the Commission will promote the emergence of regional (and possibly sectoral) joint support schemes between Member States based on cooperation mechanism, such as a common, European approach to offshore wind development in the northern seas).*"[3]

It is, however, clear that supranational support schemes entail challenges and also partially unforeseen or undesired effects.

The volume and liquidity of a supra-national certificate market was necessary in order for Norway to join such a support scheme. Nonetheless, the natural differences regarding available renewable energy sources in Norway and Sweden entail challenges with respect to harmonisation in practice. In Sweden approx. 50 % of the power production is based on renewable sources, while in Norway the

3 Report from the Commission to the European Parliament, the Council (…). Renewable Energy progress report, COM/2013/0175.

renewables share is already more than 95 %. Thus, it is likely that the effect of the common market will be that Sweden increases the share of renewable production at the expense of fossil production, whereas Norway will increase the amount of renewable power production but not the *share of* renewable production.

So far one can observe increased activities in the markets for new renewable energy both in Sweden and in Norway. However, from a national perspective, a risk of joining a common market is that the increased liquidity may only or mostly benefit one of the countries, e.g. that most of the projects will be developed in Sweden. Even though both Norway and Sweden are obliged to finance half of the new production, there is no mandatory regulation regarding where the new production will be realised. A potential consequence is therefore that Norwegian consumers and Norwegian industry to a large extent finance new renewable production in Sweden. This is indeed the case so far; according to a joint report from the Swedish and the Norwegian regulators dated 3 September 2013, production capacity in the range of 4,7 TWh has been initiated under the joint scheme up until the first half of 2013. Of this, the Swedish share is 4,1 TWh, whereas only 0,6 TWh has been initiated in Norway. One important element in this respect is that the Swedish market was in operation prior to Norway joining. Thus, Swedish projects have been one step ahead. However, the trend seems to continue also after the establishment of the common market.

Notwithstanding the establishment of a common market, commercial, industrial, natural and regulatory differences between Norway and Sweden will remain. This may affect investment decisions and in turn entail that it will not always be the best project (in terms of use of natural resources) that is developed first. Investors will choose to develop projects based not only on the effects of the certificate market, but also the most beneficial concession policy, grid availability, development costs, cost related to grid access, and price expectations. Thus there is no obvious link between locations with the best natural resources and the location of new installed power production. Still, in light of the overarching aims of the Renewables Directive, the common Swedish-Norwegian market for Electricity Certificates so far appears successful.

Poland

Liberalisation of the gas market in Poland

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Characteristics of the Polish gas market

The Polish gas sector in the space of a few recent years has undergone breakthrough changes as far as regulations, structure, organisation and ownership are concerned. Drivers of change have included the necessity to align national regulations with EU standards through transposition, and creating entities strong enough to finance their own investment outlays. In accordance with EU law all Member States were obliged to implement into national legislation the provisions of the 3rd Energy Package, which came into force on 3rd March, 2011. The process of implementing EU regulations has not been concluded, however; once it comes into full effect, the new legislation will facilitate integration of the energy market and will speed up the sluggish rate of development restraining competition in the Polish gas market.

The Polish gas market can be described as non-competitive and regulated by public authority – according to the President of the Energy Regulatory Office ("**the President of the ERO**"). By the end of 2012 all market participants, irrespective of whether they operated in trading, supply, distribution or transmission, storage and regasification of gas, were obliged to prepare respective tariffs and submit them to the President of the ERO for approval. Currently the gas market (upstream and downstream) is fully dominated by a company controlled by the State Treasury of Poland – Polish Oil and Gas Company ("PGNiG"), which sells 98% of gas in Poland. PGNiG controls all the gas storage facilities located in Poland, as well as almost the entire Polish gas production and distribution network. It is virtually an exclusive gas importer – with an entitlement to 100% of transmission capacity on all entry points. Moreover, by being the biggest gas producer in Poland, PGNiG is calling the shots in the gas wholesale market. Gas trading companies outside the PGNiG Capital Group have no stake in gas wholesaling. In 2012 gas was still traded under provisions of bilateral agreements. Thus far gas has not been sold in Poland through stock exchanges or hubs.

The current shape of the gas market has been inherited from a long-standing single-supplier market where the monopolist was the only decision-maker. Technical and price barriers to entry for new entities were also contributing factors. One of the fundamental barriers to creating a competitive gas market is the regulatory policy, where PGNiG calculates the tariffs effectively obtaining an undervalued gas price. PGNiG throws the costs of imported gas and domestically produced gas together into one basket. Maintaining the price basket for PGNiG is unfavourable for competition in the domestic market. Companies showing possible interest in providing Poland with gas, have remarked that entering the market is virtually impossible, because the new market actor would not be able to offer comparable prices. Bearing in mind that decommissioning the PGNiG price basket would above all increase prices for the end-consumer in households, it should be expected that in the first place the regulator will undertake action towards opening the market for big end-consumers.

Another key barrier to developing the gas market in Poland is restricted access to gas resources for new entrants (PGNiG claims practically the entire imported gas plus on top of that it remains the largest gas producer in Poland). PGNiG is the sole proprietor and designated operator of underground storage capacities and until recently practically the only user at that. Another factor holding back potential competition from entering the market is stringent rules on maintaining particular gas reserves. Another obvious step in the direction of a competitive gas market is improving connections with neighbouring countries. Today's gas transmission system in Poland is still relatively isolated from other countries. It enables only unidirectional flow (East-West). Gas Transmission System Operator GAZ-SYSTEM SA ("**TSO**"), however, plans to implement a range of investment projects in 2013-2020 which are aimed to change that. Long-term agreements between PGNiG and Gazprom as well as *de facto* no third party access to the Yamal pipeline are also a considerable hurdle in the way of developing competition.

To summarise, current barriers to entry for new wholesale gas suppliers and developing competition are:

- no inter-system connections,
- insufficient storage infrastructure,
- gas prices in the domestic market dictated by the "price basket", which prevents reflecting the true market value of gas, and
- rigid rules on calculating tariffs making or impossible to have a flexible and competitive approach to customers.

Liberalisation milestones

From 2009 the Polish government was taken certain measures aimed at boosting competition on the gas market, either by legislation or operations, to decrease PGNiG's share in the market and to open the gas market for new participants. However, owing to the lack of satisfactory progress in the liberalisation of the gas market, in particular in the transposition of Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in gas and repealing Directive 2003/55/EC (hereinafter "**2009/73 Directive**"), in October 2012 the Commission requested that the European Court of Justice impose daily penalty payments on the Republic of Poland of € 88,819.20. The infringement procedure against Poland has acted as a catalyst for Polish authorities to deregulate its gas prices in the wholesale segment of the market, which was actually not in line with the Second Energy Package. But it has not resulted in speeding up the legislative process. Below we describe key factors of the liberalisation process in the gas market in Poland.

1. Access to the infrastructure – realisation of TPA rule

Since 2009, PGNiG has been obliged to make part of its storage capacity available to competitors, which should enable gas traders and suppliers to maintain gas reserves in Poland. As of 1 June 2012 onwards, the PGNiG's underground storage capacities are operated by a dedicated entity named Operator Systemu Magazynowania Sp. z o.o. which was established by PGNiG in 2011 in order to meet the unbundling obligations set forth in Directive 2009/73/EC. Furthermore, new legislation adopted in 2011 provides for broader exemptions from the obligation to maintain mandatory gas reserves, and provides that the mandatory gas reserves might, subject to certain conditions, be maintained outside Poland.
In connection with these legislative measures, the TSO is building in Świnoujście, through its wholly owned subsidiary, Polskie LNG, an LNG re-gasification facility ("**LNG terminal**"), which is scheduled to be completed in December 2014. In the first stage of operation, the LNG terminal will enable the re-gasification of 5 bn. m³ of gas annually. In the next stages, depending on the increase on demand for gas, it will be possible to increase the dispatch capacity up to 7.5 bn m3, without the need to increase the area on which the terminal will be constructed. This shall enable new participants to import extra quantities of gas onto the Polish market and to offer more competitive prices. Furthermore, the TSO has built new interconnectors with the German and Czech gas systems (Cieszyn and Lasów interconnections). At the cross-border point in Cieszyn following an assessment of the technical and commercial terms and conditions, firm day ahead capacity had started to be offered. The capacity was previously offered on an interruptible basis. This change of provision of transmission services offers a higher certainty for customers using this point that their deliveries from the Czech direction will be executed. Additionally in June 2013, the TSO and ONTRAS - VNG Gastransport GmbH, Germany, for the very first time offered the bundled capacity products at the interconnection point Lasòw. The first three quarters – with 57 980 kWh/h (5 200 m3/h) each - of 2014 were auctioned as a pilot project on the specially dedicated platform "PRISMA". As a result of the shipper bids the following bundled capacities were allocated:

1. 2nd quarter of Gas Year 2013/2014 [January 2014 – March 2014] auctioning 57 980 kWh/h (5 200 nm3/h): allocated capacity: 57 000 kWh/h, free capacity: 980 kWh/h;
2. 3rd quarter of Gas Year 2013/2014 [April 2014 – June 2014] auctioning 57 980 kWh/h (5 200 nm3/h): allocated capacity: 20 100 kWh/h, free capacity: 37 880 kWh/h;
3. 4th quarter of Gas Year 2013/2014 [July 2014 – September 2014] auctioning 57 980 kWh/h (5 200 nm3/h): allocated capacity: 21 115 kWh/h, free capacity: 36 865 kWh/h;

Additionally, the TSO commenced construction of the facilities allowing for physical reverse gas flow from Germany to Poland at the Yamal pipeline.
The actions described above will presumably lift a barrier to new participants' entry to the gas market and enable new gas traders to offer gas to consumers for a competitive price.

2. Creation of gas trading platform on commodity exchange

On 20 December 2012, the Polish Power Exchange launched its platform for trading natural gas. Contracts traded on the gas exchange provide for deliveries of gas in the same amount in all hours of the delivery period. The price of gas in each contract is expressed in PLN per MWh. In the current legal system, exchange transactions on the gas market can be concluded and cleared only with the intermediation of brokerage houses and commodity brokerage houses which are members of the Polish Power Exchange and members of the Exchange Clearing House, operated by the Warsaw Commodity Clearing House, which is responsible for clearing and settlement of transactions on the gas market. As regards gas transportation, the transactions concluded on the gas exchange are performed by the TSO. Having assessed the effects of the abovementioned actions aimed at the introduction of competition into the Polish gas market, the President of the ERO found that the Polish wholesale gas market, understood as the sale of gas to other entities for further resale, meets the conditions allowing the acknowledgment of this market as a competitive one. As a result, the President of the ERO announced that it may grant exemptions from the tariff obligation to gas traders selling gas on the wholesale market, including the Polish Power Exchange. For the time being, such exemptions have been granted to more than 20 companies active in the Polish wholesale gas market.

3. Gas Release Programme

As a consequence of disputes instigated by large local gas consumers (in particular chemical companies), the Polish government has undertaken steps to create a wholesale gas market. In 2012, the President of the ERO negotiated with PGNiG a so-called "Gas Release Programme" (*Program Uwalniania Gazu*) which seeks to force PGNiG to yield part of its share of the gas market to competitors by the voluntary sale of a significant part of gas by public auction or through the gas commodity exchange. As the results of those negotiations were not satisfactory, the President of the ERO published "Roadmap for gas prices release in Poland" – a document providing for conditions to be fulfilled prior to release of the gas traders from the obligation to use tariffs approved by the President of the ERO. In respect of publication of the road map for gas, the platform for trading gas on the Polish Power Exchange was launched.
Additionally, on August 14, 2013 the President of the Republic of Poland signed an amendment to the Energy Act, which entered into force on September 11, 2013 with the aim of avoiding penalty payments for infringement of EU related obligations. One of the most relevant changes is the obligation for gas suppliers and traders to sell certain amounts of gas on a Polish Power Exchange. In 2013 gas suppliers and traders are obliged to sell 30% of gas volume through the Power Exchange. In the year 2014 the volume of gas shall increase to 40% and from January 1, 2015 gas suppliers and traders are obliged to sell 55% of their whole gas volume through the Power Exchange. Another important factor is statutory protection of the poorest energy consumers. The amendment introduces the definition of vulnerable customers who may apply for social benefits (energy supplement) to buy gas. By this amendment further liberalisation and increased trading and supplies shall be expected with simultaneous entry of new players onto the Polish gas market.

4. New Gas Law

On October 9, 2012, the Polish Government published the final draft of the Gas Law ("**New Gas Law**"). The proposed New Gas Law will have a significant impact on the Polish upstream gas sector, which is currently generally outside the scope of the 1997 Energy Law and therefore exempt from obligations related to energy licences, tariffs, compulsory gas reserves, accounting burdens, and similar matters. Adoption of the new law will change the regulatory regime applicable to *inter alia* investors engaged in the supply and trading of gas in Poland. Below we set out the most important proposals which will determine a new structure of the future Polish gas market.

New obligations for gas producers

Under the 1997 Energy Law, gas producers are not subject to energy licences or tariff requirements unless they are engaged in gas trading (i.e. they both buy and sell gas at the same time). Therefore, if any given entity sells on the market exclusively its own gas production, it is not required to have a trading licence under the 1997 Energy Law and the sale price is not subject to approval by the President of the ERO in the form of a tariff approval.

The new Gas Law will extend strict gas market regulation to all gas producers selling their production, which is to be delivered to customers (whether by a gas transmission/distribution system and/or infrastructure used for the liquefaction of gas/re-gasification of LNG). In particular, such producers shall be obliged to obtain a licence authorising them to sell gas in Poland. Such producers will also have to sell 55% of their total production volumes through the Polish Power Exchange (beginning January 2015). Gas companies will be obliged to sell their production at the price set forth in the tariff approved by the President of the ERO. A gas producer will be released from the foregoing tariff requirement only if the President of the ERO determines that it conducts its activity in the competitive market.

Under the New Gas Law, gas producers shall be obliged to maintain their accounts so as to ensure that costs and revenues, as well as profits and losses, can be calculated separately for each of their activities: production (extraction); distribution; liquefaction; sale of gas; and re-gasification of LNG. There will also be an obligation to keep and reveal to the regulator specific information relating to sale contracts concluded with wholesale customers.

Under the New Gas Law, gas producers shall also be burdened with certain obligations related to the security of gas supplies, i.e.: reporting obligations; and obligations to prepare and periodically review contingency procedures. Entities selling gas to protected customers (households, hospitals, schools, preschools and other similar customers, as well as heating companies supplying heat to those customers) shall also be obliged to keep gas reserves (at the time being, compulsory gas reserves are maintained by all gas importers unless such enterprises are exempt from that obligation due to a limited turnover or number of customers).

New obligations for owners of transmission pipelines

The New Gas Law shall also provide for TPA duties applicable to enterprises engaged in the transmission of gas within mining pipelines. Such TPA obligations shall be similar to those existing under the 1997 Energy Law. In particular, the enterprise shall be authorised to refuse to provide transmission services within mining pipelines in case of: (i) inconsistency of technical parameters between the mining pipeline system and the transmission pipeline system; and/or (ii) inconsistency of quality parameters between the gas in mining pipeline system and transmission pipeline system – if there is no technical or economic justification to remove those inconsistencies. The obligation to provide transmission services shall also be removed if the gas transmission service would: (i) reduce current or planned gas or crude oil production for which the mining pipeline was built; or (ii) make it impossible to satisfy justified demand of the mining pipeline system's owner/user or the entity transmitting the extracted gas within the scope of gas transmission and treatment.

New powers of the national regulator

Under the New Gas Law, the President of the ERO shall also be granted certain extraordinary regulatory powers with respect to enterprises which, in the opinion of the President of the ERO, have "*market power which may pose a threat to the proper functioning of market mechanisms*". The President of the ERO shall be authorised to impose on such enterprises, for a period not exceeding 2 years, the following obligations:

- to sell a specified quantity of gas and/or transmission services and/or storage capacity – on the conditions set forth by the President of the ERO;
- to sell gas at a price not exceeding the price set by the ERO; and
- to sell gas at the price set by the ERO.
- Breach of the above obligations shall be subject to severe financial penalties (up to 10% of the income generated in the preceding fiscal year) and withdrawal of licence.

5. Summary

The situation in Poland may be described as unsatisfactory. For many years Polish authorities were unable to introduce systemic solutions that followed from EU law and the practical experience of many countries with a liberalised market. However, recently Poland has speeded-up actions towards full liberalisation of the gas market and allowed for the entry/exit model with a virtual trading point and established gas trading on the Polish Power Exchange. One step forward was the exemption from submitting tariffs for approval for gas traded on the wholesale gas market, which will finally allow competition among suppliers. Moreover, there will be a mandatory gas release program in which PGNiG, the dominant market player, will be obliged to sell gas on the energy exchange. Another positive effect is the progress of infrastructure development in Poland. Poland enhances diversification and has enabled gas supplies to be obtained from new sources. This will also allow for real market integration, meaning free trade in natural gas. Polish membership of the EU has forced the need to properly develop gas transmission infrastructure. With new projects coming online — such as the LNG terminal and interconnectors with its south and western neighbours, Poland will significantly diversify its supply of this fuel. Nevertheless, the investment needs are still vast and include modernisation and development of the internal grid, additional storage facilities, further new interconnectors with EU Member States (eg. Lithuania), and completion of the LNG terminal.

Serbia

Power Purchase Agreements and Bankability of RES Projects in Serbia

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Power Purchase Agreements (PPA) set out the terms and conditions for the sale of electricity between project parties, particularly regulating important matters on timing and the initiation of production, the terms of delivery of electricity, payment mechanisms, force majeure clauses and the termination of sales and purchases. The PPA represents a crucial project document in a renewables project. Accordingly, the structure and scope of the PPA are of the utmost significance for renewables investors, particularly institutional investors and other lenders financing these projects. Having the most recent Serbian PPA models published in July this year, the following paragraphs endeavour to provide a short analysis on the current status and discussions on this topic in Serbia, as one of the most interesting destinations for RES investments in Non-EU Europe.

The purpose of a PPA

The nominal object of PPAs is the regulation of the sale and purchase of electricity produced in energy generation facilities, where the producer (seller) and the entity conducting take-off (buyer) are agreeing to particular terms on the conditions, price and time period of purchase.

The PPA's purpose is to secure project revenues for the seller at a guaranteed price during the term of the agreement, mitigating market risk. Naturally, one of the most important principles is that the generated revenue is sufficient to service the loan during the repayment period. Therefore, it is understandable that the PPA enables financing of these types of projects and represents one of the most important project documents in the view of the financier.

Features of a bankable PPA

Speaking in general terms, a project can be deemed "bankable" when the proposed structure of the project, its specific features and the relevant project documents satisfy the lender and provide justification for financing the endeavour. The decision whether a PPA is bankable or not would depend on a simple test conducted by the lenders: will this PPA support the project in a manner that will guarantee revenue and, consequently, repayment of the loan.
The separate features and clauses supporting this and contributing to a good, bankable PPA are numerous; the following paragraphs will make short reference to such. Firstly, the security of performance of the buyer is very important in this sense. Guarantees related to the performance of buyer obliga-

tions and the dependence of the consideration of costs (fixed and variable), including outside factors (inflation, currency rates, etc.) are likely the first clauses being closely scrutinised by lenders.

The performance of the producer (seller) and the technical details on delivery are also quite important for implementation of PPA. The delivery point, as a rule, represents a *border line* regarding liabilities arising from the transfer of electricity. Accordingly, precise and well-shaped clauses defining the delivery point should avoid problems in determining losses and liabilities in this sense. Also, clauses related to metering equipment at the delivery point should feature clear obligations for producers (to install and maintain such equipment), as well as clear clauses on buyers' rights to access and read the metering parameters and to secure the buyer's position resulting from potential errors in such readings.

The buyer should be also granted the right of curtailment, and in this sense, the right to order the reduction or cessation of electricity delivery. Electricity is usually curtailed as a result of a default of one of the parties, which should result in paid damages to the other party. Extraordinary circumstances such as natural disasters could excuse such obligations and the party responsible for repairing the project is usually liable for such damages. In situations where liability is not defined properly in the contract, parties may negotiate *force majeure* clauses to resolve these issues. The compensation here is a significant point in the negotiations; the seller's interest is naturally to cover these cases with compensation and loss of profit clauses as much as possible. Lenders focus on these clauses very closely, since this could be a crucial point in the decision on whether the agreement can be deemed "bankable"e or not.

The default and termination of a PPA are very important segments as well. Usually, defaults occur as a result of a failure of the buyer to pay or other breaches (representatives and warranties, loss/change of security). Damages and penalties are used as a remedy in these cases, however termination and step-in rights are also considered. Step-in rights basically represent the rights of the lender to remedy the breach and avoid termination by taking control over the project. Such right gives security to the lender: in case of insolvency of the developer of the project (or the seller), the financiers have on disposal an instrument to *cure* the situation and enable further performance of the project.

The change in law is also much discussed, and moreover a required clause. A bankable PPA should feature a clause that prevents amendments to the applicable law from influencing the terms of the agreement during its duration. This clause typically prevents substantial amendments (such as a legislative change in relation to guaranteed subsidies) from affecting the commercial value of the project and often provides a *bona fide* obligation to negotiate PPA amendments.

PPA Models in Serbia

The Serbian Ministry of Energy adopted the official PPA model and Preliminary PPA, based on which privileged power producers will be able to utilise incentives for green electricity (i.e. the feed-in tariff) on 16 July 2013[4].

The PPA and Preliminary PPA have been adopted months after the first drafts were prepared and published by the Ministry in March of this year 2013. Months of vigorous discussions amongst stakeholders to get the best possible models (specifically in terms of bankability) took place. Even though these model agreements represent a step forward, the first impressions are that they do not address the main concerns of financiers and investors in the sector. The main reason for this is the fact that the laws and regulations themselves (which regulate the content of the PPA and Preliminary PPA) are such that they do not provide for optimal solutions to investors and that consequently the model agreements cannot fully meet the investors' needs at this moment.

Serbian PPA Issues

Considering the general observations above, relating to the common features of a good and bankable PPA, the main issues detected in the Serbian models applicable at this point are outlined below. These

4 The PPA and the Preliminary PPA were published in the Official Gazette of the Republic of Serbia no.62/13 from 16 July 2013.

comments and views are given from the perspective of the lender and represent some of the conclusions reached during public debate on the matter.

First of all, both lenders and investors in general need reassurance that changes in legislation, regulations, the taxation code and similar matters, will not affect adversely the economics of the project. The generator must be in the same position commercially as it was at the time the PPA was concluded. Another critical issue is the certainty of the final PPA. It is natural to expect that lenders would require certainty that a PPA will be signed once the project is operational and the contractual terms on which the PPA will be entered into will not change. The general conclusion has been reached that the provisions of local law at this point are not tailored to provide this reassurance.

Regarding the objections related to the grid connection, the preliminary PPA and the incentive mechanism do not address the risk that the grid will not be ready to evacuate power in time for commissioning. In this direction, setting a date by which the system operator must ensure that the HV network is ready to accept power from the seller might help.

The concept of commissioning is not defined and leads to the risk that disputes arise concerning this process. It may be possible to address this issue with modifications to the relevant Rulebook on Commissioning as well as the Serbian Law on Planning and Construction.

Since commissioning and awarding of the final PPA may involve certain actions being taken by the responsible authorities, which are not under the control of the seller, banks debated that these risks need to be addressed. The provided three month period is also relatively short according to the banks who have suggested the need for giving consideration to the idea of extending the window and that obliging public suppliers to off-take electricity during this period could positively affect the interest of financiers.

At present, the risks related to curtailment are passed to the seller through particular clauses in the PPA and relevant applicable by-laws, while the remedy is provided through an extension of the PPA. Financiers commented that curtailment is not insurable by the seller and the suspension in revenue during repeated curtailments will cause it to breach debt service obligations. An issue that was also raised is the ambiguity whether an extension in the PPA would be valid under the incentive period as defined in the regulatory framework.

Further, the model PPA imposes certain deadlines on the seller for transferring guarantees of origin to the buyer. This approach concerns the lenders, as the ability of the seller to transfer the certificates of origin to the buyer in a timely manner will depend on the seller first being able to obtain those certificates from the relevant competent authority.

With regard to the amendments, the applicable by-law on incentive measures for privileged power producers states that the model PPA can only be amended for the purposes of a specific project with prior written consent of the Ministry of Energy. This provision, which has proved problematic for investors and lenders, leaves no flexibility to the parties to make necessary amendments to reflect the commercial terms of specific projects. Also, it seems to delay pending decisions from the Ministry.

It can be argued that standard market practice in any project financing is that the seller has the right to assign the Agreement by way of security in favour of the lenders. The investors commented that the Serbian model PPA should make it clear that this remedy is permissible.

Also, the dispute resolution clauses were also a focus of recent debate and many commented that they are not in line with market standards. Specifically, these clauses permit **forum** *shopping* between arbitration in France and Serbia. The argument here was that parties to the PPA need assurance on which jurisdiction the parties may submit a dispute; most of them were clear that foreign arbitration is preferable.

Considering that promissory notes (envisaged in the model PPA) are not standard practice in the context of project financing, investors argued that the form of payment guarantee should be limited to an irrevocable government guarantee or letter of credit/bank guarantee from an international bank with an acceptable rating. The duration and

amount of the proposed security is also of concern to lenders.
Lenders also continue to be concerned by currency risk and the fact that the date of conversion is carried out on the date of the payment and not on the date of invoicing thereby leading to foreign exchange risk during the intervening 15 day payment period (or longer, in cases of delayed payments).
Furthermore, as stated above, it is standard that termination events are clearly defined and the circumstances under which either party can terminate must be clearly identified. The lenders would also consider that these circumstances should include revocation of the generation licence, repudiation, insolvency and default of either party. In this regard, lenders reasoned that the cure periods should also be quantified and expressly identify remedies which could include termination payments.

Finally, it is worth mentioning the proposals that, in the case of wind and solar projects, the incentive mechanism should clarify that the seller would be able to obtain the final privileged power producer status even in circumstances where, for any reason, the installed capacity of the facility is less than the originally anticipated capacity. This would most certainly give extra security to investors and lenders.

Future tendencies

The Ministry of Energy previously announced changes in the regulatory framework in the renewables sector by the end of 2013, and hopefully, this will lead to more bankable model Power Purchase Agreements.
Further changes to the Energy Law are expected in the following months of 2013, in the direction of harmonisation of Serbian legislation with the EU 3rd Energy Package. The implementation of these changes should enable legislators and the Ministry to produce and hopefully enact more bankable PPAs. Most of the comments and proposals mentioned above have been presented to policy makers and investors can hope for implementation of some of them in the future.
As a final note, it is yet to be seen how this will affect the development of new green projects and whether Serbia will be able to reach its targets for green energy in gross consumption by 2020 (from the current 21% to 27%) with the current system of incentives and the new model agreements. The focus of the authorities in the past few years gives us the right to be optimistic and to hope that the need for more bankable PPA will be recognised, enabling a tangible rise in the volume of renewable projects in Serbia and further development of the energy sector in general.

From German to European Elections

You may not able to win an election on energy issues, but you can surely loose it. That is what Angela Merkel may have thought when, immediately after the Fukushima incident and a few days before regional elections in Baden-Württemberg, she announced her sudden intention to abandon nuclear energy. The turn-about was not preceded by any serious impact assessment of the financial and technical consequences but, for the sake of democracy, was not contested. Remember: The merit of Chancellor Kohl had been to seize the opportunity of German unification without bothering about calculating the financial consequences.

Mrs Merkel's move came to late to impede the ecologists to win in Baden-Württemberg where for the first time in German history a member of the Green Party be came prime minister. But she succeeded in undermining the Greens - who had started as an antinuclear movement – from their raison d'être. In the national polls in September 2013 the Greens fell from 11 to 8% and Merkel's party surged from 34 to 42% - falling nevertheless short of the necessary majority in Parliament. Mrs Merkel has to look for a partner – or the Social Democrats or the Greens – to form a government - and to distribute the competence for energy between the Minister of economic affairs defending the concerns of industry and the Minister of Environment fighting climate change. The coalition will also decide which party should provide a candidate for the European Commission to be nominated in 2014.

That may be more difficult than in the past because the next Commission will be chosen under the new rules of the Lisbon Treaty. When proposing a Commission president to be elected by Parliament, the European Council has "to take account" of the result of the elections to the EP. In this perspective, parties have made an agreement that each should present a candidate for the job of Commission President, mimicking national elections where the leader of the winning party becomes prime minister.

Observers predict that Martin Schulz will head the Socialist list, although Jacques Delors has proposed his former head of cabinet Pascal Lamy. The Liberals may put forward Guy Verhofstadt, and the Greens José Bové. Within the centre-right European People's Party Michel Barnier seems to have the best chances, although European Commissioner Viviane Reding and Swedish prime minister John Fredrik Reinfeldt are also mentioned - and even Herman Van Rompuy, feeding hopes of a change in the Lisbon Treaty which would allow the presidency of the European Council to be merged with the presidency of the Commission. At present, Frenchman Barnier is European Commissioner for the internal market and services while Schulz from Germany is president of the European Parliament. If either will win the European polls in May he will provoke some headaches at home. In Germany, conservative Merkel would have to "send" a Socialist, whose party, in turn, would loose one ministerial job in the government. In France, Socialist Hollande would have to "support" a Conservative from the opposition (although Barnier and his enthusiasm to regulate the financial industry sometimes seem more to the left than French socialists). And both would have to end the incestuous tradition that the Commission president is chosen among national prime ministers.

Imagine the result of the European elections to be similar to the German elections: The People's Party heads the polls but fails to get the necessary majority to make the Parliament vote for its candidate. The Socialists and the Liberals try to form a coalition but do not succeed in agreeing on an alternative candidate; to hide their failure they announce that they will never accept Barnier. The European Council seizes the opportunity to state that there is no clear result of the European elections to be taken account of and, after the usual bargaining, agrees upon a candidate who appeals to some and does not disturb the others too much. That is where Barroso, Tusk, and Van Rompuy may reappear on the scene.

As important as human actors and faces may be, the voters should decide according to the substantive issues at stake. Your European Energy Journal will compare, in April 2014, the energy programs of all parties.