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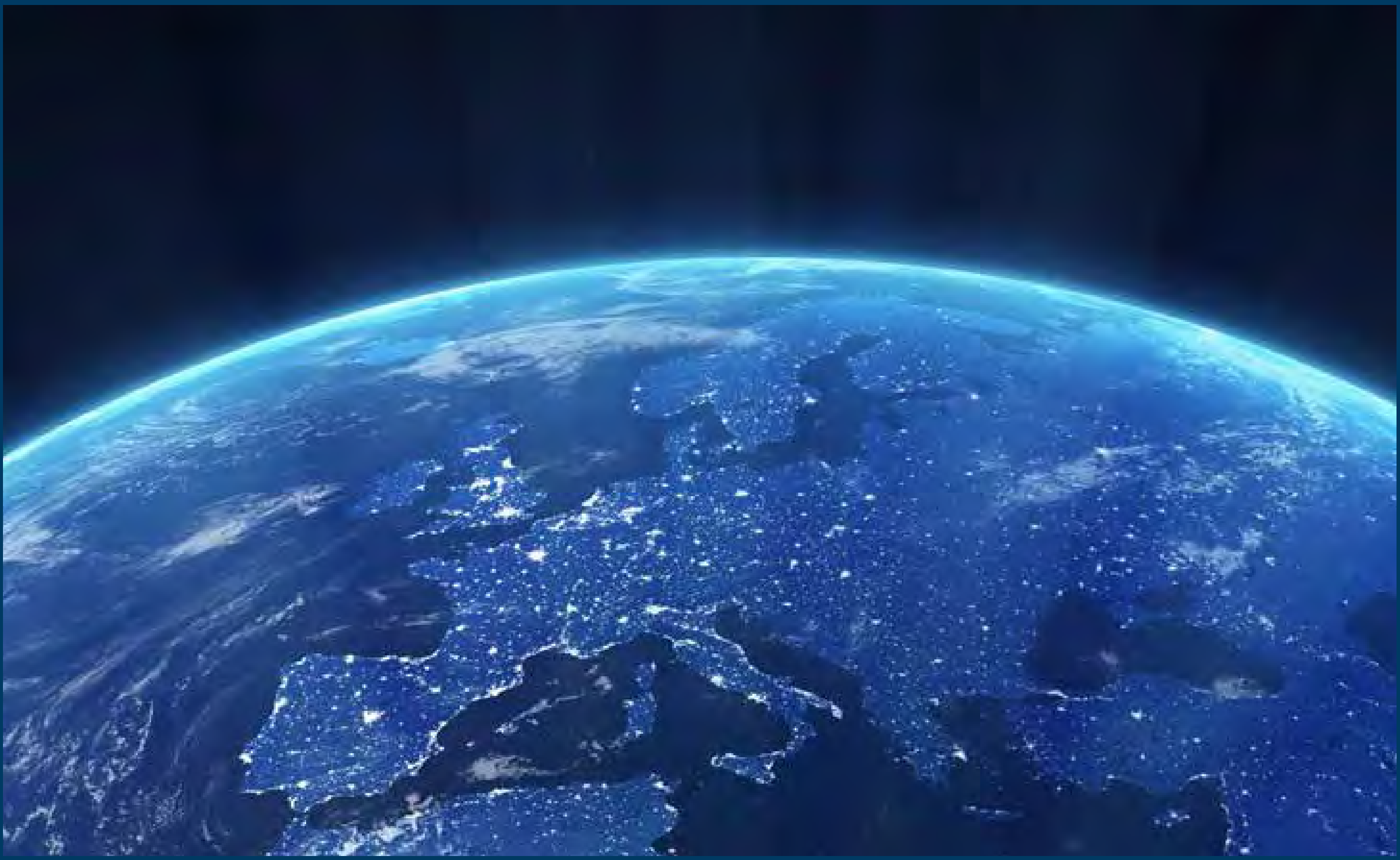

A SURVEY OF CURRENT ISSUES IN THE EUROPEAN ENERGY SECTOR

THE EUROPEAN ENERGY HANDBOOK 2015

SECTOR SURVEY
NINTH EDITION

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February 2015

THIRD ENERGY PACKAGE

Throughout this publication, we refer to the two Directives and three Regulations adopted by the European Council and the Parliament on 13 July 2009 as the “Third Energy Package”. For ease of reference, the Directives and Regulations adopted as part of the Third Energy Package: EU Directives 2009/72/EC, 2009/73/EC and Regulations (EC) No 713/2009, No 714/2009 and No 715/2009 are referred to as the “Third Electricity Directive”, the "Third Gas Directive", the “ACER Regulation”, the “New Electricity Regulation” and the “New Gas Regulation”, respectively. Where the context so requires, we refer collectively to the two Directives as the “Third Electricity and Gas Directives” and to the Regulations as the “New Electricity and Gas Regulations”, as appropriate.

CLIMATE CHANGE PACKAGE

We refer to the four Directives, one Regulation and one Decision adopted by the European Parliament on 17 December 2008 and the European Council on 6 April 2009 as the “Climate Change Package”. For ease of reference, throughout this publication, we refer to EU Directives 2009/29/EC, 2009/28/EC, 2009/31/EC and 2009/30/EC as the “New EU ETS Directive”, the “Renewable Energy Directive”, the “CCS Directive” and the “Biofuel Directive” respectively. Further, we refer to EU Decision No 406/2009/EC and Regulation (EC) No 443/2009 as the “GHG Reduction Decision” and the “Emissions Standards Regulation”, respectively.

Where required, we have referred to the previous internal energy market directives 1996/92/EC and 1998/30/EC as the "First Electricity Directive" and the "First Gas Directive", respectively and to Directives 2003/54/EC and 2003/55/EC as the "Second Electricity Directive" and the "Second Gas Directive", respectively.

Throughout the publication, we refer to Transmission System Operators as “TSO” and to Distribution System Operators as “DSO”.

We use the following abbreviations for the various unbundling models:
FOU: Full Ownership Unbundling;
ITO: Independent Transport Operator;
ISO: Independent System Operator

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INTRODUCTION

I am delighted to introduce the 2015 edition of "The European Energy Handbook" which provides an in-depth survey of current issues in the energy sector in 42 European jurisdictions.

This year's edition focuses on recent legal and commercial developments in each jurisdiction and covers issues as diverse as the design of electricity markets, the reform of the support schemes for renewable electricity, new cross-border interconnections, new state aid guidelines, taxation issues for the upstream sector and significant commercial transactions and privatisations in the energy sector.

In addition to contributions for the European Union, Belgium, France, Germany, Spain, Russia and the United Kingdom from our own offices, this year we have contributions from Schönherr (Albania, Austria, Bulgaria, Croatia, Czech Republic, Hungary, Montenegro, Romania, Serbia, Slovakia and Slovenia), Peterka & Partners (Belarus), Karanovic-Nikolic (Bosnia and Herzegovina and the Former Yugoslav Republic of Macedonia), S. A. Evangelou & Co LLC (Cyprus), Kromann Reumert (Denmark), Raidia Leijns & Norcous (Estonia, Latvia and Lithuania), Roschier (Finland), Kyriakides Georgopoulos & Daniolos Issaias (Greece), Arthur Cox (Ireland), Studio Legale Legance (Italy), Signum (Kazakhstan), Arendt & Medernach (Luxembourg), Buttigieg, Refalo & Zammit Pace Advocates (Malta), Nauta Dutilh (the Netherlands), Arntzen de Besche Advokatfirma AS (Norway), WKB Wierciński, Kwieciński, Baehr (Poland), Esquivel Advogados (Portugal), Mannheimer Swartling (Sweden), Homburger (Switzerland), Kolcuoğlu Demirkan (Turkey), BBA//Legal (Iceland) and Sayenko Kharenko (Ukraine).

Whilst 2014 was supposed to be the year in which the internal market for energy would be completed, not all Member States have transposed the Third Energy Package into national law and the European Commission has referred a number of Member States to the European Court of Justice for either partial or complete failure to implement the same.

2015 will see intensified efforts to integrate the European energy market and is set to be an important year for the electricity market as the EU Target Model for electricity market integration is expected to be fully implemented this year.

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The gas markets are likewise anticipating further changes: In January, ACER published its updated Gas Target Model, which covers matters such as security of supply, the future of wholesale markets, the role of gas in complementing power generation from renewables, and new development along the gas value chain.

The security of gas supply is another topic which is likely to receive a lot of attention in 2015 as the European Commission has, in January 2015, opened a new consultation seeking views on EU rules to guarantee the security of gas supplies, in a bid to further improve Europe's resilience to gas supply disruptions. This follows stress tests carried out in October last year which showed that better cooperation and coordination between EU Member States was desirable.

In short, 2015 will be another busy year for the European energy sector.

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February 2015

ENERGY LAW IN THE EUROPEAN UNION

Recent developments in the European Union energy market

Silke Goldberg, counsel, Herbert Smith Freehills

This article provides an overview of significant and recent developments in the European energy market since January 2014. For more detail on how individual countries have adopted and implement EU-wide initiatives, please consult the relevant national chapter.

NEW EUROPEAN COMMISSION AND DIRECTOR GENERAL ENERGY

Internal EU politics were, throughout much of 2014, dominated by elections to the European Parliament and the appointment of a new Commission. In addition to policies on jobs and investment and a digital single market, the energy sector featured high on the agenda of the new Commission who stated said that the creation of an Energy Union and tackling climate change would be at the heart of its decision-making.

The Commission set out four key objectives for its term until 2019, chief amongst which is (i) the creation of an Energy Union, followed by (ii) the diversification of energy sources; and (iii) a reduced energy import dependency for the EU as a whole. The fourth objective is linked to the EU's climate commitments and aims to make the EU a leader for renewable energy and the fight against global warming.

The importance of the internal energy market and climate issues for the Commission is also reflected in the appointment of not only a Commissioner (in the person of Miguel Arias Cañete) for Climate Action & Energy, but also a Vice President of the Commission with a specific remit for the Energy Union (in the person of Maroš Šefčovič).

Whereas Commissioner Cañete's brief includes

- increasing Europe's energy security by diversifying sources of energy imports and uniting Europe's negotiating power in talks with non-EU countries;
- selecting energy infrastructure projects to help establish a European Energy Union;
- proposing new EU laws and rules to implement the 2030 climate and energy framework and steering negotiations with the European Parliament and national governments;
- further developing an EU policy for renewable energy to make the EU the world leader in the sector; and
- strengthening and promoting the Emissions Trading System,

Vice-President Šefčovič has been tasked with

- establishing a European Energy Union by connecting infrastructures, enforcing legislation and increasing competition to help drive down costs for citizens and businesses and boost growth;
- working to prevent energy shortages, diversifying sources of energy imports and ensuring a united European voice in negotiations to improve our energy security;
- helping to mobilise additional investment in power grids, renewable energy installations and other energy infrastructure;
- improving energy efficiency, especially for buildings; with a binding target of 30% less energy use by 2030; and
- Coordinating the Commission's efforts to ensure the EU reaches its climate and energy targets for 2020 and 2030.

Another new senior appointment on the civil service side of the European Commission saw Dominique Ristori appointed as the new Director General of DG Energy to succeed Philip Lowe following the latter's retirement. Prior to his appointment, Mr Ristori was a key player in shaping and preparing the first Directives on energy internal markets, as well as launching the Madrid and Florence Fora.

ENERGY UNION

In his July 2014 speech to the European Parliament, the now President of the European Commission, Jean-Claude Junker set out his vision for a European Energy Union. In recognition of Europe's reliance on imports of gas and other fuels, Mr Junker stated that an energy union must be achieved with the pooling of both power and infrastructure resources, a statement which points back to the roots of the European Union in the Schuman plan for the pooling of French and German energy resources in the nascent ECSC.

Senior commentators such as Donald Tusk have noted that the EU is still made up of a patchwork of inefficient "energy islands" and have expressed the hope that a functioning internal energy market would reduce wastage and lower prices as well as generate savings of up to €40 billion a year by 2030 if the EU energy grids were fully integrated.[1]

2030 CLIMATE AND ENERGY FRAMEWORK

The 2030 framework for climate and energy (the "2030 Framework") as proposed by the Commission in January 2014 draws on the experience and lessons of the 2020 climate and energy framework. It builds on the longer term perspective set out by the Commission in 2011 in the Roadmap for moving to a competitive low carbon economy in 2050, the Energy Roadmap 2050 and the Transport White Paper. This suite of documents reflects the EU's objective of reducing greenhouse gas emissions by 80-95% below 1990 levels by 2050 as part of the effort required from developed countries as a whole.

At its core, the 2030 Framework consists of the following key elements which will in due course be reflected in legislative initiatives or regulatory decisions:

- a binding greenhouse gas reduction target

- an EU-wide binding renewable energy target
- an improvement in the level of energy efficiency
- a reform of the EU emissions trading system ("ETS")
- secure energy supplies that are also affordable and competitive; and
- a new governance system for the energy sector.

The 2030 Framework aims to make the European Union's economy and energy system more competitive, secure and sustainable and also sets a target of at least 27% for renewable energy and energy savings by 2030 and a greenhouse gas reduction target of at least 40% compared to 1990. The 2030 Framework is also trying to achieve greater regulatory certainty for investors and a coordinated approach among Member States as it looks at policy targets over a longer period of time.

NEW STATE AID GUIDELINES

In July 2014, the European Commission published updated guidelines on "State aid for environmental protection and energy 2014 – 2020," and these became applicable from 1 July 2014. A main tool proposed by the Commission is requiring Member States to set out the likely scenario "but for" the grant of aid. This scenario is then used to judge whether the aid is merited.

Once the notification threshold is passed, the Commission's assessment of the application has two parts: what the aid is for, and the overall effect of how it is given. In terms of assessing the support scheme and compatibility, the project must meet all of these criteria:

- Incentive effect;
- Contribution to a well-defined objective of the common interest;
- Need for state intervention;
- Appropriateness of the aid;
- Proportionality of the aid;
- The extent to which if affects competitiveness between Member States; and
- The transparency of the aid.

Given the current focus at an EU-wide level is on the increased generation and use of renewable energy, the Guidelines include a stand-alone section on how aid for renewable energy is to be treated. Furthermore, a separate section for aid given to energy infrastructure, with the exception of oil infrastructure, is included. The common interest criteria will be fulfilled as such projects are considered to be of benefit to the internal market. The need for aid, on the other hand, must be met by demonstrating that tariff financing would be insufficient to support the project.

BRIDGE 2025

On 23 September 2014, ACER published its "A Bridge to 2025" document which sets out a summary and analysis of the challenges likely to face the energy industry in the coming years and on the responses necessary to tackle these.

In addition to looking at the challenges facing Europe, Bridge to 2025 also sets out five objectives to be achieved over the coming decade:

- establishing a liquid and competitive wholesale energy market;
- improving security of supply;
- transitioning to a low carbon economy and increasing the use of renewable energy;
- developing a retail market that benefits consumers; and
- building stakeholder dialogue, cooperation and new governance arrangements.

As well as setting out ACER's vision for challenges and the regulatory landscape, A Bridge to 2025 also looks at the make-up, technology use and market structure. Market integration is seen as cornerstone in improving liquidity, competition and cooperation with the EU's neighbours (with some already committed to adopting energy *acquis*).

In addition to the above objectives, the report also sets out proposals for the implementation of existing regulation and additional supporting regulatory initiatives. As such, ACER intends to

- implement fully the Third Energy Package, which is hoped will encourage the formation of competitive and liquid markets;
- develop and set out EU-wide criteria (to combat the issue of national regulators having different policies and support schemes). This is to be achieved via a Roadmap to 2025;
- develop and update (the update having now been published) the GTM with a focus on security of supply and ways to deal with potential disruptions – such as those looked at in the European stress tests;
- encourage the development of flexible responses (including DSR);
- encourage new service providers to enter the market and preventing the DSO market becoming monopolistic;
- enhance consumer protection;
- establish and engage with stakeholder panels (including consumers) so any discussions on the future of European energy markets can be undertaken in an open, "holistic" and constructive way;
- improve regulatory oversight of ENTSOs and other energy bodies; and
- encourage the participation of and cooperation with third party countries and their regulatory agencies – Norway is presented as an example.

Of note is that ACER believes it should be given the power to issue binding decisions in relation to ENTSOs "core" tasks. This could be seen as an indication of future trends, however, it remains to be seen whether this suggestion will be reflected in EU legislation.

PROJECTS OF COMMON INTEREST

To further the vision of an integrated market, in November 2014 the Commission announced €647million would be allocated to Projects of Common Interest (PCI). In order to qualify as a PCI, the project must:

- Contribute to market integration and increase/further competition
- Improve security of supply
- Reduce CO_2 emissions

The money will go toward energy infrastructure projects, including the works for the Poland-Lithuania interconnection (gas); and works for the North Atlantic Green Zone Project (a UK and Ireland project) which will enhance grid control and improve demand side management; and various studies on the feasibility of interconnections.[2]

A consultation was launched on 23 December 2014 and will run until 13 March 2015. The objective of the consultation is to gather views and contributions on the need for gas and electricity projects that will further the above three objectives.[3]

MARKET COUPLING AND INTERCONNECTORS – AN INTERNAL ENERGY MARKET

The Commission has explained that the most efficient way to an integrated energy market is through regional cooperation and initiatives. In February 2014, 14 Member States[4] established the day-ahead market coupling. This mechanism is designed to ensure energy flows between Member States in the best way possible – minimising loss and bringing prices closer together. Furthermore, in May 2014, the South-West market coupled with the North-West. This mechanism is only for electricity flows.

A similar scheme for gas had also been developed over the course of 2013 and 2014. The PRISMA platform, established in 2013, allows for the auctioning of capacity along interconnectors in a uniform manner. So far, this platform is used by 28 TSOs who are responsible for transporting 70% of Europe's gas.

ACER has started to release Progress Reports on the status of the Electricity and Gas Regional Initiatives (ERI/GRI). The ERI report released in October 2014 (the most recent to date), sets out the progress of the day-ahead market coupling mechanism. Broadly, progress has been heralded as a positive, but the "Central Southern Europe" ("CSE") region has pushed back the launch date to February 2015.[5]

From 27 to 28 November 2014, the Florence Forum considered, inter alia, whether the EU is moving any closer to a an Internal Electricity Market ("IEM"). Broadly, the project has been viewed as a success. However, the report into the IEM made it clear that further work is still required. In particular, the Commission highlighted the need for more grids and better rules, in the form of network codes and PCIs. In addition, the report drew attention to a number of problems and threats to the IEM project. Mention is made of the difference in national policies regarding renewable energy sources and nuclear power – such as Switzerland's plan to decommission nuclear power plants versus the UK's encouragement and development of new nuclear builds. In order for there to be a true IEM, it is envisaged that policy convergence, to an extent, must occur.

The internal market progress report pointed to a number of steps that needed to be taken to ensure completion of the IEM. Further investment is necessary in energy infrastructure, such as smart grids and ending the de facto isolation of Baltic States from gas markets. The report set a target for 2020 that three quarters of PCIs should be completed. Harmonised rules were considered essential, but that these must be balanced so as to ensure that national governments do not intervene unnecessarily. In addition, although wholesale prices came down, little impact was seen on a retail level. The report pointed out that the wholesale price and retail price for energy must become more closely linked to ensure that consumers reap the benefits of lower wholesale prices.

In November 2014 the Commission published a press release announcing the signing of an agreement between the Association of the Mediterranean Energy Regulators (MEDREG), the Directorate-General for Energy and the Association of Mediterranean Transmission System Operations (Med-TSO) which hopes to establish a platform on electricity markets. The agreement is in the form of a Memorandum of Understanding.

TARGET MODEL

The ERI report of October 2014 also discusses the progress of the Intraday European target model. The initial deadline for its implementation throughout Europe was the end of 2014, but this has since been pushed back. In the implementation of the European target model for electricity, the Capacity Allocation and Congestion Management Regulation ("CACM") has a key role. The CACM Regulation was adopted by Member States in Comitology on 5 December 2014. CACM will now go through scrutiny from the European Parliament and Council and its definitive adoption is expected in early 2015.

On 8 January 2015 ACER published the updated Gas Target Model ("GTM"). The updated model focuses on: competitive markets, wholesale markets, self-evaluation, gas's role in complementing renewable generation, and new developments.

Competitive markets

It is ACER's position that competitive markets will enhance security of supply. The view taken is that the more diverse the supply is (and as a result more competitive) the less Europe will rely on a narrow base of gas suppliers. The updated GTM reinforces this, and recommends improving "market-based measures" in an effort to bring more suppliers into the market.

Wholesale markets

While there is some forward trading present in the EU, ACER believes that it is far below the necessary level to ensure the effective functioning of wholesale markets. The revised GTM therefore focuses on an assessment of these markets at a national level to develop assessment criteria as a means of establishing whether a market is well-functioning.

Self-evaluation

National Regulatory Authorities are also encouraged to "self-evaluate" and assess the current status of their gas markets with a view to ensuring they will meet the new GTM criteria by 2017.

The role of gas in complementing renewable generation

Although the general theme is to encourage and focus on increasing the use of renewable energy, it is appreciated that gas-fired plants are a necessary back-up. ACER proposes, therefore, that an obligation should be placed on gas and electricity TSOs to work more closely with one another.

New developments in the gas supply chain

Such developments include the intensification of LNG and CNG use in the transportation sector. The updated GTM states that national regulators allow for the use and development of these new uses by intervening where appropriate.

REMIT AND MIFID2

The Regulation on wholesale energy market integrity and transparency ("REMIT") is intended to increase transparency and confidence in wholesalers. ENTSO-E expects to publish a central information database for the publication of electricity market information by early 2015.

In December 2014, the REMIT Implementing Act was published in the Official Journal of the European Union.[6]

The Directive on Markets in Financial Instruments ((MIFID2) will "go live" on 3 January 2017. Up to this point, energy firms have fallen under a number of exemptions, a result of which means these firms have not required authorisation for their trading activities. However, MIFID2 is aimed at, inter alia, tighter regulation of such and firms and trades and is designed to bring more of these trades within the regulatory ambit. Amendments have also been made to the definition of financial instruments, thereby catching a wider range of trading activities, such as commodity derivatives that can be physically settled and are traded on an organising trading facility in addition to such things as emission allowances.

On 19 December 2014, the European Securities and Markets Authority (ESMA) launched a consultation on the implementation of MIFID2, which also includes (in draft) technical standards and methods for calculating thresholds which will close in March 2015.

CLIMATE CHANGE

2014 saw significant EU develops in the effort to combat climate change. As recently as December 2014, the Commission and the European Investment Bank (EIB) announced the introduction of a financing instrument to support projects that promote the preservation of "natural capital". Also in December 2014, the Commission released a statement informing that it would contribute €15 million to the NAMA Facility.[7] The Commission joined the UK, Germany and Denmark in its financial assistance.

In October 2014, the Commission released the annual report on progress that is being made toward meeting climate targets. According to the report, the EU is on target to make the 2020 targets, but it envisages that stronger efforts will be need in order to meet the more ambitious 2030 target.[8]

ENFORCEMENT

Over the course of 2014, a number of countries have been referred to the European Court of Justice or formally requested by the Commission to transpose EU legislation and full comply with directives and regulations on energy. To date, infringements have involved Member States not complying with their obligations relating to security of gas supply, failing to transpose fully the Energy Efficiency Directive and failing to bring national law in line with the Energy Services Directive.

In November 2014 the European Commission published the most recent requests to countries who have not fully complied with EU rules. Romania was asked to comply with the Regulation on EU Security of Gas Supply. The request follows the fact that Romania had not informed the Commission of the adoption of the Preventative Action Plan or an Emergency Plan as required under the Regulation. The date for such adoption was 3 December 2012. Romania has two months to comply, or she risks being referred to the Court of Justice.

Greece was requested to comply with the Directive concerning the energy performance and efficiency of buildings. The deadline for compliance was 30 June 2012, although this was later moved to 21 March 2013 due to a delegated regulation on cost optimal methodology being published. Greece received a reasoned opinion from the Commission.

Bulgaria and Hungary were also the subject of Commission requests in relation to their transposition, or lack thereof, of the energy efficiency directive. The deadline for transposition was 5 June 2014, and after this date the Commission wrote to Bulgaria and Hungary asking for their notifications on how the directive had been transposed into their national law. In July 2014, infringement proceedings were commenced against 24 European countries for failures to notify the Commission.

Earlier in the year, Cyprus was referred to the Court of Justice for its failure to transpose into national law the Directive on Oil Stocks. This directive aims to tackle security of supply issues by imposing minimum stock levels of crude oil (amongst other petroleum products). The deadline for transposition was 31 December 2012. Security of supply is very much a hot topic, particularly in light of the stress tests referred to above so it is likely that any further infringements will be dealt with swiftly and firmly by the Commission.

OUTLOOK FOR 2015

2015 will be a busy year given the challenges the Commission has set itself in its work programme as well as the various policy documents released in 2014. In 2015, it is likely that the European legislator will look to translate the policy objectives into implementing legislation, either in form to amendments to existing legislation or further secondary legislation such as Commission Regulations.

As part of the efforts towards the creation of the Energy Union, the EU Council is calling for the removal of so-called Energy Islands by the end of 2015. This will entail the improvement of energy integration for those countries and regions with limited interconnection capacity.

It is hoped that 2015 will bring about more investment in infrastructure, supported by the EU PCI fund, as well as seeing an end to the isolation of the Baltic States.

ACER's Work Programme for 2015 sets out four main focus areas until 2017:

- the post-2014 completion of the internal energy market;
- Work on the "infrastructure challenge", ie, the removal of energy islands and improvements of interconnections throughout the EU;
- the monitoring of wholesale energy markets (including the full implementation of REMIT)
- The longer-term regulatory challenges

ACER also highlights the importance of the smooth and comprehensive implementation of REMIT and the introduction of its market monitoring framework.

On 15 January 2015, ACER opened a new consultation on boosting the security of gas supplies for Europe, in the wake of current and anticipated disruption in the future. The consultation comes after EU-wide stress tests on the likely effects of disruption of Russian gas supplies to Europe.[9] The consultation will close on 18 March 2015.

From 20 to 21 April 2015, the Madrid Forum will take place with a view to discussing the establishment of an internal gas market.

ENDNOTES

1. See, for instance, "Europe needs the will to build an energy union", Financial Times of 21 October 2014 http://www.ft.com/cms/s/0/b8727392-592b-11e4-a722-00144feab7de.html#axzz3Q1DYMpC3
2. A full list is available here: http://ec.europa.eu/energy/infrastructure/pci/doc/20141121_cef_energy_lists.pdf
3. Consultation webpage: http://ec.europa.eu/energy/infrastructure/consultations/pci_list_new_en.htm
4. Belgium, Denmark, Estonia, Finland, France, Germany, Austria, UK, Latvia, Lithuania, Luxembourg, the Netherlands, Poland and Sweden. (Norway – non Member State).
5. A table setting out progress in full can be found here http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/1st%20ERI%20 Progress%20Report.pdf
6. It can be found here http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:JOL_2014_363_R_0009&from=EN
7. This is an instrument to support projects aimed at reducing CHG in emerging and developing countries
8. EU Gears up for 2030 Targets: http://ec.europa.eu/clima/news/articles/news_2014102801_en.htm
9. Details on the Energy Security Strategy page: http://ec.europa.eu/energy/en/topics/energy-strategy/energy-security-strategy

OVERVIEW OF THE LEGAL AND REGULATORY FRAMEWORK IN EUROPEAN UNION

INTRODUCTION AND SCOPE

The European Union legislative landscape in the energy sector (and beyond) has, in the past few years, seen some significant changes.

On 19 September 2007, European Commission published a proposal for a Third Energy Package which, after intense negotiations amongst EU Member States and between the Council and the European Parliament, was finally adopted on 13 July 2009 and entered into force on 4 September 2009 (the "TEP"). The main focus of the TEP is the further liberalisation and harmonisation of the European internal energy market and includes, amongst others, provisions as to the unbundling regime, the role of national regulators, and, more controversially, investments by third countries in European transmission systems.

In January 2008, the European Commission proposed a legislative package focussed on a range of measures designed to shape the European Union's climate change policies and actions (the "Climate Change Package") which was adopted at first reading in the co-decision procedure, having been discussed at the European Council of 12 December 2008. In accepting all of the amendments the European Parliament adopted on 17 December 2008, the Council definitively adopted the new acts on 6 April 2009, thereby passing the Climate Change Package into European law.

On the financial regulatory side of European energy markets, the rules are changing, too, with the upcoming changes as a result of the revised Markets in Financial Instruments Directive ("MiFID"), the regulation on wholesale Energy Market Integrity and Transparency ("REMIT")[1] which applies to all gas and electricity companies in Europe, and the new European Market Infrastructure Regulation ("EMIR").

This article analyses these changes, the relevant European directives and regulations and their effects at European level. For a detailed analysis of how the European Legislation impacts on EU Member States and beyond, please turn to the national chapters in this edition of EEH – the European Energy Handbook 2015.

THE THIRD ENERGY PACKAGE:

The Policy Context: From Sector Inquiry to Third Energy Package

In 2005, the European Commission undertook an inquiry into competition in gas and electricity markets (the "Sector Inquiry") as provided under Article 17 of Regulation 1/2003[2] on the implementation of the EC Treaty rules on competition, aimed at assessing the prevailing competitive conditions and establishing the causes of the perceived market malfunctioning.

Following the Sector Inquiry, the European Commission published a proposal for the TEP which was finally adopted on 13 July 2009 and entered into force on 4 September 2009. Member States had until March 2011 to transpose the majority of the provisions in the Third Electricity and Gas Directives into national law, the exception being the "third country clause" which needed to be transposed by March 2013. The Third Gas and Electricity Regulations and ACER Regulation entered into force as of September 2009. However, in order to avoid a discrepancy between the exemption regime for new infrastructure in the gas sector, which is contained in the Third Gas Directive and the corresponding regime in the electricity sector which is contained in the New Electricity Regulation, the latter was applied as of 3 March 2011. Likewise, Articles 5 to 11 of the ACER Regulation, which deal with detailed tasks of ACER, were only applied from that date.

The TEP contains three Regulations and two Directives.

- 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 (the "Third Electricity Directive");[3]
- Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/ECA Gas Directive amending and completing the existing Gas Directive 2003/55 (the "Third Gas Directive");[4]
- Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators (the "ACER Regulation");[5]
- Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003 (the "New Electricity Regulation");[6] and
- Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005 1775/05 (the "New Gas Regulation").[7]

A new unbundling regime8

For the purposes of the Third Electricity and Third Gas Directives the "unbundling" regime is of central importance. In the context of the TEP, unbundling means the separation of the operation of gas pipelines and electricity networks at transmission level from the business of producing or supplying either gas or electricity.[9]

Under the TEP there are three main unbundling options which, under certain circumstances, the Member States may select. The options are:

- the full ownership unbundling model;
- the independent system operator ("ISO") model; or
- the independent transmission operator ("ITO") model.

Additionally Article 9(9) of the Third Gas and Third Electricity Directives, respectively, contain details of an unbundling model that is not entirely congruent with the above unbundling modes but is deemed to be as efficient. This is the case in Scotland where the transmission networks are owned by Scottish Power Transmission Limited ("SPTL") for southern Scotland and Scottish Hydro-Electric Transmission Limited ("SHETL") for northern Scotland, the two Scottish transmission companies, but are operated by the National Grid. The current model in place in Scotland does not comply with the full requirements of the ISO model but is considered to be sufficient to ensure the independence of the transmission system operator[10].

The full ownership unbundling model requires the full separation of the operation of gas and electricity transportation/transmission networks and those activities related to production, generation and supply. The ownership unbundling model also puts in place new restrictions in respect of ownership. The operators of gas and electricity transmission networks are no longer permitted to be part of (or affiliated to) a corporate group which is also active in supply, generation or production. The operator of the network will also be obliged to own and control the entire network.

The ownership unbundling model does not however prevent, in certain circumstances, a person or a company from holding shares in both a network operator and an entity involved in production/supply activities provided that the shares constitute a non-controlling minority interest. Such interest must not have any voting rights or other rights of veto in the entities concerned and must not have rights to appoint members of either of the entities' boards of directors. In particular no person may be a member of the board of directors of the network operator and of a supply/production undertaking which may be particularly relevant to non-sector investors (eg, pension funds).

On 8 May 2013 the Commission released a working document setting out the Commission's practice in assessing the presence of a conflict of interest for ownership unbundling including in the case of financial investors in the context of the certification procedure for TSOs.[11] This working document is not legally binding but makes clear that in the context of TSO certification, a complete file will need to be provided and a case-by-case assessment made. Relevant elements will include the following:

- geographic location of the transmission activities and the generation, production and supply activities concerned;
- the value and nature of the participations in these activities;
- the size and market share of the generation, production and/or supply activities;
- whether the wholesale price evolution of the commodity would have consequences for the emergence of a conflict of interest; and
- access to confidential information.

Under the ISO model[12] the network must be managed by an identified ISO (which must perform all the functions of a network operator) although it is permitted for vertically integrated companies to maintain ownership of their network assets[13]. The ISO model requires the ISO to comply with the same unbundling requirements as other network operators and for it to be a completely separate undertaking from the vertically integrated company.[14] On this basis, the ISO cannot have a shareholding in any supply or production entities.

There are also several additional regulatory provisions to reinforce the ISO model which are set out in the TEP. A network owner active in supply or supply and production is required to legally and functionally unbundle[15] the part of the company with ownership of the network and will be required to finance[16] any investment decisions made by the ISO. The Commission (with assistance from the Agency for the Co-operation of Energy Regulators ("ACER")) will approve[17] the identity of the ISO and, once the ISO has been appointed, it has to commit to a ten year network investment plan[18] arranged by the regulatory authority.

A third option was introduced as a compromise after eight Member States noted that the full ownership unbundling model and the ISO model were incompatible with their national regulatory regimes. This is known as the ITO model. The ITO model can be best described as a "*status-quo-plus*" model because it permits some Member States such as France, Austria and Germany to keep in place their current structures where the TSOs belong to a vertically integrated undertaking. The model requires such undertakings to comply with additional regulations to ensure the independence of each such activity. These rules include:

- preventing the TSOs' management from having particular positions of responsibility,[19] interests or business relationships, directly or indirectly, with the relevant vertically integrated undertaking. This rule should be applicable for three years prior to their appointment to the majority of the TSO management;
- placing a minimum period of six months[20] prior to the appointment of a person to the remainder of the management team of the TSO during which that person may not hold any management position or exercise any other relevant activity in the vertically integrated undertaking. The rules are intended to encourage the relevant national regulator to vet the executive management;
- examining network development and investment decisions[21] taken by an ITO to ensure they are consistent with relevant Community-wide plans;
- working against discriminatory behaviour[22] by the ITO (and on the influence exerted by the relevant vertically integrated undertaking), and restricting the ITO's access to the capital market, to be overseen by a supervisory body; and
- enforcing compliance with the ITO provisions.[23] Penalties, depending on the breach, are defined in respect of the turnover of the ITO or of its relevant parent company. The ultimate penalty for a persistently non-compliant ITO model would be the mandatory introduction and designation of an ISO.

Pursuant to the Third Electricity and Gas Directives, the Commission was to conduct a specific review of provisions in place using, as a benchmark, effective and efficient unbundling. In October 2014, this report was published.[24] Its main findings are that there were 26 certified ITOs in 10 EU Member States (Austria, Czech Republic, France, Germany, Greece, Hungary, Ireland, Italy, Slovakia and Slovenia) the majority of which are operating in the gas sector (21), while only five ITOs are active in the electricity sector. In addition, a certification of one TSO under the ITO model was rejected in 2013, while another TSO decided to withdraw its application for the ITO certification. Moreover, there is a limited number of remaining TSOs which are likely to be certified as ITOs but for which a certification process at European level has not started yet. The findings of the Commission's report are of a preliminary nature given that the implementation of the ITO-model is in its early days as ITOs, like other TSOs, have been certified only since 2012 and have been operating under the new rules for a very short period of time. The Commission believes that it is therefore too early to draw definite conclusions on the functioning of the model and the actual independence of the ITOs in practice. Whilst the ITO model so far appears to function well in practice, the Commission has suggested that it may be further improved, for instance, by strengthening the independence of the Supervisory Board, specifying the scope of the Compliance Programmes and developing common guidance and a network of cooperation for Compliance Officers, as well as harmonising the timeframe for network development plans at national and European level. Therefore, the Commission will continue to monitor the implementation and effectiveness of the unbundling requirements under the Third Energy Package and continue to ensure that ITOs and VIUs comply with the EU competition rules.

The ITO model will only apply[25] in the Member States where TSOs continue to be part of a vertically integrated undertaking. Any Member States that have already implemented the ISO or full ownership unbundling model will not be able to revert to an ITO model. As a result the ITO model is the minimum level that will be required to constitute effective network unbundling across the EU.

The third country clause

The TEP provides that national regulatory authorities ("NRAs") need to certify any TSO as compliant with the unbundling regime before the relevant TSO is allowed to take up their function as TSOs.[26]

In addition, under the so called third country clause,[27] national regulators are required to refuse certification of a TSO if the relevant company does not comply with the unbundling requirements, and its market entry would jeopardise the Member State's or the EU's security of supply. In addition, national regulators must notify the European Commission if:

- a transmission system owner or operator that is controlled by a party from a non-EU country applies for certification; or
- any circumstances arise which would result in a party from a non-EU country obtaining control of a transmission system owner or operator.[28]

Transmission system operators (rather than the transmission system owners) must notify the relevant NRA if any circumstances[29] arise that would result in an entity from a non-EU country acquiring control of the transmission system or its operator. The relevant NRA must also seek the view of the European Commission[30] as to whether the foreign entity passes the unbundling and energy security tests and take "utmost account" of the Commission's view.

Regulatory oversight

Under the Second Electricity and Gas Directives[31] Member States were required to establish NRAs. However, the NRAs that were established across the EU had different powers and levels of independence in the different Member States. In some Member States, NRAs had substantial powers and resources and developed into well-established bodies. In other Member States, NRAs had only recently been established or had limited powers spread between different governmental divisions which were subject to certain ministerial or governmental control.

Under the Third Electricity and Gas Directives,[32] the NRAs are required to be legally distinct and functionally independent from any other public or private entity. The staff of the NRA and any member of its decision-making body are not permitted to seek or take instructions from any government or other public or private entity and must act independently of any market interest. For that purpose, NRAs will have to have an independent legal personality, autonomy over their budget, sufficient human resources and independent management.

The Third Electricity and Gas Directives strengthen the NRAs' powers of market regulation and set out additional tasks for the NRAs, in particular, in the following respects:[33]

- ensuring the compliance of transmission and distribution system operators with any third party access regime, unbundling obligations, balancing mechanisms, congestion and interconnection management;
- reviewing the TSOs' investment plans, and providing in its annual report an assessment of how far the TSOs' investment plans are consistent with the European-wide ten year network development plan;
- monitoring network security and reliability and reviewing network security and reliability rules;
- monitoring transparency obligations;
- monitoring the level of market opening and competition and promoting effective competition in cooperation with competition authorities; and
- ensuring effective consumer protection measures.

The TEP, for the first time in European energy legislation, sets objectives for the NRAs with a notable European dimension. The Third Gas and Third Electricity Directives state that the NRAs' objective is to "promot[e], in close cooperation with the Agency, regulatory authorities of other Member States and the Commission, a competitive, secure and environmentally sustainable internal market in natural gas within the Community, and effective market opening for all customers and suppliers in the Community, and ensuring appropriate conditions for the effective and reliable operation of gas networks, taking into account long term objectives".[34]

As the Sector Inquiry has demonstrated, the European energy market still requires much improvement before it can function fully as an effective competitive market. A market that would be capable of better allocating sometimes scarce resources (on time), and improving any investment decisions that are made on infrastructure assets in particular in relation to the generation of electricity.

The effect of the NRAs' extended powers is not yet clear and it will be necessary to see how the changes play out in practice before any full evaluation is possible. It is likely that it will be sometime after the adoption and transposition of the TEP before any such evaluation will be possible.

Agency for the Co-operation of Energy Regulators

In order to reinforce the position of regulators at European level and ensure continued co-operation, the ACER Regulation created the Agency for Co-operation of Energy Regulators ("ACER").

ACER is governed by the standard rules and practices which apply to Community regulatory agencies. Uniquely, ACER also has a separate board of regulators in order to safeguard the necessary independence of the regulators at the European level (the

"Regulatory Board"). Within ACER, this special board is solely responsible for all regulatory matters and decisions. It functions alongside an administrative board responsible for administrative and budgetary matters (the "Administrative Board"). The Commission provides a shortlist from which the director of ACER will be chosen. The director, who will be responsible for representing ACER and managing ACER on a day to day basis, will then be appointed by the Administrative Board in consultation with the Regulatory Board. Additionally, the structure of ACER includes a Board of Appeal competent to handle appeals against any decisions adopted by ACER.[35]

ACER is competent to:[36]

- issue opinions addressed to TSOs;
- issue opinions addressed to regulatory authorities;
- issue opinions and recommendations addressed to the Commission; and
- take individual decisions on technical issues.

ACER is competent, upon a request from the Commission or on its own initiative, to provide to the Commission an opinion on all issues which are relevant and relate to the reason why ACER was established.[37]

ACER is also required to provide the Commission with its opinion on the following:[38]

- draft statutes, lists of board members and draft rules of procedure; and
- the technical or market codes on the draft annual work programme and the draft ten year investment plan of the European Networks of TSOs for Electricity and Gas, respectively (*see below*).

ACER is permitted to provide recommendations designed to assist regulatory authorities and players in the market and to promote the sharing of information relating to good practice as well as fostering cooperation between national regulatory authorities and between regulatory authorities at regional level. Such guidelines can be part of ACER's own work programme or at the request of the Commission.[39]

Decisions taken by a regulatory authority must comply with any guidelines contained in the Third Gas and Electricity Directives and Third Gas and Electricity Regulations. Upon the Commission's or any regulatory body's request, ACER will issue an opinion on whether or not a regulatory body's decision complies with the required guidelines. A national regulatory authority may also ask ACER to issue an opinion where the application of the guidelines referred to in the Third Gas and Electricity Directives and Third Gas and Electricity Regulations is unclear.[40]

It is also possible for ACER to stand as the competent authority to select the relevant regulatory regime for infrastructure that links at least two Member States. ACER also has the power to grant exemptions from the third party access regime in cases where the infrastructure concerned is located in more than one Member State.[41]

Since the original version of the ACER Regulation proposed by the European Commission, ACER has been given a range of additional tasks, which have widened ACER's scope considerably. ACER's tasks now include:

- participation in the development of European network codes;[42]
- monitoring the development of the energy markets, in particular in relation to retail gas and electricity prices;[43]
- monitoring the implementation of the TSO's ten year infrastructure investment plans;[44] and
- establishing non-binding "framework guidelines" on conditions for access to the network for cross-border electricity and gas exchanges (*see below*).[45]

For the most part ACER's competencies are considered to be advisory in their nature but the ACER Regulation does grant decision making powers in specific areas particularly with respect to cross-border projects and co-operation.[46] ACER also fulfills the position of a "Regulator of last resort" where the national regulator of a Member State using an ISO model has failed to appoint an ISO in the required timeframe.[47]

ACER operates under a framework which appears to be designed to leave ACER some freedom to fully define and exercise its role; in some cases responding to requests from the Commission and in others producing opinions on its own initiative. Depending on how ACER's role develops and its current director's involvement and initiatives ACER may be considered the first step towards a pan-European regulator.

The ACER Regulation entered into force in September 2009 but ACER was only launched officially in March 2011. The first Director of ACER, Alberto Pototschnig, was appointed in May 2010 for a term of five years. ACER is based in Ljubljana (Slovenia).

On 19 September 2014 ACER released a paper titled *Energy Regulation: A Bridge to 2025 Conclusions Paper* that sets out the Agency's approach to the future issues in the Energy Market. The paper sets out that the five primary goals for ACER over the next ten years, none which mark a departure from its existing direction:

- enhancing Europe's energy security of supply;
- establishing and maintaining a liquid, competitive and integrated wholesale energy market;
- development of the low carbon society through renewable, flexible and smart energy supply;
- developing the retail market; and
- introducing new governance arrangements and developing stakeholder dialogue.

ACER Framework Guidelines and European Network Codes

One task of the ENTSOs (as defined below) is the preparation of European network codes pursuant to Article 8 of both (a) Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005 (the "TEP Electricity Regulation"); and (b) Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003 and as amended by Regulation No 347/2013 of 1 June 2013 the "TEP Gas Regulation").

Article 6 of both the TEP Electricity Regulation and the TEP Gas Regulation tasks ACER with the elaboration of Framework Guidelines for these European network codes which will, in turn, serve as the reference document for ENTSO's work on the codes.

Since its inauguration, ACER has commenced 22 consultations and issued Framework Guidelines (described briefly in the paragraphs below) regarding the following network code framework guidelines:

- electricity grid connections;
- capacity allocation and Congestion Management for Electricity;
- capacity allocation mechanisms for the European gas transmission network;
- gas balancing in transmission systems;
- electricity system operation;
- harmonisation tariff structures (draft at time of writing);
- interoperability and data exchange rules for Gas Transmission Networks; and
- electricity balancing.

The main conclusion that can be drawn from these consultations and the subsequent publication of Framework Guidelines is that whilst the changes proposed in each set of Framework Guidelines may be relatively small, the full impact of the proposals will only become clear when they are implemented into the market and the cumulative effects can be observed and evaluated.

Electricity grid connections48

These Framework Guidelines apply to grid connections for all types of significant grid users that are currently (or are intended to be) connected to the transmission or distribution network. They provide that the network codes shall define appropriate minimum standards and requirements applicable to all significant grid users. The Framework Guidelines specify what these standards and requirements should cover. In particular, the guidelines discuss issues such as connection of/to distribution networks, the connection regime for specific significant grid users, the imposition of special requirements on significant grid users for critical grid situations, derogations and compliance.

These Framework Guidelines also provide that the network codes are to set out:

- the procedures and requirements to co-ordinate and ensure information sharing between transmission and distribution system operators and significant grid users;
- specifications for an efficient co-ordinated system with access to real-time information; and
- the requirements for interface between transmission and distribution system operators.

Capacity allocation and congestion management ("CACM") for electricity49

These Framework Guidelines deal with the integration, coordination and harmonisation of the congestion management regimes, insofar as such harmonisation is necessary in order to facilitate electricity trade within the EU in compliance with the Third Electricity Directive and the New Electricity Regulation. The network codes produced in line with these Framework Guidelines shall set out deadlines for the implementation, in accordance with the different timeframes and across the EU, of the target model for CACM across the EU.

According to ACER, capacity calculation and the definition of zones for CACM are important elements for ensuring the optimal and coordinated use of electricity transmission network capacity. The Framework Guidelines provide that the network codes shall include provisions covering capacity calculation methods and processes which must be made publicly available by the relevant TSOs. The guidelines also state that the network codes should also set out provisions relating to:

- a definition of zones for CACM for market participants to submit their energy bids day-ahead, intraday and in the longer term timeframe;
- day ahead capacity allocation by the TSOs on the basis of implicit auctions;
- forward capacity allocation for long-term hedging solutions; and
- intraday capacity allocation so market participants can trade energy as close to real-time as possible to balance their position.

Furthermore, a common definition of force majeure should be included in these network codes to be used in all capacity allocation rules.

Capacity allocation mechanisms for the European gas transmission network50

These Framework Guidelines are aimed at ensuring more efficient allocation of capacity on the interconnection points between two or more Member States or within the same Member State and to support the creation of efficient wholesale gas markets in the EU. The network code(s) adopted according to these Framework Guidelines will be applied by TSOs taking into account possible public service obligations.

The Framework Guidelines state that the network codes must include provisions concerning:

- the definition of standardised content of transmission capacity contracts;
- general terms and conditions for capacity allocation and services;
- standard communication procedures for information exchange by TSOs with network users; and
- TSOs' duties to cooperate with adjacent TSOs and specify procedures in specified areas.

Stakeholder consultations will have to be undertaken to consider market needs and conditions before decisions are made in certain areas.

The network codes are also to set out how the TSOs offer and determine firm and interruptible capacity; adjacent TSOs must implement standardised procedures for interruptible capacity services; and all firm and interruptible capacity services for each time interval will be allocated via auctions, and regulated tariffs shall be used as a reserve price in auctions.

Gas balancing in transmission systems51

The objective of these Framework Guidelines is to promote the harmonisation of balancing regimes in order to encourage and facilitate gas trading across systems and to support the development of competition within the EU, both between Member States and within each Member State. These Framework Guidelines set out principles for network users and the role and responsibilities of TSOs. They also provide guidance on the buying and selling of flexible gas and balancing services by TSOs, balancing periods and nomination procedures, imbalance charges, TSO information provision obligations, and cross-border obligations.

The network codes to be developed on the basis of these Framework Guidelines will define a European gas balancing regime which is market based and enables efficient trading of gas by network users, including across borders. The objective is to promote the harmonisation of balancing regimes to encourage and facilitate gas trading across systems.

Under the network code, network users shall balance their portfolios by matching their inputs and off-takes from each balancing zone during relevant balancing periods, with balancing responsibilities being shared between the TSOs and network users; and network users shall take primary responsibility for matching their inputs against their customers' off-takes from the balancing zone during the relevant period, in order to minimise the need for TSOs' balancing actions.

Finally, the Framework Guidelines specify that under the network codes

- TSOs must cooperate and consult stakeholders on proposals to integrate European gas markets;
- ENTSO-G (the European network of transmission system operators for gas) is to regularly review the progress of harmonisation of rules in adjacent balancing zones in order to identify opportunities for the creation of cross-border balancing zones and market coupling; and
- there will be proposals for TSOs to implement cross-border balancing projects in the European gas regions.

Electricity system operation[52]

These Framework Guidelines aim at setting out clear and objective principles for the development of network codes on system operation. They apply to system operators of electric power transmission networks and all significant grid users, focusing on issues of electric power system and network operation. The issues covered by the Framework Guidelines include operational security and reliability rules; data exchange and settlement rules; interoperability rules; and operational procedures in an emergency. The Framework Guidelines respond to challenges faced by system operators in terms of the growing amount of distributed generation and variable generation and increasing interdependence of control areas.

They set out the minimum standards and requirements for

- system operation, covering issues of operational security;
- operational planning and scheduling;
- load-frequency control;
- staff training and certification;
- emergencies and restoration; and
- new applications.

It is likely that the full impact of the Framework Guidelines and the European network codes will be cumulative and their impact on the market will only be fully felt once a number of them have been implemented.

Harmonised tariff structures53

The Framework Guidelines on rules regarding harmonised transmission tariff structures for gas focus on ensuring efficient gas trade and competition in relation to such trades, the avoidance of cross-subsidies and undue discrimination between network users. One of the central concerns is the promotion of cost reflective tariffs so as to encourage new investment in the sector. It is also hoped that harmonised tariff structures will contribute to more transparency to encourage competition. One of the aims of the Framework Guidelines is to establish an appropriate tariff system that enables shippers to book capacity products according to their business and risk profiles, and to allow for efficient allocation and use of infrastructure. The Framework Guidelines aim to avoid excessively low/high tariffs at borders and propose options enabling revenues collected from interconnection points to cover associated target revenues. By way of a general principle, the draft Framework Guidelines stipulate that tariff remuneration has to be consistent with risks and deliver proper signals to develop transmission capacity.

By requiring that stakeholders will be provided with necessary information to understand tariff evolution, these Framework Guidelines attempt to promote a more transparent tariff evolution for investors and stakeholders.

The scope of these Framework Guidelines extends to entry points from LNG terminals and production facilities as well as any other entry point to the transport system; they may also apply to entry/exit points to or from storage facilities.

On 15 March 2013, in its letter to ACER, the European Commission expressed concerns about the degree of harmonisation of the cost allocation methodologies and the determination of the reference price chapter and suggested amendments of the provisions on transparency, mitigating measures and definition. Following up on these concerns, ACER is revising the cost allocation methodologies and the determination of the reference price chapter.

As part of this revision, the original deadline for the final Framework Guidelines was extended by the Commission from 30 November 2013. On 31 March 2014 ACER published it justification document for the draft Framework Guidelines which it invited ENTSOG to expand further. In response to this, ENTSOG in turn published an Initial draft Network Code on Harmonised Transmission Tariff Structures for Gas which it consulted on until 30 July 2014. At the time of writing the projected deadlines are that ENTSOG will submit the final draft of the network code to ACER on 31 December 2014 and ACERs Reasoned Opinion will be published in March 2015.

Interoperability and data exchange rules for Gas Transmission Network[54]

These Framework Guidelines focus on addressing the following barriers to the free flow of gas in Europe by the following measures:

All TSOs are to establish standardised interconnection agreements between adjacent TSOs in different Member States to remove cross-border trade restrictions and increase competition. The network code developed pursuant to these guidelines outlines the framework for such standardised interconnection agreements which is to be applied if the relevant TSOs are unable to agree their own interconnection agreements after twelve months of negotiations.

The network code will also require neighbouring TSOs to agree on the handling of gas quality differences on either side of an interconnection and to provide relevant network users with information of gas quality, including variations in quality; and require TSOs to provide detailed descriptions of the process used to calculate the technical capacity of their system. Adjacent TSOs will be required to cooperate to reduce discrepancies in maximum capacity at either side of an interconnection. The network code is expected to establish a procedure for identifying and dealing with such discrepancies. The network code will also introduce provisions relating to the harmonisation of units used by TSOs, encourage TSOs to address barriers resulting from differences in odorisation practices and provide a "data exchange solution" for TSOs to exchange data amongst themselves or to counterparties.

Electricity Balancing55

The Framework Guidelines on electricity balancing introduce a national balancing reserve and balancing energy procurement specifications and stipulate that cross-border balancing exchanges are to pursue the following objectives:

- safeguarding operational security of supply;
- foster competition in balancing markets;
- facilitate wider participation of demand response & renewables;
- increasing overall social welfare; and
- promoting cross-border balancing exchanges.

Under these Framework Guidelines, TSOs are required to publish certain information on their websites, such as terms and conditions for balancing markets, and the necessary data to ensure an efficient functioning of balancing markets.

The Framework Guidelines also clearly delineate roles of the TSOs who will be formally responsible for organising balancing markets and striving for their integration, whilst keeping the system in balance. TSOs will also be responsible for procuring the required balancing services from Balance Service Providers and for co-ordinating with other system operators when balancing offers are activated in their system.

What will be the effect of the Framework Guidelines?

It is not possible to give a detailed description of each of the Framework Guidelines in this chapter, as these are very technical and detailed. The benefit of such coherent European codes are generally to be found in the intended elimination of inconsistencies at national level regarding, eg, tariff structures, capacity allocation rules, balancing arrangements and trading timetables and security of supply measures. At present, such differences in market design lead to market segmentation, with some national markets remaining split into different local tariff or balancing areas. However, at the same time, the development of the European network codes will necessarily cause some friction to the existing, national approaches and is likely to be a long term project the results of which will be cumulative and not be available for some time.

Cooperation between Transmission System Operators

The increasing energy demand and simultaneous import dependency of the EU will require improved transmission networks which are able to cope with the "energy traffic" created by the export and import of electricity and gas in peak demand conditions.

Cooperation in grid operation is therefore indispensable, especially in the electricity sector, where co-operation between TSOs will make an important contribution to network reliability particularly in heavily interconnected areas. The greater transparency and visibility of network development issues it creates will allow investments to be made where they are most effective and improve network reliability through coordinated investments.

The Third Electricity and Gas Regulations[56] formalise the cooperation between transmission network operators, which at present is channelled through platforms such as GTE and ETSO, through the establishment of a European Network for Transmission System Operators for the electricity and gas sector ("ENTSO-E" and "ENTSO-G", respectively). The ENTSOs' responsibilities include the following core areas that are set out below:[57]

- the development of coherent market and technical codes needed for the integration of the electricity and gas markets, which the ENTSOs are tasked to develop in co-operation with ACER and the Commission on the basis of the framework guidelines developed by ACER (see above);
- the development of common network operation tools to ensure coordination of network operation in normal and emergency conditions, including a common incident classification scale, and research plans;
- the finance and management of cooperative research and innovation activities focused on the technical development of European electricity and gas networks in relation to energy security, efficiency and low carbon technologies;
- the coordination of grid operation, ie, to exchange network operational information and the coordinated publication of information on network access; and
- the coordination of the planning of network investments and the monitoring the development of the transmission network capacities. The two ENTSOs must publish a European-wide and ten year forward-looking investment plan every two years.

The overall effect of the increased co-operation of TSOs in the framework of the strengthened ENTSOs will undoubtedly be a greater degree of market harmonisation which in turn might result in better network and operational reliability and as such in better security of supply. Therefore, and given the range of issues with which the new ENTSOs will be charged, the question arises whether the ENTSOs are only a stepping stone on this journey towards greater network harmonisation and interoperability, the next stop being a single European TSO under ACER as the single European regulatory authority.

Transparency and record keeping obligations

The Third Electricity and Third Gas Directives also set out a number of record keeping obligations on electricity generators, gas network operators, and supply undertakings that are required to keep a record of all data relating to operational decisions and trades.[58]

The Commission hopes that these obligations enable regulators to effectively assess allegations of market abuse and study past behaviour of market participants. In particular, the Commission believes that a review of the relevant records enables regulators to investigate whether operational decisions were based on sound economic reasoning rather than attempts to manipulate the market. The Commission has stated that these record keeping obligations are, in the case of some types of traders (eg, banks), not in addition to relevant record keeping obligations of such traders under the Markets in Financial Instruments Directive.

Access to storage and LNG facilities

The Guidelines for Good Third Party Access Practice for Storage System Operators ("GGPSSO") of the Madrid Forum are voluntary guidelines which were found not to have been widely implemented. The New Gas Regulation seeks to make the GGPSSO binding on relevant market participants.

The Third Gas Directive also establishes legal and functional unbundling rules for storage system operators that are part of supply undertakings[59] and enhances the NRAs' powers to manage any access to gas storage.[60]

The Third Gas Directive and the New Electricity Regulation have been put in place to change and update the current legislation which deals with exemptions from regulated third party access for major new infrastructure.[61] The European legislators aimed to set out a streamlined procedure with respect to exemptions for the overall benefit of the market. Article 36 of the Third Gas Directive sets out a list of applicable conditions and detailed procedural provisions and is therefore much more comprehensive than the previous Article 22 of the Second Gas Directive. However, the procedural requirements have become more complex with advent of ACER as part of the decision making process in cases where the infrastructure crosses the borders of two or more Member States.

Development of energy infrastructure

Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009[62] ("The New TEN-E Regulation")

The New TEN-E Regulation was adopted on 17 April 2013 and entered into force on 15 May 2013. It sets out guidelines for the development and interoperability of priority corridors and energy infrastructure at European level.[63] It establishes 12 strategic regional groups, based on a priority corridor and a geographic area, for energy infrastructure with a trans-European/cross-border dimension.[64] The New TEN-E Regulation sets out a process to establish on a two-yearly basis Union-wide lists of 'Projects of Common Interest' (" PCIs"), which will contribute to the development of energy infrastructure networks in each of the 12 corridors.[65] The PCIs are adopted by the decision-making body of each regional group consisting of the Commission and Member States.[66] Article 4 of the New TEN-E Regulation provides detailed criteria that PCIs must meet.

Under this new regulation, PCIs will be subject to different, improved, regulatory treatment as well as faster and more efficient permitting procedures. They may receive funding under the Connecting Europe Facility[67] and the EU financial assistance.[68]

The New TEN-E Regulation puts in place process requirements for granting PCI permits. These requirements include:

- giving priority status to PCIs;[69]
- time limits for the permit process;[70]
- a "one-stop-shop" permit;[71]
- a single co-ordinating authority;[72] and
- a requirement that Member States assess the potential for streamlining permitting procedures.[73]

The Commission published guidelines on streamlining environmental assessment procedures for energy infrastructure PCIs as required by Article 7(4) of the New TEN-E Regulation.[74] The purpose of this guidance is to support Member States in defining adequate legislative and non-legislative measures to streamline the environmental assessment procedure and to ensure coherent application of the environmental procedure for PCIs.

EMISSIONS TRADING – FINANCIAL SERVICES LEGISLATION:

MIFID

The European Commission published its legislative proposals to revise the Markets in Financial Instruments Directive ("MiFID") on 20 October 2011, four years after the MiFID implementation date of 1 November 2007.[75] The changes to MiFID, known informally as MiFID II, have resulted in a significant overhaul of the way in which financial markets operate in Europe. In its press release of 20 October 2011 the European Union stated that MiFID II aims "to make financial markets more efficient, resilient and transparent, and to strengthen the protection of investors." On 15 April 2014, the European Parliament endorsed MiFID II and MiFIR. They were adopted on 13 May 2014 by the Council of the European Union and published in the Official Journal on 12 June 2014, coming into force on 2 July 2014. Member States must implement the provisions by 3 January 2017. On 22 May 2014 ESMA published a Discussion Paper and Consultation Paper on MiFID implementation.[76]

The legislation is divided in two; a new directive and a new regulation:

MiFID Level 1 Directive (2004/39/EC) will be recast, with a new directive amending the following provisions:

- specific requirements regarding the provision of investment services;
- the scope of exemptions from the current directive will be stricter (this may be relevant for the energy sector);
- requirements relating to the organisational and conduct of business for investment firms;
- organisational requirements for trading venues;
- authorisation and on-going obligations applicable to providers of data services;
- powers available to competent authorities;
- sanctions; and
- rules applicable to third-country firms operating via a branch.

A regulation on the Markets in Financial Instruments ("MiFIR") is also proposed, which will establish uniform and directly applicable requirements in relation to:

- disclosure of trade transparency data to the public and transaction data to competent authorities;
- removing barriers to non-discriminatory access to clearing facilities;
- mandatory trading of derivatives on organised venues;
- specific supervisory actions regarding financial instruments and positions in derivatives; and
- provision of services by third-country firms without a branch.

The Commission's legislative changes contained within MiFID II and MiFIR, follow the preparatory work of the Committee of European Securities Regulators (replaced by the European Securities and Markets Authority ("ESMA") in January 2011) and the Commission in 2010, including the Commission's consultation paper on the review of MiFID in December 2010.

Importantly for the energy sector, emission allowances may now fall within the scope of MiFID and will be classified as financial instruments, so that both derivatives and secondary spot markets in emission allowances will be subject to financial market regulation. Spot contracts (which currently include transfers of EUAs) do not currently constitute "financial instruments" under MiFID and have therefore been largely unregulated. Under Article 38(2) of the MiFID Level 2 Implementing Regulation,[77] a "spot contract" is defined as a contract for the sale of a commodity, asset or right, under the terms of which delivery is scheduled to be made within the longer of two trading days and the period generally accepted in the market for that commodity, asset or right as the standard delivery period. The proposed changes to MiFID would be set out in the following way:

- futures and other derivatives in relation to emission allowances (previously under Annex I C (10) instruments) will now be in C(4); and
- there will be a new category of "financial instrument (Annex I Section C (11)) to cover emission allowances, including units recognised for compliance with the requirements of the Emissions Trading Scheme. Spot trading in emissions allowances will therefore be regulated under MiFID.

REMIT

The European Parliament has adopted the text of a regulation on wholesale Energy Market Integrity and Transparency ("REMIT")[78] which is applicable to energy companies in Europe and contains rules that prohibit the use of inside information, require the public disclosure of that inside information and prohibit certain behaviour constituting market manipulation. It was announced in December 2011 and has been phased in over 2012. Member States had until 29 June 2013 to implement all necessary procedures.

As the structure of the energy markets becomes increasingly pan-European it is more difficult for national regulators to function effectively as they do not have access to Europe-wide information. ACER is positioned to operate as if it is a central European regulator collecting and screening wholesale transaction market data, performing initial assessments of anomalous events and then reporting to the national regulators for enforcement if necessary.[79] As noted above the precise role of ACER has not been defined but with its Europe-wide perspective ACER is able conduct a more comprehensive review as a centralised body and then hand down to the national regulators the roles relating to punishment, prosecution and enforcement. In this respect, on 29 October 2013, ACER published 3rd Edition of the Guidance Paper[80] on its website in relation to REMIT and its implementation.

The key features of the regulation are outlined below:

- the regulation prohibits insider trading[81] and market manipulation[82] in relation to wholesale energy products; this now includes supply contracts to certain large consumers;
- the regulation requires timely public disclosure of inside information; this now extends to information regarding the business or facilities which a market participant, or its parent or a related undertaking, owns, controls or operates, in whole or in part;[83]
- additional reporting obligations regarding transactions and the status of operational assets will apply;[84]
- national regulatory authorities had to be given enhanced investigatory and enforcement powers[85] by 29 June 2013 and penalty rules must be devised and implemented.

All market participants will need to ensure that appropriate measures are in place regarding the disclosure and use of information between group entities (and related undertakings) to minimise the impact of these measures.

In ACER's 2014 Annual Report[86] into REMIT, it reiterated its commitment to investigating market abuse and the Director has called for further funding in order to fulfil this role.

EMIR

The final text of the Regulation of the European Parliament and of the Council on OTC Derivatives, Central Counterparties and Trade Repositories was published on 27 July 2012 in the Official Journal of the European Union.[87] The regulation is also known as the European Market Infrastructure Regulation ("EMIR").

EMIR entered into force on 16 August 2012. However, implementation will be gradual. The technical standards on various topics regarding the clearing obligation, CCP requirements and trade repositories entered into force on 15 March 2013 by Commission delegated regulation.[88] Thereafter the Commission must formally adopt technical standards through delegated acts. Existing EU CCPs have six months from 15 March 2013 to apply for reauthorisation, and once a CCP has been authorised under EMIR, ESMA will consider whether to apply a clearing obligation to the derivatives it clears.[89]

EMIR introduced significant changes to the over-the-counter ("OTC") derivatives market by mandating central clearing for standardised contracts and imposing risk mitigation standards for non-centrally cleared contracts. On 12 February 2014 the reporting of OTC to trade repositories started and the reporting of collateral and valuation data commenced on 12 August 2014. The clearing obligation will apply to both financial counterparties and non-financial counterparties who exceed certain thresholds, and will apply broadly to OTC derivative contracts, including interest rate, credit, equity, foreign exchange and commodity derivatives.

The following paragraphs set out the main elements of the Mandatory Central Clearing.[90] Financial entities will be required to clear all standardised eligible OTC derivative contracts through central counterparties ("CCPs"). The first CCP was given authorisation on 18 March 2014. Non-financial firms will only be subject to the clearing rules if their OTC derivative positions reach specified clearing thresholds, with a carve out for hedging transactions. Intragroup transactions are excluded. A third country firm that would be subject to the clearing obligation if it were established in the EU will also have to abide by the central clearing obligations for any transaction with an obligated EU entity, or for any transaction where the contract has a direct, substantial and foreseeable effect within the EU. The Regulatory Technical Standards for third country transactions have been reported in the Official Journal and the main provisions have been applicable from 10 October 2014.

- Collateral: Parties to cleared OTC derivative contracts will need to post initial and variation margin.
- CCPs:[91] National competent authorities will be responsible for authorising and supervising CCPs in their jurisdiction. CCPs will be required to have established default procedures in the event of a clearing member's non-compliance with the rules, and a mutualised default fund to which members of the CCP must contribute.
- Non-Centrally Cleared OTC Derivatives:[92] Non-centrally cleared OTC derivative contracts will be subject to strict procedures to reduce counterparty credit risk and operational risk including the requirement for timely confirmation of terms (where possible by electronic means), robust and auditable processes for portfolio reconciliation, marking to market procedures, dispute resolution, and procedures for the accurate and appropriate exchange of collateral. Again, intragroup transactions are largely sheltered from these requirements.
- Reporting:[93] All counterparties and CCPs must ensure that the details of all derivative contracts, regardless of how they are cleared, are reported without duplication to trade repositories no later than the working day following the conclusion, modification or termination of a contract. The obligation is not subject to any thresholds. The obligation will extend to contracts entered into before the Regulation that are still outstanding on the date of the Regulation's entry into force. Reporting obligations may be delegated (eg, to prime brokers or asset managers). Trade repositories will publish aggregate positions by class of derivatives. Reporting failures will be met by penalties.
- ESMA: ESMA will have significant responsibility, including (a) identification or approval of contracts subject to clearing and recommendation of clearing thresholds,[94] (b) surveillance of trade repositories, including the grant and withdrawal of their registration,[95] and (c) authorisation and supervision of CCPs from third countries.[96]

The pieces of legislation proposed by the European Union in the form of EMIR, REMIT and MiFID II cannot be viewed in isolation, especially from the perspective of energy companies. The new legislation is designed to regulate the financial sector by increasing reporting requirements, increasing transparency and increasing the control of the regulator. This is with the aim of helping to prevent another financial crisis. Emissions trading, parts of which were previously unregulated, will now be subject to these pieces of legislation and reporting and systems requirements will increase. As a result energy companies will have to spend both time and money to ensure that they are in line with the rules as they come into force. This will include ensuring that effective systems are in place to deal with the reporting requirements and completing impact assessments to establish whether they fall above the thresholds set by the legislation. As the directives and regulations are inter-linked energy companies will want to ensure that any systems updates that they put into place can cover the reporting requirements across all three pieces of legislation.

THE EU CLIMATE CHANGE PACKAGE:

The Climate Change Package contains the following legislative measures:

- Directive 2009/29/EC of the European Parliament and of the Council of 23 April 2009 amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community (the "New EU ETS Directive");[97]
- Decision No 406/2009/EC of the European Parliament and of the Council of 23 April 2009 on the effort of Member States to reduced their greenhouse gas emissions to meet the Community's greenhouse gas emission reduction commitments up to 2020 as amended by Protocol [12012JN03/08] (the "GHG Reduction Decision");[98]
- Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directive 2001/77/EC and 2003/30/EC as amended by Directive 2013/18 (the "Renewable Energy Directive");[99]
- Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No 1013/2006 as amended by Directive 2011/92 (the "CCS Directive");[100]
- Directive 2009/30/EC of the European Parliament and of the Council of 23 April 2009 amending Directive 98/70/EC as regards the specification of petrol, diesel, and gasoil and introducing a mechanism to monitor and reduce greenhouse gas emissions and amending Council Directive 1999/32/EC as regards the specification of fuel used by inland waterway vessels and repealing Directive 93/12/EEC (the "Biofuel Directive");[101] and
- Regulation (EC) No 443/2009 of the European Parliament and of the Council of 23 April 2009 setting emission performance standards for new passenger cars as part of the Community's integrated approach to reduce CO_2 emissions from light-duty vehicles as amended by Regulation No 397/2013, Relation Regulation No 63/2011 (the "Emissions Standards Regulation").[102]

In this overview article, the key elements of the Climate Change Package are described and analysed. For a detailed analysis as to the impact the Climate Change Package is having in Member States, please refer to the relevant national chapters in this edition of EEH – the European Handbook 2015.

New EU ETS Directive

The New EU ETS Directive amends the pre-existing version of the EU Emissions Trading Scheme, introduces a number of important changes to the EU ETS that take effect from Phase III (2013-2020) of the scheme, and provides a clearer sense of the future of the scheme. It introduces a declining emissions cap, increased auctioning of allowances and longer trading phases. In addition, the New EU ETS Directive expands the EU ETS to cover new activities and gases, including:

- CO_2 emissions from the petrochemicals, ammonia and aluminium sectors;
- nitrous oxide emissions from the production of nitric, adipic and glyocalic acid; and
- perfluorocarbon emissions from the aluminium sector.

Although much of the attention on Phase III has surrounded its expansion, the New EU ETS Directive confirmed that the EU ETS will continue to be focused on large energy intensive sectors.

The increased harmonisation and centralisation of the operation of the EU ETS is a central element of the New EU ETS Directive.[103] As part of this change towards a more centralised approach, the allocation of allowances has, since 2013, been made on the basis of centrally approved allocation plans rather than by Member

States alone.[104] This represents a change from the previous practice which EU ETS participants claimed led to competitive distortions within sectors due to different allocation rules being adopted by Member States. Likewise, the administration of the New Entrant Reserve (equivalent to 5% of total annual allowances) is now centralised;[105] and records relating to trading in allowances are to be held in a central register. The proceeds from auctioning 300 million allowances reserved for new entrants to the EU ETS are to be used to support renewable energy projects and up to 12 CCS demonstration projects.[106]

Overall, the New EU ETS Directive decreases the previous EU-wide allowance cap. From 2013, the cap will decrease year on year by 1.74% of the Phase II cap from the total amount of 1.974 billion allowances in 2013 to 1.720 billion in 2020 (equivalent to an overall reduction of 21% in allowances available by 2020 compared to 2005). After 2020, the cap will have to be lowered by 2.2% to meet the 2030 targets. Allowances issued from 2013 onwards can be banked for use in any subsequent phase of the scheme.[107]

One major change is a shift away from allocating allowances to operators free of charge, to a process involving the compulsory auctioning of allowances. Free allocations of allowances will be phased out progressively. Article 1(11) of the New EU ETS Directive provides that, from this year, all allowances not allocated free of charge in accordance with provisions in Article 1(12) of the New EU ETS Directive are to be auctioned.[108]

For the electricity sector, stricter rules now apply in that no allowances are to be allocated free of charge to electricity generators as of this year (please see below for details on certain exceptions). 88% of the allowances[109] to be auctioned will be being given to Member States in proportion to their verified emissions for 2005 or the average of the period from 2005 to 2007, whichever is higher. A further 10% of allowances[110] are to be distributed amongst certain Member States for the purpose of solidarity and growth, thereby taking account of lower GDP per head and higher prospects for growth and emissions. Another 2% of auctioned allowances are to be distributed to the nine Member States which, in 2005, had achieved greenhouse gas emissions reductions of at least 20% compared to 1990 levels.[111] The option available to Member States to exempt small installations has been extended to cover all small installations regardless of sector or the nature of the activity undertaken. The emissions threshold below which an installation is classified as "small" has been raised from 10,000 to 25,000 tonnes of CO_2 emitted per year. In addition, in the case of combustion installations, the capacity threshold has been raised from 25MW to 35MW. Member States have also been given the option of excluding hospitals from the exemptions.[112]

Member States may compensate certain installations for EU ETS costs passed on to them through higher electricity prices if these costs might otherwise expose them to the risk of carbon leakage.

In order to assist Member States with less developed generating infrastructure and economies, certain Member States may opt to derogate from the rule preventing the allocation of allowances to electricity generators free of charge. This option is only available where certain conditions relating to the interconnectivity of the electricity grid, the share of fossil fuels in electricity generation, and GDP per capita are fulfilled. Even if the option is exercised, 30% of the allowances available for electricity generators must be auctioned in 2013, rising progressively to 100% by 2020, and the Member State must invest in energy infrastructure, clean technologies and energy diversification an amount equal to the market value of the free allocation. In addition, free allocations can only be made for emissions from installations that were operational or under construction no later than the end of 2008.[113]

The New EU ETS Directive contains detailed provisions as to the criteria to be used to determine sectors exposed to a significant risk of "carbon leakage" (such as the relocation of manufacturing or other activities covered by the scheme outside the EU where similar emission reduction constraints have not been imposed). The Commission was tasked with identifying those sectors facing significantly increased production costs, ie, costs comprising more than 5% of its gross value added, and international competition (more than 10% non-EU imports and exports).[114] The Commission has undertaken a review of carbon leakage, and has produced a list of sectors determined to be at risk.[115] The Commission has also determined transitional Union-wide rules for the harmonised free allocation of emission allowances.[116]

With regard to credits generated by Clean Development Mechanism (CDM) and Joint Implementation (JI) projects, the New EU ETS Directive envisages two scenarios.[117]

Generally, the New EU ETS Directive extends the ability to use credits generated by CDM and JI projects issued in respect of emission reductions occurring before 2013 or generated by projects established before 2013 into Phase III of the EU ETS.

Prior to or without a global successor agreement to the Kyoto Protocol, operators of relevant installations are able to use credits allocated to them for the period 2008 to 2012 that they have not already used. However, in this scenario, only credits from project types which were accepted by all Member States during the 2008 to 2012 period are eligible for use, in order to guarantee that JI/CDM credits are treated equally throughout the EU ETS. Provided that the new credits do not increase the overall number of credits available, JI/CDM credits from new energy efficiency or renewable energy projects that promote sustainable development can be used in accordance with agreements concluded with third countries; and JI/CDM credits derived from new projects that start from 2013 onwards are allowed from Least Developed Countries without the need to conclude an agreement with these countries.[118]

If a global successor agreement to the Kyoto Protocol is reached, the limit on the use of JI/CDM credits will be automatically increased by up to half of the additional reduction effort, and operators of participating installations may, in addition to the credits provided for in the New EU ETS Directive, use CERs, ERUs or other approved credits from third countries which have ratified the international agreement on climate change succeeding the Kyoto Protocol.[119]

In another change from previous practice, the EU ETS has, from 2013, been extended to cover the capture, transport and storage of CO_2. However, in order to support the development of CCS, operators do not need to surrender any allowances for CO_2 that is permanently stored in a licensed CCS facility (see section below on the CCS Directive).[120]

Member States were obliged to transpose the New EU ETS Directive into national law by 31 December 2012. In order to avoid any legal uncertainty, the New EU ETS Directive specifies that the relevant directives amended by the New EU ETS continued to apply until 31 December 2012.[121]

In January 2014, the Commission issued a Communication[122] proposing the creation of a market stability trading reserve in order to address the issues faced by the EU ETS, but at the time of writing this requires approval from both the European Parliament and the Council. On 23 October 2014 published its Conclusions on 2030 Climate and Energy Policy Framework[123] in which it endorsed the contents of the Commission's Communication and may be seen as the commencement of Phase IV EU ETS.

The GHG Reduction Decision

The GHG Reduction Decision provides for binding greenhouse gas emissions targets for individual Member States for sectors of the economy not covered by the EU ETS and provides an indication of the extent to which Member States will be required to address and reduce emissions from non-EU ETS sectors (such as surface transport, construction, and agriculture) over the next decade.

The targets for individual Member States amount to an average reduction of 10%.[124] This reduction, combined with the agreed 21% reduction for EU ETS sector emissions, is designed to ensure that the EU meets its current overall target of a 20% reduction in emissions by 2020.

Those Member States with lower per capita income and strong prospects for future economic growth may increase their greenhouse gas emissions by up to 20% by 2020 compared to 2005 levels, whereas Member States with higher income per capita must reduce their emissions by up to 20% by 2020. A reduction target of 16% has been set for the UK, and a reduction target of 14% has been set for Germany and France. The individual targets are the same as those proposed by the Commission when it announced the climate and energy package in January 2008, but they will be reviewed if an international agreement succeeding the Kyoto Protocol can be agreed.[125]

In order to set a trajectory to meet the target of a 20% reduction in emissions by 2020, the GHG Reduction Decision also sets annual binding emissions limits for each Member State. Several flexibility measures are provided, allowing Member States to bank and borrow up to 5% of limits between years; transfer "overachieved" emissions reductions between Member States; and use, without limit, credits generated by emissions reduction projects within the EU.[126]

Pursuant to the GHG Reduction Decision, Member States which are required to reduce their emissions, or are allowed to increase them by up to 5%, may use an additional amount of CERs equal to 1% of 2005 emissions, subject to the relevant CERs stemming from CDM projects in less developed countries.[127] *De facto*, the only Member States likely to benefit from this measure are Austria, Finland, Denmark, Italy, Spain, Belgium, Luxembourg, Portugal, Ireland, Slovenia, Cyprus and Sweden.[128]

Member States already monitor and report greenhouse gas emissions annually. The GHG Reduction Decision now provides that, if a report indicates non-compliance with a limit for a given year (taking into account any use of the flexible measures or CDM/JI credits), the Member State will have to submit a corrective action plan to the Commission detailing the measures they intend to take to rectify the situation.[129] Further measures to deter Member States from exceeding their limits include a deduction from a Member State's emission allocation for the following year and the temporary suspension of the eligibility to transfer part of the Member State's emission allocation and JI/CDM rights to another Member State until corrective action has been taken.[130] The GHG Reduction Decision does not, however, include the enforcement mechanism requested by the European Parliament which would have required a Member State that fails to meet its target to pay an "excess emissions penalty" equivalent to the fines payable under the EU ETS ie, €100 per tonne of CO_2 emitted.

The GHG Reduction Decision is in force.

On 23 October 2014, the European Council endorsed a further target of 40% reduction on GHG from 1990 levels by 2030.[131] This is a collective target for the Member States.

Changes in EU ETS

As a result of security issues relating to fraud and theft in the EU ETS market, in early 2011 the Commission took immediate steps to temporarily suspend all national registries until they fulfilled certain minimum security requirements. The Commission Regulation (EU) No 1193/2011 of 18 November 2011[132] (the "2011 Regulation")[133] introduced further and more long-term, security measures, such as the introduction of the single EU registry for the EU ETS which is to replace the national registries from 2013. The 2011 Regulation was repealed and has now been replaced by the Commission Regulation No 389/2013 of 2 May 2013 (the "2013 Regulation").[134] The 2011 Registries Regulation was updated so as to put in place a formal exchange mechanism to use international credits under the directly in EU ETS, see Section 6 of the 2013 Registries Regulation for these provisions.[135] The 2013 Regulation sets out operational and maintenance requirements (amongst others) for the Union registry for the trading period commencing 1 January 2013 and subsequent periods, as well as for the independent transaction log provided for in Article 20(1) of Directive 2003/87/EC. It also provides for the creation of a communication system between the Union registry and the independent transaction log.[136]

The 2013 Regulation applies to (a) EUAs created for the trading period of the EU ETS commencing on 1 January 2013 and subsequent periods, and (b) aviation allowances to be auctioned that were created for the trading period running from 1 January 2012 to 31 December 2012.[137]

The new measures, which were first adopted in the 2011 Regulation, are said to align the new Union registry (implemented August 2012) with security measures generally used in the financial sector. Most provisions apply from the date that the single EU registry became fully operational. A few measures have been effective since the entry into force of the 2011 Regulation (ie, 30 November 2011), and some will be implemented during the next software update, the date of which is uncertain at the time of writing. The main security measures and their applicability are summarised below.

- A 26-hour delay on EUA transfers between registry accounts, so that fraudulent trades can be spotted before the completion of the transfer (except for transfers to an account on the trusted account list of the transferor).[138] This delay could prove to be problematic, particularly in chain transactions (which are common in the carbon and commodity markets) as it increases the complexity of such transactions. Under the 2013 Regulation, account representatives may cancel transactions during the delay period should they suspect that the relevant transfer was initiated fraudulently, giving rise to further transaction uncertainty.[139]

- A new authorisation system requiring at least two people to sign off before a transfer can be made (except for transfers to an account on the trusted account list of the transferor, and transactions initiated by exempted external platforms).[140]
- Confidentiality in respect of the unique serial number of the EUAs or the Kyoto Protocol unit held or affected by a transaction (except as otherwise required by EU law, or proportionate national laws pursuing a legitimate objective).[141]
- An obligation on each Member State to designate a national administrator to access and manage its accounts.[142]
- The discretion of the national administrators to ban from holding an EU ETS registry account anyone who is under investigation for, is reasonably suspected of or has in fact been convicted of fraud involving EUAs, money laundering or terrorist activities in the last five years.[143] This is likely to mean that more extensive requirements for vetting of account holders will need to be introduced at a national level, and that contractual arrangements between traders will need to be amended to reflect these forthcoming changes.
- Access to confidential information held in the EU registry will be granted to relevant national authorities. In addition, Europol will be granted permanent read-only access to the database.[144]

The new security measures in the 2011 and 2013 Regulations will also be important alongside other changes in the EU ETS regime. From January 2013 the system of auctioning carbon allowances have played a more prominent role. The New EU ETS Directive marks the end of free allowances for electricity production except in limited circumstances[145] and it is expected that these allowances will have be procured at market price using the more transparent auction process. Free allowances will be available for those industry sectors with significant risks of carbon leakage but will no longer be available for those without.[146] In 2013 more than 40% of all carbon allowances will be auctioned promoting a fairer overall system.[147]

The EU has also recently moved to address surplus of carbon allowances. Since 2009, as a result of the financial crisis, there has been a growing surplus of allowances and international credits compared to emissions. This has significantly weakened the carbon price signal.[148] The Commission has proposed introducing an amendment to the Directive 2003/87/EC that will allow for "backloading" of allowances.[149] According to the Commission, this would mean postponing the auctioning of 900 million carbon allowances from the years 2013-2015 until 2019-2020.[150] On 3 July 2013, the European Parliament voted to accept the Commission's proposal for backloading.[151]

The Renewable Energy Directive

The Renewable Energy Directive promotes the use of renewable sources for electricity generation and sets a target for energy from renewables of 20% of total energy consumption across the EU by 2020, including a further target of 10% for energy from renewable sources for each Member State's transport energy consumption.

In order to achieve the overall targets, the Renewable Energy Directive sets a mandatory national target for each Member State stating the overall share of gross energy consumption that must come from renewable energy sources, taking the differing levels of progress achieved by Member States to date into account.[152] The mandatory national targets provide certainty for investors and should encourage technological development. To ensure that the mandatory national targets are achieved, Member States are required to follow an indicative trajectory towards the achievement of their target and each is required to produce a National Action Plan. The plan sets national targets for the share of energy from renewable sources to be used to meet demands for transport, electricity, heating and cooling in 2020. Member States are free to decide their preferred mix of renewable sources, but were required to present National Action Plans, based on an "indicative trajectory", to the Commission by 30 June 2010.[153] Progress reports are required be submitted every two years. The plans need to be split so that three sectors are identified separately, namely: electricity, heating and cooling, and transport.[154]

Member States can apply financial support schemes in relation to the mandatory targets, although it will not be mandatory to link these with schemes in other Member States. The Renewable Energy Directive also lays down rules relating to statistical transfers[155] between Member States, joint projects between Member States and with non-EU countries[156], Guarantees of Origin,[157] administrative procedures,[158] information and training,[159] and access to the electricity grid for energy from renewable sources.[160]

The Renewable Energy Directive contains interim targets for all Member States, in order to ensure steady and measurable progress towards the 2020 targets:[161]

- 30% of the overall 2020 target to be achieved between 2013 and 2014;
- 45% of the overall 2020 target to be achieved between 2015 and 2016; and
- 65% of the overall 2020 target to be achieved between 2017 and 2018.

Whilst there are no financial penalties imposed in relation to any failure in achieving the above targets, the Commission may issue infringement proceedings if Member States do not take "appropriate measures" to try and meet their targets.

Member States can:

- cooperate on joint projects renewable energy projects;[162]
- work with non-EU countries on renewable electricity generation projects;[163]
- link their national support schemes[164] to those of other Member States; and,
- under certain circumstances, count the import of "physical"[165] renewable energy from third-country sources towards their targets.

It may, under certain circumstances, be possible to count "virtual" imports, based on investments in non-EU countries towards a Member State national target.[166]

A system requiring open trading in renewable energy certificates between participants across Member States was rejected in favour of a system only permitting Member States themselves to transfer excess renewable energy credits. These "statistical transfers" can only take place if the Member State has reached its interim renewable energy targets.

The Renewable Energy Directive states that Guarantees of Origin in relation to renewable energy are only to be used to prove the quantity of energy from renewable sources in a supplier's energy mix to final consumers. Member States must ensure that a Guarantee of Origin is issued in response to a request from a generator of renewable electricity and that guarantees are given in relation to each 1MWh generated.[167]

In addition, the Renewable Energy Directive establishes binding criteria to ensure that biofuel and bioliquid production are environmentally sustainable. For the purposes of meeting national targets, energy from these sources must fulfil the requisite criteria. The criteria relate to biodiversity, the protection of rare, threatened or endangered species and ecosystems, and greenhouse gas emissions savings.[168]

After 2017, any greenhouse gas emissions savings resulting from the use of biofuel produced in existing biofuel production plants must at least amount to 50% compared with the emissions from using fossil fuels[169], whereas greenhouse gas emissions from the use of biofuel produced in new installations (ie, those installations which commence production after 1 January 2017) must be at least 60% lower than those from fossil fuels. Unlike traditional, "first-generation" biofuel, it is thought that second-generation biofuels do not present the same risks to the security of food supplies as these biofuels are, for example, produced from wastes, residues, or biomass such as algae, wood residues, or paper waste.

In the past, many smaller producers of renewable electricity have argued that a lack of transparency and restricted access to electricity grids has prevented them from competing in the market. The directive requires Member States to ensure that transmission and distribution system operators provide either priority access or guaranteed access to the grid for electricity produced from renewable energy sources.[170] System operators are required to provide any new generator wishing to be connected to their network with a timetable and a comprehensive estimate of costs associated with the connection[171]. Member States are also obligated to develop transmission and distribution grid infrastructure, intelligent networks, storage facilities and systems that can be operated safely while accommodating renewable generation.[172]

In their National Action Plans, Member States are required to assess whether there is a need to build new district infrastructure for heating and cooling using energy produced from renewable sources (including large biomass, solar and geothermal facilities) in order to achieve their mandatory 2020 national target.[173] Local and regional administrative bodies should be advised to "ensure equipment and systems are installed for the use of heating, cooling and electricity from renewable sources, and for district heating and cooling when planning, designing, building and refurbishing industrial or residential areas". In particular, they should be encouraged to include heating and cooling systems when planning city infrastructures.[174]

Member States were required to have transposed the Renewable Energy Directive by 5 December 2010.[175]

On 17 October 2012, the Commission published a proposal to amend the Renewable Energy Directive so as to limit global land conversion for biofuel production, and raise the climate benefits of biofuels used in the EU. The use of food-based biofuels would have to meet the 10% renewable energy target of the Renewable Energy Directive would be limited to 5%.[176]

The CCS Directive

The climate change and renewable energy package includes a directive which provides a framework for carbon capture and storage in the EU (the CCS Directive) supporting CCS as an emissions reduction option.

The key provisions of the CCS Directive are:

- the creation of a permit-based CCS storage regime to be administered by Member States and the amendment of existing EU legislation which prohibits or inhibits CCS;[177]
- the establishment of a regime for operators holding permits to pass long-term liability for leakage from storage sites to the licensing Member State, provided certain hand-over criteria are met;[178] and
- requirements for all new combustion plants in the EU built without CCS to have space for CCS equipment and to have carried out studies into the availability of storage sites and the feasibility of "retro-fitting" capture equipment.[179]

By joining up the funding mechanism under the New EU ETS Directive and the provisions of the CCS Directive, the Climate Change Package provides that CCS is financially incentivised through the EU ETS from Phase III (2013–2020) and Member States can opt-in for the inclusion of CCS in Phase II (2008–2012) (see section on the New EU ETS Directive above). The inclusion of CCS in the EU ETS combined with the allocation of up to 300 million EU ETS allowances from the new entrant reserve have allowed the EU to fund up to 12 CCS demonstration projects.[180] Practically, support for such projects is to be provided via Member States and the mechanics of how and when such support will be made available are currently unclear.

As a result of the CCS Directive, CO_2 stored in geological formations is not to be classed as "emitted" for the purposes of the EU ETS so that credit is given to power stations with CCS technology which are not to be required to surrender allowances for CO_2 which is stored.

Under the CCS Directive there are two types of permit. Firstly an exploration permit which permits certain specified exploration works to be carried out and entitles the permit holder, on an exclusive basis, to explore within the area covers by the permit for appropriate geological formations.[181] Secondly a storage permit which relates to the development and utilisation of geological formations contained in the permit area as storage sites for CO_2, and permits the injection of CO_2 to such formations.[182]

The criteria for the grant of a storage permit are rigorous and involve substantial site characterisation in order to assess its suitability for permanent storage. Applicants must also satisfy technical and financial requirements. As well as delineating the storage complex, storage permits are to contain a number of important provisions including the requirements for operating the storage facility, the total quantity of CO_2 to be stored, the requirements with regard to the composition of the CO_2 stream and an approved monitoring plan.[183]

Permits are to be issued by the competent authority in each Member State. However, the Commission proposes to review and comment on each individual storage permit application before it is awarded and Member States are obliged to take the Commission's comments into consideration.[184]

The CCS Directive also deals with issues relating to liability for damage from CO_2 leaks from storage sites. The Directive contains specific provisions both in respect of damage to the local environment and the climate. With regard to the former, the CCS Directive applies the Environmental Liability Directive (2004/35/EC) to the storage of CO_2 which aims to ensure that any operator of a storage facility prevents and remedies any damage caused by CO_2 leakage.[185] Liability for climate damage resulting from leakage is covered by the inclusion of CCS in the revised EU ETS Directive so that EU ETS allowances need to be surrendered for leaked emissions.[186]

The CCS Directive requires the storage operator to take corrective measures to remedy any leakage, and the storage operator remains responsible for the storage site for as long as it represents a risk (even after closure), until the site is handed over to the competent authority of the relevant Member State.[187] The relevant Member State is required to assume responsibility for storage sites in its territory from the point of handover.[188] Once a handover has occurred, subject to an important caveat, there should be no further liability for the operator.

The CCS Directive contains a provision stating that where there is fault on the part of the operator, including deficiencies in data, concealment of relevant information, negligence, wilful deceit or a failure to exercise due diligence, the competent authority may recover the costs incurred from the operator, even after the transfer of responsibility has taken place.[189] This is a broad derogation from the principle of liability handover. How this is translated into national legislation will be of great interest to operators of storage facilities.

As part of the permitting regime, Member States may require operators to lodge financial security for their prospective liabilities before the injection of CO_2 into a storage facility commences.[190] The scope of these liabilities and the form that the security will take is a matter for individual Member States to decide and will no doubt come under scrutiny when the CCS Directive is implemented at national level. In addition, Member States are entitled to require a contribution from the operator to cover future liabilities as a condition of the handover of responsibility. Member States are permitted to set the level of this contribution subject to a minimum of not less than the cost of monitoring the site for 30 years post-closure.[191]

Whilst stopping short of compulsory CCS for new power plants, there are requirements on the operators of all new combustion plants in the EU with a capacity in excess of 300MW which are built without CCS capabilities to have assessed whether suitable storage sites are available, whether transport facilities are technically and economically feasible and whether it is technically and economically feasible to retrofit the plant for CO_2 capture. The relevant competent authority in the Member State should also ensure that the operator has secured suitable space on the site for the installation of equipment necessary to capture and compress CO_2.[192]

By amending directives relating to the waste and ground water to permit to permit the injection of CO_2 into storage sites, the Climate Change Package removes a significant part of the current prohibitions on CCS under EU legislation.

In addition to the financing support mechanisms in the CCS Directive, financial support for carbon capture and storage is also forthcoming under the European recovery plan.[193] On 20 March 2009, EU leaders agreed proposals for €5 billion of investment in energy and broadband infrastructure projects as part of the European Energy Programme for Recovery (EEPR)[194.] EU recovery plan. The €5 billion came entirely from unspent money in the EU budget. Under the plan Germany, the UK, Poland, the Netherlands and Spain were to receive €180 million each, Italy was to receive €100 million and France €50 million. 13 projects were shortlisted as funding candidates, among them Hatfield, Kingsnorth, Longannet and Tilbury in the UK, Eemshaven and Rotterdam in the Netherlands and Hürth and Jänschwalde in Germany. CCS technologies also benefit from funding from the EEPR. Initially six projects were identified as eligible for up to €1billion funding. As of 30 April 2014, one project has successfully completed its pilot stage, two are on-going and three have been terminated early. The total support paid to these projects stands at €374,871,355.

Member States were required to transpose the CCS Directive into national law by 25 June 2011. There were as many as 26 Member States in breach of the transposition requirements when the deadline fell but as of 24 July 2014 only three Member States are yet to have completed transposition.[195]

The Biofuel Directive

The measures introduced by the Biofuel Directive have provided a significant boost to the European biofuel market.

The Biofuel Directive introduces amendments to two previous European directives relating to the quality of petrol and diesel (Directive 98/70/EC of the European Parliament and Council relating to the quality of petrol and diesel fuels as amended by Directive 2003/17/EC). The changes provide for a mechanism for the reporting[196] of and reduction in the life cycle of greenhouse gas emissions from fuel; enable the more widespread use of ethanol in petrol; and tighten environmental quality standards for specified fuel parameters.[197]

The Biofuel Directive obliges fossil fuel suppliers to reduce greenhouse gas emissions from their fuels throughout their life-cycle by 6%, a reduction from the Commission's initial proposal for a binding 10% reduction. Member States may also require suppliers to comply with intermediate targets (a 2% reduction by the end of 2014 and a 4% reduction by the end of 2017).[198] The use of Certified Emissions Reductions obtained from projects related to flaring reductions is expected to produce a further 2% reduction which will not be linked to EU oil consumption.

Perhaps the most significant change brought about by the Biofuel Directive is the increase in the permissible content of biological components of petrol to up to 10% by the phasing in of 10% Ethanol (E10) petrol. Petrol meeting the pre-existing requirements (containing up to 5% by volume of ethanol) was permitted to be marketed until 2013; at the time of writing, there was no indication as to whether or not such provision was to be extended. This transitional period was introduced to mitigate the potential damage that would be caused to vehicles which were not calibrated or covered by a warranty allowing the use of petrol with an ethanol content of over 5% by volume.[199] In addition, Article 3(3) gives flexibility to Member States to place such petrol on the market for a longer time if deemed necessary: "Member States shall require suppliers to ensure the placing on the market of petrol with a maximum oxygen content of 2.7% and a maximum ethanol content of 5% until 2013 and may require the placing on the market of such petrol for a longer period if they consider it necessary. They shall ensure the provision of appropriate information to consumers concerning the biofuel content of petrol and, in particular, on the appropriate use of different blends of petrol."

There are also changes to current diesel specifications. Under the Biofuel Directive the content of fatty acid methyl ester (FAME) in diesel is permitted up to 7% by volume and for other advanced biodiesel blends there is no restriction at all in the conventional diesel specification. Although allowances are made for Member States that want to make biodiesel blends with a FAME content of 10% by volume available, as a result of the new specification, diesel constituting up to 7% by volume of FAME (B7) is likely to be the grade of diesel predominately available on the European market.[200]

European legislators intend the Biofuel Directive to incorporate sustainability criteria for biofuel used to meet greenhouse gas reduction requirements. Despite criteria being set out in the Renewable Energy Directive, these criteria had not been agreed by the time that the package was adopted. The European Commission has been tasked with developing a methodology to assess the environmental impact of biofuel across their life-cycle, and produced a report to this effect in January 2011.[201] A second report was issued in February 2013 which focuses in particular on the impact in developing countries.[202]

Member States had until 31 December 2010 to transpose the Biofuel Directive into national law.[203] The Biofuel Directive has had a significant impact on fuel suppliers throughout the distribution chain as well as fuel producers, who more so than other affected parties, have had to adapt to meet the new quality criteria.

The Emissions Standards Regulation

Despite improvements in fuel efficiency, CO_2 emissions from road transport across the EU increased by 26% between 1990 and 2004, and now account for almost a third of the EU's total emissions. When it became apparent that voluntary car industry reduction targets would not be met, the European Commission proposed new legislation to impose enhanced emissions performance requirements. The Emissions Standards Regulation sets the first legally binding standards for CO_2 emissions from passenger cars. This Regulation promotes the adoption of improvements in technology in the sector in order to meet requirements to reduce, from current levels, to 130g of CO_2 per km travelled (as an EU average for new cars). Additional measures are also promulgated to achieve a further 10g per km which include the increased use of sustainable biofuel and increase efficiencies from technology such as improved air-conditioning systems and tyres. The Emissions Standards Regulation was amended by Regulation 397/2013[204] which replaced Annex II in the Emissions Standards Regulation on monitoring and reporting of emissions.

The Emissions Standards Regulation is much less demanding than the European Commission's original proposal, which had sought to impose significant financial penalties for missing targets that would have applied in full from 2012. The car industry argued strongly that lead-in times for new car development would have made complying with the proposed targets within this timeframe impossible.

The obligations are now being phased in until 2015. From 2012, on average 65% of a manufacturer's newly registered cars have been required to comply with the manufacturer's target. This grew to 75% in 2013 and will increase to 80% in 2014 and 100% from 2015 onwards.[205] Additional credit[206] will be given for very low emission vehicles, and in certain circumstances for biofuel-capable cars, until 2016. The target for each manufacturer will be set by reference to a limit value curve, with manufacturers of heavier cars being allowed higher emissions than those of smaller cars, but also being required to make steeper cuts from current fleet average emission levels.[207]

Manufacturers (including companies within the same manufacturing group) may agree to pool together to meet the emissions targets.[208] In that case, a nominated pool manager is responsible for paying any penalties, and evidence must be provided that it is sufficiently financially robust to do so. In order to discourage cartel behaviour amongst pool members that are not part of the same group of companies, pools must allow open, transparent and non-discriminatory participation on commercially reasonable terms, and the usual anti-competition rules apply. Pool members are not allowed to share information (eg, on pricing or research developments) other than that which directly relates to compliance with their targets. This does not preclude collaboration agreements which are unconnected with the pooling agreement and do not otherwise violate applicable laws or regulations.[209]

Small-scale manufacturers (registering fewer than 10,000 cars per year) and niche manufacturers (registering fewer than 300,000 cars per year) may benefit from lower targets. Small-scale manufacturers may put forward a reduction target consistent with their reduction potential in light of economic, technological and market considerations, but such reduced targets are only available for a maximum of five years, whereas niche manufacturers, instead of having a target set by reference to the limit curve, are able to apply for a lower target of a reduction of 25% from 2007 emission performance levels. These lower targets were required to be achieved by 2012.[210]

Manufacturers may seek to gain credit of up to 7g of CO_2/km travelled for eco-innovations shown to improve CO_2 emissions performance, provided the improvements go beyond what is otherwise required by the regulation. However, over time, eco-innovations (and in particular reductions in car weight) will be subsumed into required standards and no extra credit will be given.[211]

The Emissions Standards Regulation's penalty scheme was also amended from the original proposal to ensure that manufacturers who only miss the target by a small margin are less severely penalised. The fines will now be:

- €5/g per new car registered for the first g/km over target;
- €15 for the second g/km over target;
- €25 for the third g/km; and
- €95 for each gram above three grams until 2019.

From 2019 the full penalty of €95 for each g/km over the target will apply.[212]

From 2011 onwards manufacturers have been notified by the Commission of any shortfall in meeting their targets for the previous year. Inaccuracies can be challenged and the notice will be confirmed by 31 October of the relevant year. Details of each manufacturer's performance are also published.[213]

A longer-term target of 95 grams of CO_2 per kilometre travelled by 2020 is also specified in the Emissions Standards Regulation. Mechanisms for meeting this goal and penalties for missing it will be set following a review of the regulation which will be completed by 1 January 2013. That review must encompass a review of all targets applying from 2012 and the small-scale manufacturer and niche market derogations. It must also include an overall assessment of the impact of the regulation on the car industry and dependent industries such as parts providers.[214] The Commission proposed a regulation amending the Emissions Standards Regulation on 11 July 2012 that would, from 2020 onwards, have set a target of 95 g CO_2/km as average emissions.[215] In June 2013, however, this proposal was blocked.[216] At time of writing, no new date has been set for the policy to be approved.

The Emissions Standards Regulation has already entered into force and is directly applicable in all EU Member States, although its measures will be introduced gradually until 2016.

The way ahead for Europe's climate change regime

Taken as a whole, the Climate Change Package is the EU's first attempt to create a comprehensive European legal regime covering the carbon and renewable energy sectors, helping to inform investment decisions in these sectors, by securing a future for carbon trading and laying the foundations for future investment in renewable technologies, biofuel and the development of carbon capture and storage.

At policy level, the Climate Change Package aims to achieve a reduction of at least 20% in the levels of greenhouse gas emissions by 2020; rising to 30% if an international agreement is reached committing other developed countries to comparable emission reductions and economically more advanced developing countries to contributing adequately according to their responsibilities and respective capabilities; and a 20% share of EU energy consumption to be generated from renewable sources by 2020.

As the Climate Change Package was only fully transposed into national law in 2012, it will be some time before its real impact can be assessed. In addition, the European Parliament and the Council have made it clear throughout the legislative process that the Climate Change Package is not the final word in the EU's climate change initiative, emphasising that the EU now has to set its sights beyond 2020 to make even greater cuts in greenhouse gas emissions to meet the target of halving global emissions by 2050. This is likely to include stricter future emissions limits affecting more sectors, but will also involve stimulating technological developments to ensure that industry players, particularly those in energy intensive industries, implement new technologies.

ENERGY EFFICIENCY

The improvement of energy efficiency in the EU is another element of the EU's Europe 2020 Strategy for smart, sustainable and inclusive growth and the transition to a resource efficient economy.

Directive 2012/27/EU of the European Parliament and of the Council of 25 October 2012 on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC (the "Energy Efficiency Directive")[217] establishes a common framework of measures for the promotion of energy efficiency within the Union in order to ensure the achievement of the Union's 2020 20% headline target on energy efficiency and to pave the way for further energy efficiency improvements beyond that date. It lays down rules designed to remove barriers in the energy market and overcome market failures that impede efficiency in the supply and use of energy, and provides for the establishment of indicative national energy efficiency targets for 2020.[218]

The Energy Efficiency Directive requires Member States to set energy efficiency targets that take into account the EU's 2020 energy consumption targets.[219] Articles 24(1) and 24(2) of the Energy Efficiency Directive require Member States to issue reports on progress made towards achieving national energy efficiency targets and National Energy Efficiency Action Plans. As required in Article 24(11), the Commission then makes the reports publicly available.[220]

UPSTREAM

Directive 94/22/EC of the European Parliament and of the Council of 30 May 1994 on the conditions for granting and using authorizations for the prospection, exploration and production of hydrocarbons (the "Hydrocarbons Licensing Directive")[221] concerns conditions imposed on the grant and use of authorisations for the prospection, exploration and production of hydrocarbons.

Generally Member States have sovereign rights over hydrocarbon resources located within their territories. It is up to each Member State to determine the precise geographical areas where the rights to prospect, explore and produce hydrocarbons may be exercised. It is also the Member States' responsibility to authorise particular entities to exercise such rights.[222]

The introduction of the Hydrocarbons Licensing Directive was aimed at reinforcing the integration of the internal energy market, encouraging greater competition within the market and improving the security of supply. The Hydrocarbons Licensing Directive has achieved its aims by establishing a set of common rules which guarantee fair, non-discriminatory access to rights of prospection, exploration and production of hydrocarbons.

The Hydrocarbons Licensing Directive provides that there must be limits to the geographical area and duration of an authorisation. These limits must be proportionate and should be determined based on what is justified to ensure the best possible exercise of the rights granted, taking into account both economic and technical factors.[223] The aim of this is to prevent any single entity from having exclusive rights to an area where the prospection, exploration and production could be more effectively carried out by several entities. The provisions which reserve the right to obtain authorisations for single entity for a specific geographical area within the territory of a Member State were abolished in 1997 by Member States concerned.

According to the Hydrocarbons Licensing Directive, the procedures for granting authorisations must be transparent and based on objective and non-discriminatory criteria.[224] The application process must be open to any interested entities.[225] Selection from among the various entities must be based on criteria relating to their technical and financial capabilities, the way in which they propose to prospect, explore and/or bring into production the hydrocarbons from the geographical area in question and, if the authorisation is put up for sale, the price which the entity is prepared to pay in order to obtain the authorisation.

All the information relating to the authorisation (type of authorisation, geographical area which may be applied for in whole or in part, deadline envisaged for granting the authorisation, selection criteria, etc.) should be published in the Official Journal of the European Union at least 90 days before the deadline for the submission of applications.[226]

The Hydrocarbons Licensing Directive provides the Member States with the right to make access available to these hydrocarbon resources by granting rights but Member States may impose requirements further to considerations of national security, public safety, public health, security of transport, protection of the environment, protection of biological resources, the planned management of hydrocarbon resources or to the payment of a financial contribution or a contribution in hydrocarbons.[227]

The Hydrocarbons Licensing Directive also introduces principles of reciprocity with countries outside the EU. The entities of a particular Member State must receive treatment in third countries which is comparable to that which the entities of third countries receive in the Community.[228]

The Member States are required to provide an annual report containing information[229] on the geographical areas which have been opened, the authorisations granted, the entities holding those authorisations and the available reserves in their territory.

Directive 2004/17/EC[230] runs concurrently with the Hydrocarbons Licensing Directive and regulates the procurement procedures of entities operating in the water, energy, transport and telecommunications sectors.[231]

Directive 2013/30/EU of the European Parliament and of the Council of 12 June 2013 on safety of offshore oil and gas operations and amending Directive 2004/35/EC ("The Offshore Safety Directive"232)

In March 2013, following lengthy negotiation, the European Commission, Council and European Parliament reached political agreement on a new directive seeking to address the risk of major accidents from offshore oil and gas operations in EU waters. The directive entered into force on 19 July 2013.

The Offshore Safety Directive will apply to existing and future installations and operations. There are provisions limiting its applicability to landlocked Member States and Member States with no offshore activities. The main features of the Offshore Safety Directive include:[233]

- provisions establishing minimum conditions for safe offshore oil and gas operations[234] including the submission by operators of a major hazards report prior to commencement of offshore operations;[235]
- provisions improving the response mechanism for accidents and requiring operators to include emergency plans[236] as well as an assessment of "oil spill response effectiveness;[237]
- the requirement that oil and gas operations only be conducted by operators appointed by licensees or licensing authorities;[238]
- provisions imposing financial liability for environmental damage on licence holders (not operators)[239] and extending area of liability for all damage from territorial waters of the Member State to the entire continental shelf area;[240]
- provisions ensuring the independence and objectivity of the competent authority – Member States must ensure a clear separation between regulatory/environmental functions on the one hand and economic functions on the other so to avoid conflicts of interest;[241]
- the requirement that licensing authorities consider whether potential licensees have adequate provision for liabilities potentially deriving from operations;[242]
- rules on transparency and sharing of information;[243] and
- cooperation between Member States with regard to emergency response plans and trans-boundary emergency preparedness and response.[244]

No later than 19 July 2019, the Commission will submit a report to the European Parliament and Council assessing implementation of the directive.[245]

Member states with offshore waters will have two years to transpose the directive into national legislation, while a landlocked country will only have to transpose it once a company registers in such a country and conducts operations outside of the Union.[246]

The Offshore Safety Directive does not require mandatory financial security to be provided (as was strongly requested by the European Parliament). However, it obliges the Commission to report by 31 December 2014 on the availability of such instruments as well as on the handling of claims for third party compensation for damage caused by oil and gas operations.[247]

ENDNOTES

1. Regulation 2011/1227; OJ L 326 of 08.12.2011, p. 1
2. Council Regulation (EC) No 1/2003 of 16 December 2002 on the implementation of the rules on competition laid down in Articles 81 and 82 of the Treaty (OJ L 1 of 4.1.2003, p. 1), as amended by Council Regulation (EC) No 411/2004 (OJ L 68 of 6.3.2004, p. 1), Council Regulation (EC) No 1419/2006 (OJ L 269of 25.09.2006, p. 1), Council Regulation (EC) No 169/2009 (OJ L 61 of 05.03.2009, p. 1), Council Regulation (EC) No 246/2009 (OJ L 79of 26.02.2009, p.1) and Council Regulation (EC) No 487/2009 (OJ L 14825.02.2009, p. 1)
3. OJ L 211of 14.08.2009, p. 55
4. OJ L 211of 14.08.2009, p. 94
5. OJ L 211 of 14.08.2009, p. 1
6. OJ L 211 of 14.08.2009, p. 15
7. OJ L 211of 14.08.2009, p. 36
8. The unbundling provisions are contained in Articles 9 to 11 and 13 to 14 Third Electricity Directive and Articles 9 to 11 and 14 Third Gas Directive.
9. Articles 9 in the Third Electricity Directive and Third Gas Directive, respectively.
10. See Commission Decision in relation to Scotland, last accessed on 25 July 2013 at http://ec.europa.eu/energy/gas_electricity/interpretative_notes/doc/certification/2012_019_020_uk_en.pdf

11. Commission Staff Working Document on Ownership Unbundling: "The Commission's Practice in Assessing the Presence of a Conflict of Interest Including in Case of Financial Investors" last accessed on 25 June 2013 at http://ec.europa.eu/energy/gas_electricity/interpretative_notes/doc/implementation_notes/swd_2013_0177_en.pdf

12. Articles 13 Third Electricity Directive and Article 14 Third Gas Directive.

13. Article 14(1) Third Electricity Directive and 15(1) Third Gas Directive.

14. Article 13(2)(a) Third Electricity Directive and Article 14(2)(a) Third Gas Directive

15. Article 14(1) Third Electricity Directive and 15(1) Third Gas Directive

16. Article 13(5)(b) Third Electricity Directive and Article 14(5)(b) Third Gas Directive

17. Article 13(1) Third Electricity Directive and 14(1) Third Gas Directive (approval by Commissioner). Articles 3(1) of the New Electricity and Gas Regulations provide for opinions given by ACER.

18. Article 13(2)(c) Third Electricity Directive and 14(2)(c) Third Gas Directive

19. Article 19(3) Third Electricity Directive and Article 19(3) Third Gas Directive

20. Article 19(8) Third Electricity Directive and Article 19(8) Third Gas Directive

21. Article 22 Third Electricity Directive and 22 Third Gas Directive

22. Article 21 Third Electricity Directive and 21 Third Gas Directive

23. Article 37(5) Third Electricity Directive and Article 41(5) Third Gas Directive

24. http://ec.europa.eu/energy/gas_electricity/doc/2014_iem_communication_annex3.pdf

25. Article 9(8) of both the Third Electricity Directive and the Third Gas Directive

26. Article 10 of both the Third Electricity Directive and the Third Gas Directive

27. Article 11(3) of both the Third Electricity Directive and the Third Gas Directive

28. Article 11(1) of both the Third Electricity Directive and the Third Gas Directive

29. Article 11(2) of both the Third Electricity Directive and the Third Gas Directive

30. Article 11(5) of both the Third Electricity Directive and the Third Gas Directive

31. Directives 2003/54/EC and 2003/55/EC, respectively

32. Article 35 Third Electricity Directive, Article 39 Third Gas Directive

33. Article 37 Third Electricity Directive, Article 41 Third Gas Directive

34. Article 36(a) Third Electricity Directive, Article 40(a) Third Gas Directive

35. On the structure of ACER, see Article 3 ACER Regulation

36. Article 4 ACER Regulation

37. Article 5 ACER Regulation

38. Article 6(1) ACER Regulation.

39. Articles 7(2) and 7(3) ACER Regulation

40. Article 7(4) and 7(6) ACER Regulation

41. Article 9(1) ACER Regulation

42. Article 6(4) ACER Regulation

43. Article 11(1) ACER Regulation

44. Article 6(8) ACER Regulation

45. Article 4(e) ACER Regulation

46. Articles 7(7) ACER Regulation

47. Article 8(1) ACER Regulation

48. Framework Guidelines on Electricity Grid Connections, published by ACER on 20 July 2011 and available electronically on ACER's website: http://acernet.acer.europa.eu/portal/page/portal/ACER_HOME/Public_Docs/Acts%20of%20the%20Agency/Framework%20Guideline/Framework%20Guidelines%20On%20Electricity%20Grid%20Connections/110720_FGC_2011E001_FG_Elec_GrConn_FINAL.pdf; last accessed on 2 August 2013

49. Framework Guidelines on capacity allocation and congestion management for electricity, published by ACER on 29 July 2011 and available electronically on ACER's website: http://acernet.acer.europa.eu/portal/page/portal/ACER_HOME/Public_Docs/Acts%20of%20the%20Agency/Framework%20Guideline/Framework_Guidelines_on_Capacity_Allocation_and_Congestion_M/FG-2011-E-002%20(Final).pdf; last accessed on 2 August 2013

50. Framework Guidelines on Capacity Allocation Mechanisms for the European Gas Transportation Network, published by ACER on 3 August 2011 and available electronically on ACER's website: http://acernet.acer.europa.eu/portal/page/portal/ACER_HOME/Public_Docs/Acts%20of%20the%20Agency/Framework%20Guideline/Framework_Guidelines_on_Capacity_Allocation_Mechanisms_for_t/FG-2011-G-001%20(final).pdf; last accessed on 2 August 2013

51. Framework Guidelines on Gas Balancing in Transmission Systems, published by ACER on 18 October 2011, available electronically on ACER's website: http://acernet.acer.europa.eu/portal/page/portal/ACER_HOME/Public_Docs/Acts%20of%20the%20Agency/Framework%20Guideline/Framework%20Guidelines%20on%20Gas%20Balancing%20in%20Tr/FG%20Gas%20Balancing_final_public.pdf; last accessed on 2 August 2013

52. Framework Guidelines on Electricity System Operation, published by ACER on 3 December 2011, available electronically on ACER's website: http://acernet.acer.europa.eu/portal/page/portal/ACER_HOME/Stakeholder_involvement/Public_consultatations/Closed_Public_Consultations/PC-05%20-%20FG%20on%20System%20Operation/Final%20Version%20of%20the%20FG/FG-2011-E-003_02122011_Electricity%20System%20Operation.pdf; last accessed on 21 June 2012

53. http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Framework_Guidelines/Framework%20Guidelines/Framework%20Guidelines%20on%20Harmonised%20Gas%20Transmission%20Tariff%20Structures.pdf

54. Framework Guidelines on Interoperability and Data Exchanges Rules for European Gas Transmission Networks were published by ACER on 26 July 2012 and are available electronically on ACER's website: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Framework_Guidelines/Related%20documents/FG%20on%20Interoperability%20and%20Data%20Exchange%20Rules%20for%20European%20Gas%20Transmission%20Networks.pdf ; last accessed on 25 July 2013

55. The Framework Guidelines on electricity balancing were published by ACER on 25 September 2012 and are available electronically from ACER's website: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Framework_Guidelines/Framework%20Guidelines/Framework%20Guidelines%20on%20Electricity%20Balancing.pdf last accessed on 26 July 2013

56. Articles 5 of the New Electricity and New Gas Regulations, respectively

57. Articles 8 of the New Electricity and New Gas Regulations, respectively

58. Articles 44 Third Electricity Directive and article 40 Third Gas Directive

59. Article 15 Third Gas Directive

60. Articles 33 and 41 (n) Third Gas Directive

61. Article 36 Third Gas Directive and Article 17 New Electricity Regulation

62. OJ L 115 of 25.04.2013, p. 39 – 75

63. Article 1(1) New TEN-E Regulation

64. Article 3(1) New TEN-E Regulation

65. Article 3(4) New TEN-E Regulation

66. Article 3(1) New TEN-E Regulation

67. Article 15 New TEN-E Regulation

68. Article 14 New TEN-E Regulation

69. Article 7(3) New TEN-E Regulation

70. Article 10(2) New TEN-E Regulation

71. Article 8(3) New TEN-E Regulation

72. Article 8(1) New TEN-E Regulation

73. Article 7(5) New TEN-E Regulation

74. http://ec.europa.eu/energy/infrastructure/pci/doc/20130724_pci_guidance.pdf last accessed on 31 July 2013.

75. Proposal for a Directive of the European Parliament and the Council on Markets in Financial Instruments repealing Directive 2004/39/EC of the European Parliament and of the Council (COM (2011) 656/4)

76. http://www.esma.europa.eu/news/ESMA-consults-MiFID-reforms?t=326&o=home

77. Commission Regulation (EC) No 1287/2006 of 10 August 2006; OJ L 241 of 02.09.2006, p. 1 – 25

78. Regulation 2011/1227; OJ L 326 of 08.12.2011, p. 1

79. ACER internet publication: "*Questions and Answers on REMIT*" which can be found at http://acernet.acer.europa.eu/portal/page/portal/ACER_HOME/Activities/REMIT/ACER%20Guidance%20and%20Questions%20%20Answers%20on%20REMIT last accessed on 2 August 2013

80. http://www.acer.europa.eu/remit/Documents/REMIT%20ACER%20Guidance%203rd%20Edition_FINAL.pdf

81. Article 3 REMIT

82. Article 5 REMIT

83. Article 4 REMIT

84. Article 8 REMIT

85. Article 18 REMIT

86. http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/REMIT%20Annual%20Report%202014.pdf

87. Regulation 2012/648; OJ L 201 of 27.7.2012, p. 1

88. Commission Delegated Regulation 148/2013: OJ L 052 of 23.02.2013, p. 1 – 10; Commission Delegated Regulation No 149/2013: OJ L 052 of 23.02.2013, p. 11 – 24; Commission Delegated Regulation 150/2013: OJ L 052 of 23.02.2013, p. 25 – 32; Commission Delegated Regulation 151/2013: OJ L 052 of 23.02.2013, p. 33 – 36; Commission Delegated Regulation 152/2013: OJ L 052 of 23.02.2013, p. 37 – 40; Commission Delegated Regulation 153/2013: OJ L 052, 23.02.2013, p. 41 – 74

89. Article 89(3) EMIR

90. Article 4(1) EMIR

91. Articles 14 and 16 EMIR

92. Article 11 EMIR

93. Article 9 EMIR

94. Article 5(2) EMIR

95. Article 55 EMIR

96. Article 25(2) EMIR

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ENERGY LAW IN ALBANIA

Recent developments in the Albanian energy market

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SETTLEMENT BETWEEN THE REPUBLIC OF ALBANIA AND CEZ A.S.

On 23 June 2014 the Republic of Albania and CEZ A.S. signed an agreement (the "Settlement Agreement") ending their long-running dispute relating to an electricity distribution licence.

During the period of 2011 and 2012, CEZ Distribution encountered many financial difficulties, thus leading to the deterioration of the relationship between CEZ and various power sector authorities of the Republic of Albania, leading to claims and counter-claims between Parties.

On 21 January 2013, the licence on distribution and supplying of energy which was granted to CEZ Distribution in 2009, was revoked by the power sector authorities of Albania. Hence, CEZ Distribution came under an interim administration.

On 15 May 2013, CEZ filed a notice of arbitration under the UNCITRAL Arbitration Rules (United Nations Commission on International Trade Law) against the Republic of Albania under the Energy Charter Treaty. At the same time, the former Ministry of Economy, Trade and Energy of the Republic of Albania was starting an ICC arbitration based on MBA.

The Settlement Agreement brought to an end the arbitration proceedings initiated by CEZ A.S. over the revocation of their electricity distribution licence by the electricity regulator ERE when CEZ A.S. was placed into administration on 30 January 2013.

The Settlement Agreement transfers shares in electricity distribution company CEZ Albania from CEZ A.S. to the Ministry of Economic Development, Trade and Entrepreneurship, with the result that CEZ Albania is now wholly owned by the government. Further, on 7 July 2014, ERE approved CEZ A.S.'s request to change its trading name from CEZ Shpërndarje to "*Operatori i Shpërndarjes së Energjisë Elektrike*" ("OSHEE"). The Settlement Agreement was approved by Parliament as Law 114/2014 on 31 July 2014.

CEZ A.S., according to the Settlement Agreement, transferred shares to the Albanian state, which was represented by the Ministry of Economic Development, Trade and Enterprise for free (for a symbolic 1 Euro), whereas CEZ Albania (the Albanian Company) will pay the total amount of 94.9 million Euros to CEZ A.S (the parent company of CEZ Albania) by 2018. According to the Settlement Agreement, the amount of 94.9 million Euros is paid from the Albanian budget to CEZ Albania, but does not represent any compensation for damages that CEZ may have suffered, but only contractual obligations related to loans or supply agreements entered into in regular form by CEZ Albania.

INVESTMENTS IN THE DISTRIBUTION NETWORK

The Albanian government hopes that, with the approval of the Settlement Agreement and the resolution of the legal status of CEZ Albania (now OSHEE as explained above), investors in the distribution network of Albania such as the World Bank, BERD, KFW and IFC will be more inclined to invest again in that sector. According to the discussion that the Albanian government is conducting with the investors, the Settlement Agreement paved the way for these financial institutions to provide investments in the power sector up to an amount of approximately US$200 million, disbursed within the four next years.

NEW MEASURES AGAINST ELECTRICITY THEFT

On 22 October 2014 the Albanian government announced a new National Action Plan (the "Plan") with the aim of combating the theft of electricity. The Plan aims to address illegal interference in the electricity network by way of additional powers for law enforcement forces including the state police. To give effect to the Plan, the Albanian parliament has passed Law 98/2014 which makes several amendments to the Criminal Code (the "Code") to insert more stringent measures in relation to such illegal interference with the electricity grid. As a result, Article 137 of the Code now provides that any theft of electricity, damage to electricity meters or other unauthorized interference with the electricity network or measurement systems which is performed with the aim of generating illegal profits is a criminal offence. This offence is punishable by up to three years' imprisonment if committed by more than one person in collusion with each other, commercial or repeat offenders.

The government expects that implementation of the Plan will reduce the amount of stolen electricity by around five per cent per annum from the current estimated levels of around 20 per cent of the total energy consumption.

TERMINATION OF WATER CONCESSIONS

In July 2014, the Minister of Industry and Energy announced the termination of 14 water concessions agreements. The termination followed inspections by the Ministry of Industry and Energy which revealed a number of legal breaches by the concession companies, such as delays in the registration of the company to the relevant authorities, delays with the investments and delays with the submission of technical projects to the Concession Authority.

NEW LEGISLATION ON RENEWABLE RESOURCES ADOPTED

Parliament has adopted a new law on renewable resources. Law 138/2013 aims to stimulate the production and consumption of renewable energy, and is in line with the Renewable Energy Directive.

The law defines electricity produced from renewable energy sources as being that derived from power plants that use solely renewable energy resources rather than fossil fuels. Renewable energy resources are considered to include hydro, wind, solar, air, geothermal, hydrothermal, sea waves and tidal power as well as urban and industrial waste.

According to Law 138/2013, the producers of renewable energy may request and obtain a connection to the grid if the network system operator has no other higher economic efficiency opportunity for the relevant points of connections. The purchaser of renewable energy will sign an agreement drafted by the ERE which will not exceed a period of 15 years.

The law also introduces specific measures for the promotion of solar-powered water heating systems, including new exemptions from customs duties and VAT for solar panel manufacturers and installers. Under the new law, the ERE remains the regulator for energy production and trading, whereas the National Agency of Natural Resources is in charge of the monitoring of the use of renewable resources, as prescribed in Article 9 of Law 138/2013.

TAP PIPELINE

Works on the Albanian section of the TAP pipeline project are expected to commence in 2015. To date, the Albanian government has signed an agreement with the Swiss government for the preparation of human capacities in the gas sector over a period of four years. The process of expropriating lands along the intended pipeline route is ongoing.

ENERGY LAW IN AUSTRIA

Recent developments in the Austrian energy market

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EUROPEAN UNION

Start of infringement proceedings against Austria

In July 2014, the European Commission referred Austria to the Court of Justice of the European Union for failing to transpose the Energy Performance of Building Directive (the "Directive") and proposed to impose a daily fine of approximately €39,600. The Directive requires Member States to establish and apply minimum energy performance requirements for all buildings, ensure the certification of buildings' energy performance and ensure regular inspections of heating and air conditioning systems. The Commission claims that the Directive still has not been fully transposed, especially with regard to measures relating to energy certificates, minimum energy performance requirements and nearly-zero energy buildings. The infringement proceedings are still pending.

NEW ENACTMENTS

Enactment of the Federal Energy Package

In July 2014, the Austrian parliament passed the Federal Energy Package with which the Federal Energy Efficiency Act (*Bundes-Energieeffizienzgesetz* – the "EEffG") was enacted and various amendments to regulations on combined heat and power cogeneration plants were introduced (the "Federal Energy Package").

The EEffG contains measures not only to transpose the EU Directive on Energy Efficiency 2012/27/EU but also provides for specific efficiency obligations for enterprises, energy suppliers and the federal state. Certain larger enterprises have to take measures to increase their energy efficiency, eg by conducting energy audits or by introducing environmental management systems. As of 1 January 2016 energy suppliers have to take energy efficiency measures amounting to 0.6% of their total previous year's energy sales to end-consumers. The EEffG further provides for annual modernisation of state-owned real estate to increase energy efficiency. The measures taken by the obliged enterprises and the federal state shall account for an increase of energy efficiency of 70PJ by the year 2020. By doing so, the cumulative end use energy savings target as set out in Article 7 of Directive 2012/27/EU shall be achieved. Among other measures, a national monitoring facility for the evaluation of energy savings, and the coordination of energy efficiency action plans was established.

The federal energy package further seeks to establish a regulatory framework intended to assist operators of heat and power cogeneration plants within the competitive environment of the Austrian energy market. The newly introduced Green Certificates for Cogeneration Plants Act (*KWK-Punkte Gesetz* – the "KPG") establishes a system of financial support for existing as well as for newly constructed or modernised heat and power cogeneration plants. The KPG obliges end-users to acquire green certificates (*KWK-Punkte*) to evidence that a certain amount of consumed electricity stems from cogeneration plants. The specific amount of green certificates which have to be purchased is determined by end-users' network level (end-users on level 7 have to purchase 10, end-users on level 1-3 have to purchase 9,820 green certificates, whereas the price ranges from €0.5 – €1 per certificate). To ensure compliance with the EU state aid regime (Art 107 and 108 TFEU) no public funds are being employed and the state has no access to the financial support granted to the beneficiaries. Pursuant to Art 108 TFEU Austria has notified the Commission of the KPG as a non-aid measure. The proceedings before the Commission are still pending.

Ordinance on the Change of Suppliers 2014 (*Wechselverordnung 2014* – the "WVO")

In July 2014, E-Control published the WVO 2014. As with the previous in force Ordinance on the Change of Suppliers, which was enacted in 2012, the WVO 2014 sets minimum standards for the conclusion of an energy supply contract between an energy supply undertaking and a consumer, termination of such contract and the change of energy suppliers. Under the WVO, change of suppliers is processed automatically and through a platform suppliers exchange the relevant data. As a centre-piece the WVO 2014 introduced a maximum period for the execution of the change of suppliers, namely three weeks.

Ordinance on Energy Management Data (*Erdgas-Energielenkungsdaten-Verordnung 2014/ Elektrizitäts-Energielenkungsdaten-Verordnung 2014* – the "EnlD-VO 2014")

The EnlD-VO 2014 seeks to provide E-Control with energy data enabling the energy regulator to assess the energy situation in Austria. The EnlD-VO 2014 obliges all market players on the Austrian natural gas and electricity market (ie network operators, producers, and storage companies) to regularly report on data relating to the quantity of imported, produced, stored, and distributed natural gas and electricity and to provide forecasts on the energy supply to E-Control. Further, the ordinance provides for reporting obligations in case of significant and critical impacts to the energy situation in Austria (eg reduction of imports, amendments to contracts with regard to quantities of natural gas, and deficiencies of networks). Based on the data provided, E-Control will decide whether disturbances on the energy gas market endanger the security of supply and require counteracting emergency measures.

According to EnlD-VO 2014, each energy company has to appoint a responsible person for the collection of data and the transposition of emergency actions ordered by E-Control.

Amendment to the Gas Market Model Ordinance 2013

The Gas Market Model Ordinance (*Gas-Marktmodell-Verordnung*) 2012 prepared the legal ground for the successful introduction of a new gas market model in Austria on 1 January 2013. After receding in the run-up to the transition in December 2012, trading activity at the virtual trading point (the "VTP") has picked up again and has normalised to the high levels observed in previous years. Also, daily balancing for customers without load meters, introduced to facilitate retailers' supply activities, has proven to be a practical approach. Linepack has so far been sufficient to cover these consumer imbalances. However, several deficiencies of the market model have been identified and have resulted in a draft of a new Gas Market Model Ordinance 2013 which introduced some adjustments regarding:

- nomination and re-nomination rules (clarifications on the applicability);
- the clearing and settlement agent's balancing rules (more details, and minor revisions to reflect the market reality and the capacity situation);
- the special balance groups of the clearing and settlement agent, the market area manager and the system operators (more explicit rules); and
- the group of customers in the daily balancing regime (extension).

The 2014 amendments to the Ordinance seek to improve further the efficient and market-based mechanisms for capacity allocations and accounting. Inter alia, the amendments introduce provisions regarding the use-it-or-lose-it principle for capacity allocations, the possibility to reserve network capacities in the distribution network for a maximum period of three years, and the possibility to establish a special balance group for net losses and specifies accounting mechanisms of injection and withdrawals at the cross border network interconnections in the distribution area of Vorarlberg and Tyrol.

Amendments to the Gas System Charges Ordinance 2013

On 20 December 2012, E-Control adopted the Gas System Charges Ordinance 2013. This ordinance sets the transportation system utilisation charge, the transportation system admission charge and the transportation system provision charge. It determines the cost cascading procedure, the billing and invoicing modalities for the system charges as well as the fee for performing the responsibilities of a distribution area manager. The ordinance further provides rules on the auction of entry and exit capacities. In 2014, the system charges were adopted and minor amendments (eg with regard to smart metering) were introduced.

Amendment to the Ordinance on Energy Labelling (*Stromkennzeichnungsverordnung* – the "SVO")

The SVO obliges electricity traders to indicate the proportion of primary energy sources which was used in the previous year. Amendments to the SVO, *inter alia*, provide for specifications in regard to the labelling of energy produced by wind and solar power plants. Further amendments were introduced with regard to a network operator's duty to report the quantity of energy which was delivered to and produced by pump storage plants.

Amendment to the Electricity Tax Act (*Elektrizitätsabgabegesetz* – the "EAbgG")

In July 2014, the Austrian parliament passed an amendment to the EAbgG which exempts producers of energy from renewable energy sources from taxation for own-use prodcution. The exemption limit was defined with 25,000kWh/year. The amendment aims to support sustainable national energy production from renewable energy resources.

CERTIFICATIONS

Gas TSO certification revealed to be more difficult than expected

In 2012, the TSO Baumgarten-Oberkappel Gas Transmission Corporation ("BOG") applied for independent transportation operator ("ITO") certification with E-Control. The certification application of BOG as a TSO related to its operation of the West-Austria-Gasleitung ("WAG"). WAG is a very important (single) pipeline which connects the Slovak network in the East with the Penta West and MEGAL pipelines in the West, two major pipeline systems running through Germany and, ultimately, France. In March 2013, the application of BOG was rejected by E-Control since BOG did not comply with the ITO certification criteria as set out in the Austrian Natural Gas Act (*Gaswirtschaftsgesetz* – the "GWG"). Following the rejection of BOG's application, on 1 September 2014, BOG was merged into the TSO Gas Connect Austria GmbH ("GCA"). Consequentially, GCA filed for an application for certification as ITO for the WAG, which was granted in July 2014. GCA therefore continues BOG's business as universal successor (*Rechtsnachfolgerin*).

Trans-Austria-Gas-Pipeline GmbH ("TAG") applied for TSO certification under the ISO model for the Trans Austria Gas Pipeline. The Trans-Austria-Gaspipline is a major gas pipeline which connects the Slovak network with the Italian network. In March 2013, TAG's application was rejected by E-Control, as TAG could not sufficiently meet the independency criteria. Therefore, TAG was required to restructure its business. In November 2013, TAG re-filed its application for certification as TSO but decided to unbundle under the ITO model. In July 2014, E-Control granted the request and certified TAG as TSO under the ITO model for the Trans-Austria-Gas Pipeline. However, E-Control ruled for a series of resolute conditions requiring TAG to continue the comprehensive restructuring process. The restructuring is currently underway and has been partly completed.

According to most recent media information[1] a process to sell a minority stake in gas transmission networks owned by Austrian gas company OMV is expected to launch in 2015. However, it is not clear whether this market rumour, which was not officially confirmed by OMV so far, would materialise in the short term. A sale of a minority stake had already been expected to start towards the end of last year. However, the sale process is likely to have been delayed as OMV is currently about to look for a new CEO following the resignation of Gerhard Roiss in October 2014.

ENDNOTE

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ENERGY LAW IN BELARUS

Recent developments in the Belarusian energy market

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INTRODUCTION

Currently, the consumption of fuel and power resources in the Republic of Belarus runs to 44 million tons of reference fuel with the contribution of natural gas in the production of heat energy and electricity exceeding 90%. Natural gas makes up 80% of the total volume of consumption of boiler and furnace fuel.

The Belarusian domestic fuel and power resources could theoretically cover up to 15 to 17% of the current demands of Belarus, although they are not currently used to this extent. At the same time, around 80% of Belarusian domestic fuel and power resources are represented by renewables. Therefore, natural gas, which is mostly imported from Russia, is currently critical in the heat and power production in Belarus and domestic resources are not sufficient to replace its use and importation.

In order to reduce the importation of natural gas (for which Belarus is entirely dependent on Russia) and increase cost effectiveness and the reliability of the operation of power plants, Belarus imports electricity from Russia and Ukraine. To reduce the existing imbalance in the structure of consumption of fuel and power resources in Belarus:

- construction has begun on a Belarusian nuclear power plant with a capacity of 2340MW;
- modernisation of the Belarusian energy system is taking place;
- domestic fuel and power resources are in active use; and
- the usage of renewables is increasing.

The development of the energy sector of the Belarusian economy is being carried out in accordance with the State Programme for Development of the Belarusian Energy System (the "State Programme") for the period to 2016, which was established by the Belarusian government in February 2012. The activities provided by the State Programme are linked with plans for development and operational regimes of energy sources in all sectors of the Belarusian economy and also take into account the necessity of establishing spare capacity for the adjusting of operational regimes of the Belarusian energy system after putting the Belarusian nuclear power plant into service.

It is planned that implementation of the activities provided by the State Programme will make it possible to achieve the following results by the end of 2015:

- to save more than 1.2 million tonnes of reference fuel (over the 2011 to 2015 period);
- to decrease fuel use in the production of electricity to 234 to 240 grams of reference fuel per kWh, from 268.9 grams of reference fuel per kWh in 2010, (ie, before the State Programme began);
- to decrease the level of consumption and depreciation of fixed capital (assets such as buildings, production and transmission facilities etc.) in the energy sector to 40% from 51.2% in 2010. The depreciation of assets in the energy sector is a particular issue in Belarus as the production facilities and the equipment are old and inefficient. The State Programme aims to modernise the facilities, thereby driving down the overall depreciation figures;
- to decrease electricity and heat distribution losses by 2 percentage points, which were 11.19% for electricity distribution losses and 10.11% for heat distribution losses in 2010; and
- to substitute up to 1.26 billion m^3 of natural gas in fuel and energy balance of the Belarusian energy system by saving resources and using other sorts of fuel in 2016.

SIGNIFICANT ENERGY POLICY ISSUES

In late January 2014, the Presidium of the Belarusian government approved in principle the Law of the Republic of Belarus "On the Electric Power Industry". This document provides reforms for the Belarusian energy system using the new (for the Belarusian environment) principle of division (separation) of competitive and monopolistic types of activities in the energy sector. Currently there is no such separation of these activities, as GPO "Belenergo" is essentially monopolistic in all the relevant sectors. The aim is to establish a more competitive environment for participants in the Belarusian electricity market. The first part of the reforms (in 2014 to 2015) will establish the Republican Unitary Enterprise "Belgeneracia" (*Республиканское унитарное предприятие «Белгенерация»*) which will be state property and will operate 12 high pressure power plants. As a result, this entity will control the main volume of energy production.

The state-controlled "Belgeneracia", together with the Belarusian nuclear power plant, other major producers of electric power (with source capacity 50MW and higher) and producers of electric power from renewables, will form the new wholesale electricity market which will be operated by a managing company established instead of the existing energy market monopolist GPO "Belenergo" (*Государственное производственное объединение электроэнергетики «Белэнерго»*). This company will buy electricity in the wholesale market for its further distribution and will also be authorised to import and export electric power to and from the wholesale electricity market.

The purchasing of electricity from the wholesale market will only be able to be carried out by regional energy supplying organisations (in volumes not covered by their own production capacities) and major industrial consumers of electricity who get electric power via connected electrical networks with a voltage of 220kV or higher.

The new retail electricity market will be formed by: (i) regional energy supplying organisations (currently subsidiaries of GPO "Belenergo") with their own production capacities, distribution and sales divisions; (ii) producers of electric power with source capacity less than 50MW; (iii) producers of electric power from renewables financed by the state budget; and (iv) consumers, who get electric power via connected electrical networks with a voltage of 04 to 110kV.

As the second part of the reforms, it is planned that, simultaneously with the realisation of the first part of the reforms, energy consumption supervising subsidiaries of regional energy supplying organisations will be set up as separate entities and the state agency "Gosenergonadzor" (*Государственное учреждение «Госэнергонадзор»*) will be established on that basis. Thus, energy consumption supervision in Belarus will be transformed from in-house (GPO "Belenergo") to the state agency level.

As the third part of the reforms, it is intended that the operation of high voltage electric lines and transforming stations with a voltage of 220 to 750kV, and interstate electric lines and transforming stations with a voltage of 10 to 110kV, will be transferred from regional energy supplying organisations to the newly established single state-controlled authorised operator - the Republican Unitary Enterprise "Vysokovoltnye electricheskie seti" (*Республиканское унитарное предприятие «Высоковольтные электрические сети»*). The new operator will, at the same time, also take over the role of the national dispatching centre of the Belarusian energy system (which is currently the "Republican Unitary Enterprise ODU" (*Республиканское унитарное предприятие «ОДУ»*)). Realisation of this stage will only be possible after the liquidation of the cross-subsiding which exists in the Belarusian energy system, which is planned for 2017.

The future of the Belarusian Energy Market in relation to the Eurasian Economic Union Treaty

The Republic of Belarus, the Republic of Kazakhstan and the Russian Federation, on the basis of the Declaration on Eurasian Economic Integration of 18 November 2011, signed the Eurasian Economic Union treaty on 29 May 2014, in Astana. The Eurasian Economic Union is the next stage of integration in the post-Soviet era which intends to replace the Eurasian Economic Community beginning from 1 January 2015.

The Eurasian Economic Union is aimed at providing freedom of movement of goods, services, capital and labour within the Union and coordinated, consensual and uniform policy making of its Member States in the economic sectors designated by the treaty and other international treaties concluded within the framework of the Union. Unlike the Eurasian Economic Community, the Union is defined as an international organisation of regional economic integration having an international legal personality.

The Eurasian Economic Union treaty provides, inter alia, coordination of the Member States in the energy industry. The treaty stipulates that for the effective use of the potential of the fuel and power industries of the Member States and in order to provide main energy sources, ie, electric power, natural gas, oil and oil products, for their national economies, they will develop long term mutually beneficial co-operation in the energy industry, conduct coordinated energy policies and perform step-by-step formation of common energy source markets, taking into account the need to maintain security of the energy supply.

The treaty, with consideration of its transitional provisions, provides that the Member States will form, by the creation of necessary legal and other conditions, both a:

- common electricity market of the Union which will be based on the already synchronised electricity systems of its Member States, by 1 July 2019; and
- common natural gas market and common markets for oil and oil products, by 1 January 2025.

The Member States agreed in this regard in the treaty that they will first work out appropriate conceptions and programmes for the formation of the above-stated common markets. Following the fulfilment of the potential measures stipulated in these programmes, they will conclude respective international treaties of the Union concerning:

- the formation of the common electricity market of the Union including, inter alia, the uniform rules of access to the services of the natural monopolies in the electricity sector;
- the formation of the common natural gas market of the Union including, inter alia, the uniform rules of access to the gas-transport systems situated on the state territory of the Member States; and
- the formation of the common oil and oil products markets of the Union including, inter alia, the uniform rules of access to the systems of transportation of oil and oil products situated on the state territory of the Member States.

The Eurasian Economic Union treaty was ratified by the Belarusian parliament on 9 October 2014 with an additional statement that the Republic of Belarus will fulfil its obligations undertaken by signing the treaty in good faith and will undertake other measures for its implementation on the condition that first bipartite or tripartite particular arrangements are made with regard to the abolishing of barriers and limitations to the trade of certain goods and the rendering of some services including trade of energy sources[1].

These arrangements must contain, inter alia, provisions regarding the inadmissibility of their deprivation at any time after they were achieved until the full elimination of the respective barriers and limitations to the trade of certain goods and the rendering of some services which still exist between the Member States of the Eurasian Economic Union.

Meanwhile, the Russian parliament ratified the Eurasian Economic Union treaty on 26 September 2014 and the Kazakh parliament did so on 1 October 2014, without any reservations or additional statements which would make the ratification and/or implementation of the treaty dependant on the fulfilment of any conditions.

Oil Industry

In the process of negotiations for the signing of the Eurasian Economic Union treaty the Republic of Belarus proposed the elimination, from 2015, of all existing barriers and limitations concerning the trade of oil products between the member states which could allow it to divest itself of the obligation to pay export tariffs to the Russian state budget for exported oil products produced in Belarusian refineries from Russian oil imported free of tariffs. This could bring an extra US$3-4 billion annually into the Belarusian state budget, all other things being equal. However, the treaty was concluded in May 2014 on the basis that the common oil and oil products market would only start from 2025, and prior to that the existing barriers and limitations would remain in force.

As compensation, the Russian Federation agreed to allow the Republic of Belarus to keep in its state budget part of the export tariffs on oil products, (otherwise payable to Russia), the sum being US$1.5 billion in 2015, with further reconsideration of the sum of the export tariffs to be kept in the Belarusian state budget for 2016 and the following years by additional agreements of the parties.

Soon after the conclusion of the treaty, in summer 2014, the Russian government declared its intent to realise in 2015 to 2017 a tax reform (the "Tax Reform"), in a step-by-step approach, on an annual basis, to decrease the rates of export tariffs on oil and oil products (to the same level as the rates established by Kazakhstan) and at the same time to increase the rate of the tax on mining operations for oil extraction with a simultaneous reduction of excise taxes on fuel, in order to prevent price growth on the internal market.

The Tax Reform is intended to stimulate the modernisation of Russian refineries. Whilst legal in as far as regards the Eurasian Economic Union is concerned, which allows each Member State to have its own an independent tax policy, the Tax Reform could result in Belarusian refineries operating at a loss due to the increased price of oil for processing and also lead to a drop in income of the state budget due to the decreased export tariffs on oil products which Belarus intends to retain in its budget in the future. The total losses for the Belarusian economy for 2015 as a result of the Tax Reform have been estimated to be at least US$1 billion by Belarusian officials.

This was the reason why the Belarusian parliament ratified the Eurasian Economic Union treaty with the aforementioned option. The ratification passed after the Russian Federation agreed to compensate the losses by granting the Republic of Belarus a right to keep in its state budget a whole sum of export tariffs on oil products in 2015, which was established in the protocol of allotment of export tariffs signed by the parties. In 2015, it is planned to start negotiations on the allotment of export tariffs for 2016 to 2017, depending, inter alia, on the results of the Tax Reform. The total sum of export tariffs which will be kept by the Republic of Belarus in 2015 cannot be predicted precisely because it depends on oil prices, the price of exported oil products and certain other factors. It was estimated by Belarusian officials to be at least US$2.5 billion, of which US$1.5 billion was previously stipulated by the parties, and at least US$1 billion is compensation for the Tax Reform.

The Republic of Belarus and the Russian Federation also agreed the volume of the supply of Russian oil to Belarus and Belarusian oil products to Russia and Russian oil transit through Belarus.

The Russian Federation will export 23 million tons of oil to Belarus in 2015 and 24 million tons from 2016 to 2024 annually. Belarus will supply 1.8 million tons of fuel in 2015.

In 2015 the volume of Russian oil supplies to Belarus will be governed on a quarterly basis based on the volume of Belarusian oil products supplied to the Russian market. The field-specific state authorities of Russia and Belarus, which are the Russian Ministry of Energy and the Belarussian Ministry of Economy, respectively, will check the fulfilment of the schedule of supplies of Belarusian fuel on the Russian market each three-month period before the 15th day of the month before the appropriate quarter. In the case of non-fulfilment of quarter obligations (by exceeding the quarter schedule volume by 10% or more), Russia reserves the right to decrease oil supplies in Belarus at the volume calculated by multiplying the volume of non-supplied fuel by 5.

The volume of Russian oil transit through Belarus in 2015 will be kept at the 2014 level of 61.6 million tonnes.

Gas Industry

The gas industry in the Republic of Belarus is being developed in compliance with international treaties ratified by the country. International relations in the gas sector in the common economic area which includes the Republic of Belarus, the Russian Federation and the Republic of Kazakhstan are governed by the agreement about rules regarding the access to gas transportation systems, including the basic principles of price formation and tariff policy, concluded in Moscow on 9 December 2010 (the "Agreement").

The parties stipulated in article 5 of the Agreement that they shall facilitate the achievement of prices for natural gas which shall provide the same profit for supplies of natural gas on the domestic market as for the supplies on the foreign markets by all participant states to the Agreement by 1 January 2015. The fundamental idea is to remove the current difference in profit margins applied by Russian and Kazakh gas suppliers to gas supplied to their internal market on the one hand and to the export markets on the other hand (currently the profit margin on export prices is substantially larger than on the prices of supplies to the internal market). As this target will not be achieved in time (at least Russian prices are still not adapted), the price of natural gas supplied by Russia to the Republic of Belarus in 2015 will continue to be governed by the provisions of the agreement between the government of the Republic of Belarus and the government of the Russian Federation regarding the order of formation of prices (tariffs) for supplies of natural gas to the Republic of Belarus and its transportation by gas transportation pipelines situated on the territory of the Republic of Belarus, concluded in Moscow on 25 November 2011.

This agreement provides a temporary regime between (solely) Belarus and Russia of price formation for natural gas under which the price of gas supplied by Russia to Belarus shall be the same as the price of gas supplied by Russia to its internal market, save for an increase for costs of:

- transportation, established at fixed rates per each 1,000 m^3 of gas supplied to Belarus from Russia;
- gas storage in underground gas storage facilities in Russia; and
- gas distribution by JSC "Gazprom".

Furthermore, the 25 November 2011 agreement will govern determination of tariffs for services of transportation of natural gas via gas transportation pipelines of the joint stock venture "Gazprom transgaz Belarus" (*Открытое акционерное общество «Газпром трансгаз Беларусь»*) which is the former joint stock venture "Beltransgaz" (*Открытое акционерное общество «Белтрансгаз»*) through the territory of the Republic of Belarus.

It is important to note that the above mentioned agreement about the order of formation of prices (tariffs) was concluded simultaneously and linked with the agreement between the government of the Republic of Belarus and the government of the Russian Federation about the conditions for purchasing shares and further activities of the joint stock venture "Beltransgaz" in such a manner that the validity of both agreements is interdependent.

In 2015 supplies of natural gas to the Republic of Belarus are planned at the volume of 23 billion m^3 and transit of natural gas through the territory of the Republic of Belarus is planned at the volume of 42.4 billion m^3.

Projects in the Energy Industry for foreign investments

The following projects, which use direct foreign investment, are part of the on-going modernisation of the Belarusian energy system.

GPO "Belenergo" plans to construct:

- a 20MW Nemnovskaya hydropower station (estimated investment: US$134 million);
- a 5.1MW Mogilevskaya hydropower station (estimated investment: US$29.4 million);
- a 4.9MW Shklovskaya hydropower station (estimated investment: US$28 million);
- a 5.65MW Orsha hydropower station (estimated investment: US$48.1 million);
- a 33MW Beshenkovichi hydropower station (estimated investment: US$186 million); and
- a 13MW Verkhnedvinsk hydropower station (estimated investment: US$158 million).

GPO Belenergo is also planning, again with the use of foreign loans, the following projects in the electricity:

- construction of the 330kV high voltage power line Beriozovskaya GRES[2] – Pinsk - Mikashevichi (with an estimated need of US$140 million in foreign loans);
- reconstruction of the 220kV electric substation Stolbtsy and construction of the 330kV high voltage power line Stolbtsy – Baranovichi (with an estimated need of US$50 million in foreign loans);
- reconstruction of Minsk TEC-3[3] (with an estimated need of US$100 million in foreign loans);
- implementation of gas vapour technologies at Mozyr TEC (with an estimated need of US$70 million in foreign loans); and
- reconstruction of Bobruysk TEC-2 with the mounting of a gas turbine installation and silencer/boiler (with an estimated need of US$100 million in foreign loans).

Significant new energy installations

The Republic of Belarus has commissioned the construction of a nuclear power plant "AES-2006", which has been designed by the joint stock venture "Atomenergoproyect" (*Открытое акционерное общество «Атомэнергопроект»*) from St. Petersburg. The project features improved Generation III+ water-cooled power reactors which provide advanced reliability and safety. Construction started in February 2013 with the excavation of a pit for Unit 2 of the plant. Pursuant to the construction contract, the first unit will be put into operation in November 2018, and the second unit will follow in July 2020.

On 14 February 2014, the Department of Nuclear and Radiation Safety of the Ministry for Emergency Situations of the Republic of Belarus (*Департамент по ядерной и радиационной безопасности Министерства по чрезвычайным ситуациям Республики Беларусь*) issued the licence for installation of Unit 2.[4]

The total planned expenditure is US$470 million in 2014 for construction work on the reactor and turbine buildings, an evaporative cooling tower and the spray cooling ponds of Unit 1, and continuing with the construction and commissioning of housing for the nuclear power plant employees and their families.

The construction of the plant is financed 90% by the state export loan with a limit of US$10 billion granted by the Russian Federation under the agreement between the governments of the Republic of Belarus and the Russian Federation which was concluded in Moscow on 25 November 2011.[5] To cover the final 10%, which include advance payments for the construction, Russian Vnesheconombank (*Государственная корпорация «Банк развития и внешнеэкономической деятельности (Внешэкономбанк)»*) is providing a credit line with a limit of US$500 million.

In 2012, on the Western Dvina River, construction was begun on the Vitebsk hydroelectric power plant which is intended to be the most powerful hydroelectric power plant in Belarus with an installed capacity of four hydraulic units of 40MW. Its construction is being carried out in order to improve the energy security of Belarus by involving renewable energy resources in the fuel/energy balance. Putting the Vitebsk hydroelectric power plant into operation will save about US$7 million a year by reducing importation of natural gas with the aim of generating electricity.

In July 2014, preparatory works on excavation of a bypass channel with a length of over 860 metres and damming of the pass of the Western Dvina River were finished. In addition, access roads and engineering service lines to the construction site, dormitories and a canteen for employees were also built. Concrete and reinforcing shops were put into operation and the construction of major facilities of the plant, including the power house and the spillway, began.

Commissioning of the Vitebsk hydroelectric power plant is planned for 2017.

The construction is being carried out by the Chinese company CNEEC. The cost of the construction is US$189.55 million and is financed by means of a loan provided by the China Development Bank and the funds of the Republican Unitary Enterprise "Vitebskenergo" (*Республиканское унитарное предприятие «Витебскэнерго»*).

Changes and trends for using renewables

Currently in Belarus there are 70 generating plants running on renewable energy sources. During January to June 2014 they fed 47.9 million kWh of electricity into the Belarusian energy grid which amounted to 85.5% of the total volume of electricity they produced (the rest of produced electricity was used for their own needs), while the total electricity generation in the country during this period amounted to 16.5 billion kWh. It is apparent from the above that the overall share of renewables in the overall electricity generation in Belarus is minor, as most electricity in Belarus is still generated with imported natural gas.

Nevertheless, Belarus is planning to set up quotas for establishing new renewable energy power plants in the country, targeting the limitation of supplies of inefficient and worn-out generating equipment for renewables and also the reduction of budget expenses, as due to the existing tariff policy and other conditions, the production of energy from renewable sources is good for business but not beneficial enough for the state. As GPO

"Belenergo" reported, a draft government regulation has been prepared and submitted to the Belarusian government for its consideration and adoption.

Meanwhile, the state has begun to reduce tariffs on "green" energy. For example, in May 2014, the basic tariff for the purchase of hydro and solar generated electricity by supply subsidiaries of GPO "Belenergo" was reduced for the first ten years of operation.[6]

ENDNOTES

1. Belarus is, for example, currently obliged to pay to the Russian state budget part of export tariffs collected for export of oil products produced from Russian oil by Belarusian refineries and exported outside of the Customs Union.

2. GRES is a transliteration of Russian ГРЭС, which is the abbreviation for "*государственная районная электростанция*" – meaning state regional power plant, which is basically a power plant for producing electricity only.

3. TEC is a transliteration of Russian "ТЭЦ", which is the abbreviation for "*теплоэлектроцентраль*" – basically a combined heat and power plant.

4. The construction works in Belarus are not licensed as yet. The licence mentioned above is needed under the law for carrying out activities involving nuclear energy and ionising radiation sources including designing, production, allocation, construction, installation, adjustment, operation, diagnosing, repair, maintenance and decommissioning of nuclear facilities. It would cover initial construction works such as the excavation of a pit for the nuclear facility or building of necessary infrastructure which might start in advance of the main construction works. For the construction of a nuclear reactor containment structure itself (which is the next and main stage of construction of a power plant), the licence for carrying out activities involving nuclear energy is a prerequisite.

5. The inter-governmental agreement concerned the disbursement to the government of the Republic of Belarus of the state export loan for the construction of the nuclear power plant on the territory of the Republic of Belarus.

6. GPO "Belenergo" is obliged by law to purchase renewable electricity generated at a price determined by so-called "stimulating" tariffs. GPO "Belenergo" establishes different tariffs for different kinds of power consumers/economic activities which have to be approved and published by the Ministry of Economy of the Republic of Belarus. One of them is the tariff for industrial and similar consumers which use up to 750kVA of electric feeding grid capacity. This tariff basically stipulates at what price GPO "Belenergo" sells electricity to this class of consumers. GPO "Belenergo" has to buy renewably generated electricity at a price calculated on the basis of the multiplication of the aforesaid tariff (basic tariff) by such coefficients as are stipulated in the law. The coefficients differ depending on the kind of renewable resources used. For solar energy the increasing coefficient (applicable for first 10 years of power plant operation) was 3 until May 2014 and has been decreased to 2.7. For hydraulic power plants it was 1.3 until May 2014 and is now 1.1.

ENERGY LAW IN BELGIUM

Recent developments in the Belgian energy market

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LEGISLATIVE AND POLICY UPDATES

A new energy plan for Belgium: security of supply and an end to nuclear

In March 2014, the grand plan for the future of Belgian energy proposed by the then Secretary of State for the Environment, Energy, Mobility and Institutional Reform, Melchior Wathelet, was passed by the House of Representatives.[1] The Act introduces a mechanism for the establishment of a strategic reserve to secure Belgium's energy supply and to reduce (and ultimately end) the country's reliance on nuclear energy.[2] The Act also amends the *Law on the Organisation of the Energy Market 29 April 1999*[3] and transposes the Third Electricity Directive by reorganising the Belgian energy market. The measures already adopted in the framework of this plan include:

1. The support of existing energy supply facilities, including financial subsidies and relief;
2. The creation of a back-up system to attract new production facilities, including the call for tenders in January 2014;
3. The closure of nuclear plants Doel 1 and Doel 2 in 2015; and
4. Extending the operating timeframe for nuclear plant Tihange 1 by 10 more years in consideration for a fee amounting to 70% of its profits. This money will be invested in new offshore facilities that are thought to reduce costs to consumers and attract new investment into Belgium.[4]

CREG and Elia have subsequently published a timeframe for the implementation of this amendment, aiming to start contracting by 1 November 2014.[5]

The project is currently pending a decision by CREG with respect to whether or not a price analysis submitted by Elia on 25 July 2014 is 'manifestly unreasonable' or not. At the time of writing, this decision had not been made publically available.[6]

Trio of energy policy proposals passed by the Council of Ministers

On 14 February 2014, the Council of Ministers passed three important energy law reforms proposed by the then Secretary of State Wathelet (the "Reforms") which are an integral part of the grand energy plan for Belgium.

Subsidy reform for offshore wind farms

After a period of relatively generous subsidies for wind farms, the Reforms attempt to equalise financial subsidies to reduce costs to the consumer while at the same time, guaranteeing profitability margins to the producer, according to a press release issued in December 2013.[7] The subsidy available for future wind farm projects will now be adjusted to electricity prices as set out in the Executive Order of 4 April 2014.[8] In effect, financial subsidies will increase if the price of electricity decreases, and if the price of electricity is high, the subsidies will decrease to avoid unjustly inflating the profits of the producers.[9] The objective of this policy reform is to attract investors in the renewable energy sector and to prevent consumers from incurring higher charges due to development costs. CREG will evaluate the subsidy required by developers at the start of their project and will reconsider its position every three years. The subsidy reform does not apply to offshore projects that are already under construction or have already been completed. Belgium is assumed to have merely utilised 1/3 of its total capacity for windmills thus far.

This part of the policy reform formalises the agreement reached between producers of offshore windmill energy and industrial users (the 'Dralans-agreement').

This subsidy is not without criticism. In fact, some analysts are critical of the subsidy reform which they suggest merely disguises a "double tax" imposed on Belgian consumers.[10]

A legal basis for the completion of three projects in the North Sea

The Executive Order will provide a legal basis for the following energy infrastructure policies including providing for:

- The issue of a request for tender (*concessieprocedure*) to build a 'socket' (*stopcontact*) that connects offshore windmills with the mainland;
- The request for tender to build an energy atoll, or "ring island", that is capable of generating hydroelectricity off the coast of Zeebrugge;
- The possibility for the TSO to create a joint-venture aimed at realising an interconnection with Great Britain (the "NEMO-project").

Compensation scheme for the victims of energy disasters

In light of the Ghislenghien disaster nearly 10 years ago (the final amount of compensation amounting to over €30 million paid by Fluxys in 2012)[11] the Council of Ministers also adopted a number of provisions relating to the establishment of a compensation scheme to be managed by Fluxys with the goal to provide easier access to compensation for victims of energy disasters. The scheme will pay damages for personal injury and economic losses caused by energy accidents. The level of indemnity and the methods of accessing the fund will be outlined in an Executive Order, which will facilitate access to a guaranteed amount of compensation and avoid drawn out legal proceedings or frustration of legal claims due to liquidation or insolvency of the energy provider at fault.

Relaxation of Energy Regulations in Flanders

In an effort to prevent companies from relocating their business to countries with less progressive (or less stringent) energy regulations, the Flemish government lowered the $C0_2$ levy on electricity prices for the Flemish industry. The total relief offered by this measure is estimated at €60 million.[12]

Voluntary industry agreement to increase consumer protection

The then minister of economy Johan Vande Lanotte and the then Secretary of State Wathelet reached an agreement with representatives of the energy sector on several matters relating to consumer protection. The voluntary agreement requires that energy suppliers must:

- advise their customers on the tariff that is most favourable to the consumer;
- cease renewing fixed-term contracts automatically;
- pay interest on any delayed refund to the customer; and
- allow customers to switch suppliers without incurring a surcharge.[13]

Increased life expectancy for Belgian nuclear power plants

Despite the 2003 nuclear phase out plan, on 18 December 2013, legislation was adopted that prolongs the life of nuclear power plant Tihange 1 from 1 October 2015 until 1 October 2025.[14] This was soon followed by the sudden shutdown of Doel 3, 4 and Tihange 2 by Electrabel in the middle of 2014 due to damage to the reactors[15], which sparked debate as to whether other plants should have their lives extended as well.[16] The schedule for the planned deactivation of Belgium's nuclear power plants is currently:

- Doel 1: 15 February 2015
- Doel 2: 1 December 2015
- Doel 3: 1 October 2022
- Doel 4: 1 July 2025
- Tihange 1: 1 October 2025
- Tihange 2: 1 February 2013
- Tihange 3: 1 September 2025

In return for the prolonged use of Tihange 1, the state will receive 70% of its profits. This money will be invested in offshore developments.

As mentioned above, debate continues as to whether the government should also prolong the life of nuclear power plants Doel 1 and Doel 2 to 31 March 2015 and 31 March 2016 respectively, or run the risk of power cuts during winter. If the life of these plants will be extended, further capital investment will be needed, with conservative estimates amounting to hundreds of millions of euros.[17] At the time of writing, no law had been passed to extend the lives of Doel 1 and 2, which are expected to close in 2015 as indicated above.

A New Licensing and Projects Approvals Authority

Pursuant to European Parliament regulations (EU No 347/2013) regarding trans-European energy infrastructure projects, in October 2013, the Council of Ministers approved an agreement between the federal and regional governments to establish an overarching committee for the coordination and facilitation of licences for energy projects.[18] This "cooperation agreement" was entered into by the federal and regional governments on 27 February 2014.[19]

The committee consists of:

- Secretariat (fulfilled by the federal energy administration), functioning as a first point of contact for project managers, the European Commission and neighbouring countries.
- Coordination Department, tasked with the supervision of the committee.
- Follow-up committees who will monitor specific projects.

This committee is intended to be a "one stop shop" for all administrative approvals in relation to energy infrastructure projects.

Tariff pricing powers: now regional rather than federally based

Following on from the Belgian political crisis of 2010-2011, the second stage of the momentous Sixth State Reform,[20] was published in the Official Gazette on 31 January 2014. This had the effect of transferring, *inter alia*, the competence of tariff pricing for the distribution of gas and electricity from the Federal Government to the Regional and Community Governments. These transfers became effective on 1 July 2014.[21] The relevant authorities are as follows:

- Wallonia: the Walloon Commission for Energy (CWaPE).[22]
- Brussels-Capital region: the Brugel (*Commission de Regulation pour L'Energie en Region de Bruxelles-Capitale*).[23]
- Flanders: the Flemish Regulatory Body for the Electricity and Gas Market (VREG).[24]

The tariffs previously established by CREG (the federal regulator) have been frozen by the government pursuant to the safety net regulation until 31 December 2014 and will remain in force until that date.

From 1 January 2015 onwards, the regional authorities will establish tariffs for two-year set intervals. VREG has indicated that it intends to instate an income-based regulation method (*inkomstenregulering*), thereby following the approach maintained by the Dutch and UK regulators. Conversely, CWaPE and Brugel will continue to apply the "cost plus" method previously applied by CREG during a "transition period" of 2015 to 2016.[25] After such time, CWaPE and Brugel intend to make some modifications to the methodology.

A new TSO liability regime

The Flemish Energy Decree of 8 May 2009 was amended by Decree of 20 December 2013[26] by inserting a new liability regime for TSOs. The amendment establishes a mechanism aimed at compensating users in cases of unplanned long-term interruptions (four hours or longer) of electricity/gas-supply or loss of income due to delayed connection services. The liability of TSOs is capped at €2 million per incident (with the exception of personal injury) and, in turn, the TSO can recover losses from the entity (or natural person) that caused the incident.[27]

The scope of the amendment is limited to the Flemish Region and its substantive provisions will enter into force on 1 January 2015.[28]

Court Proceedings and Disputes

A ruling by the CJEU in C-204/12 and C-208/12 (Essent Belgium)

In *Essent Belgium NV v Vlaamse Reguleringsinstantie voor de Elektriciteits – en Gasmarkt*,[29] the Brussels Court of First Instance referred a question to the Court of Justice of the European Union (the "CJEU") for a preliminary ruling. The case concerned claims by Essent that Belgium had breached the prohibition of quantitative restrictions (Article 34 TFEU) as well as the principle of non-discrimination (Article 18 TFEU). These allegations were based on administrative fines that had been imposed by VREG on Essent on the basis of the latter's failure to produce a sufficient amount of green certificates issued in the Flemish Region to meet its quota obligation. Essent was able to demonstrate that it had guarantees of origin for the production of green electricity in the Netherlands, Norway and Denmark, but these certificates were not deemed satisfactory by VREG to discharge Essent of its obligations. In the last issue of the Energy Handbook the CJEU had not made a ruling on this case. The CJEU eventually found that VREG's actions did not violate Union law and that Member States were allowed to require certificates that were supplied in a particular region, provided that:

- mechanisms are established that ensure the creation of a genuine market for certificates so that it is actually possible for the suppliers to obtain certificates under fair terms; and
- the penalties imposed by the regulator are proportionate and not punitive in nature.

Nuclear tax case dismissed

On 17 July 2014, the Constitutional Court rejected a claim by Electrabel, EDF Luminus, and EDF Belgium regarding the 'nuclear tax' of €549 million imposed on them.[30] The government had levied this tax to limit the profit made by claimants from their exploitation of nuclear power plants. The claimants argued that the tax was too onerous and unevenly divided among the stakeholders. Electrabel, especially with €480 million due, regarded its expected contribution as disproportionate. Furthermore, Electrabel argued that the amount in tax exceeded the profits it made from the power plant.

Ultimately, the Constitutional Court held the arguments lacked foundation and dismissed all claims. Electrabel still has proceedings onfoot before the Court regarding the same taxes.[31]

Market developments

Between December 2012 and May 2014, Belgian electricity and gas prices have decreased significantly, by 29.6% and 20.6% respectively. Owing to these considerable changes in price, Belgian energy prices are almost on a par with its neighbouring countries (France, the Netherlands, and Germany). Since August 2013 Belgian gas and electricity prices have fluctuated between being equal to, and being 1-3 €/MHh above, the average price in neighbouring countries. These drastic changes in energy prices can be attributed to the safety net regulation, which was promulgated to this effect.[32]

In comparison to 2012, the total consumption of energy was marginally reduced in 2013. Electricity consumption went from 81.7TWh in 2012 to 80.6TWh in 2013 (-1.4%) and gas usage decreased from 185.6TWh to 183.2TWh (-1.3%).

Furthermore, whereas in 2012, 48% of the offered electricity was derived from renewable sources, in 2013 only 31% came from such sources. However, the amount of energy produced by offshore windmills has increased by 185.7MW to a total of 566.1MW in 2013. This increase is attributed to the operation of the C-Power windmill park as well as 25 additional windmills by Northwind.

The level of competition in the energy market improved from 2012 to 2013, as displayed by the HHI index numbers below (taken from the joint-regulators publication for 2013):[33]

Table 1: Herfindahl-Hirschmann-index: concentration of the market in 2012 and 2013 based on number of access points (Table taken from Joint Regulators Publication for 2013)[34]

	2012	2013
Brussels – Electricity	6.605	5.902
Flanders – Electricity	3.094	2640
Wallonia – Electricity	3.587	3.334
Brussels – Natural gas	6.476	5.721
Flanders – Natural gas	2.815	3224
Wallonia – Natural gas	3.261	3.195

This trend is also displayed by an increase of Belgian consumers switching providers, as set out in the table below comparing the data from 2012 and 2013:

Table 2: Relative number of access points that switched energy supplier in 2012 and 2013 (Table taken from Joint Regulators Publication for 2013)[35]

	2012	2013
Brussels – Electricity	10.3%	14.3%
Flanders – Electricity	16.5%	15.4%
Wallonia – Electricity	11.6%	13.6%
Brussels – Natural gas	12.9%	18.3%
Flanders – Natural gas	18.9%	18.7%
Wallonia – Natural gas	15.0%	21.2%

Entry by Poweo

A new (potentially) significant stakeholder has entered the Belgian market. Poweo, owned by the Direct Energie group, has obtained licenses for the supply of electricity and gas in Wallonia and has begun to offer its services there. The company intends to expand its business to Brussels and Flanders in 2015 and aims to have 400,000 customers by 2018.[36]

Belgian industry paying more for electricity

Regardless of the general decrease in prices for consumers, the industrial prices for electricity remain considerably higher than those in Belgium's neighbouring countries. A study conducted by Deloitte (instructed by Febeliec) concluded that Belgian industrial users pay more for electricity than their competitors in neighbouring countries. In 2013 this range was 12-45%. The study furthermore expects that the insecurity surrounding the defective nuclear power plants Doel 3 and Tihange 2 might foster this disparity in pricing.[37]

Restart of operations for Rodenhuize Max Green

Belgium's largest biomass power station (215MW, covering 320,000 families), Rodenhuize Max Green, operated by Electrabel, resumed its operations on 28 August 2014 after having paused production since the beginning of 2014 due to a dispute regarding green certificates that has now been settled.[38]

New methodologies for calculating gas tariffs

CREG has reached separate agreements with Fluxys as well as Elia for a new methodology of calculating gas infrastructure and transport tariffs from 2016 until 2019. These agreements will in due course be presented to the Belgian parliament for approval.[39]

Investment and infrastructure

EDF investment in renewables

EDF Luminus has invested €100 million in 2014 in renewable energy sources. The investment included the building of windmill parks in Olen, Lumen and Spy, as well as a renewal of its hydroelectricity stations.

There are, furthermore, rumours that EDF Luminus is considering to build a new nuclear power plant.[40]

ExxonMobil plans for investment in Antwerp

ExxonMobil is planning to invest more than USD 1 billion in the port of Antwerp. The company is planning to build an oil refinery that converts raw oils into fuel suitable for ships. Such an investment would mean that ExxonMobil has invested more than USD 2 billion in total in the port of Antwerp over a period of 10 years.[41]

Belgian offshore grid

In April 2014, Elia obtained a licence for the construction and operation of the Belgian Offshore Grid in the North Sea. The licence concerns the Alfa Island, a high-voltage station at sea, three cables between Alfa and the coast, and two additional cables. However, it depends on project Stevin and the cooperation with other parties (Plug at Sea, Belgian Offshore Platform) whether it will actually be possible to create the Belgian Offshore Grid.

In addition, on 27 May 2014, Elia also obtained a licence for the construction of three high-voltage power stations in West-Flanders.[42]

Smart turbines

Elia, Eandis, and Wind aan de Stroom are cooperating in a project to improve energy-efficiency through the construction of 'smart' wind turbines. In the beginning of 2015, the first six prototypes of these advanced wind turbines are due to be tested in the Waaslandhaven.[43]

Request for tender for new power generators

On 18 November 2013, a request for tender was issued by Ministerial Decree for the construction and operation of new power generators in Belgium to safeguard Belgian energy supply. The deadline for offers was on 22 July 2014. It is reported that Delta, Dils-Energie, and Essent Power have made an offer.[44]

Alegro project

On 17 December 2013, the Walloon government approved the initial design for the "ALEGrO" project. This project will connect the Belgian and German energy markets through underground cables. The Walloon approval is the first step towards the official licence for this project, that is scheduled to be completed in 2019. The ALEGrO project is a Belgian policy priority and was included on the list of Projects of Common Interest that was published by the European Commission on 14 October 2014.[45]

On 15 May 2014, the Walloon government adopted a decree stipulating the content of an environmental impact study, which will be revealed to the public later in 2014. It is expected that a public consultation process will commence in early 2015.

Stevin high-voltage project

At the start of 2014, the Stevin project was at risk of not going ahead due to legal proceedings launched by various private parties and local authorities against the GRUP (regional land-use plan) for Stevin. Elia was able to reach an out of court settlement with the parties and announced in September 2014, that it intended to kick-off the project in early 2015.[46] The Stevin project involves an upgrade the high-voltage grid (380kV) between Zeebrugge and Zomergem.[47] A Belgian judicial advisory authority (*Raad van State*) is currently considering whether it will approve of the settlement.

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ENERGY LAW IN BOSNIA AND HERZEGOVINA

Recent developments in Bosnia and Herzegovina's energy market

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Bosnia and Herzegovina ("BH"), is thought to have great deal of potential in relation to the generation of energy. BH is divided into two entities and one district, these include: the Federation of Bosnia and Herzegovina ("FBH"), the Republic of Srpska ("RS") (the "entities"), and Brčko District. The regulatory authorities in the energy sector are divided between BH and the entities.

Despite its complex constitutional system, the fact that the BH government and the entities' governments have recently been heavily criticised for their political ineptitude, and the economic crisis, the situation in the energy sector is constantly improving.

Energy sector developments are particularly evidenced by the number of upcoming and ongoing projects and a significant number of regulatory changes over the last several years. There has also been an increase in foreign investments in the BH energy sector, illustrating the effective regulatory changes and increasingly favourable business climate of the country.

REGULATORY CHANGES IN BOSNIA AND HERZEGOVINA

Decree on Incentives for Electricity Generation came into force in FBH

Since the new Law on Use of Renewable Energy Sources and Efficient Cogeneration started being applied in 2014 the government of the FBH subsequently enacted the Decree on the Incentives for Electricity Generation from Renewable Sources (the "Decree").

In the RS, the internal act regulating similar issues was enacted in 2013.

After years of non-existence or limited regulation in relation to renewable energy, the newly enacted Decree has established a framework for generation from renewable energy sources ("RES") throughout the entire territory of BH.

The Decree, *inter alia,* regulates the method for determining and collecting fees from end users in order to support RES generation. It also sets the criteria in terms of the size of individual plants that may have privileged generator status, and regulates the maximum time for construction and connection of the plant to the network.

According to the Decree, all end users are obliged to pay an incentive fee in order to support RES-related generation.

Action Plan for use of RES in FBH

The FBH Government has enacted an action plan for use of RES (the "Action Plan"). The Action Plan is an integral part of the overall National Action Plan for the use of renewables in BH. The Action Plan sets binding targets for FBH for 2020 on the share of renewables in the total consumption of electricity, heating and cooling energy and energy transport. According to the Action Plan, the FBH 2020 target for gross consumption of energy from renewables is set at 41 per cent of total gross energy consumption, while the share of renewable energy in the final consumption should amount to 44 per cent.

The Action Plan will be updated each year by the end of March.

The FBH Renewables Operator Established

The Law on Use of Renewable Energy Sources and Efficient Cogeneration in FBH provides for the establishment of a unique RES operator ie, the Operator for Renewable Energy Sources and Efficient Cogeneration ("RES Operator").

The RES Operator was established in the summer of 2014. The RES Operator has many competences related to regulation of the RES sector and the provision of benefits and is, *inter alia*, the authority for:

- concluding agreements with generators of electricity from RES in relation to mandatory purchase/take-over of energy under guaranteed or wholesale market prices;
- collecting and recording data on the amount of energy produced by qualified generators;
- keeping and maintaining the registry of issued guarantees of origin and registry of other projects;
- maintaining a separate account for the payment of energy from RES; and
- rendering acts necessary for the regulation of the RES sector.

The RES Operator is also responsible for conducting different types of research, providing information to the public on incentives for RES, developing appropriate educational programs, organising public and specialised discussions, workshops, trainings and RES promotion.

The Bylaw on the Issuance of Guarantees of Origin enacted in RS

At the end of 2013, the Regulatory Commission for Energy of RS ("RCERS") enacted a bylaw regulating the issuance of guarantees of origin and their transfer. The rationale for the implementation of such a bylaw is the fact that the RS Law on Renewable Energy provides for competence of RCERS in connection to issuance, transfer and cancellation of guarantees of origin. Also, the bylaw provides a more detailed regulation of guarantees of origin.

This bylaw regulates the content of guarantees of origin, conditions and process of their issuance, transfer and cancellation of guarantees and maintenance of the registry of guarantees by RCERS.

ENERGY SECTOR PROJECTS

RES power plants – hydro power plants

BH is one of few countries in Europe with an integrated system for the construction of facilities for the production of energy from renewable sources. All parts which are installed in the power units are produced in BH.

BH has invested over €100 million in RES to date. At the moment there are 28 power plants for generation of energy from renewable sources in FBH. Eight RES power plants are operating in the RS. Around 30 objects are under construction.

The most recent and valuable projects, which will have a significant positive impact on the local communities, are all geographically located on the territory of RS. These include the Gozva River power plant, the Medna hydro power plant and the hydro power plant Mrsovo.

Gozva River

The construction of a small hydro power plant on the Gozva River is currently underway. The expected energy generation of this power plant is approximately 22GWh. According to publicly available information, this generation capacity should be enough to supply around 6,000 households.

As one of the projects of the municipality Foča, it is expected that the project will bring the local community revenue of around €60,000 on a yearly basis. The plant should start with the generation by the end of the next year.

Hydro Power Plant Medna

The government of RS has approved the licence for construction of the hydro power plant Medna, laying the foundation for the commencement of its construction. The facility will be located in the municipalities of Mrkonjić Grad and Ribnik. The facility will be operated by LSB Elektrane, an investment vehicle set up by the project investors, Interenergo and Keleg, an Austrian energy group which owns the company Interenegro. The investment for the construction is valued at €20 million. The project is expected to be finalised over in next two years.

It is expected that the plant will generate 21GWh of electricity, which is estimated to be enough to supply 6,000 households. The investment will benefit the local community with the introduction of concession fees, new jobs, a better supply of electricity and will promote the RES sector in general.

Hydro power plant Mrsovo

Hydro power plant Mrsovo is the latest project being carried out of Comsar Energy in RS. The power plant will provide clean and renewable energy for the region. Comsar Energy has stated that the installed capacity of this hydro power plant will be 36.8MW and the projected annual generation will be 141GWh of electricity. The reservoir will cover about 200 hectares of land, with water flowing along the regional route, Brodar – Rudo – Priboj. The plant should be operational by 2016 and connected to the power system of RS.

Mrsovo is located on the Lim River, close to the confluence with the Drina River, in the Rudo Municipality. The economic and social impact of the Mrsovo project will benefit the Rudo municipality by increasing its employment capacity and raising significant revenue. The investor's intention is to uphold the environmental balance and the natural beauty of the area, and to keep the River Lim clean and clear.

Construction of wind farms planned in Southern BH

The company, ENERGY 3 d.o.o. Mostar ("Energy 3"), which is active in the field of research and development of RES projects, is planning to construct the wind farm Pločno close to the city of Mostar in southern BH. The company has already initiated the procedure to the necessary permits.

It is planned that the wind farm will consist of 15 wind generators with an individual capacity of 3MW, and a total capacity of 48MW. The wind farm Pločno will be situated between the mountains Velež and Preni, above the valley Bijelo Polje.

As a reference, Energy 3 has been engaged for eight years already on the development of different energy studies which are now the basis for the valuation and assessment of the influence of the wind farm on the environment surrounding the proposed location for the wind farm.

Also, Kreditanstalt für Wiederaufbau ("KfW"), the German development bank, has approved a loan of €65 million to Elektroprivreda BiH for financing the construction of a wind farm in Podveležje, for a period of 15 years with a 3 year grace period.

The investment is valued at €71.8 million. Podveležje is located at the foot of the mountain Velež. The power capacity of Podveležje is planned at 48MW and the annual generation is estimated at 100GWh. Elektroprivreda BiH has been granted the concession for a period of 30 years.

European Investment Bank grant of €755,000

The European Investment Bank ("EIB") will provide a grant of €755,000 for the construction of the wind farm Vlašić Travnik in central BH.

The grant will be given to Elektroprivreda BiH, in order to provide financial and advisory assistance during the implementation of the project. The government of FBH has already rendered a decision on the acceptance of the EIB grant.

Biomass power plants operational in BH

Nemila power plant

This small biomass power plant in the village of Nemila close to the city of Zenica recently became operational. The installed capacity of the power plant is 3MW. This project is implemented as a cooperative initiative between the Czech Republic and the municipality of Zenica, FBH.

At the beginning it is planned that the power plant will provide heating for around 90 households and four public institutions. In the next two years, biomass will be provided by Natron Hayat, a company registered for the production of paper and related products.

Gradiška power plant

The first biomass power plant in RS became operational in April 2014. The project was implemented as a cooperative initiative between the municipality of Gradiška and IEE, a local company.

The European Bank for Reconstruction and Development Loan to the City of Prijedor

The European Bank for Reconstruction and Development ("EBRD") is providing funding in the amount of up to €7 million for the supply and installation of a new combined heat and power generation plant based on biomass in the City of Prijedor. It is expected that the project would be implemented by Toplana a.d. Prijedor, a public company owned by City of Prijedor. This project will introduce consumption based billing, which will improve the quality of services in the City of Prijedor.

The project will also be supported by grant funding of up to €2 million from the Swedish International Development Cooperation Agency (Sida).

This project should contribute to environmental protection, have a positive impact on the environment and decrease the emission of CO_2.

Solar power plant in Livno Municipality

The government of Canton 10 in FBH has awarded the concession for construction of photovoltaic panels with a capacity of 450MW on a 1000 hectare site in Livno municipality, location Livanjsko polje. This project is expected to be the biggest solar park in Europe, with the potential to generate expected electricity of approximately 600,000kWh. The project is valued at €500 million.

The construction is scheduled to begin in 2016, and the solar park is expected to become operational by 2018. The local investment vehicle, Solbus, is owned by the Shanghai-based company, Hareon Solar Technology, and Prinz Karl Thurn and Taxis Management based in Zollikon, Switzerland, has been granted the concession.

Thermal power plants in BH

Both RS and FBH governments have planned activities in relation to the expansion and increase of generation of existing thermal power plants.

Ugljevik III

Comsar Energy has begun the construction of Ugljevik 3 Thermal Power Plant, which will become operational in 2016. This power plant will use the brown coal from the surface mines situated in Delići, Peljave-Tobut and Baljak in the Ugljevik Municipality.

According to the Comsar Energy review, the plant will be characterised by the following[1]:

- installed power projection of 2x300MW;
- base power plant design, operating 7,300 hours a year;
- two blocks, each containing a boiler, a turbine and a generator, as well as a common 210m-high chimney and all other necessary supporting systems and facilities;
- steam boilers with sub-critical parameters and featuring a circulating fluidised bed combustion technology;
- highly efficient, two-stage, limestone-based sulphur recovery which will take place within the boiler and the desulphurization unit;
- application of a direct air-cooling condenser (a system which will minimize the plant's fresh water needs);
- full wastewater treatment and reuse within the plant's systems;
- coal, limestone, slag and ash transported through closed conveyor belts to prevent environmental pollution arising from waste disposal and the use of vehicles; and
- connection of the unit to the power supply system through the existing switchyard of the 400/110kV Ugljevik Substation.

Tuzla and Kakanj thermal power plants

Unit 7 of the thermal power plant, Tuzla, is an investment of Elektroprivreda BiH valued at BAM1,499 million (approx. €750 million). It is expected the generation from this power plant will be at rate of 2,756GWh. The consortium, Gezhouba Group Company Limited (CGGC) and Gunagdong Electric Power Desing Institute (GEDI) China, has been elected as the project partner for construction of the 450MW coal-fired power generation unit.

The project at the Tuzla power plant in northern Bosnia is one of the largest investments in energy infrastructure in the Balkans. The new unit in Tuzla plant would remain fully owned by Elektroprivreda BiH, as well as its capacity and output. The proposed model of investment is for Elektroprivreda BiH to invest 15 per cent. and for the other 85 per cent to be granted as a loan by EXIM Bank of China.

Also Elektroprivreda BiH is investing in the construction of Unit 8 of the Kakanj thermal power plant, generation capacity of 1,755GWh. This investment is valued at BAM1,035.2 million (approx. €520 million). The thermal power plant Kakanj is located on the left bank of the river Bosna, Central Bosnia, which has significant geological reserves of brown coal.

Oil exploration by Shell

The FBH Law on Research and Exploitation of Oil and Gas in 2013 established a framework for the continuation of geological research of oil and gas, with a focus on sustainable development of the oil sector. This law provides the basic framework for the development and construction of the plants and infrastructure with a high level of energy efficiency and protection of the environment with minimal negative influences.

In light of the above regulatory changes, the FBH government has signed a Memorandum of Understanding with Shell Exploitation Company B.V. ("Shell") to conduct a detailed assessment of the prospects for oil and gas exploitation in FBH. After the assessment, Shell officially expressed interest in starting negotiations for concessions for the exploitation of oil in FBH.

Also, the FBH government has recently published a tender for the selection of professional consultants for the purpose of conclusion of an agreement for a 25 year period, in order to explore and exploit the resources of oil on the territory of FBH.

These negotiations will increase foreign investments in FBH which will enable substantive financial benefits to the entity as well as BH. They will also strengthen the economy through the construction of the entire infrastructure for the use and transport of oil and gas.

ENDNOTE

1. "TPP Ugljevik" available at http://comsar.com/projects-technologies/tpp-ugljevik.

ENERGY LAW IN BULGARIA

Recent developments[1] in the Bulgarian energy market

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The energy sector in Bulgaria has recently experienced several significant developments. At the beginning of 2014 the government announced that the 2020 EU renewable energy target had been achieved – and exceeded, due to the new solar and wind capacities commissioned by the end of 2012. As a result, the costs incurred by the preferential feed-in tariff increased substantially ahead of schedule. Since the regulator was unwilling to allocate these costs to end consumers by increasing the regulated electricity prices (as provided by law), they created a deficit in the budget of the public provider and the end suppliers. In turn, this prompted amendments to the energy laws, which were disputed and subsequently revoked as unlawful by the courts.

Another major topic of discussion and concern in the energy industry was the insolvency threat faced by the National Electricity Company and the related attempted revocation of the licences of the end suppliers. 2014 also saw the completion of unbundling of the TSO and the launch of the renewable energy balancing market. Also, the free electricity exchange moved closer to completion as its future operator obtained its licence. Another notable development is the establishment of a new advisory body – the Energy Board, in an attempt to streamline the discussions on the issues and identify efficient measures to resolve them at expert level. Finally, the implementation of the South Stream Transmission Gas Pipeline, the key gas project for Bulgaria, encountered allegations of non-compliance with European law which eventually triggered an infringement procedure of the European Commission against Bulgaria.

2020 RENEWABLE ENERGY TARGET ACCOMPLISHED

The 2020 target share of renewable energy set out in the Renewable Energy Directive for Bulgaria is 16%. Due to the substantial interest in renewable energy investments since the Bulgarian accession to the European Union and the introduction of the incentives scheme in the Law on Energy from Renewable Sources ("RES Law"), a total of 1,702MW[2] new capacities of solar and wind plants were developed and commissioned by January 2014, ahead of schedule. On the other hand, industry electricity consumption has declined during the recent economic crisis. Due to the new capacities and the lower consumption by the end of 2012 Bulgaria accomplished the 2020 target – and exceeded it, by reaching a 16.4% share of renewable energy.[3] As an imminent consequence of this report the incentives for renewable energy provided in the RES Law – the preferential feed-in tariff and the long-term power purchase agreements in particular, no longer apply to new projects (ie projects which have not been under development by December 2013).

RENEWABLE ENERGY FRAMEWORK REVISIONS

The RES Law has been subject to several revisions since 2011, each intended to make the regime more restrictive and to cool off the investor interest. Some revisions affected projects under development and were in breach of the constitutional principle of the rule of law and predictable legal framework. The latest amendment to that respect was adopted in December 2013 and entered into effect on 1 January 2014 introducing two main changes.

Firstly, a new 20% fee was introduced on solar and wind plant revenues from electricity sale at preferential feed-in tariffs (the "20% fee"). It was to be deducted from the payment under the long-term power purchase agreements by the public provider or the end suppliers (depending on the plant capacity).

Secondly, the law set a threshold for the amount of electricity to be purchased from renewable energy plants at preferential feed-in tariffs. Unlike the previous regime, according to which the entire amount of electricity produced was to be purchased at a preferential price, since 1 January 2014 only the amount within the average annual period of operation of the plant would be sold at the higher price. Any electricity produced in excess of that average will attract a lower price approved by the national energy regulator. The 'average annual period of operation' is defined by each plant according to the instructions of the State Energy and Water Regulator Commission ("Regulatory Commission"). The changes affect all projects, including those in operation being developed and financed upon reliance of the incentives provided in the legal framework prior to the amendment, thus causing serious tension between the industry and the authorities.

THE CONSTITUTIONAL COURT CHALLENGE

The 20% fee was challenged in January 2014 by the President of Bulgaria before the Constitutional Court on grounds of violation of the constitutional principles of the rule of law and predictable legal framework for investments as well as discrimination of solar and wind plants.[4] Though the case was timely admitted for review, the procedure was delayed and a decision was issued seven months later.[5] The court confirmed that the introduction of the 20% fee is discriminatory and unconstitutional on several grounds:

- Firstly, according to the law, a state fee is to be paid for a service or an action of state authorities requested by and granted to a legal entity or person.
- Secondly, the amount of the fee is to be calculated in a transparent and objective manner. In the case at hand, the producers of electricity from solar and wind energy do not request nor receive any service nor consideration from the state authorities and the 20% amount has not been justified properly in the course of the legislative amendment.
- Thirdly, the 20% fee is discriminatory as it singles out solar and wind plants out of the renewable energy group and imposes the negative measures specifically on them without proper justification.

- Finally, the amendment retroactively affects plants in operation and thus violates the constitutional requirements for safe and predictable investment environment.

On these grounds, the court revoked the 20% fee RES Law amendment and the fee ceased to be effective from 10 August 2014. However, the revocation does not have a retroactive effect and the payment of the 20% fee made until its revocation remains valid (ie, the producers are not entitled to reimbursement of the amounts withheld from their revenues from electricity for the period 1 January to 10 August 2014). Since reimbursement cannot be achieved under Bulgarian law, the producers are currently considering alternative options for compensation on the basis of international law.

REVOKED DECISION OF THE REGULATOR ON ACCESS FEES

In September 2012 the Regulatory Commission imposed interim access fees (*временна цена за достъп*) on producers of electricity from renewable energy sources.[6] The calculation of the amount of the fees was based on the income of the producer from the plant and the classification was made by type of renewable energy source and by applicable feed-in tariff. Solar plants entitled to the highest preferential feed-in tariff had to pay approximately 40% of their income, whilst biomass plants owed only about 1–2%. Clearly, the method of calculation of the fees did not meet the transparency and objectivity standards applicable to such cases. The new fee was welcome by the end suppliers and the public providers since at that time they were struggling to pay their obligations for purchase of electricity from renewable energy sources because of the decrease in the end consumer regulated electricity prices and influx of new solar and wind capacities in 2012. As a practical solution, the end suppliers and the public provider promptly started deducting the amount of the interim access fees from the payments for purchase of electricity under their power purchase agreements. The producers were required to sign a trilateral protocol with the end supplier/public provider and the grid operator who was actually entitled to receive the interim access fees for its services.

The decision was appealed by producers before the Supreme Administrative Court. Since the interim access fee was differentiated by type of renewable energy source and applicable feed-in tariff, each appeal was reviewed separately by the court resulting in several hundred separate lawsuits moving at different speeds. Ultimately, the decision of the Regulatory Commission was revoked by the Supreme Administrative Court on grounds of non-compliance with the legal requirements for defining and imposing of such fees.[7] The revocation has a retroactive effect and invalidates the revoked interim access fee entirely. Consequently, the payments made on grounds of the revoked fee could be deemed as unduly paid and subject to reimbursement. As soon as the revocation became effective those entitled to it producers requested reimbursement of the amounts unduly withheld from their electricity purchase payments on behalf of the grid operators. The latter generally declined to repay until the Regulatory Commissioned issued an explicit instruction to that effect. The instruction of the Regulatory Commission regarding the interim access fee issue was released almost a year later in March 2014.[8] According to the estimations of the Regulatory Commission only the transmission grid operator (ie, ESO) was entitled to receive access fees in the amount of BGN2.45 per MWh, net VAT (approx. €1.27).[9] This fee was to be paid only by solar and wind plants – both connected to the transmission and to the distribution grids, allegedly because they cause the bulk of costs for the operation of the transmission grid. With respect to the consequences of the revocation of the interim access fees decision, the Regulatory Commission issued a specific instruction.[10] It provided that the producers with solar and wind plants who have not appealed or whose interim access fees have not yet been revoked with an effective court decision, are entitled to receive back the difference between the higher interim access fee and the final access fee from the grid operator until 15 April 2014.[11] The Regulatory Commission stated that for producers whose interim access fees have been revoked pursuant to a court decision, the reimbursement of the paid amounts is to be administered according to the general civil procedure rules for unjust enrichment. Considering the financial issues of the transmission grid operator, the reimbursement of the interim access fees presents a serious challenge.

PUBLIC PROVIDER UNDER INSOLVENCY THREAT

Since the amendment of the Energy Law in July 2013 introducing the single-buyer model, the National Electricity Company EAD ("NEK"), a wholly-owned subsidiary of the state-owned Bulgarian Energy Holding EAD, has been required to purchase the entire amount of electricity produced, particularly the electricity from renewable energy sources at the respective preferential feed-in tariffs. The electricity produced by renewable energy plants connected to the distribution grid, is to be re-invoiced to NEK by the end suppliers, who purchase it under the long-term power purchase agreements with the producers.

While required to purchase the electricity produced from renewable energy sources at preferential prices, NEK as public provider is to sell it at the lower regulated prices to end consumers (the regulated prices have been decreased three times since March 2013 for political reasons). As a result, NEK has incurred a deficit in its budget, which reached approx. €750,000 by the middle of 2014 according to the Regulatory Commission. The unpaid obligations to purchase electricity from renewable energy sources and the electricity produced under the long-term power purchase agreements with the thermal power plants Maritza 1 and 2 form nearly half of the deficit (€360,000). As result of this deficit, NEK has been slow to pay its obligations for the last couple of years. Since 2013 NEK has been delaying the payments to its suppliers due to the growing financial deficit in the company. The end suppliers dealt with this issue by setting off their counter receivables towards NEK, which currently makes only partial payments (approximately 50%), if any, to its suppliers. Under the general regime of the Bulgarian law, a set off can be made between two counter receivables of two parties provided that the receivables are due and payable. However, in February 2014, upon a complaint from NEK, the Regulatory Commission opened an investigation against the end suppliers regarding the set offs and a month later issued penalty decrees claiming that this practice is in violation of the Energy Law and the terms and conditions of the end suppliers' licences.

For any other company such a deficit might have already led to an insolvency procedure. For the creditors of NEK, particularly the producers of electricity from renewable energy sources, however, this option is not feasible. As a subsidiary of the state-owned Bulgarian Energy Holding, NEK has been able to avoid insolvency for the time being as the government and the Regulatory Commission struggle to find a long-term solution. Beside the political aspect of the issue, there is also a legal problem as the Energy Law provides that the insolvency of the public provider is to be administered under a special law to ensure the security of electricity supply. Such law, however, has never been adopted by the Bulgarian Parliament and therefore the initiation of an insolvency procedure against NEK by a creditor under the standard insolvency rules of the Commercial Law is likely to stumble in court.

In October 2014, the regulated electricity prices for end consumers were finally increased by approximately 10%. According to the estimations of the Ministry of Economy, Energy and Tourism, this measure alone will allow NEK to liquidate the deficit within a period of three to five years. In the meantime NEK will continue to incur an annual deficit of approximately €350,000. For its creditors this period might be too long, particularly to producers with solar and wind plants that are required to repay their loans granted for the development of the projects from the income from the sale of electricity at preferential prices. Therefore, the authorities aim to find a more timely solution of the deficit issue by amending the regulatory framework.

ATTEMPTED END SUPPLIERS LICENSES REVOCATION

As the end suppliers have continued to set off their outstanding receivables towards NEK as they matured, the Regulatory Commission has started to initiate proceedings for revocation of the licences of the end suppliers. The Regulatory Commission claims that the set off under the general contract law regime is not applicable to the receivables of the end suppliers because the latter are regulated under the special regime for compensation of the costs of the end suppliers set out in the Energy Law and the Ordinance for electricity prices. The Regulatory Commission has the authority to determine the method and the amount of compensation of such costs while the end suppliers are to comply with its instructions. Further, the Regulatory Commission states that the set off deprives NEK of much needed turnover funds and therefore exposes the public supplier and in turn the public electricity supply to risk. The threatened revocation of the licences of the end suppliers prompted a strong reaction and the proceedings were monitored tacitly by the European Commission. Therefore, it was generally expected that revocation – the heaviest sanction, would eventually be replaced by substantial fines. In May 2014 the Regulatory Commission announced the result of its investigation stating that the end suppliers had committed licence breaches by unduly increasing their costs by more than €400 million since 2009. The total amount of the fines imposed for the alleged violations was estimated by the current Head of the Regulatory Commission to amount to at least €25 million. The end suppliers contested the allegations stating that they would appeal the penalty decrees before the competent courts.

RENEWABLE ENERGY BALANCING MARKET

The electric system balancing is set out in principle in the Energy Law and regulated in detail in the Rules for Electricity Trade ("Rules").[12] The balancing, as part of the operational matters, requires a producer to compensate for deviations between the forecast and the actual production of electricity and settle the imbalances at the balancing market. A producer of electricity from a renewable energy source, who is required to balance, has two main options: (i) to join a combined balancing group by choice or (ii) be registered ex oficio in the respective special balancing group.[13] The Rules provide for a special balancing group for producers of electricity from renewable sources which will be coordinated by the end suppliers or the public provider depending on the grid connection of the producers.[14] On 6 January 2014 the Regulatory Commission issued NEK a licence for special balancing group coordinator. It required that the signing of balancing agreements with the respective producers (ie, those connected to the transmission grid) is completed by 24 January 2014, the intention being to start balancing effectively from 1 February 2014. Given the short notice, the producers raised their concerns about the feasibility of the requirement. On 20 January 2014 the Regulatory Commission followed with a statement that failure to sign a balancing group participation agreement will lead to sanctions. It also expanded the requirement to include the end suppliers. The deadline was subsequently extended to 30 January 2014. Given that non-compliance might have triggered a penalty ranging from approx. €10,000–500,000 for a non-compliant producer, the Regulatory Commission in general has managed to achieve its target and the special balancing groups were formed.

The effective start of the balancing market was made on 1 June 2014. Since then, the method of calculation of the balancing costs, particularly for renewable energy producers, has been subject to discussions amid allegations from the renewable energy industry. The producers claim that the forecasts submitted by them are unjustly corrected by the coordinators (especially by NEK) and that the prices for deficiency and surplus (*цени за излишък и недостиг*) are being defined by the coordinators in a manner which is not transparent and highly questionable.

ALLEGED COMPETITION VIOLATIONS BY END SUPPLIERS

The Bulgarian Commission for Protection of Competition ("Competition Commission") initiated proceedings against nine companies from the groups of EVN, CEZ and Energo-Pro for alleged abuse of a dominant position in the electricity market with respect to electricity supply of end customers.[15] Following the initial investigation into the compliance of electricity traders in 2013, the Competition Commission opened proceedings against the said companies regarding suspected coordinated common market practice of electricity supply to end business customers connected to the low– and middle-tension distribution grid. This discriminates against independent electricity traders and curtails the electricity trade, particularly by delaying the initial switch of electricity suppliers by the end customers and the exchange of material information within the group of the suspected companies. The EVN, CEZ and Energo-Pro companies have contested the allegations claiming full compliance with the competition rules. The maximum sanction which could be imposed by the Competition Commission is 10% of the turnover of each company for the previous year.

ELECTRICITY SECTOR UNBUNDLING

Bulgaria applies the ITO unbundling model of the Third Electricity Directive. Until recently, the electricity transmission grid network has been owned by the company licensed as public provider and transmission grid operator –NEK, a wholly-owned subsidiary of the state-owned Bulgarian Energy Holding EAD. The transmission grid network was managed by a subsidiary of NEK – the Electricity System Operator EAD ("ESO"), licensed as electricity system manager. By the end of 2013 NEK and ESO started their restructuring in order to comply with the unbundling requirements of the ITO model. Since both companies are licence holders under the Energy Law the restructuring had to be approved in advance by the regulator. In December 2013 the Regulatory Commission issued a decision (i) allowing the spin-off of ESO from NEK and the transfer of the transmission grid network of NEK (together with all assets and grid related contracts) to ESO and (ii) amending the respective licenses of both companies.[16] NEK's licence as a transmission grid operator was terminated along with ESO's licence for electricity system management; ESO was granted a licence for special balancing group operator and for transmission grid operator for a 35-year period, effective from the date of registration of the restructuring in the Trade Register – 4 February 2014. ESO acquired the title on the transmission grid network and the related assets and contracts as a successor of NEK by virtue of the restructuring. From an operational perspective, though, the handover of the documentation and reallocation of the staff and contracts has required a substantial amount of time which caused delays in the day-to-day business of both companies.

ELECTRICITY EXCHANGE

The launch of the electricity exchange has been in the planning stage for a few years. While the necessary amendment of the Energy Law was made in July 2012, the Electricity Trading Rules have been subject to several revisions, with yet another one pending as new issues are arising in the course of preparation of the launch from an operational perspective. Still, the expectations grew higher after the amendment of the Energy Law which brought a large group of end consumers – those connected to the grid at middle-tension level (*средно напрежение*), away from regulated electricity prices and into the free market. The launch of the balancing market in June 2014 indicated further the determination of the authorities to achieve liberalisation of the electricity market.

The latest development with that regard is the licensing of a company as an electricity exchange operator. In March 2014 the Regulatory Commission issued a licence for electricity exchange operator (*организиране на борсов пазар за електрическа енергия*) to Bulgarian Independent Electricity Exchange EAD, a subsidiary of the state-owned Bulgarian Energy Holding.[17]

NEW ADVISORY BODY: THE ENERGY BOARD

The issues accumulated in the energy sector in the recent years, as outlined above, prompted the industry to suggest, through a vigorous campaign, the establishment of an expert body where the discussions on the issues and the possible solutions could be held on expert level to achieve a more sustainable approach in the regulation of the energy sector. The idea has been discussed since the introduction of the controversial 20% fee. After the caretaker government took office, the Council of Ministers (in August 2014) created by decree a new permanent advisory body to the government the Energy Board the purpose of which is to analyse at an expert level the issues in the energy sector and to propose legislative amendments and regulatory measures for solving them in a transparent, non-discriminatory and efficient manner. The head of the Energy Board is the Deputy Prime Minister of Economy, Regional Development and Investment Designs. The Board members include representatives of all branches of the energy sector (eg, transmission and distribution grid operators, end suppliers and the public provider, recognised industry associations, the labour unions, the banks, etc.). The Energy Board is to hold regular monthly sessions as well as ad hoc meetings whenever necessary and for the time being the advisory body is regarded by the industry as a step in the right direction to resolving the issues in the energy sector in a more efficient and transparent manner.

THE SOUTH STREAM TRANSMISSION GAS PIPELINE ISSUE

The South Stream Transmission Gas Pipeline, a key project for Bulgaria, was granted "national significance" status by the Bulgarian government.[18] Due to this preferential regime the construction was expected to start in the fall of 2014. However, the implementation of the project, particularly the terms and conditions regarding third party access to the future gas pipeline and the public procurement regarding its construction, has raised concerns on the part of the European Commission, which started an investigation in January 2014. The scope of review included the disputed public procurement procedure and the agreement between Bulgaria and Russia signed in 2008, which seemed to be granting priority access to the gas pipeline for both countries, while restricting the access of third parties. In the meantime, in the spring of 2014, the Parliament initiated a procedure for amendment of the Energy Law such as to allow the South Stream to be excluded from the third party access requirements of the Third Energy Package.[19] The procedure was still pending, when in June 2014 the European Commission launched infringement proceedings against Bulgaria for the alleged violation of the requirements of the Third Energy Package related to the development of the South Stream Project, ordering Bulgaria to stop the zoning and construction of the project until resolution of the issue.[20] In summary, the suspected non-compliance related to the obligations of Bulgaria under Directive 2004/17/EU, Art. 49, 56 and 207 of the EU Treaty as well as its obligations under Directive 2004/18/EU. The current government officially announced that it would comply; however, the development and construction proceedings were effectively stopped only two months later under the caretaker government.[21]

In late 2014, the Russian government announced a stop to the South Stream project.

ENDNOTES

1. The article is based on Bulgarian legislation and the information publicly available by 27 October 2014.
2. According to Decision No. EM-03 of 1 July 2014 of the Regulatory Commission.
3. Second national progress report on the promotion and use of energy from renewable sources dated December 2013 – Ref.Ares (201419337 – 07/01/2014).
4. The challenged provisions are Art. 35a paragraphs 1, 2 and 3, Art. 35b paragraphs 1, 2, 3 and 4, Art. 35 paragraphs 1, 2 and 3 and Art. 73 paragraphs 1, 2, 3 and 4 of the RES Law introduced with §6 it. 2 and it. 3 of the Transitional and Concluding Provisions of the State Budget Law for 2014.
5. Decision No. 13 of 31 July 2014 on case No. 1/2014 of the Constitutional Court.
6. Decision No. 33 of 14 September 2012 of the Regulatory Commission.
7. The revocation was achieved for the appealed part of decision (eg, the fee applicable to solar plants commissioned in the first half of 2012). According to Bulgarian law the appellant has to demonstrate legitimate interest in filing of the appeal. Therefore, if an appeal is filed by a producer with a solar plant commissioned in the first half of 2012, the court considers for review only the interim access fee applicable to such plants.
8. Then the regulator approved the final access fees closing the procedure which was initiated in September 2012.
9. Decision No. Ц-6 of 13 March 2014 of the Regulatory Commission.
10. Decision No. KM-1 of 13 March 2014 of the Regulatory Commission.
11. The producers of electricity from renewable sources other than wind and solar energy are to be reimbursed for the entire amount paid as interim access fees.
12. The Electricity Trading Rules (*Правила за търговия с електрическа енергия*) issued by the Regulatory Commission, promulgated in State Gazette issue 66 of 26 July 2013, last amended in State Gazette issue 39 of 9 May 2014.
13. With respect to renewable energy producers, the option to balance as a stand-alone was waived by the amendment of the Rules in May 2014.
14. Until January 2014, the Rules had never been applied in practice (except for the purpose of tests) and remained dormant because the material prerequisites for the operation of the balancing were missing and the costs for balancing of renewable energy plants were generally borne by the grid operators.
15. Rulings No. 1007, 1008 and 1009 of 23 July 2014 under case KZK-305/554/2013 of the Competition Commission.
16. Decision No. R-205 of 18 December 2013 of the Regulatory Commission.
17. Decision No. L-422 of 31 March 2014 of the Regulatory Commission.
18. The South Stream project was granted the national significance project status (*проект с национално значение*) under the Spatial Development Law and the national site status (*национален обект*) under the State Property Law.
19. The draft bill was approved in principle (*на първо четене*) on 4 April 2014.
20. Infringement proceeding No. 2014/2176 of the European Commission.
21. Despite the issue, a representative of Gazprom announced in the autumn that they expected to receive a construction permit for the project after the parliamentary elections in October 2014.

ENERGY LAW IN CROATIA

Recent developments in the Croatian energy market

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The transposition of the Third Energy Package into national law is an on-going process that continues to bring many new developments to the country's energy sector. On 1 July 2013, Croatia joined the EU. This is expected to open the energy market further to potential domestic and foreign investors in the near future. However, the European Commission's Internal Energy Market progress report released on 13 October 2014 indicates that competition in Croatia's energy market is still very limited and further market opening is required to improve the investment climate and create incentives for new entrants.[1] Currently, the most discussed energy infrastructure projects in Croatia relate to the (re)construction of the thermal power plant Plomin in Istria and the planned construction of the LNG terminal on the island of Krk in the North Adriatic. The Croatian upstream sector is being put into focus with the government's plan to substantially expand oil and gas exploration and production activities in Croatia: the first international offshore licensing round has been launched in April 2014 and the first international onshore licensing round in July 2014.

SIGNIFICANT CHANGES TO THE LEGAL AND REGULATORY FRAMEWORK

Following the enactment of key energy-related laws in 2012 and 2013, legislative activities in 2014 focused primarily on the preparation and adoption of various secondary legislative instruments but also on further amendments to the existing legislation.

GENERAL ENERGY LAW

On 11 November 2012, in compliance with the Third Electricity and Gas Directives, the new Energy Act (*Zakon o energiji*, Official Gazette of the RoC 'Narodne Novine' Nos. 120/12 and 14/14) and the Act on the Regulation of Energy Activities (*Zakon o regulaciji energetskih djelatnosti*, Official Gazette of the RoC 'Narodne Novine' No. 120/12) entered into force. Both laws introduced a new general legal and institutional framework for energy activities in all energy sectors.

The new Energy Act lays down measures aimed at ensuring a secure and reliable energy supply as well as efficient power generation and use, energy policy and development measures, energy activities, public service obligations, energy prices, network connection terms and conditions and energy supply and customer protection.

Under the new Act on the Regulation of Energy Activities, the Croatian Energy Regulatory Agency (*Hrvatska energetska regulatorna agencija*; "HERA") has been vested with greater powers and responsibilities, in particular to set energy tariff rates. Feed-in tariff rates for electricity generated from renewable energy sources ("RES"), cogeneration and biofuel production are the only tariff rates set by the government.

On 26 July 2014, the new HERA Decision on the Procedure for Keeping Separate Accounts for Energy Operators (*Odluka o načinu i postupku vođenja razdvojenog računovodstva energetskih subjekata*, Official Gazette of the RoC 'Narodne Novine' No. 86/14 (the "Decision") entered into force. The Decision regulates the manner and procedure of conducting separate accounting and separate monitoring of business events. It lays down detailed rules in relation to special and separate bookkeeping, separation of asset accounts, liabilities, revenues and expenses, content and delivery of financial statements of the energy operators for the purpose of regulation of energy activities. Licensed energy operators carrying out one or more energy activities are subject to the Decision.

Although the new laws governing electricity and gas markets now provide for a simplified licensing procedure for electricity and gas traders or suppliers based in EU Member States interested in entering the Croatian energy market, HERA is still applying the old licensing rules in the licensing procedure in accordance with the existing Ordinance on Licenses for the Performance of Energy Activities (*Pravilnik o dozvolama za obavljanje energetskih djelatnosti*, Official Gazette of the RoC 'Narodne Novine' Nos. 118/07 and 107/09). This is due to a lack of new implementing bylaws, which, when adopted, should stipulate the exact licensing requirements.

ELECTRICITY

The Third Electricity Directive has been transposed through the new Electricity Market Act (*Zakon o tržištu električne energije*, Official Gazette of the RoC 'Narodne Novine' No. 22/13) with effect from 2 March 2013. The law establishes rules for the generation, transmission, distribution, supply and trade of electricity. It lays down rules relating to customer protection, the organisation and functioning of the electricity sector and open access to the market. It also lays down universal service obligations and the rights of electricity customers, including final customer rights, unbundling and transparency of accounts, financial statements, network access rules and reciprocity rules and cross-border transmission of electricity.

Perhaps the most significant change brought about by the new Electricity Market Act concerns the implementation of the unbundling regime. Croatia has opted for the independent transmission operator ("ITO") model, pursuant to which HEP Operator prijenosnog sustava d.o.o., which was renamed in July 2013 the Croatian Transmission System Operator (*Hrvatski operator prijenosnog sustava d.o.o*; "HOPS") will belong to the vertically integrated HEP Group (*Hrvatska elektroprivreda d.d.*; "HEP")[2], but will have to comply with strict regulatory conditions to ensure effective independence. However, the certification process of HOPS is still pending before HERA and has not been yet notified to the European Commission. In July 2014, HOPS adopted its first Ten Year Network Development Plan (2014 – 2023).[3]

Despite the fact that the Croatian electricity market has been fully opened since 1 July 2008, the electricity generation, distribution, and supply sectors are still dominated by HEP Group companies. *De facto* opening of the electricity market took place in June 2013 when two new retail players – the German energy company RWE and the Slovenian company GEN-I – have entered the Croatian electricity supply market.

Currently, there is only one relevant market for electricity trading in Croatia. Wholesale electricity trading is based exclusively on bilateral agreements. However, it should be noted that the Electricity Market Act introduces different wholesale electricity markets for the first time: (i) a bilateral electricity market; (ii) a balancing electricity market; and (iii) the electricity stock exchange. To this end, the Croatian Energy Market Operator (*Hrvatski operater tržišta energije d.o.o.*; "HROTE") and HOPS signed a co-operation agreement on the establishment of an electricity stock exchange on 7 November 2013. The Croatian day-ahead electricity exchange CROPEX is expected to be put into operation, instead of by the end of 2014 as planned, in the first quarter of 2015.

In the course of 2013 and 2014, HERA adopted and/or amended a large number of bylaws prescribed by the new Electricity Market Act, such as:

- the methodology for determining prices for the calculation of balancing energy to parties responsible for imbalances (*Metodologija za određivanje cijena za obračun električne energije uravnoteženja subjektima odgovornim za odstupanje*, Official Gazette of the RoC 'Narodne Novine' Nos. 121/13 and 82/14) with effect from 1 October 2013;
- the methodology for determining tariff rates for last resort supply (*Metodologija za određivanje iznosa tarifnih stavki za zajamčenu opskrbu električnom energijom*, Official Gazette of the RoC 'Narodne Novine' No. 158/13) with effect from 1 January 2014;
- the decision on tariff rates for last resort supply (*Odluka o iznosu tarifnih stavki za zajamčenu opskrbu električnom energijom*, Official Gazette of the RoC 'Narodne Novine' No. 73/14) with effect from 1 July 2014; and
- the methodology for determining tariff rates for electricity supply within the universal service (*Metodologija za određivanje iznosa tarifnih stavki za opskrbu električnom energijom u okviru univerzalne usluge*, Official Gazette of the RoC 'Narodne Novine' Nos. 116/13 and 38/14) with effect from 27 March 2014, etc.

Nevertheless, much of the secondary legislation, which will ensure the full and effective implementation of the Third Electricity Directive and the Electricity Market Act, still remains to be adopted.

THERMAL ENERGY

On 6 July 2013, in compliance with the Renewable Energy Directive and the Energy Efficiency Directive, the new Thermal Energy Market Act (*Zakon o tržištu toplinske energije*, Official Gazette of the RoC 'Narodne Novine' Nos. 80/13, 14/14 and 102/14) entered into force. The law has brought substantial changes to the regulation, organisation and functioning of the thermal energy sector aimed at developing market, promoting new investments in heating systems, energy efficiency in the thermal energy generation and use as well as enabling improved and more effective relations between market participants in the thermal energy market. To this end, one of the important amendments introduced by the new law is related to the unbundling of the thermal energy generation, distribution and supply and the introduction of a thermal energy customer as the new energy activity.

In the course of 2014, HERA adopted a large number of bylaws prescribed by the new Thermal Energy Market Act, such as the General Conditions for Thermal Energy Supply (*Opći uvjeti za opskrbu toplinskom energijom*, Official Gazette of the RoC 'Narodne Novine' No. 35/14) with effect from 1 September 2014, the General Conditions for Thermal Energy Delivery (*Opći uvjeti za isporuku toplinske energije*, Official Gazette of the RoC 'Narodne Novine' No. 35/14) with effect from 1 September 2014, the Grid Rules (*Mrežna pravila za distribuciju toplinske energije*, Official Gazette of the RoC 'Narodne Novine' No. 35/14) with effect from 1 September 2014, the methodology for determining tariff rates for generation of thermal energy (*Metodologija utvrđivanja iznosa tarifnih stavki za proizvodnju toplinske energije*, Official Gazette of the RoC 'Narodne Novine' No. 56/14) with effect from 15 May 2014, the Methodology for determining tariff rates for distribution of thermal energy (*Metodologija utvrđivanja iznosa tarifnih stavki za distribuciju toplinske energije*, Official Gazette of the RoC 'Narodne Novine' No. 56/14) with effect from 15 May 2014, and the Ordinance on the Allocation and Calculation of Costs for Supplied Thermal Energy (*Pravilnik o načinu raspodjele i obračunu troškova za isporučenu toplinsku energiju*, Official Gazette of the RoC 'Narodne Novine' No. 99/14) with effect from 1 September 2014, etc.

RENEWABLE ENERGY

In October 2013, the Croatian government adopted the National Action Plan for RES for the period until 2020. By 2020, it targets the achievement of the following share from RES in total electricity production: 79.6% from large and small hydropower plants; 10.5% from wind farms; 8.3% from biomass plants; 0.9% from geothermal plants; and 0.7% from solar power plants.

Since the National Action Plan for RES sets a target for wind energy of 400MW by 2020, the Croatian government aims to attract more investments in biomass plants, cogeneration plants and small hydropower plants. This changed focus is now also reflected in the current tariff system for electricity production from RES and cogeneration (*Tarifni sustav za proizvodnju električne energije iz OIEiK*, Official Gazette of the RoC 'Narodne Novine' Nos. 133/13, 151/13, 20/14 and 107/14), effective as of 1 January 2014. In particular, the tariff system provides for a cut in the feed-in tariff rate for wind power.

Due to a lack of available capacity for the connection of the wind farms to the grid, it is currently only possible to connect up to 400MW of wind energy to the grid. According to information available on the website of HOPS, the quota of 400MW has been reached. Thus, new wind farm projects have been put on hold.

Under the existing tariff system the maximum quota for solar energy has been set at 12MW: 5MW for integrated solar power plants; 2MW for integrated solar power plants located on state-owned facilities, which have a capacity of up to 300kW; and, 5MW for non-integrated solar power plants.

In the course of 2013 and 2014, a number of pieces of secondary legislation have been adopted and/or amended, such as:

- the new regulation on setting up the system of guarantee of electricity origin (*Uredba o uspostavi sustava jamstva podrijetla* *električne energije*, Official Gazette of the RoC 'Narodne Novine' Nos. 84/13 and 20/14) with effect from 11 July 2013;

- the Rules on using the registry of guarantee of electricity origin (*Pravila o korištenju registra jamstava podrijetla električne energije*, HROTE of 16 April 2014);
- the Regulation on fees for promoting electricity production from RES and cogeneration (*Uredba o naknadi za poticanje proizvodnje električne energije iz OIE i kogeneracije*, Official Gazette of the RoC 'Narodne Novine' No. 128/13) with effect from 1 November 2013; and
- the Ordinance on attaining the status of eligible electricity generators (*Pravilnik o stjecanju statusa povlaštenog proizvođača električne energije*, Official Gazette of the RoC 'Narodne Novine' Nos. 132/13, 81/14 and 93/14) with effect from 12 November 2013, etc.

Although the preparation of the new Act on the RES is still pending, no draft proposals are made publicly available so far.

GAS

The transposition of the Third Gas Directive has taken place through the new Gas Market Act (*Zakon o tržištu plina*, Official Gazette of the RoC 'Narodne Novine' Nos. 28/13 and 14/14) with effect from 14 March 2013. The law establishes rules for the generation, transportation, distribution, supply and storage of gas and the operation of LNG terminals. It lays down the rules relating to customer protection, organisation and functioning of the natural gas sector and open access to the market. It also sets out the criteria and procedures applicable to the granting of a concession for gas distribution and a concession for building a distribution system, rules relating to the third party access, balancing group model, public service obligations and the rights of gas customers, including final customer rights, unbundling and transparency of accounts, financial statements, network access rules, reciprocity rules and cross-border transportation of gas.

As regards the unbundling, the new Gas Market Act has transposed all the three model options envisaged by the Third Gas Directive. Although the unbundling of activities related to gas transportation and storage already happened in 2002, the certification process of PLINACRO as ownership unbundled TSO before HERA is still pending.

The INA-MOL dispute

INA-INDUSTRIJA NAFTE d.d. ("INA") is the key market player in the Croatian gas industry, a vertically integrated company with MOL Hungarian Oil and Gas Plc. (49.08 per cent) and the Croatian government (44.84 per cent) as its biggest shareholders.[4] Under the Shareholders' Agreement (2009), MOL gained operational control of INA. Although the shareholders' agreement committed the Croatian government to take over the gas trading business of INA (ie, the import business of PRIRODNI PLIN) by December 2010, this issue remains unresolved during the ongoing negotiations between the government and MOL. At the end of November 2013, MOL lodged an ICSID claim against the Croatian government under the Energy Charter Treaty before the ICSID tribunal in Washington. In January 2014, the Croatian government initiated arbitration under UNCITRAL rules in Geneva to nullify the 2009 Amendments to the Shareholders' Agreement and the Gas Master Agreement (and its First Amendment).[5] Following the final court judgment in June 2014 sentencing the former Croatian Prime Minister to imprisonment for taking a bribe from MOL in 2008 in exchange for securing MOL's dominant position in INA, the dispute for control over INA continues. However, both parties agreed to continue negotiations in order to find a solution. Since the Croatian government is focused on the issue of INA's corporate governance and wants to renegotiate the 2009 shareholders' agreement, allegedly one solution would be that MOL sells its stake in INA to a new strategic investor.

Postponement of full gas market liberalisation until April 2017

Despite the fact that the Croatian gas market has legally been fully opened since 1 August 2008, the necessary conditions for the actual opening of the market have been met only recently. Primarily these are related to the construction of the Croatian Hungarian interconnector gas pipeline (Donji-Miholjac – Dravaszerdahely) and are important technical pre-conditions for the gas system itself and the adoption of gas related bylaws. The first signs of *de facto* opening of the market have occurred in the gas season 2012/2013 following the removal of price cap for gas supplies to eligible customers and new wholesale suppliers entering the market. Under the old legal regime, all public suppliers used to purchase gas at prices regulated by the Croatian government from the company PRIRODNI PLIN. In light of this, INA (through its affiliated company PRIRODNI PLIN) as the major wholesale natural gas supplier, and at the same time, the importer of natural gas, continued to dominate the gas supply market with a market share of nearly 68% until 31 March 2014.

Following the latest amendments to the Gas Market Act with effect from 13 February 2014, barriers to market access have remained a problem. On 1 April 2014 the state-owned electricity utility HEP was appointed the new supplier on the wholesale market in Croatia, taking over the similar role of 'supplier of public suppliers' from a procurement entity PRIRODNI PLIN. This means that in the period until 31 March 2017 HEP will be the key wholesale gas supplier to other Croatian suppliers with PSOs for the needs of household customers. INA, as the only Croatian producer of natural gas, is under an obligation to sell a set volume of gas to HEP at a regulated price. For a further three years, from 1 April 2014 until 31 March 2017, the Croatian government will continue to regulate the price at which gas produced in Croatia is sold to HEP and the price at which HEP then sells to other PSO suppliers. In addition, HEP has been awarded 70% priority for booking storage capacity with the only underground natural gas storage PSP Okoli operated by Podzemno Skladište Plina d.o.o. (owned by PLINACRO; "PSP"). These government measures, which were put in place on 1 April 2014,[6] constitute barriers to cross-border gas trade and raise serious concerns as to compliance with the Gas Market Directive.[7,8] In its Internal Energy Market progress report released on 13 October 2014, the Commission has pinpointed that postponing full liberalisation of the Croatian gas market until April 2017 contradicts Croatia's commitments under the accession negotiations.[9]

Other significant changes introduced under the new law are related to the introduction of the entry-exit model and a virtual trading point ("VTP") as of 1 January 2014. VTP is defined as a point of gas trading after its entry into the transmission network and prior to its exit from the transmission network including the gas storage system. To trade on the VTP it is not required to book entry – exit capacity or storage system capacity. However, only a balancing responsible party (*voditelj bilančne skupine*) who is a transmission system user is entitled to trade on the VTP. This means that in fact only market parties in possession of supply or trade licence and who have signed a transport contract with the TSO can gain access to VTP. HROTE publishes on its official website the form which allows the placing of a bid for the purchase or sale of gas on the VTP. Trading at the VTP is done independently between the balancing responsible parties; neither the TSO nor HROTE act as a clearing house, hence every party bears the counterparty risks of the other. The parties can use bespoke agreements or the standard agreements published on HROTE's website.

On 24 June 2014, in accordance with the requirements of the EU Regulation No. 994/2010 on Security of Gas Supply, the Croatian government adopted the Preventive Action and Emergency Plan by way of a decision on the Plan of Intervention on Measures for the Protection of Gas Supply Security of the Republic of Croatia (*Odluka o donošenju Plana intervencije o mjerama zaštite sigurnosti opskrbe plinom Republike Hrvatske*, Official Gazette of the RoC 'Narodne Novine' No. 78/14).

In order to ensure the full and effective implementation of the new legal framework, a whole set of new secondary legislations were put in place in the course of 2014, such as:

- the General Conditions of Natural Gas Supply (*Opći uvjeti opskrbe plinom*, Official Gazette of the RoC 'Narodne Novine' No. 158/13) with effect from 1 January 2014;
- the Gas Distribution System Grid Code (*Mrežna pravila plinskog distribucijskog sustava*, Official Gazette of the RoC 'Narodne Novine' No. 158/13) with effect from 1 January 2014;
- the Rules on the Gas Market Organisation (*Pravila o organizaciji tržišta plina*, HROTE No. 9/14)[10] with effect from 1 October 2014;
- the Transport System Grid Code (*Mrežna pravila transportnog sustava*, PLINACRO No. 6/14)[11] with effect from 1 January 2014;
- the Storage Code (*Pravila korištenja sustava skladišta plina*, PSP No. 12/13)[12] with effect from 1 January 2014; and
- the Regulation on the amount and method of payment of fees for the concession for gas distribution and concession for building of distribution systems (*Uredba o visini i načinu plaćanja naknade za koncesiju za distribuciju plina i koncesiju za izgradnju distribucijskog sustava*, Official Gazette of the RoC 'Narodne Novine' No. 31/14) with effect from 1 April 2014.

In addition, HERA also adopted the following methodologies and decisions in the course of 2013 and 2014:

- the methodology for determining tariff rates for gas distribution (*Metodogija utvrđivanja iznosa tarifnih stavki za distribuciju plina*, Official Gazette of the RoC 'Narodne Novine' No. 104/13) with effect from 22 August 2013;
- the methodology for determining tariff rates for gas transportation (*Metodologija utvrđivanja iznosa tarifnih stavki za transport plina*, Official Gazette of the RoC 'Narodne Novine' Nos. 85/13 and 158/13) with effect from 28 December 2013;
- the methodology for determining gas system balancing energy prices (*Metodologija utvrđivanja cijene energije uravnoteženja plinskog sustava*, Official Gazette of the RoC 'Narodne Novine' No. 158/13) with effect from 28 December 2013;
- the methodology for determining prices for non-standard services for gas transport, distribution, storage and public service of gas supply (*Metodologija utvrđivanja cijene nestandardnih usluga za transport plina, distribuciju plina, skladištenje plina i javnu uslugu opskrbe plinom*, Official Gazette of the RoC 'Narodne Novine' No. 158/13) with effect from 4 January 2014;
- the methodology for determining tariff rates for gas storage (*Metodogija utvrđivanja iznosa tarifnih stavki za skladištenje plina*, Official Gazette of the RoC 'Narodne Novine' No. 22/14) with effect from 20 February 2014;
- the methodology for determining tariff rates for public service of gas supply and last resort supply (*Metodologija utvrđivanja iznosa tarifnih stavki za javnu uslugu opskrbe plinom i zajamčenu opskrbu*, Official Gazette of the RoC 'Narodne Novine' No. 38/14) with effect from 1 April 2014; and
- the methodology for determining fees for the connection to the gas distribution or transmission system and for increasing the connection capacity (*Metodologija utvrđivanja naknade za priključenje na plinski distribucijski ili transportni sustav i za povećanje priključnog kapaciteta*, Official Gazette of the RoC 'Narodne Novine' No. 76/14) with effect from 25 June 2014.

DOWNSTREAM OIL

On 20 February 2014, a new Act on Oil and Oil Derivatives Market (*Zakon o tržištu nafte i naftnih derivata*, Official Gazette of the RoC 'Narodne Novine' No. 19/14) came into force. Perhaps the most significant change introduced under the new law is that the price of crude oil and petroleum products is to be set by the market. By way of exception, the Croatian government can, for the purpose of consumer protection, market regulation or if justified by other reasons, set the maximum retail prices for certain petroleum products for a continuous period of maximum 90 days. Other significant changes brought by the new law are that oil transportation by oil pipeline is no longer regulated energy activity and the negotiated third party access is no longer based on the tariff system for oil transportation. The price for oil transportation by pipeline is based upon negotiated commercial conditions.

Much of the secondary legislation, which will ensure the full and effective implementation of the new legal framework, remains to be adopted in the upcoming period. On 20 November 2014, a new Ordinance on Data Delivery by the Energy Undertakings to the Ministry (*Pravilnik o podacima koje su energetski subjekti dužni dostavljati Ministarstvu*, Official Gazette of the RoC 'Narodne Novine' No. 132/14) entered into force.

UPSTREAM

Currently, there are 60 production (also called exploitation) concessions of hydrocarbons (57 onshore and 3 offshore) in Croatia.[13] In 2013, a completely new general legal and institutional framework for the exploration and production of mining and hydrocarbon resources as well as carbon dioxide capture and geological storage was introduced in Croatia in order to meet the requirements of both the Hydrocarbons Licensing Directive and the CCS Directive. Three key interrelated pieces of legislation were put in place: the new Mining Act (*Zakon o rudarstvu*, Official Gazette of the RoC 'Narodne Novine' Nos. 56/13 and 14/14), which takes effect from 18 May 2013; the Hydrocarbons Exploration and Production Act (*Zakon o istraživanju i eksploataciji*, Official Gazette of the RoC 'Narodne Novine' Nos. 94/13 and 14/14), which takes effect from 30 July 2013; and, the Ordinance on Permanent Disposal of Gas in Geological Structures (*Pravilnik o trajnom zbrinjavanju plinova u geološkim strukturama*, Official Gazette of the RoC 'Narodne Novine' No. 106/13), which takes effect from 31 September 2013.

In accordance with the Act on Establishment of the Hydrocarbon Agency (*Zakon o osnivanju Agencije za ugljkovodike*, Official Gazette of the RoC 'Narodne Novine' No. 14/14), the Croatian

Hydrocarbon Agency (*Agencija za ugljikovodike*; "AZU") was established in February 2014. The AZU provides operational support to competent administration authorities in the domain of exploration and production of hydrocarbons and permanent geological storage and it is responsible for, *inter alia*, the launch of a public tender process for the award of a licence for exploration and concession for production, supervision of the licensed activities as well as cooperation with investors, etc.[14]

Finally, the government adopted the Regulation on Fees for Exploration and Production of Hydrocarbons (*Uredba o naknadama za istraživanje i eksploataciju ugljikovodika*, Official Gazette of the RoC 'Narodne Novine' Nos. 37/14 and 72/14), which takes effect from 24 March 2014.

The adoption of the new legal framework applicable to the exploration and production of hydrocarbons has resulted in the opening of the upstream market. Following this, at the end of 2013 the Norwegian seismic imaging services company Spectrum Geo conducted seismic surveys of hydrocarbons reserves in the Adriatic. Results from the seismic surveys revealed the existence of potential deposits of gas and oil in the central and southern Adriatic.

The first international offshore & onshore licensing rounds launched

With the aim of substantially expanding exploration and production activities in the upcoming period, the Croatian government launched the first international offshore licensing round for the exploration of 29 blocks in the Adriatic Sea, covering approximately 36,823 km², on 2 April 2014. The application period has ended on 3 November 2014.[15] At the moment, a strategic environmental assessment ("SEA") process is ongoing. The Framework plan and programme for the exploration and production of hydrocarbons in the Adriatic has been submitted for public consultation from 29 August until 29 September 2014.[16] According to the most recent publicly available information, the expert committee has selected the first three applications out of six received, among which are allegedly the US company Marathon Oil, the Italian company ENI and the Croatian company INA. It is expected that the Government will adopt the final selection decision(s) until mid December. The PSA with the selected applicants is expected to be signed in the course of March 2015 after the SEA process is completed.

Subsequently, the first international onshore licensing round for the exploration of 6 blocks across the Drava, Sava and East Slavonia regions, covering approximately 15,000 km², has been open since 18 July 2014. The application period ends on 18 February 2015. The licence award deadline is set for 18 March 2015 and the PSA execution deadline for 18 June 2015.[17] An SEA process has been initiated recently. The Ministry of Economy recently launched a public consultation on the Framework plan and programme for the exploration and production of hydrocarbons onshore.[18]

The bid documentation for both the offshore and onshore licensing round includes a draft of PSA agreement with royalty and applicable taxes. The licence may be granted for a maximum of 30 years and covers the exploration period of up to five years and the production period. The exploration period may be extended maximum twice for a period of six months in justified cases.

Expected changes to the legal framework on safety of offshore gas and oil operations

While the recent government actions are primarily aimed to boost investment in Croatia's upstream gas and oil sector, there are serious concerns among environmental NGOs and the public that the offshore drilling plans in the Adriatic pose a significant threat to the marine environment and coastal economies in particular country's thriving tourism industry and fisheries activities.

Under the existing legal framework, the Ordinance on the main Technical Requirements on Safety and Security of Offshore Exploration and Production of Hydrocarbons in the Republic of Croatia (*Pravilnik o bitnim tehničkim zahtjevima, sigurnosti i zaštiti pri istraživanju i eksploataciji ugljikovodika iz podmorja Republike Hrvatske*, Official Gazette of the RoC 'Narodne Novine' No. 52/10) sets out special minimum requirements applicable to offshore oil and gas operations. In addition to the measures enshrined in the Croatian primary and secondary legislation, and EU regulations, a whole set of specific measures will have to be implemented in the course of offshore oil and gas operations to prevent and reduce pollution in case of accident and to achieve a high level of environmental protection.[19]

Croatia has until 19 July 2015 to transpose the requirements of the Offshore Safety Directive into national law. However, no draft proposals are publicly available so far. In light of this, the implementation of the Offshore Safety Directive will have implications on the responsibilities and liability of offshore operators and licence holders in Croatia. Operators of planned offshore gas and oil installations and operations in Croatia will have to comply with new national legislation by 19 July 2016. However, existing installations will have until 19 July 2018 to comply with the new regulatory requirements.

NEW LEGAL FRAMEWORK FOR KEY ENERGY INFRASTRUCTURE PROJECTS

The implementation of legislative and non-legislative measures as required by the New TEN-E Regulation is still pending. In September 2014, the Ministry of Economy published the Manual on the permit granting process for PCIs.[20] In the context of the legal framework proposed,[21] the Center for Monitoring Business Activities in the Energy Sector and Investments (*Centar za praćenje poslovanja energetskog sektora i investicija*; "CEI") is designated as the national one-stop-shop authority for Projects of Common Interest ("PCIs").

At the outset, CEI was established by the Croatian government at the end of March 2012 with the objective to improve and monitor investment projects undertaken by the state and state-owned companies in the energy sector. For this purpose, the register on investments has been set up in January 2013.[22]

PROPOSED AMENDMENTS TO THE STRATEGIC INVESTMENT PROJECTS ACT

The main aim of the Act on Strategic Investment Projects of the Republic of Croatia (*Zakon o strateškim investicijskim projektima Republike Hrvatske*, Official Gazette of the RoC 'Narodne Novine' No. 133/13), which was put into force on 14 November 2013, is the establishment of the one-stop-shop for projects of strategic importance to the Croatian state. These could include private, public or public-private investment projects, among others, in the areas of energy, transport, infrastructure or environmental protection etc.

The law lays down detailed criteria that projects must meet and the procedure for assessment and selection of strategic investment projects. For instance, a project must meet a minimum eligibility threshold of (i) €20 million, or (ii) €10 million in case the project would be co-financed from the EU funds and programmes, or (iii) €2.7 million if the investment would be implemented in less developed areas, or falls within the area of agriculture and fisheries.

If a project has obtained strategic investment status, all of the administrative procedures necessary for preparation and implementation of the designated strategic project should be streamlined and accelerated.

So far, only five projects have been included into the list of strategic projects. Among energy infrastructure projects these are the planned construction of the coal fired thermal power plant Plomin C in Istria[23] and the construction of the LNG terminal on the Island of Krk in the North Adriatic (see below for further details regarding the status of projects).

Since the current implementation of this law has revealed certain deficiencies, in particular in relation to criteria for eligibility of (private) projects, whose financing has not yet been completed, and the need to strengthen the administrative capacity for the preliminary verification of project applications, the Croatian government has proposed a number of amendments to the existing legislative framework in order to remedy these shortcomings and improve investment conditions in Croatia. On 12 December 2014, the Croatian Parliament adopted the Act on Amendments to the Act on Strategic Investment Projects of the Republic of Croatia.[24]

The most important amendments include:

- Introduction of new rules governing the 'potential strategic projects', as projects which could be implemented on predominantly state-owned real estate, on the real estate under majority co-ownership of the state and the local and regional self-government units, as well as on the maritime domain. Since the statutory language is rather vague and unclear, these possibilities have been highly criticised for – among other things – enabling the government to dispose of real estate properties under a special legal regime (eg forests and maritime domain) and thus open door to preferential treatment, personal gain and corruption.

  In contrast to the current procedure, the proposed amendments envisage that the selection of a strategic investor for such projects must be conducted by way of a public invitation to tender.
- Simplifying the requirements with regard to the verification of the financial capacity of the applicants. So far, private investments projects were not in position to provide evidence on a financial close at this very early stage and hence could not be selected.
- Introduction of an obligation for interested private investors to provide suitable collateral and evidence of secured sources of funding in the amount of at least 10% of the total project value within 60 days as of the adoption of the government's Decision on Designation of Strategic Investment Project.
- Administrative check of public-private and private investment projects will be handled by the Agency for Investments and Competitiveness (*Agencija za investicije i konkurentnost*; "AIK") or by the Center for Monitoring Business Activities in the Energy Sector and Investments (*Centar za praćenje poslovanja energetskog sektora i investicija*; "CEI") for projects within the energy sector.
- Alongside the Ministry of Economy, both the AIK and CEI will be entrusted with new tasks at the operational level.
- Involvement of the Croatian Ministry of Foreign and European Affairs (*Ministarstvo vanjskih i europskih poslova*) and the State's Attorney Office of the Republic of Croatia (*Državno odvjetništvo Republike Hrvatske*) in the formal process of conclusion of the Agreement on the Preparation and Implementation of the Project with the private investors in order to avoid potential state liability in case of a claim for breach of investors' legitimate expectations.

INCLUSION OF CROATIAN LNG TERMINAL IN THE UNION LIST OF PCIS

Several energy infrastructure projects in the field of electricity, gas and oil in Croatia have been included in the final list of PCIs published by the European Commission in October 2013.[25]

Among the identified projects in Croatia are two electricity clusters, the construction of a new high-voltage power transmission interconnection line between Croatia's Lika region and Banja Luka in Bosnia and Herzegovina and a new high-voltage power transmission interconnection line between Žerjavec in Croatia, Heviz in Hungary and Cirkovce in Slovenia.

Perhaps one of the most important projects in the gas sector, and especially so in the wake of the Ukrainian crisis, concerns the planned construction of the LNG terminal on the Island of Krk in the North Adriatic with a capacity of 4-6 billion m^3/year. This would open a cross European North-South corridor and improve the natural gas supply security of the region. On 29 October 2014, the project has been included in the indicative list of key energy infrastructure eligible for financial support under the CEF-Europe.[26] Currently, the project development company LNG Hrvatska d.o.o. (with HEP and PLINACRO each holding 50 percent of the equity shares thereof) is in process of obtaining the location permit. According to the most recent publicly available information, HEP is expected to take over the shares of PLINACRO (as the only country's TSO) in order to comply with the requirements of the Third Energy Package. On 5 November 2014, LNG Hrvatska d.o.o. launched a public tender for the selection of business, financial and legal advisor during the preparation phase for the construction of the LNG terminal.

Furthermore, the list also contains the Ionian-Adriatic Pipeline ("IAP"). The IAP project intends to connect the existing and the planned Croatian gas transportation system, via Montenegro and Albania with the Trans Adriatic Pipeline ("TAP") or similar. The total gas pipeline length from the Croatian town Split to Albanian town Fieri is 540km and an annual pipeline capacity of 5 billion m^3. This project, as a last costly N-1 solution for Croatia, would create a new energy corridor for the region.[27]

Additionally, the JANAF-Adria pipelines project has been given PCI status. The project involves the reconstruction, upgrade, maintenance and increase in capacity of the existing JANAF and Adria pipelines linking the Croatian Omisalj seaport, through Hungary, to the Southern Druzhba pipeline in Slovakia.

PLOMIN C PROJECT

As already mentioned above, one of the most important strategic investment projects at the moment is the planned construction of the coal fired thermal power plant Plomin C in Istria. By carrying the label "strategic investment project", it will benefit from faster and more efficient permit granting procedures and improved regulatory treatment. The current power plant consists of two boiler units, TPP Plomin 1 built in 1969 and TPP Plomin 2 built in 2000. Both are operated by the HEP, and the latter is co-owned with RWE Power AG. The project relates to the replacement of the existing TPP Plomin 1 unit with new unit Plomin C which will have a capacity of 500MW. The total project value is estimated to amount to around €800 million.

The project Plomin C is disputed by local community, civil society groups and environmental experts due to the fact that the plant will be coal-fired. However, in July 2012 the HEP launched the process of selecting a strategic partner for the coal-fired thermal power plant. On 2 September 2014, after the selection process between the three tenders received, the choice of the preferred bidder was made in favour of the consortium, consisting of the French energy company Alstom and the Japanese Marubeni Corporation. The second-ranked bidder is the Abeins (Spain) and Daewoo (South Korea) Consortium and the third-ranked one is Edison (Italy). Reportedly, the contract negotiations up to the signing of the contract with the preferred bidder are expected to be finalised by the beginning of 2015. The new Plomin C plant is expected to be put into operation by 2019.

ENDNOTES

1. Commission Staff Working Document Country Reports accompanying the document Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions "Progress towards completing the Internal Energy Market" (SWD/2014/0311 final of 13 October 2014, p. 30); available at http://ec.europa.eu/energy/gas_electricity/doc/2014_iem_communication_annex2.pdf.

2. HEP Group chart is available on the website of HEP at www.hep.hr.

3. Available on the website of HOPS at www.hops.hr.

4. INA Group chart is available on the website of INA at www.ina.hr.

5. Further information on the negotiations around INA's shareholding is available on the website of MOLGROUP at http://www.molincroatia.com/negotiations.

6. *Odluka o cijeni plina po kojoj je proizvođač prirodnog plina, prirodni plin proizveden na području Republike Hrvatske dužan prodavati opskrbljivaču na veleprodajnom tržištu plina* (Official Gazette of the RoC 'Narodne Novine' No. 29/14), *Odluka o cijeni plina po kojoj je opskrbljivač na veleprodajnom tržištu plina dužan prodavati plin opskrbljivačima u javnoj usluzi opskrbe plinom za kupce iz kategorije kućanstvo* (Official Gazette of the RoC 'Narodne Novine' No. 29/14), *Odluka o određivanju opskrbljivača na veleprodajnom tržištu plina* (Official Gazette of the RoC 'Narodne Novine' No. 29/14), *Odluka o određivanju obveze proizvođaču prirodnog plina prodaje prirodnog plina opskrbljivaču na veleprodajnom tržištu plina* (Official Gazette of the RoC 'Narodne Novine' No. 29/14), *Odluka o određivanju prioriteta prilikomprovođenja postupka za raspodjelu kapaciteta sustava skladišta plina opskrbljivaču na veleprodajnom tržištu plina* (Official Gazette of the RoC 'Narodne Novine' No. 29/14).

7. http://www.naturalgaseurope.com/western-balkans-european-energy-security-alan-riley

8. http://www.icis.com/resources/news/2014/04/09/9770833/european-commission-to-probe-new-croatian-natural-gas-market-regulation/

9. Commission Staff Working Document Country Reports accompanying the document Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions "Progress towards completing the Internal Energy Market" (SWD/2014/0311 final of 13 October 2014, p. 33); available at http://ec.europa.eu/energy/gas_electricity/doc/2014_iem_communication_annex2.pdf.

10. Available on the website of HROTE at www.hrote.hr.

11. Available on the website of PLINACRO at www.plinacro.hr.

12. Available on the website of PSP at www.psp.hr.

13. http://www.azu.hr/Portals/0/Dokumenti/CHA-License-Round-Opening.pdf

14. Further information is available on the website of AZU at www.azu.hr.

15. Further information on the offshore licence round is available on the website of AZU at: http://www.azu.hr/1st-offshore-license-round.

16. Further information is available on the Ministry of Economy's website at http://www.mingo.hr/page/odluka-o-izradi-okvirnog-plana-i-programa-istrazivanja-i-eksploatacije-ugljikovodika-na-jadranu-i-odluka-o-provodenju-postupka-strateske-procjene-utje

17. Further information on the onshore licence round is available on the website of AZU at: http://www.azu.hr/en-us/1st-Onshore-License-Round.

18. The public consultation process takes place from 27 October until 27 November 2014. Further information is available on the Ministry of Economy's website at http://www.mingo.hr/page/odluka-o-izradi-okvirnog-plana-i-programa-istrazivanja-i-eksploatacije-ugljikovodika-na-kopnu-i-odluka-o-provodenju-postupka-strateske-procjene-utjeca

19. See, to that effect, Annex 2 of the Tender Guidance to apply for 1st Croatian offshore licensing round for licenses for the exploration and production of hydrocarbons available at: http://www.azu.hr/1st-offshore-license-round.

20. Croatian version of the published Manual on the permit granting process for PCIs (*Priručnik za postupanje u postupcima odobravanja dozvola za projekte od zajedničkog interesa (PZI)*) is available on the Ministry of Economy's website at www.mingo.hr.

21. Croatian version of the published Draft Act on Amendments to the Act on the Center for Monitoring Business Activities in the Energy Sector and Investments is available on the Ministry of Economy's website at www.mingo.hr. The public consultation process has taken place from 25 April until 9 May 2014.

22. Further information is available on the website of CEI at www.cei.hr.

23. *Odluka o proglašenju projekta pod nazivom Rekonstrukcija TE Plomin – zamjena postojećeg bloka 1 s blokom C u cilju modernizacije i povećanja kapaciteta, strateškim projektom Republike Hrvatske* (Official Gazette of the RoC 'Narodne Novine' No. 61/14).

24. Croatian version of the published Draft Act on Amendments to the Act on Strategic Investment Projects of the Republic of Croatia as a final proposal together with a report on public consultation is available on the Croatian Parliament's website at http://www.sabor.hr/prijedlog-zakona-o-izmjenama-i-dopunama-zakona0052.

25. http://ec.europa.eu/energy/infrastructure/pci/doc/2013_pci_projects_country.pdf.

26. http://ec.europa.eu/energy/infrastructure/pci/doc/2014_cef_energy_lists.pdf.

27. Commission Staff Working Document Country Reports accompanying the document Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions "Progress towards completing the Internal Energy Market" (SWD/2014/0311 final of 13 October 2014, p. 36); available at http://ec.europa.eu/energy/gas_electricity/doc/2014_iem_communication_annex2.pdf.

ENERGY LAW IN CYPRUS

Recent developments in the Cypriot energy market

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INTRODUCTION

In 2014, a series of developments took place in the energy industry in Cyprus. These developments relate to the growing utilisation of Renewable Energy Sources ("RES"), the further exploration and appraisals of hydrocarbons in the Cyprus Exclusive Economic Zone ("EEZ") and the progress of a cross-border electricity grid.

In the past, energy consumption in Cyprus was broadly dominated by oil and petroleum products.[1] However, with the island's 2020 RES target indicator at 13%, the energy mix has seen a firm increase in energy diversification.[2] Going forward, Cyprus aims to reduce energy dependence whilst improving efficiency and making effective arrangements for energy security.

Cyprus also aims to provide attractive fiscal regimes[3] in order to incentivise investors, and despite its recent financial turmoil, the energy industry is experiencing a substantial influx of international investment.

The recent discoveries of natural gas in the Cyprus EEZ have shown promising prospects of development of the hydrocarbons industry, which is still in its infancy and is currently undergoing commercial and legislative developments. Parallel to the upstream oil and gas activities currently taking place in the Cyprus EEZ, the government also announced invitations of interest for proposals of participation in the joint venture that will be responsible for the development, financing, construction and operation of gas storage facilities and a Natural gas Liquefaction Plant.

In all energy-related activities the Ministry of Energy, Commerce, Industry and Tourism ("MCIT") and the Cyprus Energy Regulatory Authority ("CERA") have purported to provide, for the protection of the environment, the facilitation of healthy competition and encouraging the development of RES. The Ministry has also devised a policy regarding the objective of contributing to the European Strategic Oil Stock Scheme.[4] CERA has undertaken to fully align Cyprus policy with the European Directives and Regulations of the Third Energy Package on natural gas and electricity markets by the end of 2015 as well as targeting relatively low Greenhouse Gas emissions ("GHG") by 2020.

With the country going through a financial crisis, the prospect of reducing the amount of energy required for either the provision of products and services, or for private use, is attractive for both businesses and customers who are looking to make savings where they can. Strategic energy efficiency constitutes a top priority for Cyprus as an effective energy efficiency plan may result in reducing Cyprus' reliance on oil imports for power generation.

In complying with its EU obligations under the EU's Energy laws, Cyprus has adopted the European Commission's new Energy Efficiency Directive. For transposing the Directive to national legislation, two laws were amended and secondary legislation was adopted. The Law for Energy in End-Use and Energy Services and the Law for the Promotion of Combined Heat and Power Generation were adopted in June 2014.

ELECTRICITY

The legal framework surrounding the electricity sector in the Republic of Cyprus is comprised of three interrelated pieces of legislation. The Electricity Law Cap 170, which regulates and governs the generation, transmission and distribution of electricity; the Electricity Development Law Cap 171, which regulates the relationship between the Electricity Authority of Cyprus ("EAC") the state and the consumer; and the Electricity Market Regulation Law[5], which amended and repealed a number of sections in the aforementioned pieces of legislation and has established significant authorities and procedures to align the internal electricity market of the Republic of Cyprus with EU policy.

The Energy Service of the MCIT is the government authority that overseas and coordinates the energy sector in Cyprus and prepares the requisite legislation and policies. The MCIT is currently in the process of improving its standard of oversight by implementing necessary checks and balances within the sector.

Authority within the electricity sector of Cyprus lies with EAC and CERA. EAC is an independent semi-governmental company established by the Electricity Development Law Cap 171. EAC had a monopoly on the generation and supply of electricity in Cyprus until its succession to the EU in 2004. CERA regulates and serves to protect the security, quality and safety of electricity generation. CERA reserves the right to issue licences for all activities relating to electricity and gas and is responsible for approving tariffs, dispute resolution and securing a reliable electricity system. The Electricity Market Regulation Law provides that CERA is an independent authority not under the control of any ministry.

Another key body within the sector is the Transmission Systems Operator ("TSO"). Pursuant to the Electricity Market Regulation Law the ownership of the transmission system has been unbundled from its operation with the creation of the TSO, although the DSO remains under the EAC's control.

The TSO is deemed to regulate access to the electricity grid, codes for transmission and distribution and the general maintenance or development of the grid. Therefore, the TSO is able to act independently and avoid any conflict of interest.

Cyprus has been classified as a 'small isolated system' under both the Second and Third Energy Packages based on the fact that the island's industry has not integrated with any other neighbouring systems. This status currently grants the island derogation from the application of various Articles of Third Electricity Directive 72/2009/EC including the basic models for Unbundling of Transmission Systems. Cyprus is therefore allowed to maintain its current framework and structure on TSO unbundling.

Liberalisation of the electricity sector began to align with the targets set by the First and Second Electricity Directives concerning the common rules of the internal electricity market. These policies aim to protect consumers from monopolistic market conditions. The Republic of Cyprus was allowed to delay the requirement of 100% liberalisation until 2014. In 2009, the market had been further liberalised to 65% allowing even non-domestic users to select their suppliers. As of January 2014 the market has been fully liberalised. However to date, no private power plants have been built.

A CERA report commissioned to LDK E-Bridge in 2013[6] which involved a study relating to the remodelling of the electricity market in Cyprus, has provided the regulatory body with three option scenarios as to how the market can be restructured (ie, (i) Gross Pool; (ii) Bilateral Contracts; and (iii) Net Pool). These scenarios involve and take into account the possibility of integrating RES into the market. The report,[7] published in March 2014, produced an evaluation presenting the 'Net Pool' model as the most appropriate trading arrangement approach for the Cyprus electricity market. The options were evaluated by CERA in terms of efficiency, sustainability and security, alignment with EU Directives and the protection of consumers from undesirable market conditions. In September 2014, CERA published its opinion[8] and proposed to the MCIT to proceed with the 'Net Pool' approach. In addition, CERA has also sought counsel for the detailed design of this model and is also currently planning for public consultation.

EAC has also introduced net-metering within the industry via the "Solar Energy for All" Scheme, a service which allows electricity consumers (households, local administration buildings and commercial industrial units) who are also electricity producers (via an eligible on-site generating facility delivering to the grid) to offset their generated electricity against the electric energy provided by the utility to that consumer. This scheme aims to incentivise investment in electricity assets and provide for a healthier, more competitive market.

Building a cross-border electricity grid to serve the purpose of linking the island's electricity distribution and transmission system has been a main concern for the MCIT. Though the electricity system in Cyprus operates without cross-border links, on 8 August 2013 the MCIT signed a Memorandum of Understanding ("MoU") with Israel and Greece on cooperation in the fields of energy and water, welcoming joint projects in the energy sector to enhance the security of energy supply, sustainable development and cooperation among the countries in the region. Following the MoU, it has been agreed that parties will co-operate in constructing what is known as the EuroAsia Interconnector. The project is essentially an electrical cable bridge with three arches that will create a network of electrical energy amongst the three states via their established EEZs. This project is aimed at enhancing the pan-European grid network and will be the first energy bridge between Europe and Asia.

GAS MARKET

Currently there is no gas production or trading in Cyprus. The principal legislative instrument governing the domestic gas sector is the Gas Market Law 183(i)/2004 (as amended) (the "Gas Market Law") which has been put in place in anticipation of the arrival and production of gas in Cyprus. Under the Gas Market Law the overall policy responsibility for the gas sector rests with the Council of Ministers. The Council has the authority to appoint a body responsible for the operation of the transportation and storage network as a whole. Furthermore, under the Gas Market Law, CERA is the national regulatory body that has oversight over the gas market and can issue regulations in relation to issues governed by the Gas Market Law.

As part of the efforts to secure an uninterrupted supply of Natural Gas, the Government has established a 100% government-owned natural gas public company, DEFA, which is responsible for the internal gas market in Cyprus; for the import, storage, distribution and transportation of LNG and the management of the distribution and supply system of LNG in Cyprus. DEFA's role is to ensure that Natural Gas is available in power plants and industrial plants. At the time of writing, efforts towards the import and use of natural gas for power generation are under development. DEFA has invited applicants to place bids for the supply of natural gas for a period of up to ten years. Four proposals were received, however DEFA requested to extend the validity of these bids so as to carefully carry out the commercial examination. Negotiations will soon take place between DEFA and the bidders.

The statutory framework for third party access to the gas transportation system is contained in section 7 and 47(2)(a) of the Gas Market Law. Access is governed by CERA. CERA has the power to approve the tariffs and terms and conditions. Under the Gas Market Law, where an application is received for third party access in respect of construction facilities, supply or import of natural gas, CERA will evaluate the application in an objective and non-discriminatory manner. Regulations issued by CERA provide information on tariffs for transportation and distribution.

Currently there is no LNG terminal in Cyprus. Due to the recent discoveries of natural gas and developments in the hydrocarbons sector, there are plans for the construction and development of a Transmission and Distribution Natural Gas Pipeline Network. This network will consist of three pipelines that will supply the three Power Stations of the Electricity Authority of Cyprus in Vasilikos, Dhekelia and Moni. The initial network will serve as the backbone for the development of the future network which will extend to households, businesses, city buses and other public transport, cogeneration plants and greenhouses. The initial network is estimated to have a total length of about 80km. The project has already secured sponsorship of €10m from EU funds under the European Economic Programme for Recovery.

DEFA has received four proposals to supply natural gas to the island as an interim solution for power generation by the EAC before its own reserves become available. Based on its initial invitation for proposals, issued in January, DEFA is seeking up to 10 years of natural gas to be supplied, commencing in January 2016. The tender published by DEFA calls for the supply of between 0.7 and 0.95 billion cubic meters of natural gas annually to the Cypriot market through two delivery routes. One route will begin supplying gas in early 2016 and the other no later than the second half of 2017.

In August 2014, DEFA announced that it had finished assessing the bids submitted by interested suppliers of natural gas and would commence direct negotiations with the bidders. The evaluation concerned the application of a set of pass/fail criteria for proposals received. The criteria included:

- the bidder's financial standing;
- creditworthiness;
- experience and technical capability; and
- the technical suitability of the bidder's proposal.

HYDROCARBONS EXPLORATION AND EXPLOITATION

Offshore exploration in Cyprus for oil and gas is ongoing. Cyprus has established its sovereign right to hydrocarbons in the EEZ and in recent years has signed several agreements setting up its EEZ. The discovery of hydrocarbons and their exploitation will minimise Cyprus' dependency on imported energy supplies in the future.

The legal framework applies to the territorial waters, the continental shelf and the EEZ of Cyprus. It compromises the Hydrocarbon (Prospection, Exploration and Exploitation) Law 2007 (No. 4(I)/2007) and the Hydrocarbon (Prospection, Exploration and Exploitation) Regulations 2007 & 2009 (No.51/2007 and No. 113/2009). The laws and regulations implement Directive 94/22/EC concerning the conditions for granting and using authorisations for prospection, exploration and production.

There are three separate authorisations for upstream hydrocarbon activities. These authorisations cover three separate phases in the life cycle of hydrocarbon assets:

- Prospection – this authorisation does not exceed one year;
- Exploration – this authorisation does not exceed three years but can be renewed up to another two terms. On each renewal, 25% of the initial licence area is relinquished. In the event of a commercial discovery the licensee may apply for an exploitation licence; and
- Exploitation – this authorisation does not exceed 25 years but can be renewed for another ten years.

The conditions and requirements for an authorisation for exploration and exploitation are to be set out in an Exploration and Production Sharing Agreement ("EPSA") whilst a prospecting authorisation does not require an EPSA.

In accordance with the SEA Directive 2001/42/EC, MCIT has also carried out a Strategic Environmental Assessment ("SEA") of the area in which the oil fields are located. In this assessment, they have evaluated the likely consequential effects of setting up a hydrocarbon project in that area with regards to the marine life and environment. Further, the SEA also binds licensees to carry out an Environmental Impact Assessment which they are bound to comply with. In doing so they must conduct offshore activities within each licensed area in an environmentally acceptable and safe manner consistent with legislation and good industry practice.

The Exploration and Production Sharing Contract ("ESPC") issued and published by the MCIT sets out all of the terms and conditions of upstream activities agreed between the state and an international oil company. The Hydrocarbons Regulations empower the Minister[9] to issue a model production sharing contract[10] that a selected applicant enters into with the state. There has been a previous model contract[11] issued for the first licensing round of 2007 however, since the second licensing round of 2012, an updated version has been published. The current model agreement sets out fundamental aspects of the project such as minimum work obligations, the development and production plans as well as all upstream fiscal provisions. Such fiscal arrangements include the payments of a signature bonus (payable upon signing of the contract), a production bonus (payable in two tranches upon reaching two distinct target production levels) and the formulae for cost oil recovery and profit oil sharing.

The island's EEZ is divided into 13 blocks. There have been two licensing rounds so far. In the first licensing round in 2007, a licence was issued to Noble Energy International Ltd (Noble) for the exploration and exploitation of Block 12, the Aphrodite Gas Field where Noble has subsequently discovered natural gas. Appraisal activities are currently taking place to confirm and evaluate the recoverable quantities which is necessary for the planning and development of the infrastructure plans for the Cyprus hydrocarbons market as whole.

Following the second licensing round held between 11 February 2012 – 11 May 2012, 15 bids with a total of 33 applications were made for nine out of twelve; the MCIT awarded licences to the consortium of ENI-KOGAS for blocks 2, 3 and 9 and to Total for blocks 10 and 11. EPSCs licences were signed in January 2013 and February 2013, respectively. ENI-KOGAS carried out their first exploratory well in September 2013 and undertook first appraisal drillings in September 2014. Total are expected to carry out their first exploratory well in the first half of 2015.

The exploratory drillings within the EEZ in 2014 and 2015 will enable Cyprus to obtain a realistic view of what the oil reserves are in the relevant blocks.

Currently the government plans to build an LNG terminal adjacent to the Vasilikos area in Limassol for the liquefaction of natural gas and for the export of LNG by tanker to international markets.

On 26 June 2013 a Memorandum of Understanding was signed by the Republic of Cyprus, Noble and the Delek Group (Delek & Avner). This event was the first of several steps to be taken for the monetisation of Cyprus' offshore resource wealth. The agreement relates to the investment and construction of an LNG terminal to operate in the Vasilikos area. The agreement was expected to set off a series of future agreements with other partners and actors as well. With the aim of further aligning actions for the development of a land LNG Terminal, the Cypriot government and representatives of the ENI-KOGAS joint venture, in August 2014 signed a Memorandum of Understanding (MoU) similar to the one signed in 2013 with Noble. This agreement aims at investigating areas of cooperation related among other matters to the onshore LNG option. The agreement marks the completion of a series of agreements that Cyprus has with the licensees of the Blocks.

However, Noble's findings in themselves do not justify the pursuit of this endeavour. The final investment decision for the construction of the LNG terminal depends on the exploits of ENI-KOGAS, Total and Noble in the Cyprus EEZ, as the LNG terminal requires the discovery of at least 6 trillion cubic feet of gas to be commercially viable. Additional quantities of natural gas will allow a final investment decision for the construction of the LNG terminal. Noble will also be conducting further exploratory work in the EEZ.

If the natural gas quantities commercially justify the construction of an LNG plant, the plant will include facilities for the liquefaction of natural gas and the storage and export of LNG by tanker for transportation to the international markets. The Vasilikos Oil Terminal will also include facilities for the storage of operational oil reserves; facilities for the storage of strategic oil reserves and facilities to operate as an oil trading hub.

As mentioned above DEFA is responsible for the internal gas market in Cyprus and, in addition to that, a National Oil Company has been established. The private company was named KRETYK and has now been renamed to Cyprus National Hydrocarbons Company ("CNHC"). Aiming to increase transparency and establishing appropriate checks and balances a number of changes have been adopted with regards to the management of CNHC. These changes include the abolition of the previous board of directors and the appointment of a seven-member non-executive board and the authority granted to the Auditor-General to monitor the company's financial results and the actual operation of the company.

RENEWABLE ENERGY SOURCES

Cyprus is almost totally dependent on imported oil for its energy supply, with a small but growing contribution from RES. In accordance with the EU 20-20-20 initiative the government promotes the use of RES mainly through offering financial initiatives. Specifically, over the last few years the government has offered several financial grants to promote solar energy. Cyprus ranks highly at a global level in solar energy use for water heating in households[12] and has generally achieved an improvement in the RES share within the island's energy mix. The RES sector in Cyprus mainly involves wind farms and photovoltaic parks. The sector has set targets to reach 13% of the energy mix by 2020. Currently, the maximum output from RES in Cyprus (on average) reaches 181MW and the National Action Plan ("NAP") has set out to reach a minimum of 584MW by 2020.

RES initiatives in Cyprus include the EOS project[13] in Alasa, Limassol which will mainly utilise a Concentrated Solar Thermal (CST) storage system where water will be pumped through coils of stainless steel pipes in steel tanks containing high purity graphite blocks. The result will produce super-heated 'dry' steam which in turn will power a turbine to produce electricity. The main advantage of this particular system is the fact that the system itself is autonomous and can operate around the clock. Production is expected to begin in 2016 at 45% capacity and gradually reach full capacity by 2017. Production will be sold to the EAC at a price which is 40% cheaper compared to current sell prices of the EAC. This technology is also environmentally friendly as the water that evaporates into steam is re-circulated through the system; there are no Greenhouse Gas emissions involved and no chemicals or batteries are needed. The total cost of the EOS project in Cyprus is expected to be around 175m Euros and has received an EU grant which is expected to be between 47 and 60m Euros.

As required by the Renewable Energy Directive, Cyprus has adopted a national renewable energy action plan that has been in effect since 2010. In April 2014, Cyprus adopted and published its 3rd National Energy Efficiency Action Plan in compliance with Directive 2012/27/EU. The plan provides for all measures that are to be taken in order to achieve the mandatory targets, including energy efficiency and energy saving measures.

CLIMATE CHANGE

Cyprus has over the past few years started climate change mitigation initiatives to reduce industry emissions and improve the general protection of the environment. The most important development remains the implementation of the strategy for adapting to climate change which aims to strengthen and increase Cyprus' capacity to respond to climate change and its impacts, as well as identifying the potential opportunities associated with this sector and formulating proposals for specific action in both the short and long term. Operating as a two stage process, the national strategy for climate change adaptation initially focused on the creation of a knowledge base with regards to the implications of climate change, combining policies to maximise successful adaptation. The second phase, which consists of the implementation and monitoring of the strategy, was initiated in 2013. The implementation of the strategy is expected to be a long process, demanding close cooperation of all stakeholders.

In relation to the storage of carbon dioxide, Cyprus has implemented the CCS Directive by Law 71(I)/2012 which sets out the terms governing the application and issuance of storage permits. Despite legislative developments, there are, as yet, no carbon capture and storage projects in Cyprus. The CCS Directive covers the criteria for the sites of storage spaces as well as the obligations of the entity responsible for the storage. The Biofuel Directive was transposed into national law by Law 111(I)/2013.

With regards to the Renewable Energy Directive, Law 66(I)/2005 (as amended) includes the provisions relating to the use of biofuel and other renewable sources for transportation, and Law 33(I)/2003 (as amended) provides for the promotion of renewable energy sources in accordance with the provisions of Directive 2003/30/EC on the Promotion of the use of Biofuels and other Renewable Fuels for Transport.

ENDNOTES

1. These accounted for 96.3% of the island's energy consumption
2. RES energy mix share growth from 2.5% to 4.9% (2006-2010)
3. Revenue generation from energy-related activities
4. 2009/119/EC
5. Law 122(I) of 2003
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ENERGY LAW IN THE CZECH REPUBLIC

Recent developments in the Czech energy market

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RECENT MERGERS AND ACQUISITIONS

Several transactions have been completed in the past 12 months in the energy sector. Some of the most relevant mergers and acquisitions in the Czech Republic are presented below.

The largest energy deal in 2013 was the sale of Net4Gas, the gas distribution network, by RWE of Germany to a consortium comprising Allianz Capital Partners and Borealis Infrastructure Management. The sale was part of a broader disposal programme at RWE, which needed to reduce its debt to refocus its business to mitigate low power prices in a weak European economy and Germany's complete nuclear exit over the next 10 years.

The joint venture deal, which has been valued at €1.6 billion (US$2 billion), including debt, saw Allianz and Borealis each acquire a 50 percent stake in Net4Gas. One of the reasons behind the sale was pressure from the European Commission ("EC") to complete the separation of gas trading from the respective transmission system operator.

At the end of 2013, Energetický a Průmyslový Holding, a.s. ("EPH"), a Czech Republic-based company that provides coal mining, electricity and heat production and distribution along with electricity and gas trading services, bought back a 40% stake in its shareholdings from PPF Group N.V. ("PPF"). The transaction is estimated to be valued at €1.1 billion. The transaction involved EPH cancelling the shares which it was acquiring from PPF in order to increase the stakes of the remaining shareholders. Post transaction, Mr. Daniel Kretinsky, the Chairman of EPH, raised his stake from 20% to 37%, Mr. Patrik Tkac's stake increased to a 37% share and J&T, Mr. Tkac's financial group, holds the remaining 26% stake in the shareholdings of the company.

During the first quarter of 2014, the City of Prague completed a takeover of Pražská plynárenská Holding ("PPH") from German-based E.ON. The acquisition was carried out in two interconnected steps. The first step involved the City of Prague purchasing a 49% share in the parent company Pražská plynáreská for approximately €80 million. The second step involved PPH acquiring a 49.35% stake in its subsidiary Pražská plynárenská from E.ON for approximately €150 million. The City of Prague will gain exclusive control over PPH and Pražská plynárenská, the second-largest gas distribution company in the Czech Republic. The transaction was approved by the Czech Competition Authority ("ÚOHS").

In April 2014, a group of private investors acquired EVRAZ VÍTKOVICE STEEL, a.s. ("EVS") from the Russian group EVRAZ plc for approximately €66 million. The group of private investors included Martinley Holdings, Nabara Holdings, Vitect Services, Hayston Investments and Dawnaly Investments, each owning 20% of EVS, which is a manufacturer of rolled steel products. EVRAZ plc is a multinational vertically integrated steel making and mining company founded in Russia and headquartered in London.

At the beginning of May 2014, the Hungarian refinery giant MOL Group entered into an agreement to acquire 125 Agip petrol stations in the Czech Republic from the Rome-based multinational oil and gas company ENI (ITA). After closing the deal, MOL will acquire the second largest share of the market with a total of 174 petrol stations and will also control the network of Pap Oil and Slovnaft petrol stations. The agreement also includes the purchase of ENI's activities in Slovakia and Romania. MOL Group is an international oil and gas company headquartered in Budapest, Hungary. It has a network of more than 1700 petrol stations in Central and Eastern Europe.

In October the ÚOHS obtained another merger filing application from MOL Group which asked ÚOHS for approval of its acquisition of LUKOIL in the Czech Republic.

SIGNIFICANT NEW INSTALLATIONS/PROJECTS

In 2013 ČEZ, a.s. ("CEZ"), the state-controlled power producer, had to complete a procurement procedure for the construction of two planned nuclear units in the location of the Temelín nuclear power plant for the amount of €7 billion. Based on the previous communication with the Czech government, CEZ cancelled this procurement procedure due to economic reasons in April 2014. The managing director of CEZ stated that without the state guarantee guaranteeing future electricity prices for the new Temelín nuclear power plant units, the completion (expansion) of the nuclear power plant would not be possible.

Despite this, CEZ still intends to support the development of nuclear power generation. CEZ will now focus on the Long Term Operation project for Dukovany nuclear power plant ("LTO EDU").

LTO EDU is one of the most important projects of the CEZ Group. The main aim of LTO EDU is to obtain a permit for the Dukovany nuclear power plant ("DNPP") which will keep it in operation for a further 10 years at least. By 2015 the first nuclear reactor of DNPP will have been operating for 30 years. At this age, the DNPP must be able to prove that its equipment is in a condition which allows for the long-term, reliable and safe operation of the plant. If this cannot be demonstrated, CEZ will not obtain a prolongation of the permit necessary to continue its operations. A separate application form must be submitted to the State Office for Nuclear Safety ("SONS") for every nuclear reactor.

SIGNIFICANT TRENDS IN THE ENERGY MARKET

As already stated above, the Czech Republic supports nuclear power generation.

Since the Czech Republic has almost achieved its obligatory limits regarding the generation of energy from renewable sources, it has stopped subsidising newly installed photovoltaic power stations, apart from very small installations for the direct (on-site) consumption of so generated electricity. The approach of the Energy Regulatory Office ("ERÚ") also contributes to a political environment that is less supportive of the renewable energy sector, especially in relation to solar power generation. The Czech Republic also continues to support policies which promote the energy efficiency of buildings.

SIGNIFICANT ENERGY POLICY ISSUES

The key national energy policy document is the State Energy Concept ("SEC"), most recently approved in November 2012. The SEC specifies the state's priorities and determines its objectives towards influencing the development of the energy sector in the next 30 years within a market-oriented economy.

The SEC aims to achieve energy security with 80% of all electricity produced domestically. The Czech Republic currently produces around 60% of its electricity from coal, with its six nuclear units supplying just over 30%. The new policy aims to change this balance, with the goal of reducing coal's share of the energy mix to a third of current levels by 2040, with nuclear power's share increasing to at least 50%. The increase in nuclear power will be achieved through life extensions to all existing units at the DNPP and the construction of a further unit (or units) at the Temelín nuclear power plant.

In November 2012 the Czech government also approved a renewable energy policy ("REP") that aims to promote the use of renewable sources of energy. The REP sets the way for the Czech Republic to achieve a 13% share of renewable sources in total energy consumption by 2020, as is required by the EU. The REP reports that after achieving the 13% target, no operating support will be provided to any renewable sources in the following period.

A policy document which is equally as important to the energy sector as the SEC and REP is the Policy Statement of the Government ("SCG"). The SCG specifies the government's priorities as follows:

- updating the SEC;
- decreasing the energy intensity of production by modernising the industry;
- ensuring energy security for the Czech Republic;
- seeking opportunities to diversify energy resources, especially in relation to oil and natural gas;
- reducing the energy consumption of public and private buildings;
- revising the system of renewable energy support;
- supporting research and development in renewable energy and energy storage;
- ensuring the operation of the DNPP after 2025;
- supporting of the ecologisation of district heating and combined heat and power generation;
- enforcing the consistent revitalisation of coal mine sites; and
- supporting the development of smart grids.

THE IMPACT OF THE FINANCIAL CRISIS ON THE ENERGY SECTOR

The financial crisis has impacted the energy sector in the Czech Republic. For instance, the government has withdrawn financial support for new energy resources with effect from January 2014. However, there were several other reasons for this withdrawal of support aside from the financial crisis and economic recession in the EU and Czech Republic. These other reasons were namely: (i) the existing support scheme was beyond the economic resources of the Czech Republic; (ii) the amount of the support threatened the competitiveness of Czech companies; and (iii) the Czech Republic had already achieved a 13.5% share for renewable energy in final energy consumption by 2013, which was well ahead of the National Renewable Energy Action Plan deadline of 2020.

However, the energy sector seems to have been affected less by the financial crisis than any other industry sector.

LAW ENFORCEMENT ACTIVITIES BY THE COMPETITION AUTHORITIES

In the past 12 months, the ÚOHS has not performed any law enforcement action in the energy sector.

There are several pending complaints against CEZ and E.ON operated DSOs regarding their alleged abuse of their dominant positions to discriminate against certain photovoltaic power plant operators in relation to their connection to the grid in 2010, as photovoltaic power plants connected to the grid after 31 December 2010 received far lower subsidies. The claims have been submitted by the Association of Solar Power Plant Operators. However, the ÚOHS still has not opened any administrative proceedings.

The ÚOHS commenced administrative proceedings in relation to another complaint, which was ultimately unsuccessful. EPH complained that Czech Coal had abused its dominant position by immediately withdrawing coal deliveries to EPH´s heating plant Opatovice. Czech Coal confirmed that the reason for this withdrawal was the low price they were receiving for the coal which they were contracted to deliver. However, Czech Coal was obliged to supply coal at this price by an agreement which was valid until 2015. The ÚOHS terminated its investigation and concluded that there was no need to continue with its administrative proceedings. The ÚOHS did not consider that harm had been caused to consumers or other competitors. The ÚOHS seems to have disregarded the fact that the harm was not caused only because the court ordered Czech Coal to continue supplying Opatovice with immediate effect. Without this court order, all habitants and companies in Pardubice, Hradec Králové and its surroundings would have been without heat and electricity supplies, which was obviously of no interest to the ÚOHS.

No further complaints or administrative proceedings have been made public by the ÚOHS.

PROCEEDINGS LAUNCHED BY THE EUROPEAN COMMISSION AGAINST THE CZECH REPUBLIC

In past 12 months the European Commission has launched two proceedings against the Czech Republic for non implementation of EU Directives in the energy sector.

EU Directive (2010/31/EU)

In October 2013 the European Commission formally requested the Czech Republic to ensure full compliance with its obligations under EU legislation on energy efficiency in buildings (Directive 2010/31/EU). The European Commission sent a reasoned opinion to the Czech Republic asking it to notify the European Commission of all their transposition measures for the directive, which had to be transposed into national law by 9 July 2012.

EU Energy Services Directive (2006/32/EC)

In January 2014 the European Commission formally requested the Czech Republic to bring its national law in line with the EU Energy Services Directive (2006/32/EC). Under this directive Member States must ensure that the end consumers of energy are provided with competitively priced individual meters that accurately reflect their actual consumption. Individual metering plays a crucial role in the promotion of the efficient use of energy, as it allows energy consumers to better monitor their individual consumption of electricity and gas, as well as their usage of central heating systems and hot water boilers. Individual metering is also needed for the provision of bills based on actual consumption. The EU Energy Services Directive (2006/32/EC) had to be fully transposed into national law by 17 May 2008.

Currently, the Czech Parliament is discussing an amendment to the Act on Energy Management which, if adopted, will fully implement both EU directives.

SIGNIFICANT OTHER INDUSTRY DEVELOPMENTS

Reduction of electricity price

The most significant development in the energy sector is a reduction in the regulated portion of final electricity prices by more than 10% in 2014.

This is due to a drop in the market price of electricity which has favourably reduced the cost of transmission and distribution losses, and also the year-on-year decline in economic indices had strongly contributed to the reduction in the regulated charges for electricity transmission and distribution.

Another factor was the efficient purchase of ancillary services to balance the electricity grid and the influence of the correction factor from preceding years, which helped to reduce the charge for the system services provided by ČEPS, a.s., the Czech transmission system operator ("CEPS").

Finally, an amendment to the Act on Supported Energy Sources introduced a cap of CZK495/MWh (approximately €18/MWh) on the element of the final price which represents the costs incurred in the promotion of renewable energy sources, which also implies an appreciable reduction compared with 2013.

As a result of changes mentioned above, the portion of the final price of electricity for households which represents regulatory costs has decreased by an average of 10.8% in 2014, year-on-year.

Smart metering

The New Electricity Directive obliges Member States of the EU to implement smart metering ("SM") for their electric energy systems. The Czech Republic, in accordance with this directive, has carried out a techno-economic evaluation and recommended:

- a delay in the introduction of the SM until 2018;
- to continue technological development through pilot projects;
- to continuously monitor further technological development; and
- to evaluate the appropriateness, in particular the effectiveness, of the introduction of an SM mechanism within 5 years at the latest.

Paskov coal mine

In September 2013 coal producer New World Resources ("NWR") announced it was closing the Paskov coal mine in Frýdek-Místek, the only remaining active mine in the Ostrava region. Paskov is run by NWR's subsidiary OKD. The mine was making a loss and likely to remain uncompetitive in the medium term. OKD said last year that if it received no financial assistance from the Czech government it would shut Paskov by the end of 2014.

In June 2014 the minister of the Ministry of Industry and Trade signed an agreement with NWR on the reduction of mining at Paskov. According to the agreement, mining at Paskov will continue until the end of 2017 and the Czech government will pay CZK600 million (approximately €22 million) towards social programmes for the miners.

The agreement will be of no effect if coal prices drop below US$110 per metric tonne for three consecutive quarters between 1 July 2014 and 31 December 2017. OKD also retains the option to operate Paskov after 2017 if it so decides. The agreement will also be of no effect if Paskov shows positive net profit for four consecutive quarters.

IMMINENT SIGNIFICANT CHANGES TO THE LEGAL FRAMEWORK UNDER DISCUSSION

In the past 12 months the Czech legislators have amended several energy laws. Some of the relevant changes to the law and regulation of the energy industry in the Czech Republic are mentioned below.

Amendment of the Act on Supported Energy Sources

In October 2013, Amendment No. 310/2013 Coll. ("Amendment No. 310/2013") to the Act on Supported Energy Sources was released. The amendment abolishes subsidies for energy production from renewable sources put into operation after 31 December 2013. This means that the State no longer subsidises:

- electricity produced from biomass, bio-methane, bio-liquids, solar panels and biogas; and
- the heat produced from biomass.

Holders of construction permits for power plants using renewable wind energy, geothermal energy, hydropower, or biomass energy issued before the effective date of the Act on Supported Energy Sources and put into operation on or before 31 December 2015 are entitled to the subsidy according to the Act.

Subsidies will be withdrawn for decentralised electricity generators that: (i) are joint stock companies (or similar); and (ii) have not issued solely dematerialised shares or, in case of a foreign entity, fails to submit an affidavit proving the owner of shares exceeding a nominal value of 10% of the overall capital of the relevant generator.

Electricity generated by high efficiency co-generation plants will remain subsidised. The relevant rates updated annually by the ERU. In addition to the withdrawal of subsidies for new electricity generators, the amendment also freezes subsidies for ongoing power generators from renewable sources, at approximately €20/MWh.

The amendment clearly states that the subsidies withdrawn will be reimbursed by the price that end consumers pay for their electricity. This burden on consumers to subsidise the production of electricity from renewable sources has been a hot topic this year, since the ERÚ does not have the legal authority to burden consumers with these costs.

Amendment of the Energy Act and Act on Supported Energy Sources

In May 2014, Act No. 90/2014 Coll ("Amendment No. 90/2014") amending the Energy Act and the Act on Supported Energy Sources was published. This amendment contains detailed regulations concerning the rights and obligations of participants in the energy market with respect to the collection price to cover costs associated with the support of electricity. Amendment No. 90/2014 came into force with the exception of certain of its provisions, on 21 May 2014.

ENERGY LAW IN DENMARK

Recent developments in the Danish energy market

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CHANGES TO THE LEGAL FRAMEWORK

The government's 2020 Plan

The Danish government has set out an ambitious plan for Denmark's consumption of energy, including a number of ambitious goals in relation to renewable energy and protection of the climate and the environment (the "2020 Plan"). On 22 March 2012, the Danish parliament (save for the Liberal Democrats) announced a cross-party settlement (the "Energy Settlement") aimed at agreeing upon the implementation of the 2020 Plan. The Energy Settlement, which is being gradually implemented through the introduction of new legislation, contains numerous initiatives including:

- cost-reduction initiatives for companies in the energy sector;
- increasing offshore wind turbine capacity by 1,000MW, and near-shore wind turbine capacity by 500MW;[1]
- new funding towards the development and marketing of offshore wind turbine projects in order to increase competition and the effectiveness of the projects;
- increasing onshore wind turbine capacity by 500MW;
- new funding and an intention to further promote bio-based processes for both transportation and heating supply;
- a ban on oil and gas based heating installations in new buildings from 2013, and in existing buildings by 2016, along with new funding for the promotion of heating sources;
- subsidies for companies implementing renewable energy solutions in their production processes;
- establishing capacities for electricity exchange with neighbouring countries;
- implementation of a "wholesale model"; and
- new funding for R&D in renewable energy.

The proposed new Wholesale Model

As a consequence of the Energy Settlement, the Danish parliament has passed a proposal implementing a new model for electricity distribution and the supply market called the Wholesale Model (in Danish *Engrosmodellen*). The intention is to promote competition amongst electricity suppliers and to simplify a rather complex customer distribution company-supplier relationship. The new model was supposed to come into effect on 1 October 2014, however the new model has been postponed another year, and is now planned to come into effect in Q1 2016 at the earliest. Starting from autumn 2015, all end-users will only receive one invoice from the electricity supplier, and not – as is the case today – two (one from the electricity supplier and one from the distribution company).

The Wholesale Model does not entail having the same party produce and transmit the electricity; rather, the electricity supplier purchases the electricity from the producer and sells it to the end-users as a bundled product together with transmission services/fees incurred for using the grid, taxes, levies, etc. Consequently, the electricity supplier – and not the distribution company – will be responsible for settling accounts with public authorities, etc. Although intended to simplify matters for the end-user, from the perspective of the electricity suppliers and grid companies, introduction of the model appears rather complex.

All electricity suppliers must be registered with the Danish transmission system operator, Energinet.dk, (the "TSO"). Electricity suppliers delivering electricity to end-users, as opposed to wholesale electricity traders, will be obliged to participate in an insurance scheme, which will ensure that the Danish Customs and Tax Administration receives all taxes and levies collected from the end-users should the electricity supplier default on any payments to the Danish Customs and Tax Administration.

Proposed new regulation for supply obligated undertakings

End users who have not exercised their right to choose their supplier, receive electricity from a supply obligated entity working under a licence granted by the Danish Energy Agency (the "DEA"). Supply obligation is an opt-in scheme and the holder of the licence has the sole right and obligation to deliver electricity to such end-users. Previously, the licence was, as a main rule, granted to the same entity (more or less automatically), when the licence expired. The DEA found that this practice might be in violation of EU legislation. Consequently, the licence is granted to the bidder that promises to offer the lowest price to the end-users following a public tender.

Danish Climate Change Act

The Climate Change Act was passed by the Danish parliament on 11 June 2014. The Act establishes an overall strategic framework for Denmark's climate policy in order to achieve the transition into a low-emission country by 2050. The characteristics of the Act are:

(I) Establishment of an independent and academically based Climate Council.

(II) Preparation of an annual Climate Policy Report for the Danish parliament.

(III) The process of setting national GHG reduction targets.

Public Service Obligation ("PSO") levy

Before the summer of 2014, the European Commission notified Denmark that its system for financing renewables risks is discriminating against power producers in other countries and thus has to be reformed. The European Commission thinks it is discriminating that Denmark gives a subsidy to those that produce green electricity in Denmark but does not give it to those that generate it abroad and then sell it to Denmark, and this is a violation of the EU legislation. At first, the Danish government disagreed and tried to convince the Commission that the PSO levy was not in contravention of EU legislation. However, the Danish government has now decided to negotiate with the European Commission to change the subsidy system. It appears that the European Commission and the Danish government will come to a compromise; however, no details have yet been released.

RENEWABLE ENERGY

Large scale offshore wind farms: Horns Rev III and Krieger's Flak

Statoil ASA, E.ON Wind Denmark AB, Vattenfall Wind Power A/S and DONG Energy Wind Power A/S have been prequalified for the call for tender of the Horns Rev 3 offshore wind farm. They have been selected to submit a first indicative offer for the concession contract where price will be the only criteria. Horns Rev 3 is the first concession to be tendered for based on the new Energy Settlement. In comparison, the last Danish call for tender for the Anholt offshore wind farm in 2010 only attracted one bidder, DONG Energy.

However, in June the government announced its plan to delay the commissioning of the 600MW Krieger's Flak offshore wind farm until 2022. Originally, the plan was for commissioning in 2020, but the government and the opposition Liberal Party agreed on a set of measures aimed to cut the PSO levys by DKK13.2 billion (€1.73 billion) by 2020. One of the steps in cutting the PSO levy was the two-year delay of the wind farm at Krieger's Flak.

Denmark is no longer energy self-sufficient

For the first time since 1996, Denmark was importing more energy than it exported. The revealing numbers of import and export came from the DEA's preliminary energy statistics for 2013. However, the preliminary statistics also showed a continued increase in the use of renewables. Denmark's degree of self-sufficiency in energy fell to 93% in 2013 from 102% in 2012. Denmark became self-sufficient in energy in 1997, and in 2004 Denmark produced 56% more energy than it consumed. However, since 2004, the degree of self-sufficiency has dropped due to falling production from the North Sea, and, as of 2014, Denmark consumes more energy than it produces.

Developments regarding PV systems

In the 2020 Plan, the government planned for 200MW of PV to be installed by 2020. Due to very attractive subsidies (with concomitant loss of tax revenue to the Danish state), a great number of private PV projects were seen leading to installation of more PV systems than anticipated by the government. In fact it was expected that the 2020 goal would be met by in 2013. Consequently, the legislation was changed, however, the change led to the introduction of potentially large-scale commercial PV projects, which would have led to (additional) unexpected significant revenue losses for the Danish state. The legislation was changed yet again and the new changes appear to have effectively ended the very attractive incentives for investing in PV projects. Due to the discussions between the Danish government and the Commission regarding the PSO levy, it is unclear which renewable technologies will be subsidised in the future and by how much.

OIL AND GAS

The North Sea

The DEA opened the 7th licensing round for new North Sea oil and gas licences in the end of the spring 2014. The application period ended on 20 October 2014. The areas offered for licensing are located in the Central Graben, where the majority of Danish fields have so far been discovered, and in the areas further to the east, where oil discoveries were made in the 6th licensing round. On behalf of the Danish state, Nordsøfonden will hold a 20% interest in the new licences, and the oil companies will hold an 80% interest. The financial terms of the 7th licensing round are identical to those applicable in the 6th licensing round. The DEA has announced that it has received 25 applications from oil companies interested in searching for oil and gas in the North Sea. That was a record high number compared to previous licensing rounds. The Danish authorities monitored the new licensing round closely, since it was the first round under the new tax regime, and at least one oil company, German Bayern Gas, had announced already beforehand that they would not invest further in the North Sea due to the increase in tax under the new regime.

New oil and gas strategy

In April, the government announced that it will initiate the work for a new long-term oil and gas strategy for the North Sea, and that it would be made in cooperation with the Danish oil and gas industry. The purpose of the new strategy is to maximise the efficiency of oil resource extraction in the North Sea. The current extraction percentage prognosis is 26%, but increasing that by just one percent, would increase the production value by DKK70 billion (€9.4 billion), and thus also increase the revenue for the Danish state.

The extraction percentage will depend on technology and oil prices but the DEA expects that the extraction percentage can be increased by several percentage points in the coming years with concurrently new technology becoming available

The oil and gas strategy will focus on four areas. The most important issue is to examine the need to renovate and renew the infrastructure in the North Sea in terms of production facilities and pipelines. This is to ensure that all existing resources and any new finds can be fully exploited. Work on the strategy is set to be completed by the end of May 2015.

Shale gas

In June, the City Council in Frederikshavn approved the Environmental Impact Assessment ("EIA") and district plan regarding Total's exploration well, which meant that Total and the Danish North Sea Fund are now allowed to commence test drilling for shale gas. The drilling test would not include the use of hydraulic fracturing (fracking), and the use of this method would still require further approvals.

INTERCONNECTORS

Construction of the fourth interconnector to Norway

The TSO and the Norwegian TSO (Statnett) are currently constructing the Skagerrak 4 interconnector, which is the fourth DC interconnector between Norway and Denmark. The Skagerrak 4 cable will have a capacity of 700MW. In addition to the three existing cables between Norway and Denmark, the Skagerrak 4 cable will increase the total capacity between Norway and

Denmark, from 1,000MW to 1,700MW. The new interconnection is expected to be commissioned in mid December 2014.

Preparations for interconnector to England

On 10 October 2013, the Danish TSO and National Grid Electricity Transmission plc (England) signed a cooperation agreement regarding an (the first) electricity interconnector between the two countries. Under the agreement, the parties will undertake feasibility work on such an electricity interconnector. The feasibility studies will include both technical and economic aspects of the project and are expected to be finished in 2017.

Preparations for interconnector the Netherlands

The Dutch transmission system operator, TenneT, and its Danish counterpart, TSO, gave their final approval for the development of COBRA (abbreviation of 'Copenhagen Brussels Amsterdam') cable in September 2014. This new, over 300km long interconnector, will directly connect the Dutch and Danish power grids. Completion of the cable is scheduled for early 2019. The European Commission is supporting the COBRA cable with a €86.5 million subsidy under the European Energy Programme for Recovery. The new interconnector will have a transmission capacity of 700MW, and will run from Eemshaven (Netherlands) to Endrup (Denmark). The connection will be on a direct current (DC) basis.

Two new LNG projects in the maritime sector

On 1 October 2014, a new LNG-ferry was supposed set out on the first journey between the island of Samsø and Hou in Jutland on the Danish mainland. However, due to unforeseen complications, the first journey has been postponed. The owner of the new ferry is Samsø Municipality, and the ferry is the first domestic LNG-fuelled ship in Denmark. The ferry can carry a maximum of 600 passengers and 160 cars, and is an important milestone for Samsø, which back in 1997, was selected to become Denmark's first renewable energy island.

In August, Liquiline Europe AS and Fjord Line signed an agreement that Liquiline will build an LNG bunker terminal for Fjord Line Hirtshals. Fjord Line ferries dock daily at Hirtshals with the two LNG-fuelled cruise ferries, MS Bergensfjord and MS Stavanger Fjord. The LNG bunker terminal will be the first of its kind in Denmark. It will have a storage tank with a volume of 500m^3 and a bunkering capacity of up to 400m^3 of LNG per hour.

New balancing model for gas approved by Danish Energy Regulatory Authority

The Danish Energy Regulatory Authority ("DERA") has approved the TSO's method of registration for a new model for balancing the Danish gas system. In general, the new model means that the shippers, which are the companies that transport the gas in the system, must play a more active role in balancing the Danish gas system. In this way, they ensure that the amount of gas sent in matches consumption better than as of today.

DONG Energy Group sells Stenlille Gas Storage Facility to Energinet.dk

On 20 September 2014, DONG Energy Group and the TSO, announced that they had signed an agreement, under which the TSO acquires DONG Energy's 100% ownership stake in DONG Storage A/S, and hereby the gas storage facility at Stenlille.

Energinet.dk purchased the facility for a total consideration of DKK2.25 billion (€302 milion). Stenlille Gas Storage Facility is the largest of the two gas storage facilities in Denmark (the TSO owns the other facility in Jutland), with a working gas volume of 575 million m^3, corresponding to 57% of the total Danish gas storage capacity. All gas companies will be able to use Stenlille Gas Storage Facility on fair and non-discriminatory terms. Prices and terms must be published.

ENDNOTE

1. Reduced to 400MW in connection with the political settlement called the "Growth Package" (July 2014)

ENERGY LAW IN ESTONIA

Recent developments in the Estonian energy market

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IMPACT OF FULL LIBERALISATION OF THE ELECTRICITY MARKET

Upon joining the EU, Estonia was granted a derogation which extended the deadline for full liberalisation of its electricity market to January 2013, with an obligation to open up 35% of the market by January 2009. Since January 2013, the market has been fully liberalised and all customers are required to purchase electricity on the open market.

Although following the full liberalisation of the electricity market the incumbent supplier of electricity, Eesti Energia AS, has kept a significant market share, the market is becoming more diverse and the market share of other electricity suppliers is slowly increasing. By the second half of 2014 the market share of Eesti Energia AS had decreased to 58%, followed by Elektrum Eesti OÜ with a market share of 15%. In total there are currently 15 electricity suppliers operating in Estonia.

As the prices offered by the electricity suppliers are somewhat cheaper than the price of electricity sold under the general service concept, around 78% of all customers have signed agreements for electricity supplies.

Proceedings are currently pending with the Estonian Competition Authority regarding compliance with the principle of equal treatment of market participants by the main DSO, Elektrilevi OÜ (whose sales constitute approximately 87% of the total sales of network services). Elektrilevi OÜ is a 100% owned subsidiary of Eesti Energia AS, the incumbent electricity supplier with the largest market share. Currently Elektrilevi OÜ issues one joint invoice for network services and electricity supplies only to customers who have a supply contract with Eesti Energia AS. The customers who have a supply contract with another electricity supplier receive two separate invoices, one for network services from Elektrilevi OÜ and the other from their electricity supplier. The other electricity suppliers believe this practice to be in breach of the principle of equal treatment and have initiated proceedings with the Estonian Competition Authority.

ENERGY INDEPENDENCE AND SECURITY OF SUPPLY

In 2014 Estonia's total installed net generating capacity was 2,211MW, while peak demand in 2014 was 1,510MW. For the time being Estonia's electricity consumption can be satisfied by power plants located in Estonia. However, due to environmental requirements becoming stricter, a significant portion of the existing oil shale based production capacity (in 2013 around 85% of electricity was produced from oil shale) will have to be operated on the basis of limited life time derogation starting from the beginning of 2016. Therefore, development of new generation capacities is critical to ensure Estonia's continuous energy independence and security of supply.

Unlike most other EU Member States, the electricity systems of the Baltic States are isolated from the main European grid and are directly connected to the Russian transmission grid. The only exceptions are the Estlink 1 and Estlink 2 cables between Estonia and Finland, with a total capacity of 1000MW. Upon completion of the LitPol Link, a 1000MW interconnector between Lithuania and Poland, which is expected to be commissioned at the end of 2015, the Baltic States will be effectively connected to the main European grid and it will be possible to proceed with synchronisation of the electricity systems of the Baltic States with the Continental Europe synchronised power system ("CE").

CHANGES TO THE SUPPORT SCHEMES FOR RENEWABLE ENERGY STILL PENDING

The support schemes which have been put in place to promote production from renewable energy resources do not take into account the substantial increase in the market price of electricity which has occurred over the past years in conjunction with market liberalisation. The support mechanism established under the Electricity Market Act is a fixed price for each kWh generated from renewable energy sources. However, such a system may become inadequate and too favourable towards some generators as the market price of electricity sold by these generators has steadily increased. If a fixed price support was to be added to the increased market price, the income of the generators could be excessive in comparison to that of generators of conventional electricity.

A draft act has been discussed in parliament for some time and is still pending. According to the draft, the support scheme will be revised so that the support payable will be:

- tied to the prices on the electricity exchange; and
- dependant on the market prices of the EU ETS allowances or the average price of biomass. The specific combination will depend on the renewable energy resource used and the capacity of the relevant installation.

The aim of the draft act is to find a balance between promoting production of energy from renewable energy resources and the financial burden of the support placed on end consumers (the rate of the renewable energy fee charged to consumers has risen from 0.14c/kWh in 2007 to 0.92c/kWh in 2014). The changes were also triggered by the fact that since the introduction of the support scheme in 2007 there has been a significant growth in production of electricity from renewable energy resources and as a result Estonia's renewable energy targets have already been met. Furthermore, the Estonian Competition Authority concluded in an analysis conducted in 2010 that the levels of support currently fixed under the Electricity Market Act are excessive, and in view of the increase of the market price of electricity resulting in a return of up to 40% on invested capital.

Understandably there has been a heated response from the market participants claiming that the analysis of the Estonian Competition Authority is flawed and that any reduction of applicable support schemes would be unconstitutional as investment decisions were based on existing support levels. For the time being, it remains unclear to what extent and as of when the available renewable subsidies will be reduced. The proposed principles of the revised support scheme received a go ahead from the European Commission at the end of October 2014 so it is expected that the changes will be finalised and approved in the near future.

FULL OWNERSHIP UNBUNDLING OF THE GAS TSO

Although the Third Gas Directive exempts Estonia from the requirement to implement an unbundling regime due to the isolation of the Estonian gas market, Estonia has nevertheless opted to apply the FOU model as of January 2015.

The gas TSO, AS EG Võrguteenused, is a 100% owned subsidiary of AS Võrguteenus Valdus which in turn was owned by Fortum Heat and Gas OY (51.3843%), Gazprompank (37.0264%), Itera Latvija (10.0176%) and several small shareholders (1.5717%). In November 2014 the electricity TSO, state owned Elering AS, purchased all of the shares in AS Võrguteenus Valdus which were owned by Fortum Heat and Gas OY. The sale of shares is subject to certain conditions precedents, among others, the approval of the Estonian Competition Authority regarding concentration control, the approval of the Ministry of Internal Affairs on meeting the internal security requirements imposed on the gas TSO, and the consent of the other shareholders on not using their pre-emptive right to purchase the shares in question. Both the Estonian Competition Authority and the Ministry of Internal Affairs gave their respective approvals to the transaction in December 2014. The parties' target is to fulfil the remaining conditions precedent by the end of 2014 such that Elering AS will become the majority shareholder of AS Võrguteenus Valdus starting from the beginning of 2015.

The current TSO's licence is valid until the end of 2014 and will not be renewed unless the TSO complies with the FOU requirements. Despite the pending acquisition of 51.3843% of the shares in AS Võrguteenus Valdus it is doubtful whether AS EG Võrguteenused will comply with the FOU requirements considering who the remaining shareholders of AS Võrguteenus Valdus are. It remains to be seen how AS EG Võrguteenused intends to comply with the FOU requirements and achieve certification as a system operator and issuance of a new licence to operate as the TSO. If the TSO cannot comply with the FOU requirements by January 2015 it will risk a fine of up to €1.2 million per annum and nationalisation of the transportation network. It is understood that consultations between the Estonian Competition Authority and the relevant parties are currently underway.

BALTICCONNECTOR AND LNG TERMINALS

In order to establish a competitive market in natural gas in Estonia, it is necessary to enable new suppliers to enter the market, which can be encouraged through the construction of LNG terminals and developing interconnectors to create a larger regional market. Estonia's own gas demand has been steadily decreasing over the years. It is expected that in 2014 the consumption of gas will amount to only 500 million m^3.

The construction of an interconnector between Finland and Estonia, the Balticconnector, and a LNG terminal in Finland, Estonia or Latvia has been included in the list of EU projects of common interest. There has been a lot of discussion on which country should host the LNG terminal. A study conducted at the request of the European Commission concluded that either Finland or Estonia would be the most suitable location for the regional LNG terminal. As Finland and Estonia were unable to come to an agreement on the location of the regional LNG terminal a compromise to construct LNG terminals in both Finland and Estonia was proposed by the developers, Gasum OY (Finland) and AS Alexela Energia (Estonia). However, this proposal was rejected by the European Commission in October 2014 as it was deemed not to be compliant with the prerequisites for receipt of EU support. Following discussions between the Prime Ministers of the Republic of Finland and the Republic of Estonia an agreement was reached in November 2014 on a way forward. The regional LNG terminal will be constructed in Finland by 2019, whereas the application for EU funding will have to be filed during 2016 otherwise the right to construct the regional LNG terminal will revert to Estonia. The Balticconnector will also be constructed by 2019.

A floating LNG terminal became operational in Klaipėda, Lithuania in December 2014 with expected annual capacity of 2 to 3 billion m^3. Although Lithuania's own gas demand is over 3 billion m^3 it is expected that the Klaipėda LNG terminal will increase the energy security of the Baltic States which are otherwise isolated from Europe's gas network and dependent on Russian gas supplies.

OIL PRODUCTION

Estonia has no conventional oil reserves, but produces shale oil on a commercial basis from its oil shale reserves.

Oil shale, as a non-conventional oil resource, has been under-exploited because extracting oil from non-conventional sources, including oil shale, has generally been more expensive than extracting oil from an oil well. Considering that the currently producing oil wells are gradually being exhausted, non-conventional oil is expected to increase as an alternative source of supply. The main alternative sources for liquid fuel production that could replace crude oil are heavy crude, tar sands and oil shale. The need for alternative sources, and expectations that the world oil prices will remain at a high enough level, has raised interest and investment in the development of the technologies needed to extract oil from non-conventional sources.

To date only three countries in the world are producing shale oil on a commercial basis. China has the highest output, followed by Estonia and Brazil. A number of countries, including the USA, Jordan, Morocco and Australia are looking to develop shale oil industries. There are a limited number of technologies available to produce shale oil on a commercial scale. A World Energy Council Survey of Energy Resources 2013 estimates total world resources of in situ shale oil to be 4.8 trillion barrels.

There are two key producers of shale oil in Estonia, VKG Oil AS and Eesti Energia Õlitööstus AS. In 2013 the total annual output was around 700,000 tonnes. The largest producer is VKG Oil AS who commissioned its first new processing plant based on Petroter technology in 2010 and the second processing plant in 2014. Construction of the third processing plant is ongoing and it is expected to be commissioned in 2015. Eesti Energia Õlitööstus AS is also currently commissioning a new oil processing plant based on Enefit technology and has plans to construct additional oil processing plants. Once completed and operational, these new oil plants would significantly increase Estonia's output of shale oil.

The shale oil produced has similar qualities as heavy fuel oil. The primary domestic demand for shale oil is from local boiler houses and producers of asphalt. Domestic demand is decreasing as boiler houses switch from using shale oil to gas, which is cleaner and does not need to be stored. The primary demand from the export market is from producers of bunker and marine fuels who blend it with other products and sell it to the shipping companies. Due to the low quality of shale oil it trades at a discount to Brent Crude.

The significant decrease in oil prices during 2014 may have a negative impact on continuing the development of shale oil processing technologies.

ENERGY LAW IN FINLAND

Recent developments in the Finnish energy market

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INTRODUCTION

Recent major transaction in the electricity distribution market

In December 2013, Fortum Oyj (Fortum) agreed to sell its electricity distribution business in Finland to Suomi Power Networks Oy, which is owned by a consortium of international infrastructure investors First State Investments (40%) and Borealis Infrastructure (40%), together with Finnish pension funds Keva (12.5%) and LocalTapiola Pension (7.5%). The deal was closed in March 2014. The distribution network is operated under the name Caruna Oy.

The total consideration was €2.55 billion on a debt- and cash-free basis. A total of 320 employees were transferred with the business.

According to Fortum, the decision to divest the electricity distribution business in Finland was linked to the strategic assessment of the company's electricity distribution business' future alternatives. According to Fortum, the company is also preparing for a possible sale of the Swedish and Norwegian electricity distribution businesses.[1]

The combined network length of the companies is 79,000 kilometers delivering approximately 12.6TWh of electricity to customers. Caruna Oy, with 640 000 customers, is now the largest electricity distributor in Finland, with a market share of the local electricity distribution in Finland of approximately 20%.

DEVELOPMENTS IN THE NUCLEAR ENERGY SECTOR

Construction of new nuclear plants

According to Teollisuuden Voima Oyj ("TVO"), which already operates two nuclear power plants in Olkiluoto, the construction of the third nuclear power plant, which has suffered from significant delays as it was due to be in operation already in 2009, has progressed on several fronts. Parties to the contractual dispute, TVO and the plant supplier, Areva-Siemens consortium, have issued press releases on their respective claims. According to relatively recent estimate by the consortium, the construction phase of the third nuclear power plant is estimated to be completed in the middle of 2016[2] and the commencement of the energy production is estimated to take place in 2018[3].

In 2010 a decision-in-principle for construction of a new nuclear power plant was granted to Fennovoima Oy ("Fennovoima"), which is planning to build the plant in the Pyhäjoki municipality, which is located in the northern part of the Gulf of Bothnia. The project is known as Hanhikivi 1 due to the name of the location of the planned plant. Fennovoima concluded a power plant supply agreement with Rusatom Overseas, a subsidiary of Rosatom, in December 2013. According to Fennovoima, the electricity production at Hanhikivi 1 is expected to start in 2024. Electrical output of the Rosatom supplied plant is planned to be approximately 1,200MW.[4] Fennovoima has applied for amendment to its decision-in-principle due to change of the power plant supplier and a group of minority shareholders. The application was approved by the Ministry of Employment and the Economy in September 2014, but the final decision will be rendered by the parliament of Finland.

The Finnish parliament and the Council of State granted also a decision-in-principle in 2010 for TVO to construct a fourth nuclear power plant in Olkiluoto adjacent to the other nuclear power plants. According to the decision-in-principle, a construction permit for the fourth nuclear power plant must be applied for by 1 July 2015 at the latest. TVO has applied for an extension of five years for submitting the construction permit. The application was turned down by the Ministry of Employment and the Economy in its decision on 25 September 2014.[5] In public discourse the decision was attributed to delays in the pending project.

Disposal of nuclear waste

At the end of 2013, Posiva Oy ("Posiva") – a Finnish company responsible for disposal and decommissioning of nuclear waste generated by its owners, TVO and Fortum – submitted its application for a construction permit regarding a final disposal facility in Olkiluoto. The processing of the application is currently pending and the permit is not expected to be granted before 2015. Posiva has applied for an amendment to its decision-in-principle so Posiva's deadline for submitting an application for construction permit should be extended pro rata with extension granted to TVO. Posiva's application in this respect is still pending.[6]

According to the decision-in-principle for the construction of the new nuclear power plant by Fennovoima, Fennovoima must by 2016 present either an environmental impact assessment programme for its own final disposal facility or present an agreement with Posiva and its two owners regarding the use of the Posiva facility. Posiva has been of the view that there is not enough capacity for the nuclear waste generated by Fennovoima's plant in the final disposal facility to be built in Olkiluoto.

In early 2012 the Ministry of Employment and the Economy set up a working group to lead a joint investigation by all nuclear power companies in relation to alternatives for the final deposition of spent nuclear fuel. According to the working group's conclusions, which were presented in the beginning of 2013, cooperation between the involved parties and utilisation of the knowledge of Posiva is the preferable option, but the working group explicitly refrained from taking any position on the ongoing commercial negotiations between the parties. There have been no updates on the progress of the negotiations or other issues relating to final deposition.

Production and recovery of uranium

The Council of State granted Talvivaara Sotkamo Oy ("Talvivaara") a government licence under the Nuclear Energy Act to produce uranium from the ore at the Talvivaara mine in Sotkamo. However, the Supreme Administrative Court of Finland cancelled the licence due to Talvivaara's weak financial standing, which required the Council of State to reconsider whether the licence may still be granted. The decision of the Supreme Administrative Court did not affect Talvivaara's application for environmental permit for the recovery of uranium which was granted to Talvivaara on 30 April 2014, though the permit has not yet gained legal force as it has been appealed against. Talvivaara is currently subject to restructuring proceedings.

REFORM OF ELECTRICITY AND NATURAL GAS MARKET LEGISLATION

Finnish legislation on electricity and natural gas markets underwent a reform to comply with the requirements of the Third Electricity and Gas Directives. On the one hand, the aim of this reform was to implement the requirements of these directives. On the other hand, there was a need to update the somewhat complex, scattered and partly outdated national electricity and gas market legislation. A legislative reform package entered into force on 1 September 2013 and involved a complete overhaul of the Electricity Market Act, amendments to the Natural Gas Market Act, and the enactment of the Act on the Monitoring of Electricity and Natural Gas Markets as well as the Energy Market Authority Act.

The Commission had referred Finland to the European Court of Justice for failing to fully transpose the Third Electricity and Gas Directives into national legislation.[7] The implementation deficiencies related to the unbundling of the TSO and the tasks and the independence of the national regulatory authority. Although the unbundling of the TSO, Fingrid Oyj ("Fingrid"), had been factually implemented in April 2011, when the shareholdings of the two generating companies Fortum and Pohjolan Voima in Fingrid were divested, the relevant legislative amendments were still lacking. With the enactment and entering into force of the above mentioned legislative reform package, the implementation deficiencies have most likely been taken care of.

The Ministry of Employment and Economy has set up a task force to prepare a reform of the Natural Gas Market Act and to prepare the opening of the wholesale and retail sale market of gas. The rationale for the reform is that Finland will be able to open the Finnish gas market to competition as a result of the Balticconnector (described further on in this article) and the LNG terminals. The preparation work should be ready by 1 June 2015.

DEVELOPING THE ADMINISTRATIVE ENVIRONMENT FOR WIND POWER PROJECTS IN FINLAND

Impressive targets for boosting renewable electricity production in Finland have been set in the Renewable Energy Directive. In order to meet the target of increasing the share of energy from renewable sources from 28.5% to 38%, various measures have been implemented in Finland. Perhaps the most important one is the enactments of the Act on Production Subsidy for Electricity Produced from Renewable Energy Resources ("PSRESA"), which came into effect on 25 March 2011 and establishes a feed-in tariff scheme for wind power, biogas, and wood based electricity generation.

Although the feed-in tariff scheme provides an economic incentive for the investment decisions, the procedures for obtaining planning decisions and various other permits still remain as one of the main causes for delays in relation to investments in renewable energy in Finland, wind power in particular. A recent attempt to clarify the currently unclear legal situation has been to issue a decree on thresholds for noise levels that a wind power installation is not allowed to exceed at the point of the nearest settlement. The draft decree circulated for stakeholder consultation was critised as being too strict and the drafting of the decree has stalled.

On the other hand the PSRESA was amended to include the possibility for wind power developers to obtain a so called quota decision that will guarantee that they will be within the total 2,500MW quota that can be included into the feed-in tariff scheme under the PSRESA. Such a quota decision can only be applied for at a late stage of the development once the wind power project has obtained building permits and concluded a grid connection agreement.

PILOT PROJECT ON OFFSHORE WIND POWER

In June 2013 the Ministry of Employment and the Economy launched a public tender for an off-shore wind power pilot project. Tenders had to be submitted by the end of September 2013. The ministry will fund the winning pilot project with €20 million, a sum that is expected to cover the additional costs of constructing the off-shore wind power project. The decision on which project will be funded is expected at the end of 2014.

DEVELOPMENTS IN THE WASTE-TO-ENERGY SECTOR

Vantaa Energy Oy ("Vantaa Energy") opened a new waste-to-energy incinerator on 17 September 2014. The new plant is Finland's biggest of its kind and it will produce 920GWh of district heat and 600GWh of electricity per year. The plant will handle 320,000 tonnes of waste each year. The new plant will reduce Vantaa Energy's use of fossil fuels for energy production by 30%,[8] and cut the company's carbon dioxide emission by 20% per year.[9] In addition, the plant will produce half of the district heating and 30% of the electricity needed in Vantaa's district.[10]

Generally, waste incineration is becoming an important part of waste management in Finland. Accordingly, similar technology as used in the Vantaa plant has already been exploited in incinerators located in Riihimäki, Oulu, Kotka, Mustasaari, and Turku. As a result of the commissioning of these incineration plants, mixed waste can be used as an energy resource as such, instead of collecting it in (or to) the landfill. Waste incineration has been regarded unecological, but due to plants' compliance with strict emission standards, waste incineration has become considered to be a rational solution from the waste management perspective.[11]

NEW HIGH-VOLTAGE ELECTRICITY INTERCONNECTOR BETWEEN FINLAND AND ESTONIA OPENED FOR COMMERCIAL USE

The second interconnector between Finland and Estonia, linking the Estonian electricity market with the Nordic market more efficiently, was made available for commercial operations in February 2014. The cable was laid in the fall of 2012 and the testing of the cable took place between December 2013 and February 2014, during which time the connector was also in commercial use.

The EstLink 2 has transmission capacity of 650MW, which increases the total transmission capacity between the countries to 1,000MW. The total length of the link is approximately 170km, most of which, about 145km, is constructed as a submarine cable laid on the bottom of the Gulf of Finland.[12]

NORD POOL AS PART OF THE NORTH-WESTERN EUROPE DAY-AHEAD MARKET COUPLED WITH SOUTH-WESTERN EUROPE DAY-AHEAD MARKET

The Nordic electricity exchange Nord Pool Spot runs the largest market for electrical energy in the world, measured in volume traded (TWh) and in market share. Nord Pool operates in Finland, Norway, Sweden, Estonia, Latvia, and Lithuania. In May 2014 the day-ahead markets of South-Western and North-Western Europe (including Nord Pool) were coupled, and the common day-ahead market operates from Portugal to Finland, now under a common day-ahead power price calculation using the Price Coupling of Regions (PCR) solution. Now Belgium, Denmark, Estonia, Finland, France, Germany, Austria, Great Britain, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, and Sweden all operate under a common day-ahead power price calculation using the Price Coupling of Regions ("PCR") solution. There are plans to further extend the market coupling with the PCR solution.[13]

PLANNING AND CONSTRUCTION OF LNG TERMINALS AND A GAS INTERCONNECTOR BETWEEN FINLAND AND ESTONIA

Currently, there are no LNG terminals in operation in Finland. While Gasum Oy ("Gasum") and AS Alexela Energy have officially announced that they have ended the discussions regarding the joint Finngulf LNG project, according to unofficial information in the local news, the Finnish and Estonian governments together with the respective gas companies are continuing discussions in order to find a solution through which the project could be kept as a joint operation. In one of the alternatives both countries would get a terminal so that one of them would be the main terminal and the other one would be a supportive terminal with a smaler capacity. The Finngulf LNG project is a project on the European Commission's list of approximately 250 key energy infrastructure projects, the so called "Projects of Common Interest" ("PCI"), that was published on 14 October 2013.

In addition the the Finngulf LNG project, there are at least a handful of projects in different phases, all aiming at having a LNG terminal constructed prior to 2020. Gasum's subsidiary, Skangass Oy, has made an investment decision to construct an LNG terminal with a capacity of 30,000m^3 together with a logistics chain in Tahkoluoto, Pori. The construction is expected to be completed in autumn 2016.[14] Further, Manga LNG Oy, a company owned by Outokumpu Oyj, SSAB, Skangass Oy and EPV Energia Oy, plans to develop an LNG terminal with a capacity of 50,000m^3 in Tornio. The investment decisions on the Tornio LNG terminal are expected during 2014 and if the project gets the go-ahead, commercial use of the terminal is envisaged to be commenced by the end of 2017.[15] Oy Aga Ab in turn plans to have an LNG terminal with a capacity of 10,000m^3 in operation in Rauma in 2016. The final investment decision is expected during the autumn 2014. The ministry of Employment and Economy has granted a total of MEUR65, 2 state aid to these three projects under a the decree on state aid for small scale LNG terminals, which the the Finnish government enacted in 2013.[16] In addition to these, Gasum has announced that it will, in case the discussions in relation to the Finngulf LNG project end, continue the planning of its own LNG terminal alternatives.

Gasum together with other natural gas companies in the Baltics have investigated the possibility of developing interdependent transportation systems. A submarine interconnector, BalticConnector, would involve construction of a gas pipeline between Finland and Estonia, compressor stations on both sides of the Gulf of Finland, as well as connecting onshore pipelines to the existing gas grids. In February 2011, a seabed survey for selected pipeline routes was published showing typical construction conditions for the BalticConnector pipeline. The environmental impact assessment for the BalticConnector project is currently being concluded in both Finland and Estonia.The EIA programme has been completed and was handed to officials in both Finland and Estonia in January 2014.[17]

The BalticConnector would make it possible for Finland to take actions to open its wholesale and retail sale market of gas to competition, since the BalticConnector would as a new transportation alternative allow companies other than Gasum to import gas to the Finnish market. The Balticconnector project is on the European Commission's list of approximately 250 key energy infrastructure projects.

PROJECTS OF COMMON INTEREST

By 16 November 2013, each Member State had to designate one national competent authority which is responsible for facilitating and coordinating the permit granting process for projects of common interest in accordance with the New TEN-E Regulation. The Act on Permit Procedures of European Union's Projects of Common Interest (*Laki Euroopan unionin yhteistä etua koskevien energiahankkeiden lupamenettelystä*) entered into force on 1 September 2014. The law nominated the Energy Authority as the national competent authority for Finland. The TEN-E Regulation also requires that the tasks of different authorities related to PCI must be handled without undue delay. Further, the TEN-E Regulation requires that the Member States or competent authority shall, where applicable in collaboration with other authorities concerned, publish a manual of procedures for the permit granting process applicable to projects of common interest. The Energy Authority published the required manual on 28 August 2014. The manual shall be updated as necessary and was made available to the public.

ENDNOTES

1. For more information, please see Fortum's press release from 12 December 2013 at http://www.fortum.com/en/mediaroom/pages/fortum-completes-strategic-assessment-of-its-electricity-distribution-business.aspx
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17. The Balticconnector Executive Summary available at http://www.gasum.com/gasnetwork/Documents/Balticconnector%20-%20Executive%20Summary%20Report%20-%2010022011.pdf Please refer also to http://www.gasum.com/Corporate_info/Investments/Balticconnector/

ENERGY LAW IN FRANCE

Recent developments in the French energy market

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GENERAL MARKET ISSUES

Strengthening of the government's role in controlling foreign investment into France's energy supply

Following the bid by General Electric to acquire the energy division of Alstom, the French Government issued a decree dated 14 May 2014[1] (the Alstom Decree). The Alstom Decree modifies the monetary and financial code provisions relating to foreign investment by extending the power of the government to block foreign investment in strategic activities relating (in particular) to energy supply.

By way of background, foreign investment is, under French law, subject to prior consent from the Minister of the Economy depending on:

- the type of foreign investment (ie a bid for the company, a bid for part of the company or a purchase of one third of the stake in the company);
- the type of investor (ie does the company have its registered office in the EU or a country party to the EEA, or does the company have its registered office outside these countries); and
- the type of activity concerned (ie does it fall within the scope of the activities listed in articles R.153-2 et seq of the Monetary and Financial Code).

When foreign investment is subject to the prior approval of the Minister of the economy, the transaction cannot be completed without obtaining approval. The Minister of the economy shall render their decision within two months from the date of receipt of a full and complete formal application. In the event that the Minister of the Economy fails to render a decision, the transaction is deemed approved.

The Minister of the economy may impose certain conditions (detailed in article R.153-9 of the Monetary and Financial Code) on the foreign investor to ensure that the transaction will not adversely affect the interests protected by the foreign investment rules. Breaching such conditions may lead to the payment of fines which can amount to double the transaction price.

Any transaction completed without the prior approval of the Minister of the economy is null and void. Any interested third party would be entitled to bring an action to seek the nullity of the transaction.

The Alstom Decree extends the list of activities where foreign investments are subject to the prior consent by adding the following:

Activities relating to equipment, products or services, including those relating to the safety and the proper functioning of facilities and equipment, essential to guarantee the French national interests in terms of public policy, public security or national defence, as listed below:

- *Integrity, security and continuity of the supply of electricity, gas, oil or other source of energy; [...].* [2]

The Alstom Decree came into force on 16 May 2014, but did not contain any transitional provisions. It is thought that the Alstom Decree applies to deals in progress on or after its entry into force (ie, 16 May 2014), thus companies which have already entered into negotiations relating to an acquisition in the concerned sectors and which have not formally been closed should enquire with the Ministry of the Economy whether or not the investment falls within the scope of the decree and therefore requires authorisation.

Immediately after its adoption, the decree was criticised as over-controlling protectionism in contradiction with the European principle of free trade. The EU Commission examined the wide scope of this regulation and published an open letter to Philippe Etienne, French ambassador to the European Union. In this letter, the European Commission considered that the new scope restricts the principle of free trade but considers that such restrictions falls within the limitations set out by articles 52, 65 and 346 of TFEU. Further, the EU Commission recommends that the prior approval mechanism be proportional and appropriate.

Regulated tariffs and access to the historical operator's database of customers

The consumption legislation dated 17 March 2014 (No.2014-344)[3] has launched the progressive abolition of regulated tariffs for non-household consumers. Regulated tariffs for customers directly connected to the transmission network expired on 19 June 2014, and will expire by 31 December 2014 for customers consuming more than 200MW annually, and by 31 December 2015 for customers consuming more than 30MW annually. It provided however that in cases where a consumer did not choose a new gas supplier, it shall be deemed to accept a commercial offer of his existing supplier, in order to preserve the continuity of gas supply.

This provision raised some concerns on the competition structure of this new segment of the gas market, while GDF Suez currently delivers gas on regulated tariffs in 95% of the national territory. On 9 September 2014,[4] the French competition authority issued an interim decision ordering GDF Suez to disclose its database of customers to its competitors. The information was to be made available via an Internet platform on 3 November 2014, for the data concerning business entities, and on 15 December 2014, for the data concerning households. The competition watchdog considered that GDF Suez has abused of position by using its database of customers designed for the regulated tariffs in order to commercialise its new competitive offers and thus allowing itself to maintain its dominant position. In case of failure to disclose the data, France's competition authority said it will temporarily prohibit GDF Suez from commercializing its gas supply offers.

New TSO certification for TIGF, now organised under the FOU regime

As a consequence of the sale of Total S.A.'s shares to third party companies in 2013, TIGF, which is the TSO operating the gas transmission grid in southwest France, had to apply for a new TSO certification from the French energy regulator (the "CRE"), in accordance with the procedure set out in the Energy Code and decree No. 2011-1478 dated 9 November 2011. The European Commission gave a favourable opinion on CRE's draft decision on 4 June 2014. Consequently, the CRE granted TIGF a new TSO certification on 3 July 2014. By quitting the ITO model, TIGF had to embrace the full ownership unbundling model.

New regulatory framework for the development of smart metering

The further development of smart metering systems was marked by recent decisions of the CRE. The deployment of smart metering systems is a goal set both at European[5] and national levels.[6] The decision to put in place the smart metering system was announced by the Government via the deployment of:

- "Linky" meters for electricity in 2011;[7] and
- "Gazpar" meters for gas in 2013.[8]

The aim is to replace 35 million existing electricity meters, and 11 million gas meters, with smart meters. The technical regulation relating to Linky meters was issued in January 2012.[9] By its decision on 16 July 2014,[10] the CRE has proposed a new schedule for the deployment of Linky meters, from 1st December 2015 until 31 December 2015, with a target deployment rate of 90% for ERDF to achieve by the end of 2021. Finally, in two decisions dated 17 July 2014,[11] the CRE established the economic part of incentive regulation framework for two projects, providing for:

- the control of project costs;
- the schedule of deployment; and
- the meter's performance via a bonus-malus system.

These decisions also change the methodology of the calculation of the tariffs for use of the distribution network, TURPE 4 for electricity and ARTD4 for gas. ERDF, the main French distribution network operator, launched a call for tender on the fabrication of first 3 million Linky meters in July 2013. The contracts were awarded in August 2014 to six operators for the overall amount of €250 million.[12] As for the Gazpar project, first results of the calls for tenders were made public in February 2014.[13]

DRAFT BILL ON ENERGY TRANSITION

A draft energy transition bill has been put before the French Parliament on 30 July 2014. The Parliament voted a first revised draft on 14 October 2014 which has been passed on to the Senate. The Senate is expected to vote on this draft early 2015.

The draft bill sets very challenging objectives, in particular:

- a 50% reduction in energy consumption by 2050 with an intermediary objective of 20% reduction by 2030;
- a 30% reduction in fossil fuel consumption by 2030;
- an increase in the use of renewable energy in order for it to cover 23% of the final raw energy consumption by 2020 and 32% by 2030; and
- a reduction of the use of nuclear energy in power generation of 50% by 2025.

In light of these objectives the draft bill provides for a large number of measures to enhance energy efficiency which mainly impacts buildings works, transportation, waste management, renewable energies, nuclear energy and related energy authorisation regimes.

ELECTRICITY

Regulated tariffs

Judicial control of the regulated tariffs

In its decision dated 11 April 2014,[14] the highest administrative jurisdiction in France, the Conseil d'Etat, partially cancelled regulated electricity tariffs set out in an order dated 20 July 2012. In France, there are three tariff bands ("blue", "yellow" and "green") designed according to the kW capacity. The 2012 order raised the tariffs, but limited these increases to 2%.

Firstly, the Conseil d'Etat reaffirmed that pursuant to the existing legal framework, the regulated tariffs must be set out by the relevant Ministers by taking into account:

- the full covering of the operators' total average costs incurred to provide electricity at this tariff, as evaluated at this date;
- an estimate of the evolution of these costs over the next tariff period;
- an adjustment of the tariff where there is a significant difference between the tariff and the costs, due to an overestimation or underestimation of the tariff; and
- the legislative requirement of a price convergence between the level of regulated electricity tariffs and the cost of supply of electricity distributed at a market price before 31 December 2015.

According to the decision of 11 April 2014, the increase of 2% for the "blue" and "yellow" tariffs bands is substantially lower than the level required in order to cover the costs incurred in 2011 and to compensate for provisional costs increases for 2012. Consequently, the Conseil d'Etat partially cancelled the 2012 order on this aspect and ordered the issuance of a new order within two months, retroactively increasing these two tariff bands over the period from 23 July 2012 and 31 July 2013.

In order to comply with this element of the decision, a new order dated 28 July 2014[15] has retroactively increased the "blue" tariff band for approximately 5% for the period between 23 July 2012 and 31 July 2013. However, it didn't change the "yellow" tariff band. According to the opinion of the CRE on the draft order, the existing increase of 2% was not far from the required 2.6% increase, and the 2011 exercise has already enabled partial cover of this difference.[16] Therefore, the CRE considers that it is complying with the requirements set out by the Conseil d'Etat.

On the same date, 28 July 2014, the Minister of Energy issued another order freezing the planned increase of 5% for the "blue" tariff band for the period after the 1st August 2014.[17] The Minister of energy announced that its intent was to overhaul the calculation of the regulated tariffs via the PLTE.[18] The order was challenged by the same claimant, the Association of Alternative Power Producers (*L'Association Nationale des Opérateurs Détaillants en Énergie*) ("ANODE"), before the Conseil d'Etat. However, the request for an interim suspension was rejected on the basis that the urgency criterion was not established.[19] A final decision is expected in 2015.

Draft decrees on the regulated tariffs

The NOME Law provided the new methodology for calculating the regulated tariffs, and specified that it must be adopted by 31 December 2015.[20] The CRE[21] and the French competition authority[22] have issued opinions on the draft decree establishing this new methodology on 24 September and 26 September respectively. The draft decree provides for the application of the costs accumulation method in order to ensure the contestability of tariffs by alternative suppliers. The costs accumulation method consists of the addition of the following cost components:

- the costs of access to incumbent nuclear electricity (coût de l'accès à l'électricité nucléaire historique) (the ARENH) set out by the NOME Law;
- the costs of the supplementary electricity supply, aside from nuclear, based on the wholesale forward market tariffs recorded;
- the network costs (transport and distribution);
- the costs of the guaranteed generation capacities;
- the sales costs; and
- the reasonable remuneration.

The CRE and the French competition authority both generally approve of the draft decree. However, the competition authority draws the government's attention to the fact that price capping certain elements of the tariff is not incompatible with the principle of cost coverage and therefore the two techniques must coexist.

CSPE

The charges relating to the public service obligations, which are imposed on the electricity operators are compensated through a levy (payment) per kWh consumed, fund contributions to public service electricity ((contribution au service public de l'électricité) or CSPE).

The CRE has published a report regarding the CSPE (mechanism, history and prospective) on 16 October 2014[23] where it sets out that the public service costs funded by the CSPE:

- amount to a total aggregate of about €30million for the period between 2002 and 2013; and
- could reach a total amount of nearly €100million for the period 2014-2025 (based on the assumptions of the CRE), 60% of this amount would be due to the renewable power generation park currently in use.

Formal investigation by the European Commission

In a decision dated 27 March 2014[24] regarding the French scheme providing support to the production of electricity from wind energy, the Commission opened an in-depth investigation to assess whether three types of reductions of CSPE granted to large energy consumers in France are in line with EU state aid rules. These reductions are the following:

- No CSPE beyond the above mentioned ceiling of €569.418;
- No CSPE is due on own consumption of auto-produced electricity below 240GWh per year;[25] and
- For industrial companies consuming at least 7GWh per year, the CSPE is capped at 0.5% of their annual value added.[26]

Requests for restitution

Following the Court of Justice of the European Union (CJEU) ruling dated 19 December 2013 regarding the Vents de Colère claim and anticipating the qualification as an illegal state aid of the order of 2008 regarding the wind farm feed-in tariff (see our developments below on this case), several electricity consumers have requested restitution of the CSPE paid.

Following the reception of more than 40,000 requests for restitution (mostly based on the illegality of the above mentioned order of 2008), the CRE has also issued a decision on 28 May 2014 stating that it will not proceed with the reimbursement of the paid CSPE.[27]

Constitutional claim

By a decision dated 8 October 2014,[28] the French Constitutional Court (Conseil Constitutionnel) ruled that the legal grounds of the CSPE applicable for the years 2005 to 2009[29] were compliant with the provisions of the Constitution.

Praxair SAS had filed a question on the constitutionality of these legal provisions (question prioritaire de constitutionnalité) in support of a legal claim for restitution of the paid CSPE for the years 2005 to 2009 before the French administrative courts.

Praxair SAS argued that the legislature failed to define the rules relating to rates and the collecting methods of this levy. The Conseil Constitutionnel considers instead that the legislature has sufficiently defined the rules, providing for distinct recovery procedures of the CSPE depending on the categories of contributors and the conditions for supply of consumed electricity. The decision also rejects the other grounds of challenge relating to a breach of the principle of equality before taxes and public charges, and the aim of accessibility and intelligibility of the law.

Non-interconnected territories (ZNI)

The regulated electricity supply tariffs, regarding electricity sale to end consumers, apply in the non-interconnected territories[30] (the ZNI).[31] As in the ZNI the electricity production or supply costs are well above the regulated tariffs, the CSPE is aiming at compensating the difference between the benefits from the supply of electricity and the production costs[32] (the Tariff Equalisation).

Widening of the Tariff Equalisation scope

On 1st August 2014, a decree was issued[33] which implements the amendments made by the legislature to the Tariff Equalisation regime in late 2012[34] so that the CSPE can be used in the ZNI to cover:

- the costs of importing electricity in the event that such importation costs are below the production costs in the ZNI;
- the costs of electricity storage facilities managed by the DSO;
- the costs incurred by the power suppliers when performing power demand control based on electricity consumption (reduced by the revenues eventually collected through such actions);

as long these costs are below the avoided extra production costs.

Computation of the Tariff Equalisation

Following a public consultation launched on 10 July 2014,[35] the CRE has issued a decision on 9 September 2014[36] regarding its methodology for the computation of the extra production costs covered by the Tariff Equalisation for generating electricity in the ZNI (the three other types of costs above mentioned will be analysed in a future decision).

This decision aims to ensure the consistency and transparency of CRE's methodologies for analysing investment costs of electricity generation projects in the ZNI developed by historical operators (EDF or Electricité de Mayotte), as well as other producers.

Power grid connection issues

Nature of the grid connection agreement (*convention de raccordement*)

The French Supreme Court (*Cour de Cassation*) confirmed, in a ruling dated 11 December 2013,[37] that the grid connection agreement (*convention de raccordement*) is a not an administrative contract by way of accessory to the purchase power agreement (the latter being an administrative contract by determination of the law).

Modification of the grids allocation rules between France and Spain

The transmission network system operator RTE which is affiliated to EDF, issued a letter on 21 February 2014 to request that the CRE approve a proposal to modify the actual rules governing the access to the France-Spain grid interconnection.

In a ruling dated 12 March 2014, the CRE issued a favourable opinion to this proposal,[38] subject to Spanish regulator's approval. The purpose of this modification is to transfer the management of the France-Spain interconnection under the actual CASC (Capacity Allocating Service Company) European management system.

Derogation for ElecLink related to the building of a power interconnection between the British and French power grids

The construction and operation of a power grid interconnection by a private party may only be authorised by derogation pursuant to article 17 of EU Regulation No. 714/2009 dated 13 July 2009. Such derogation must be granted by the regulatory authorities of the concerned Member States.

ElecLink submitted a request for derogation before the CRE and the Office of Gas and Electricity Markets ("OFGEM"), respectively on 11 September 2013 and 18 September 2013.[39]

OFGEM and the CRE issued a joint decision granting the derogation which was approved by the CRE on 6 March 2014.[40] The joint decision was notified to the European Commission on 20 March 2014. The European Commission issued a decision related to the derogation granted to ElecLink requesting the OFGEM and the CRE to modify their joint decision in respect of the TSO certification requirement. The amended joint decision was approved by the CRE on 28 August 2014.[41]

Efficient functioning of the electricity market

New design of the capacity mechanism

In a decision dated 28 May 2014,[42] the CRE issued a favourable opinion on the first draft of the operational rules for the capacity mechanism on the electricity market. A capacity obligation mechanism,[43] is expected to become effective by 2016.

The capacity mechanism is designed:

- to provide, in addition to the energy market, the economic incentives required to achieve the level of security of supply by certifying power capacities; and
- to ensure that such certifications could further be traded on a decentralized capacity market.

By its decision, the CRE supports the project of the capacity mechanism regulation prepared by the transmission network system operator ("RTE"), specifying the rules regarding the capacity obligation, the certification of these capacities, as well as the methodology applying to the determination of peak consumption periods. The rules are to be further approved by the Minister of Energy and first certificates are to be delivered by the end of 2014.

Development of the demand response

Recent regulatory and judicial decisions seem to be shaping the further development of the demand response ("DR") in France. There is opposition to DR from electricity suppliers as DR reduces the consumption of electricity they supply, therefore requiring reimbursement for their loss of profit. This has given rise to a number of cases. In 2009,[44] the CRE supported the idea of reimbursement, but the Conseil d'Etat has since overturned this decision.[45] Legislation dated 15 April 2013 (no. 2013-312) which created article L.271-1 of the French Energy Code, and has established a legal basis for the DR activity. More specifically, it:

- sets out the principle of reimbursement of electricity suppliers by the DR operators, taking into account "the amount of electricity injected" on the transmission network; and
- provides for the public subsidisation of demand response activity and specifies that the results of such activity must be commercialised on the wholesale energy market.

These principles are implemented by decree. Before the adoption of the latter, these principles were implemented by a transmission network operator, subject to the CRE's approval. The first provisional rules were approved on 28 November 2013, and entered into force on 18 December 2013 for a one-year period.[46] They give an important role to local distribution network operators in collecting the information related to the demand response within their perimeter and provide a methodology for the calculation of the reimbursement due by the DR operators to the electricity suppliers affected by the DR activity.

On 20 December 2013,[47] a French Competition authority issued its opinion on the draft decree implementing article L.271-1 of the Energy Code. It:

- draws attention to the risks of public subsidies for DR activity, especially regarding the state aid framework, and its impact on the bills of electricity consumers; and
- warns that involvement of system operators in the competitive landscape of demand response, not formally excluded by the draft decree, would present a risk of distorting competition and developing some further recommendations.

Following this decision, a demand response operator, Voltalis, has requested that the CRE modify its decision on 28 November 2013 limiting the role of the system operators and excluding the reimbursement of electricity suppliers. This request was rejected by the decision on 7 May 2014.[48] This decision was challenged before the Conseil d'Etat, which rejected a petition for interim suspension on 28 July 2014.[49] The final decision is expected in 2015.

Meanwhile, a decree on demand response was published on 5 July 2014[50], maintaining the public subsidy mechanism for the DR activity and the reimbursement principle.

Nuclear energy

The main new regulations that were enacted over the past year are summarised below.

An ordinance dated 10 July 2014[51] incorporates the provisions governing the operation of nuclear facilities and activities relating to defence into the French Defence Code. In addition, it includes new provisions extending the right for any person to be informed of the risks incurred linked to nuclear activities and their impact on health, safety and environment. This ordinance also strengthens the legal framework for the protection of nuclear sites, with regards to parking and traffic in their vicinity.

A decree dated 27 December 2013[52] sets out the requirements of the national plan for the management of radioactive waste and materials for the years 2013-2015. Notably, it sets out the requirements for operators of nuclear installations to manage, on a temporary and long-term basis, the radioactive waste and materials they produced. It also sets out requirements in view of improving existing waste management solutions and developing new forms of waste management.

A decree dated 25 February 2014[53] extends the application of the rules governing the French greenhouse gas emissions trading scheme to nuclear facilities. It notably extends to nuclear facilities the rules for the allocation and delivery of quotas that are currently applicable to classified installations for the protection of environment (also known as ICPE facilities).

The ministerial order dated 11 April 2014[54] approved a decision issued by the French Nuclear Safety Authority (the ASN) relating to material changes in nuclear installations. This decision specifies the provisions that the operator of a nuclear installation must implement (i) to evaluate and minimise the potential consequences of a material change implemented on the installation which would be likely to affect public health and safety and the preservation of the environment and (ii) to prepare and effect such a change.

GAS

Feed-in tariffs regulation

Waterwaste treatment plants

Regulation regarding biogas has been modified to extend the legal feed-in tariffs framework to biogas produced from wastewater treatment plants:

- a new increased feed-in tariff specific to wastewater treatment plants has been created ("PI3"), which varies depending on the maximal capacity of the installation;[55]
- existing wastewater treatment plants may also benefit from a feed-in tariff when it never beneficiated from a power purchase agreement;[56]
- the list of biogases that can be injected in the natural gas network has been extended to include biogas produced with the following inputs: materials such as mud, grease, and fluids, resulting from the treatment of wastewater treated in a digester.[57]

Mining gas

In March 2014, two decrees were enacted to set up a feed-in tariff framework related to power generated from mine gas. The purpose of this is to value the part of mine gas that is not fit to be injected in the national gas grid due to its low quality. Pursuant to these decrees:

- Mine gas fired power plants may benefit from a feed-in tariff scheme if:
  - the power output of the plant is inferior or equal to 12MW; and
  - the mine gas used for the power generation is captured without any additional intervention except for the extraction operation itself.[58]
- The minimal distance between two installations for the purpose of evaluating the aforementioned 12MW cap is set at 1500 meters.[59]

However, the ministerial order fixing the tariff rates has not been issued yet. This delay is certainly linked to the negative decision on the draft order issued by the CRE in October 2013 which held that the tariff rate provided for in the draft Order was too profitable.

Gas storage and security of supply

The decree no. 2014-328 dated 12 March 2014[60] modified several provisions of the decree no. 2006-1034 dated 21 August 2006 applying to the gas storage obligation imposed to gas suppliers in France. According to French legislation,[61] on 31 October each year any gas supplier in France must hold sufficient stocks of natural gas, taking into account its other modulation instruments, in order to fulfil its contractual obligations of supplying its customers directly or indirectly during the period between 1 November and 31 March.

With the purpose of enhancing the security of supply, the new decree amends the existing storage requirement expressed in volume by:

- reducing the storage volumes to at least 80% (against 85% in the initial decree of 2006);
- adding a storage requirement expressed in a withdrawal rate (*débit de soutirage*) to ensure the provision of the gas suppliers' customers during cold peaks; and
- including non-domestic clients that do not hold an interruptible gas supply contract in the scope of this requirement.

The method of computation of the gas storage volumes' rights was also modified by an order dated 11 March 2014.[62] It is our understanding that this order and the above mentioned decree no.2014-328 are currently being challenged before the Conseil d'Etat.

Besides, the decree dated 19 March 2004[63] imposed on gas suppliers to ensure the supply of gas to its customers in case of extreme temperatures during a 3-days peak period occurring with a statistical probability of once in 50 years. An order dated 16 June 2014[64] has specified the following elements in order to estimate the amount of gas that each supplier needs to be able to provide: a detailed methodology of calculation of such extreme temperatures and of the one-day consumption level to be taken into account for the determination of the 3-days peak period.

GRTgaz Sud and TIGF zones merge in 2015

Whilst there are currently three market zones, (GRTgaz Nord, GRTgaz South and TIGF zone), France is moving toward a single national gas market. On 13 December 2012,[65] the CRE decided to merge the TIGF and GRTgaz South zones in 2015 in order to further create a common French market by 2018.[66]

On 22 May 2014[67] the CRE specified rules of the functioning of the common market zone between GRTgaz South and TIGF starting from 1st April 2015. These rules specify:

- the creation of a common "trading region" system where transactions are to be managed by GRTgaz,

- the management of contractual and physical imbalances in the new zone, and
- the methodology for calculating the contractual imbalances.

At the same time, the creation of a single gas marketplace was reiterated in the decision on 7 May 2014.[68] It is to be based on the investment configuration which brings the Val de Saône and Gascogne-Midi projects together. The CRE has also provided for some interim measures, in particular in relation to the capacity tariffs on the North-South link.

In order to take account of some of these interim measures, in July 2014 the CRE launched a public consultation on the modification of gas transmission tariffs. On 25 September 2014[69] the CRE revealed its draft decision on the evolution of the tariff.

RENEWABLE ENERGIES

Simplification of administrative procedures for renewable projects

In an effort to simplify the process to obtain certain authorisations required to implement renewable energy projects, two ordinances have been adopted.

An ordinance dated 20 March 2014[70] and implemented by a decree dated 2 May 2014[71] allows a trial period of three years, where wind farms, biogas stations and power plants based on biogas may be granted a unique authorisation encompassing, where required:

- the building licence (*permis de construire*);
- the classified installations ("ICPE") authorisation;
- the operating licence pursuant to the energy code;
- the authorisation for private electric lines;
- the protected species waiver (*dérogation autorisant la destruction des espèces protégées*);
- the clearing autorisation (*autorisation de défrichement*).

The selected regions concerned with this unique authorisation are: Basse-Normandie, Bretagne, Champagne-Ardernne, Franche-Comté, Midi-Pyrénées, Nord-Pas-de-Calais and Picardie.

Another ordinance dated 20 March 2014[72] implemented by decree dated 20 March 2014[73] allows for a trial period of three years where a project certificate may be granted by the Préfet regarding projects where at least one authorisation provided for in the environmental code, the forestry code or the town planning code is required to implement the project. The project certificate aims are:

- identifying the applicable legal regime, the types of authorisation required and the applicable procedures to follow;
- indicating a maximum deadline for the instruction of the required authorisations; and
- warranting during a 18 month period following the date of notification of the certificate that the laws and regulations applicable to administrative procedures and decisions necessary for the implementation of the project are the ones applicable at the date of issuance of the certificate.

This procedure is only applicable for projects implemented in Aquitaine, Bretagne, Champagne-Ardenne and Franche-Comté and claims to give greater visibility to project sponsors on the procedures, rules and instruction time period applicable to a given project.

Tariffs applicable to renewable energies

Cancellation of the feed-in tariffs applicable to wind energy

The Conseil d'Etat recently cancelled a ministerial order dated 17 November 2008[74] (the "Wind Ministerial Order") setting out the feed-in tariffs applicable for onshore and offshore wind energy, with retroactive effect. It was cancelled on the basis of being an illegal state aid according to EU law.

By way of background, the Wind Ministerial Order set out the feed-in tariffs above market rates at which EDF OA or certain other power distributors (the "Compulsory Offtakers") must purchase the power generated by French onshore and offshore wind farm operators.[75] The legality of this Wind Ministerial Order was challenged by a French anti-wind energy NGO called Vent de colère.

Vent de colère claimed that the French feed-in tariff mechanism provided by the Wind Ministerial Order (the "Wind Power FIT"), and in particular its financing through a tax levied to compensate the additional costs incurred by EDF as a result of its obligation to purchase power generated by renewable sources, constituted state aid,[76] which was unlawful since it had not been duly notified to, and approved by, the European Commission.[77]

The Conseil d'Etat concluded, in a preliminary ruling dated 15 May 2012[78] (the "Preliminary Ruling") that the Wind Power FIT met all the criteria except for the first one. The Conseil d'Etat referred this question of interpretation of EU law to the CJEU, which confirmed that the Wind Power FIT mechanism is made through state resources.[79]

The final decision of the Conseil d'Etat was issued on 28 May 2014.[80] Based on the Preliminary Ruling and the CJEU ruling, the Conseil d'Etat had no choice but to qualify the Wind Power FIT as a state aid and consequently to cancel the Wind Ministerial Order since no notification had been made to the European Commission prior to its implementation.

Finally, the Conseil d'Etat ruled on a retroactive cancellation of the Wind Ministerial Order and rejected the request to make the cancellation of the Wind Ministerial Order applicable only for the future. The cancellation of the Wind Ministerial Order therefore has retroactive effect from the date of issue of the Wind Ministerial Order (ie 17 November 2008). The Conseil d'Etat also decided to limit its ruling to the sole cancellation of the Wind Ministerial Order and not to order the French state to implement recovery proceedings.

Consequences for on-going projects

As a general principle, when State aid is declared illegal, the relevant Member State must automatically recover it. When illegal State aid is notified by a Member State and then declared compatible by the European Commission, the recovery proceedings only cover the reimbursement of interest[81] payable on the sum representing the difference between the market tariffs and the State aid (ie here the purchase price as defined within the PPAs based on the Wind Ministerial Order) received until the issue, by the European Commission of a compatibility decision (ie 27 March 2014).

In addition, EDF confirmed[82] that it will continue the normal performance of power purchase agreements already in place before the cancellation of the Wind Ministerial Order.

Consequences on future projects are dealt with in the section "Enactment of new feed-in tariffs applicable to wind energy".

Enactment of new feed-in tariffs applicable to wind energy

Anticipating the cancellation of the Wind Ministerial Order, the French government subsequently prepared a new draft order designed to replace the Wind Ministerial Order[83] (the "New Wind Ministerial Order") and presented the mechanism on which it is based to the European Commission for confirmation that it is compatible with the State aid regime. This approval was granted on 27 March 2014 by the European Commission.[84]

The New Wind Ministerial Order is almost identical to the Wind Ministerial Order although it no longer applies to offshore wind farms and sets the applicable base tariff to €0.082/kWh (against €0.13/kWh in the Wind Ministerial Order). It should be noted that the CRE issued, on 28 May 2014, a negative opinion on the New Wind Ministerial Order[85] notably because such order was said to procure excessive profitability to wind farms operators.

Therefore, future on-shore wind energy projects will benefit from a feed-in-tariff which can no longer be challenged as illegal State aid.

Challenge of the new feed-in tariffs applicable to wind energy

On 1 September 2014, three French anti-wind energy NGOs (led by Vent de colère) filed before the Conseil d'Etat, an action against the New Wind Ministerial Order. According to the Syndicat des Energies Renouvelables, the French association for the promotion of renewable energies ("SER"),[86] the three organisations claim that:

- the New Wind Ministerial Order has not been properly notified to the European Commission in accordance with the new Guidelines dealing with State aids granted in connection with the protection of environment and energy;
- the New Wind Ministerial Order procures excessive profitability to wind farms operators; and
- the mechanism provided in the New Wind Ministerial Order for financing the obligation to purchase electricity[87] is a public expense that should have been voted and passed through a law.

The action is still pending before the Conseil d'Etat.

Unconstitutionality of the feed-in tariff benefiting to certain cogeneration plants

The Conseil Constitutionnel ruled, in a decision dated 18 July 2014,[88] that the mechanism entitling (under certain conditions) the operators of cogeneration plants whose output is above 12MW, to benefit from a guaranteed tariff is unconstitutional since it constitutes a breach of the principle of equal treatment between operators of cogeneration plants above 12MW.

By way of background, on 23 May 2014, the company Roquette Frères brought an action before the Conseil d'Etat to challenge the constitutionality of the provisions of Article L. 314-1-1 of the French Energy Code.

Under Article L. 314-1 of the French Energy Code, operators of cogeneration plants which output is below 12MW benefit, as for operators of solar plants or wind farms, from feed-in tariffs above market rates at which Compulsory Offtakers must purchase the power generated.

Under Article L. 314-1-1 of the French Energy Code, operators of cogeneration plants (in operation as at 1 January 2013) with output above 12MW may also benefit from a guaranteed tariff, for a maximum of 3 years, provided that had entered into a purchase power agreement (with guaranteed feed-in tariffs) prior to the entry into force of the electricity law dated 2000[89] (the "Old PPA").

As the claimant operated two cogeneration plants above 12MW but had not previously entered into an Old PPA, it could not benefit from either of these regimes. Therefore, it claimed that the provisions of Article L. 314-1-1 of the French Energy Code creates a breach of equal treatment between operators of cogeneration plants above 12MW (in operation as at 1 January 2013) depending on whether they had entered into an Old PPA.

The Conseil Constitutionnel ruled in particular that:

- the fact that some operators had entered into an Old PPA cannot, per se, justify that they could solely keep benefiting from guaranteed tariffs for an additional period of time;
- the advantage granted to operators having entered into an Old PPA is just justified by any objective differences of situations with regard to the profitability or the positive impact on the environment of cogeneration plants;
- general interest purposes (energy efficiency or security of supply) cannot justify any inequality of treatment between operators having entered into an Old PPA and the others, since the later may equally contribute to fulfilling these general interest purposes even if they had not entered into an Old PPA.

Consequently, the Conseil Constitutionnel concluded that the provisions of Article L. 314-1-1 of the French Energy Code are unconstitutional on the ground of a breach of the principle of equal treatment and must be abrogated.

The CRE published a report in April 2014[90] analyzing the costs and profitability of the solar and on-shore wind energies and putting forward recommendations that are in line with those formulated by the Cour des Comptes.

Indeed, the CRE came to the conclusion that both type of energies (which benefit from a compulsory purchase mechanism) are, in some cases, excessively profitable.[91] In order to avoid that the public financing mechanisms, borne by consumers, lead to excessive profitability, the CRE recommended that:

- the duration of the compulsory purchase mechanism be aligned on the duration of the power purchase agreement and that the corresponding feed-in tariff be adjusted so that it is adapted to the actual costs of the installations and the expected profitability;
- the structure of the feed-in tariff be reviewed and revised regularly;
- the tender mechanism be generalised to the energies that are in a competitive situation (which would tend to align the level of the feed-in tariff to the actual costs of the electricity produced);[92]
- the compulsory purchase mechanism be reserved to less competitive energies in order to foster their continuous development;[93] and
- the producers of electricity benefit from a bonus, *ex post*, that would be equal to the difference between the market price at which they sold their electricity and the actual production costs of such electricity (which would guarantee a normal profitability of the installations).[94]

The Ministry of Ecology, Sustainable Development and Energy launched a public consultation on the evolution of the sustaining mechanisms applicable to facilities producing electricity and benefiting from guaranteed tariffs through a compulsory purchase, by Compulsory Offtakers, of the electricity produced.[95] The answers were due by 28 February 2014. At this stage, no summary or breakdown of the answers received is available.

HYDROCARBONS

Mining works

Following the FNE Case (in which the Conseil d'Etat quashed the Prime Minister's decision not to repeal a decree relating to mining operations), in February 2014 the government issued a new decree which submitted all hydrocarbons exploration works to the authorisation regime provided by the Mining Code[96] (instead of the simple declaration regime).

Redrafting of the French mining code

The review of the French mining code initiated in 2011 by the previous government has not progressed since the publication on the government's website of a first draft mining code in December 2013. Announcements were made that a draft bill would be submitted in early autumn but governmental arbitration on the proposals is still on-going and no bill has been tabled in parliament so far.

New permits allocation

Up to now, only six permits for geothermal deposits have been granted in 2014. The government is currently examining several applications to prospect for liquid and gaseous hydrocarbons and may issue new ministerial orders granting licences in the coming months.

Construction and operation of pipelines

The decree dated 27 December 2013[97] relating to the gas, hydrocarbons and other chemical products transmission pipelines completes some provisions of the environmental code. It specifies the definition of the gas, hydrocarbons and chemical products pipelines and amends some provisions regarding different administrative authorisations required for the construction and operation of such pipelines.

ENDNOTES

1. Decree No. 2014-479 dated 14 May 2014 *relatif aux investissements étrangers soumis à autorisation préalable*.
2. The other new grounds triggering the Ministerial approval are:
    - Integrity, security and continuity of the water supply in accordance with the standards laid down in the interest of public health;
    - Integrity and continuity of the operation of transportation networks and services;
    - Integrity, security and continuity of the operation of electronic communication networks and services;
    - Integrity, security and continuity of the operation of an installation, facility or structure of vital importance within the meaning of articles L.1332-1 and L.1332-2 of the defence code;
    - Protection of the public health.
3. Law No. 2014-344 dated 17 March 2014 *relative à la consommation*
4. http://www.autoritedelaconcurrence.fr/user/avisdec.php?numero=14MC02
5. Directives 2009/72/EC and 2009/73/EC of 13 July 2009 concerning common rules for the internal electricity and natural gas market, Directive 2012/27/EU of 25 October 2012 relating to energy efficiency
6. Articles L. 341-4 and L. 453-7 of the Energy Code, regarding the electricity and gas respectively
7. http://www.erdf.fr/Communique_presse_ERDF_detail?actuId=278
8. http://bibliotheque.grdf.fr/uploads/media/CP_GrDF_-_Compteurs_communicants_Gazpar_-_02_08_2013.pdf
9. Order dated 4 January 2012 *pris en application de l'article 4 du décret n° 2010-1022 du 31 août 2010 relatif aux dispositifs de comptage sur les réseaux publics d'électricité*
10. http://www.cre.fr/documents/deliberations/proposition/comptage
11. http://www.cre.fr/documents/deliberations/decision/comptage-evolue-erdf2
http://www.cre.fr/documents/deliberations/decision/comptage-evolue-grdf2
12. http://www.cre.fr/documents/publications/decryptages/decryptages-numero-42
13. http://www.cre.fr/documents/deliberations/decision/comptage-evolue-grdf2
14. *Conseil d'Etat*, 11 April 2014, ANODE, n° 365219.
15. *Arrêté du 28 juillet 2014 relatif aux tarifs réglementés de vente de l'électricité pour la période comprise entre le 23 juillet 2012 et le 31 juillet 2013*.
16. http://www.cre.fr/documents/deliberations/avis/arrete-retroactif-trv-electricite-2012
17. Order dated 28 July 2014 *modifiant l'arrêté du 26 juillet 2013 relatif aux tarifs réglementés de vente de l'électricité*
18. http://www.developpement-durable.gouv.fr/Les-tarifs-de-l-electricite-n,39778.html
19. *Conseil d'Etat*, ord., 12 September 2014, *ANODE*, n° 383721.
20. Article L. 337-6 of the Energy Code
21. http://www.cre.fr/documents/deliberations/avis/tarifs-reglementes-de-vente-de-l-electricite3
22. http://www.autoritedelaconcurrence.fr/user/avisdec.php?numero=14-A-16
23. Rapport sur la contribution au service public de l'électricité (CSPE) : mécanisme, historique et prospective (http://www.cre.fr/documents/publications/rapports-thematiques/rapport-sur-la-cspe-mecanisme-historique-et-prospective/consulter-le-rapport).
24. Case No. SA.36511 (2014/C) (ex 2013/NN).
25. Article L. 121-11 of the Energy Code.
26. Article L. 121-21 of the Energy Code.
27. *Délibération de la Commission de régulation de l'énergie du 28 mai 2014 portant communication sur la contribution au service public de l'électricité*.
28. *Conseil Constitutionnel*, decision No. 2014-419 QPC dated 8 October 2014, *Société Praxais SAS*.
29. At that time, the legal basis of the CSPE was paragraphe I of Article 5 of the *loi n° 2000-108 du 10 février 2000 relative à la modernisation et au développement du service public de l'électricité*.

30. Article L. 337-8 of the Energy Code.

31. ZNI are areas of the national territory which are not connected (by electrical lines) to the mainland continental system (Corsica, Martinique, Guadeloupe, Reunion, Guyana, Saint-Pierre and Miquelon and the islands of Molène and Ushant)

32. Article L. 121-7 of the Energy Code

33. Decree No. 2014-864 dated 1st August 2014 *modifiant le décret n° 2004-90 du 28 janvier 2004 relatif à la compensation des charges de service public de l’électricité*.

34. Article L. 121-7 of the Energy Code as amended by the 2012 amending finance law No. 2012-1510 dated 29 December 2012.

35. http://www.cre.fr/documents/consultations-publiques/appreciation-des-couts-d-investissement-et-d-exploitation-d-un-moyen-de-production-d-electricite-dans-les-zni

36. *Délibération de la CRE du 9 septembre 2014 portant communication relative à la méthodologie appliquée à l’examen des coûts d’investissement et d’exploitation dans des moyens de production d’électricité situés dans les zones non interconnectées et portés par EDF SEI ou Électricité de Mayotte ou qui font l’objet de contrats de gré-à-gré entre les producteurs tiers et EDF SEI ou Électricité de Mayotte* (http://www.cre.fr/documents/deliberations/communication/zones-non-interconnectees/consulter-la-deliberation).

37. *Cour de Cassation*. 1st civ, 11 December 2013, *Société Inti énergie c./ ERDF*, No. 12-29.328.

38. http://www.cre.fr/documents/deliberations/approbation/interconnexion-france-espagne/consulter-la-deliberation

39. http://www.cre.fr/documents/consultations-publiques/demande-de-derogation-d-eleclink-au-titre-de-l-article-17-du-reglement-ce-714-2009-concernant-une-interconnexion-entre-la-france-et-la-grande-bretagne

40. http://www.cre.fr/documents/deliberations/decision/interconnexion-france-grande-bretagne/consulter-la-deliberation

41. http://www.cre.fr/content/download/12307/152002/version/2/file/140828Eleclink.pdf

42. http://www.cre.fr/documents/deliberations/avis/regles-du-mecanisme-d-obligation-de-capacite

43. Article L. 335-1 and *seq*. of the French energy code

44. http://www.cre.fr/documents/deliberations/communication/integration-des-effacements-diffus-au-sein-du-mecanisme-d-ajustement

45. *Conseil d’Etat*, 3 May 2011, Voltalis, n° 331858

46. http://www.cre.fr/documents/deliberations/approbation/effacements-de-consommation

47. http://www.autoritedelaconcurrence.fr/user/standard.php?id_rub=592&id_article=2369

48. http://www.cre.fr/documents/deliberations/decision/demandes-de-la-societe-voltalis

49. *Conseil d’Etat*, ord., 28 juillet 2014, n° 381731

50. Decree No. 2014-764 dated 3 July 2014 *relatif aux effacements de consommation d’électricité*

51. Ordinance No. 2014-792 dated 10 July 2014 *portant application de l’article 55 de la loi n° 2013-1168 du 18 décembre 2013 relative à la programmation militaire pour les années 2014 à 2019 et portant diverses dispositions concernant la défense et la sécurité nationale*

52. Decree No. 2013-1304 dated 27 December 2013 *pris pour l’application de l’Article L. 542-1-2 du code de l’environnement et établissant les prescriptions du Plan national de gestion des matières et déchets radioactifs*

53. Decree No. 2014-220 dated 25 February 2014 *relatif au système d’échange de quotas d’émission de gaz à effet de serre (période 2013-2020) et à son extension aux équipements et installations de certaines installations nucléaires de base*

54. Ministerial order dated 11 April 2014 *portant homologation de la décision n° 2014-DC-0420 de l’Autorité de sûreté nucléaire du 13 février 2014 relative aux modifications matérielles des installations nucléaires de base*

55. Order dated 24 June 2014 modifying Order dated 23 November 2011 *fixant les conditions d’achat du biométhane injecté dans les réseaux de gaz naturel*.

56. Decree No. 2014-672 dated 24 June 2014 modifying Decree No. 2011-1597 dated 21 November 2011 *relatif aux conditions de contractualisation entre producteurs de biométhane et fournisseurs de gaz naturel*

57. Order dated 24 June 2014 modifying Order dated 23 November 2011 *fixant la nature des intrants dans la production de biométhane pour l’injonction dans les réseaux de gaz naturel*.

58. Decree No. 2014-375 dated 28 March 2014 *fixant pour l’énergie électrique fournie à partir du gaz de mine la limite de puissance des installations pouvant bénéficier de l’obligation d’achat d’électricité*.

59. Decree No. 2014-380 dated 29 March 2014 modifying Decree No. 2001-410 dated 10 May 2001 *relatif aux conditions d’achat de l’électricité produite par des producteurs bénéficiant de l’obligation d’achat*

60. Decree No. 2014-328 dated 12 March 2014 *modifiant le décret n° 2006-1034 du 21 août 2006 relatif à l’accès aux stockages souterrains de gaz naturel*

61. Article L. 421-4 of the Energy Code

62. Order dated 11 March 2014 *modifiant l’arrêté du 7 février 2007 relatif aux profils et aux droits unitaires de stockage*

63. Decree No. 2004-251 dated 19 March 2004 *relatif aux obligations de service public dans le secteur du gaz*

64. Order dated 16 June 2014 *relatif à la détermination des obligations de fourniture de gaz naturel dans le cas d’une température extrêmement basse pendant trois jours consécutifs et à l’estimation de la consommation journalière lors d’une pointe de froid au risque 2%*

65. http://www.cre.fr/documents/deliberations/decision/tarif-d-utilisation-des-reseaux-de-transport-de-gaz-naturel

66. Decision on 19 July 2012 regarding orientations on the evolution of marketplaces for gas in France: http://www.cre.fr/documents/deliberations/orientation/evolution-des-places-de-marche-de-gaz-en-france

67. http://www.cre.fr/documents/deliberations/decision/place-de-marche-commune2

68. http://www.cre.fr/documents/deliberations/orientation/place-de-marche-unique-en-2018

69. http://www.cre.fr/documents/deliberations/decision/atrt5-peg-unique-2018

70. Ordinance No. 2014-355 dated 20 March 2014 *relative à l’expérimentation d’une autorisation unique en matière d’installations classées pour la protection de l’environnement*.

71. Decree No. 2014-450 dated 2 May 2014 *relatif à l’expérimentation d’une autorisation unique en matière d’installations classées pour la protection de l’environnement*.

72. Ordinance No. 2014-356 dated 20 March 2014 *relative à l’expérimentation d’un certificat de projet*.

73. Decree No. 2014-358 dated 20 March 2014 *relatif à l’expérimentation d’un certificat de projet*.

74. Ministerial order dated 17 November 2008 *fixant les conditions d’achat de l’électricité produite par les installations utilisant l’énergie mécanique du vent*

75. The Wind Ministerial Order was part of the incentives created by the French government to reach the mandatory national renewable energy targets set under EU regulation by 2020.

76. A government measure essentially qualifies as state aid if it meets the following cumulative criteria:

- the intervention is made by the state or through state resources (which can take a variety of forms);
- the intervention gives the recipient an advantage on a selective basis (eg specific companies or industry sectors);
- competition has been or may be distorted; and
- the intervention is likely to affect trade between European Member States.

77. Under articles 107 ff. of the Treaty for the Functioning of the European Union ("TFEU") and the implementing regulations, any measure qualifying as state aid must be notified to, and be declared compatible by, the European Commission prior to its implementation. State aids which have not been notified are illegal.

78. *Conseil d'Etat*, 15 May 2012, No. 324852

79. CJUE, 19 December 2013, C-262/12

80. *Conseil d'Etat*, 28 May 2014, No. 324852

81. The method for fixing the interest rate for the recovery of unlawful aid is provided for in Chapter V of Regulation (EC) No. 794/2004 of 21 April 2004 implementing Council Regulation (EC) No. 659/1999 laying down detailed rules for the application of Article 93 of the EC Treaty. The applicable interest rate shall be the rate applicable on the date on which unlawful aid was first put at the disposal of the beneficiary. The recovery rate is published on the EU's website: http://ec.europa.eu/competition/state_aid/legislation/reference_rates.html

82. In a letter received by the SER from the Clients and Markets Director of EDF OA (being the main Compulsory Offtaker under the Wind Power FIT)

83. Ministerial order dated 17 June 2014 *fixant les conditions d'achat de l'électricité produite par les installations utilisant l'énergie mécanique du vent implantées à terre*

84. Decision of the European Commission referenced "Aide d'État SA.36511 (2014/C) (ex 2013/NN)" (http://eur-lex.europa.eu/legal-content/FR/TXT/PDF/?uri=OJ:C:2014:348:FULL&from=EN)

85. Decision dated 28 May 2014 *portant avis sur le projet d'arrêté fixant les conditions d'achat de l'électricité produite par les installations utilisant l'énergie mécanique du vent implantées à terre* (http://www.cre.fr/documents/deliberations/avis/tarif-eolien-terrestre)

86. The SER said they have had access to the preliminary brief

87. Such mechanism is called the *Contribution au Service Public de l'Electricité* (CSPE). The CSPE is a tax levied on consumers to compensate for the additional costs incurred by the Compulsory Offtakers as a result of their obligation to purchase electricity produced from renewable sources

88. *Conseil Constitutionnel*, 18 July 2014, decision No. 2014-410 QPC

89. Law No. 2000-108 dated 10 February 2000 *relative au service public de l'électricité*

90. Report of the CRE, *Coûts et rentabilité des énergies renouvelables en France métropolitaine (éolien terrestre, biomasse, solaire photovoltaïque)*, published in April 2014 (http://www.cre.fr/documents/publications/rapports-thematiques/couts-et-rentabilite-des-enr-en-france-metropolitaine)

91. Please note that pursuant to Article L. 314-7 of the French Energy Code, the feed-in tariffs awarded to operators of installations producing electricity from renewable sources shall not result in an excessive profitability of such installations

92. This recommendation was also formulated in the following report of the CRE: *Contribution au Service Public de l'Electricité : mécanisme, historique et prospective*, published in October 2014 (http://www.cre.fr/documents/publications/rapports-thematiques/rapport-sur-la-cspe-mecanisme-historique-et-prospective)

93. This recommendation was also formulated in the following report of the CRE: *Contribution au Service Public de l'Electricité : mécanisme, historique et prospective*, published in October 2014 (http://www.cre.fr/documents/publications/rapports-thematiques/rapport-sur-la-cspe-mecanisme-historique-et-prospective)

94. This recommendation was only formulated in the following report of the CRE : *Contribution au Service Public de l'Electricité : mécanisme, historique et prospective*, published in October 2014 (http://www.cre.fr/documents/publications/rapports-thematiques/rapport-sur-la-cspe-mecanisme-historique-et-prospective)

95. The details of such public consultation are available on (http://enqueteur.dgec.developpement-durable.gouv.fr/index.php?sid=13245&lang=fr)

96. Decree No. 2014-118 dated 11 February 2014 modifying Decree No. °2006-649 dated 2 June 2006 *relatif aux travaux miniers, aux travaux de stockage souterrain et à la police des mines et des stockages souterrains ainsi que l'annexe à l'article R. 122-2 du code de l'environnement*.

97. Decree No. 2013-1272 dated 27 December 2013 *relatif aux canalisations de transport de gaz naturel ou assimilé, d'hydrocarbures ou de produits chimiques*

ENERGY LAW IN GERMANY

Recent developments in the German energy market

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INTRODUCTION

From an energy policy perspective, 2014 was dominated by the implementation of the coalition agreement of the German government (entered into between the conservative CDU/CSU and the social-democrat SPD (the "Coalition")) published its coalition agreement (the "Agreement"). The Agreement sets out the Coalition's energy policy aims as achieving environmental sustainability alongside security of supply and affordability. Whilst the Agreement pledges to pursue the energy transition programme known as "Energiewende", the increasing costs of the programme have led the Coalition to bring in a number of changes, particularly in terms of limiting subsidies for renewable energy projects.

2014 saw the adoption of a bill to reform the German Renewable Energies Act ("EEG"), the adoption of a fracking bill, and the tabling of the German climate package. The expansion of the German electricity grid was another important topic in 2014.

In addition to the above legislative projects, the German government also created a new ministry for energy by pooling previous responsibilities for the field of energy policy in the new Federal Ministry for Economic Affairs and Energy. In contrast to previous approaches, this is thought to enable a "one-stop-shop" for energy policy as it cover the energy market in its entirety within a single ministry.

CO-ORDINATION BETWEEN FEDERAL AND REGIONAL GOVERNMENTS

Given Germany's federal structure and the fact that the regional states (*Länder*) have certain constitutional competencies in energy matters, the federal government and the Länder have to co-ordinate their efforts regarding the implementation of the energy transition. Therefore, biannual meetings take place between both the Federal Chancellor and the Federal Minister for Economic Affairs and the heads of government of the Länder in order to discuss the status of implementation of the energy transition project. The relevant ministers of the federal government and Länder consult each other at the biannual Economic Ministers Conference on their priorities and the next steps in the energy transition. In order to implement the energy transition on the basis of a broad societal dialogue, with trade unions, research and other non-governmental organisations, the Federal Government has started to convene an "energy transition forum" dedicated to dialogue and the exchange of information.

REFORM OF THE RENEWABLE ENERGY ACT

The act for the Reform of the Renewable Energy Act (the "Reform Act") was approved by the German Bundestag on the 27 June 2014 and on 11 July by the German Upper House. It is now set to come into force on 1 August 2014.

Sigmar Gabriel, German minister of Economy and Energy, stressed that the reform would provide a reliable but ambitious expansion path for renewable energy. Whereas previous German governments emphasized the increase of renewable energy generation capacity, the Reform Act has four main objectives:

- Continuing and controlling the expansion of renewable energy
- Lowering the cost of funding
- Spreading the financial burden more fairly
- Improving the market integration of renewable energy

The main objective of the Reform Act is to reconcile cost effectiveness, environmental compatibility and security of supply, three concerns that have often been referred to as the "energy trilemma".

In spite of the emphasis on cost control, the German government is keen to point out that the long-term objective of generating 80% of electricity through renewable resources has not changed. The expansion of renewable energy in Germany is set to continue, albeit at a slower pace.

Continuing and controlling the expansion of renewable energy

The Reform Act stipulates specific targets as to the portion that energy generated from renewable sources should make up in the future:

- until 2025, this portion should total 40 – 45 per cent; and
- until 2035, this portion should total 55 – 60 per cent.

Additionally, the Reform Act sets targets for annual expansion of specific technologies:

- Installed capacity for solar power should increase by 2,500MW annually.
- Installed capacity for on-shore wind farm should be 2,500MW

In order to regulate the expansion of onshore wind capacity, the EEG now contains an expansion target of net 2,400-2,600MW/year for onshore wind power plants for the first time.

- The annual increase for biomass has been set at no more than 100MW
- Off-shore wind capacity has a target of 6,500MW by 2020 and of 15,000MW by 2030.

Lowering the costs

The objective of the Reform Act is to reduce the financial burden of the support programme for renewable energy generation. In order to achieve this objective, the Reform Act will reduce the support levels – with the introduction of technology specific tariffs which will apply to all new plant commissioned after 1 August 2014, further details and technology specific differences are set out below.

Onshore wind

The Reform Act introduces a number of changes for onshore wind; one of the consequences that have been predicted is a "race to commissioning" in 2014 to receive assistance from the old support regime which is likely to be followed by a somewhat slower year in 2015.

From 1 August, the tariff for newly commissioned onshore wind will decrease every quarter by 0.4 per cent (compared to the immediately preceding quarter) subject to the overall expansion of installed onshore wind capacity remaining within the target corridor of 2,400 – 2,600MW/year. Should this target corridor be exceeded, the rate of decrease will be accelerated accordingly. On the other hand, should the lower end of the target corridor (the "Onshore Target Floor") not be reached, the tariff will be adjusted accordingly.

If the target is exceeded by:

- up to 200MW, the reduction will be 0.5 per cent;
- more than 200MW, the reduction will be 0.6 per cent;
- more than 400MW the reduction will be 0.8 per cent;
- more than 600MW the reduction will be 1.0 per cent; and
- more than 800MW the reduction will be 1.2 per cent.

If the Target Floor is not reached in the relevant period the monthly reduction of the applicable value is decreased. For a shortfall of the Target Floor by up to 200MW, the reduction is decreased by 0.3 per cent; for a shortfall of the Target Floor by more than 200MW, the reduction is decreased by 0.2 per cent; and if the Target Floor is not reached by more than 400MW, the tariff will not be reduced.

The central problem in this approach however is that the actual tariff for each quarter will only be known, at the earliest, five months prior to its entry into force and is calculated on the basis of the reaching or otherwise of the Onshore Target Floor in the period from the last calendar day of the 18th month prior and the first calendar day of the fifth month prior to the relevant quarter. This introduces a level of uncertainty into any project's financial plans which in turn are not within the control of the project itself but determined by the speed with which its competing projects are commissioned. This scenario could lead to some interesting market dynamics in the future but will likely increase the difficulty of financing onshore wind projects.

In another significant change to the previous onshore wind regime, the Reform Act introduces changes to the reference yield model ("Referenzertragsmodell" in German). In this model, the tariff for onshore wind sets out a higher tariff for an initial period of time and a lower rate for the remainder of the 20 years (plus year of commissioning) in which the support tariff applies.

Offshore wind

The Reform Act also introduces a number of changes to the offshore regime.

The Reform Act introduces, by means of an amendment to the German Energy Industry Act (*Energiewirtschaftsgesetz*), a new mechanism for the allocation of grid connection capacity for new capacity of up to 6,500MW up to 31 December 2020. From 1 January 2021 onwards, the grid connection available for allocation capacity will increase by 800MW/year.

In the case of demand beyond these capacity targets, the relevant additional grid connection capacity will be allocated in an auction. Should a wind project fail to use its allocated grid capacity, the competent authority, the German Federal Maritime and Hydrographic Office may, subject to certain conditions, revoke allocated grid connection capacity.

It is possible that this new mechanism will make the already difficult process of offshore grid connection more complicated for projects. Further, it remains to be seen whether this process will help to alleviate the pressure on the two offshore TSOs to provide timely grid connections.

However, the structure of the current tariff regime remains largely unchanged and the availability of the popular acceleration model pursuant to which an increased tariff applies for the first eight years has been extended to plants commissioned prior to 1 January 2020.

There are two different approaches of remuneration for offshore wind farms which commence operation before 1 January 2020. Wind farm operators can choose between:

- claiming the 'initial remuneration' of 15.4 ct/kWh over a period of 12 years; or
- claiming an 'initial remuneration' of 19.4 ct/kWh for a total of 8 years (the so-called optional acceleration model).

After 12 or 8 years, as applicable, the remuneration returns to a fixed level of 3.9 ct/kWh.

Under certain circumstances, the initial remuneration of 15.4 ct/kWh can be extended beyond the period of 12 years, depending on the distance between the wind farm and the coast and the water depth at the location. The period in which the increased initial remuneration of 15.4 ct/kWh is paid is extended by 0.5 months for every full nautical mile of distance between the system and the coast over twelve nautical miles and by 1.7 months for each full metre of water depth exceeding a depth of 20 metres.

The possibility of extension also applies to wind farms for which the operator has selected the higher rate of remuneration of 19.4 ct/kWh for a period of 8 years in accordance with the acceleration model.

Regardless of whether or not the operator has chosen the acceleration model, if the remuneration period is extended, 15.4ct/kWh will be paid out during the extension period.

Overview of applicable FiTs for offshore wind farms pursuant to the Reform Act:

YEAR OF COMMISSIONING	BASIC REMUNERATION [CT/KWH]	HIGHER INITIAL REMUNERATION [CT/KWH]	INITIAL REMUNERATION IN THE ACCELERATED MODEL [CT/KWH]
2015	3,9	15,4	19,4
2016	3,9	15,4	19,4
2017	3,9	15,4	19,4
2018	3,9	14,9	18,4
2019	3,9	14,9	18,4
2020	3,9	14,4	18,4
2021	3,9	13,9	-
2022	3,9	13,4	

Solar (photovoltaic)

The Reform Act does not introduce structural changes to the support regime for solar (photovoltaic) installations; it specifies an expansion corridor of newly built capacity of 2,400-2,600 MW/ year (the "Solar Target Corridor"). The slightly changed tariff structure for solar plants will be applicable to plants commissioned from 1 September 2014 onwards.

The applicable value depends on the installed capacity of the plant.

For up to and including 10 MW it is 9.23 Cent/kWh provided that –

- the plant is affixed to, in or on a building and the building is predominantly used for purposes other than the generation of electricity from solar power
- certain zoning law provisions are complied with.

If the plant is affixed to, in or on exclusively on a building or a noise protection wall, the applicable value is for an installed capacity of

- up to and including 10kW 13.15 Cent/kWh
- up to and including 40 kW 12.80 Cent/kWh
- up to and including 1 MW 11.49 Cent/kWh
- up to and including 10 MW 9.23 Cent/kWh

Reduction of financial support

The applicable value is reduced monthly by 0.5 per cent relative to the applicable value in the previous month.

The monthly reduction is reviewed and increased or decreased every quarter, depending on whether or not the Solar Target Corridor has been met or exceeded. If the Solar Target Corridor has been exceeded in the relevant period (the period between the last day of the 14th month and the first day of the last month preceding the review) the monthly reduction of the applicable value is increased.

For an excess of –

- up to 900 MW to 1.00 per cent;
- more than 900 MW to 1.40 per cent;
- more than 1,900 MW to 1.80 per cent;
- more than 2,900 MW to 2.20 per cent;
- of more than 3,900 MW to 2.50 per cent;
- more than 4,900 MW to 2.80 per cent.

If the Solar Target Corridor has not been met in the relevant period, the monthly reduction of the applicable value is decreased.

For a shortfall of –

- up to 900 MW to 0.25 per cent
- more than 900 MW to nil
- more than 1,400 MW to nil; the applicable value is increased by 1.50 per cent once on the first day of the applicable quarter.

Spreading the burden more fairly

In Germany, the cost of the support regime for renewable energy is socialised and largely borne by industrial and domestic consumers through the mechanism of a charge (the "Reallocation Charge") which is added to electricity bills. In the past, large industrial consumers enjoyed an exemption from this reallocation charge. This exemption regime was subject to criticism from the European Commission. One of the objectives of the Reform Act is to spread the burden of the Reallocation Charge more fairly and to revoke or limit any exemptions.

Self-supply

Under the Reform Act, self-supplying entities with an installed capacity of more than 10kW will be subject to the Reallocation Charge.

For self-supply from renewable energy plants commissioned after 1 August 2014 a reduced rate of the Reallocation Charge will be payable. The reduced rate is 30 per cent until the end of 2015, 35 per cent in 2016 and from 2017 onwards 40 per cent of the full amount.

Energy-intensive corporations

Under the applicable regime prior to the Reform Act, energy-intensive corporations were exempt from the Reallocation Charge. Under the Reform Act, exemptions will be limited to corporations and specified sectors characterised by high energy costs, intensity of trade and subject to international competition that depend on the exemption to remain competitive. Eligible sectors are categorised into two lists ("List 1" and "List 2", respectively) which are annexed to the Reform Act.

In order to apply for an exemption a corporation from an eligible sector will need to provide evidence of the following:

- a certain minimum of energy consumption in the preceding financial year; and

- that its energy costs make up at least 16 per cent (17 per cent from 2015) of their gross value (for List 1 sectors) or at least 20 per cent of gross value (for List 2 sectors).

Companies benefitting from an exemption are likely to have to pay at least a certain amount of the Reallocation Charge, ie they will have to pay the full Reallocation Charge for the first GWh consumed, and thereafter, for every kWh 15 per cent of the full Reallocation Charge. The amount payable is subject to a cap (or super-cap) of 4 per cent of gross value of the corporation (the "cap") and 0.5 per cent of the gross value of the corporation (the "super cap"). The super cap applies to companies with energy costs of more than 20 per cent of their gross value. Regardless of any applicable cap, the minimum amount payable will be 0.1 cent/kWh or 0.05 cent/kWh for corporations operating in the nonferrous metals sector.

Improving the market integration of renewable energy

Compulsory 'direct marketing'

Direct marketing refers to the selling of renewably generated electricity directly to another market participant at market prices rather than to the TSO under the applicable feed-in-tariff.

Under the regime prior to the introduction of the Reform Act, direct selling was used by some large plant operators in peak times to achieve an electricity price above the feed-in-tariff. The Reform Act introduces an element of compulsory direct marketing:

- for plants with an installed capacity in excess of 500 kW from 1 August 2014; and
- for smaller plants with an installed capacity of more than 100kW from 1 January 2016.

Plants with a lower installed capacity remain entitled to a feed-in tariff as well as plants with an installed capacity of up to 250kW commissioned between 31 December 2015 and 1 January 2017.

For operators subject to the direct marketing regime, the feed-in-tariffs will effectively only be available as an emergency back-up in that such operators will only receive a reduced tariff in case of a switch back to the FIT.

Introduction of tendering

Under the regime prior to the Reform Act, TSOs were subject to a compulsory purchase obligation and as such had to take off, transmit and distribute any renewably generated electricity and pay the producer on the basis of statutory feed-in-tariffs.

The Reform Act introduces, for the first time, the concept of tenders for solar plants on open land by way of a pilot project. If this is successful, the government plans to introduce tendering for all renewable energy sources. The Reform Act does not specify the details of the intended tendering regime – this will be addressed in subsequent secondary legislation.

IMPACT ON CURRENT AND FUTURE RENEWABLE ENERGY PROJECTS

What happens to existing plant?

Offshore wind

The pre-Reform Act tariffs will continue to apply to:

- plants commissioned before 1 August 2014; and
- plants with a commissioning date between 1 August 2014 and 31 December 2014 if the developer obtained the licence under the Federal Emission Control Act (*Bundesimmissionsschutzgesetz*) on or before 22 January 2014.

For all other projects, the support regime of the Reform Act will apply.

Existing biogas plants

In general, the financial support provisions at the time of commissioning are applicable. However, support for subsequent capacity additions is capped at the output achieved in 2013 or 95 per cent of the installed capacity on 31 July 2014, whichever is the higher.

Operators of existing plants are entitled to €130 per kW flexibly provided additional installed capacity per year subject to the additional electricity being made available to the market through direct marketing.

Hydropower plants launched after 1 January 2009

If an existing hydropower plant with an installed capacity of more than 5MW is extended after 1 August 2014, the operator is entitled to financial support under the new rules for 20 years from the date of extension (not including the year of extension).

Where plants with an installed capacity of below 5MW are extended after 1 August 2014 the entitlements remain the same as under the previous rules.

State Aid

The Reform Act, which enters into force on 1 August 2014, will have a yearly budget of ca. €20 billion. The EU Commission has confirmed that the measures set out in the Reform Act are compatible with the EU state aid regime, as the Reform Act supports EU environmental and energy objectives without unduly distorting competition in the European single market.

FRACKING IN GERMANY?

On 19 December, the federal ministry for the economy and the federal ministry for the environment presented a draft framework bill (the "Framework Bill") on the use of the fracking technology in Germany. The framework bill contains amendments to a number of existing acts:

In particular, the Framework Bill provides for changes in the

- Regulation on Environmental Impact Assessment of Mining Projects (*Verordnung über die Umweltverträglichkeitsprüfung bergbaulicher Vorhaben*);
- General Federal Mining Regulation (*Allgemeine Bundesbergverordnung*); and
- Federal Mining Act (*Bundesberggesetzes*); and
- Affected Area-Mining Regulation (*Einwirkungsbereichs-Bergverordnung*)

in relation to which the federal ministry for the economy will have the lead.

The federal ministry for the environment will lead on the draft amendments to the

- Water Resources Act (*Wasserhaushaltsgesetz*),
- Federal Nature Conservation Act (*Bundesnaturschutzgesetzes*); and
- other, secondary, environmental regulations.

In the discussions following the adoption of the draft bill by the cabinet, the German government has emphasises that its guiding principle is the conservation of drinking water and public health; as such, the Framework Bill is intended to strengthen the protection of drinking water and bans unconventional fracking for shale- and coal-seam gas above 3.000 metres deep until further notice. In addition, any kind of fracking, ie, unconventional as well as conventional (eg, sandstone) will be completely prohibited in specified water protection areas (*Wasserschutzgebiete*).

Even though the Framework Bill does not translate into a total fracking ban, its implementation would mean that fracking may only be used subject to strict conditions which are stricter than those recommended by the European Commission in its communication regarding the exploration and development of hydrocarbons by high volume fracking in January 2014.

According to the recommendations of the EU Commission, a ban on all forms of fracking is unnecessary. In addition, it does not envisage a predetermined exclusion zone and does not make compulsory requirements regarding the chemical substances used. Under the auspices of the federal ministry for the environment, an act was passed altering the water and environmental requirements for the prohibition of and for risk minimisation of the dangers of fracking.

Under the Framework Bill, scientifically conducted tests to gather experience of the impact of fracking on the environment and sub-terrain will be possible subject to fracking liquids not being hazardous to water.

From 2018, an independent expert commission composed of six recognised specialist research institutes and authorities will review annually whether the environmental impact of the tests is non-hazardous. In as far as the risks arising from the tests are assessed as largely controllable; the expert commission will certify their safety in the relevant geographical formation.

The commission will be composed of six experts from different institutions which cover the scientific spectrum relevant to the questions of fracking, from, amongst others:

- Federal Environment Agency;
- Federal institute for geo-Sciences and raw materials;
- the Potsdam based Helmholtz-Centre of German Geo-Research; and
- Leipzig Helmholtz-Centre for environmental research.

Conventional fracking

The so called "conventional" fracking of natural gas in sandstone and carbonate rock (also known as Tight-Gas) has already been applied in Germany in around 320 cases for the past 60 years and is regulated by additional requirements. This applies similarly to the extraction of natural gas, oil and geothermal energy.

Fracking is banned in sensitive areas such as the conservation areas for water and/or mineral springs as well as lakes and drinking water reservoirs. The Länder may waive the ban in the vicinity of sensitive water extraction points. Fracking in national parks and nature preservation areas is prohibited. The presiding mining authorities must obtain the agreement of the water authorities for all fracking licences. The Framework Bill establishes further regulations for environmental impact assessments and new requirements per the Federal Mining Regulation by the amendment of the for the Environmental Impact Study of Mining Standards Regulation (*UVP-V Bergbau*) such as an obligation for the:

- performance of an environmental impact assessment for all fracking activities whether conventional or unconventional; and
- disposal of any flow back water as back-flowing fracking fluid may not be discharged underground.

In relation to the General Federal Mining Regulation, the Framework Bill defines stricter rules for borehole integrity, induced seismic activities and for emissions of methane and other gases. The Framework Bill also introduces higher technology standards for the removal of backflow and ground water.

Mining law and burden of evidence

The Framework Bill also introduces an amendment of the Federal Mining Act and the Affected Area-Mining Regulation which would reverse the burden of proof for possible mining damage stemming fracking activity – including the construction and operation of caves.

Overall, the Framework Bill, whilst seemingly designed to enable fracking in Germany, de facto introduces a rather strict regime of conditions and restrictions which may in fact result in only limited fracking activities in the future in Germany.

The Länder had until the end of January to provide comments on the Framework Bill before it will be debated in the German parliament later in the year.

GERMAN CLIMATE PACKAGE

In December 2014, during the conference of the Parties to the United Nations Framework Convention on Climate Change, the cabinet adopted a legislative package with a series of measures in relation to energy and climate change (the "German Climate Package").

Whilst greenhouse gas emissions are on the rise again in Germany after sliding in the 1990s due to the post-reunification modernization of East German industry, significant reductions of greenhouse gas reductions (ie, a 40 per cent drop in emissions by 2020 from 1990 levels, the equivalent of about 78 million tonnes of CO_2) constitute the core of the German Climate Package. The most contested step is making coal plant operators reduce emissions by at least 22 million tonnes, equivalent to shutting about eight plants.

The German Climate Package envisages savings of 25-30 million tonnes of CO_2 emissions via a national energy efficiency plan to modernize and insulate buildings. It also includes incentives for electric cars and stricter rules on fertilisers and waste. The reductions are intended to be brought about by a reduction in energy consumption by, amongst other measures, an energy efficiency programme that could trigger billions of euros in investment.

There is some dispute between the federal government and the Länder governments as to the allocation of the costs arising from the German Climate Package; it is, however, intended that the KfW state development bank have its building renovation programme topped up by €200 million per year to a total of €2 billion. In addition, €1 billion in tax relief will available per year until 2019 for building renovation or modernisation.

The government has acknowledged it looks likely to miss its goal of having a million electric cars on German roads by 2020. New steps include allowing the owners of electric company cars to offset half the cost of the vehicle against tax.

The German Climate Package also provides for tighter rules on fertilisers and waste will help reduce emissions by about 3.5 million tonnes and 3 million tonnes of CO_2 emissions in the agriculture and waste sectors respectively.

NATIONAL PLAN FOR ENERGY EFFICIENCY

In December 2014, the German federal government has launched the National Action Plan on Energy Efficiency ("NAPE") to reach the aforementioned efficiency targets.

NAPE places emphasis on supplying more information and advice to all relevant societal groups, including households and businesses. Another priority is the purposeful and innovative promotion of efficiency investments: Besides granting tax incentives for efficiency measures in residential buildings and special depreciation allowances for commercially-used electric vehicles, NAPE also includes a new kind of competitive tendering scheme.

Under NAPE, large-scale enterprises are obligated to conduct energy audits and sets standards for new installations and buildings. In up to 500 energy-efficiency networks, enterprises will also be expected to define and implement joint efficiency targets.

ENERGY EFFICIENCY PLATFORM: FOCUS ON JOINT DIALOGUE

An increase in energy efficiency cannot be achieved by state intervention alone. The Federal Ministry for Economic Affairs and Energy has therefore established the Energy efficiency platform to develop and discuss joint solutions together with the relevant stakeholders from business, civil society, science, the affected public departments and the federal states.

The energy efficiency platform provides guidance and support in the development of the national plan of action. Measures suggested by the participants are fed directly into the discussion about the national plan of action. The implementation of the national plan of action will also be supported and guided by the platform. The energy efficiency platform met for the first time on 10 July 2014.

ENERGY EFFICIENCY EXPORT INITIATIVE

Against this background, the German government has established the Energy Efficiency Export Initiative under the overall control of the Federal Ministry for Economic Affairs and Energy with the slogan "Energy Efficiency – Made in Germany". It supports German suppliers of products, systems and services connected with energy efficiency. Under this label, an information infrastructure is offered which is independent of individual projects and participants and which offers comprehensive information in important fields of action.

CHANGE IN ELECTRICITY MIX

In terms of the national energy mix, 2014 is a turning point in recent German energy policy: As 25.8% of all electricity generated stemmed from renewable sources, renewable sources constituted collectively largest source of electricity in Germany. According to figures provided by the federal association of the energy and water industry (*Bundesverbands der Energie- und Wasserwirtschaft*) hydro, wind, solar and biogas fuelled installations generated 157.4 billion kWh of electricity.

However, the success of renewable energy in Germany coincides with a simultaneous spike in the use of coal and lignite as primary fuel stock: in 2014, electricity generated from lignite accounted for 25.6%. Commentators have suggested that the low price of EU ETS allowances (under €5 for much of 2014, albeit with an upwards trend since July 2014 and at the time of writing at about €7/EUA) might be partially responsible for the increase in lignite use in German power stations.

EXPANSION OF THE ELECTRICITY GRID

The rapid expansion and restructuring of the electricity grids in Germany and Europe is of key importance to integrate the growing share of renewable energies successfully and new conventional power plants and to consolidate the European electricity trade. Grid bottlenecks during the winter of 2012/2013 made repeated intervention by the transmission system operators necessary to maintain system reliability. Whilst grid stability was ensured at all times, the situation in southern Germany is likely to remain tense for the moment. The planned grid expansion can improve this situation structurally and should therefore be implemented swiftly and with high priority. The requisite lines are already included in the 2009 Energy Line Extension Act (*Energieleitungsausbaugesetz*) and the approval procedures are already under way at the Länder authorities.

The Network Development Plan ("NDP") has identified, since 2012, the expected demand for new transmission lines in Germany for the years 2022 and 2030. The NDP was compiled by four German TSOs: TenneT, Amprion, 50Hertz Transmission and TransnetBW.

The NDP is audited and certified by the Federal Network Agency ("FNA"). As the national regulatory authority for Germany, the FNA is in charge of ensuring a competitively-priced expansion of the energy network. The consumer bears the costs above the network charge for the service and new construction. In 2011 these costs constituted 20% of the energy price. The network operators estimate that the upgrade of the transmission network by 2022 will cost around €20 billion. As part of this upgrade the network operators want to build 3,800km of new power-transmission lines and to modernise 4,400km of old transmission lines with more efficient technology. However, in November 2012 following an inspection, the FNA certified only one part of the planned grid. The network operators were allowed to construct only 2,750km of new transmission lines, instead of 3,800km, and to upgrade only 3,000km instead of 4,400km. In total, the FNA approved 36 new and upgrade schemes. In December 2012, the federal government confirmed the urgent demand for these projects in the bill for a Federal Demand Plan Act. At the beginning of 2013 the Bundestag will pass the Act and thereby lay the guide for planning and construction of the energy grid. A further 24 projects are already under construction. They stem from the Energy Line Expansion Act (*EnLAG*) of 2009 and encompass 970km of new power transmission lines and reinforcement of 870km of existing lines.

TOWARDS A REFORM OF THE ELECTRICITY MARKET?

The efforts of the Reform Act to introduce more market based instruments such as compulsory direct marketing and tendering procedures for new facilities which are compatible with European State Aid guidelines reflect a larger trend across the EU.

Weaning companies off from what is perceived as high levels of support with little risk has long been an ambition of many European governments as well as the European Commission as many governments have struggled to maintain the expensive support regimes put in place to achieve a higher share of renewably generated energy.

The fact that the Reform Act has, in contrast to reforms in other EU member states, not cut any tariff retro-actively and, in case of offshore wind, extended the popular acceleration tariff ought to instil confidence in investors.

However, it would seem that the proposed tendering mechanism is the source of some uncertainty which will not be eliminated until the secondary legislation for the tendering procedure is in place and has been tested in practice. Commentators have also criticised the somewhat complicated benchmarking of tariffs on a quarterly basis against technology specific target corridors as these will make it more difficult to reliably predict tariff based income – which may add some difficulty for the financing of some facilities.

Overall, it seems, the German legislators remain optimistic about the development of the RES market: It now seems likely that energy from RES will be the dominant source of power in the coming years and by 2050, the market share of RES could be up to 80%. Renewable energy must therefore be constantly integrated into the power supply system so that it can progressively replace conventional energy sources. This requires a fundamental change in the energy supply system. Ensuring a reliable, environment-friendly and economically efficient power supply is one of the major challenges of the transformation of energy policies.

The goals of the system integration of renewable energy are especially:

- reliable grid operation using a high proportion of renewable energy,
- improved flexibility of power generation and power demand,
- smart interaction of power generation, consumption and modern grids,
- efficient use of the existing grid structure.

Whilst the German government had, in its coalition agreement at the end of 2013, excluded an overall reform of the electricity market, the topic may need to be revisited. The rules of the electricity market (the "electricity market design") may therefore need to be developed to ensure that the electricity market will continue to ensure a reliable, cost-efficient and environment-friendly power supply with a growing proportion of wind and solar power in the future.

ENERGY LAW IN GREECE

Recent developments in the Greek energy market

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INTRODUCTION

Following several years of economic turmoil which has affected every part of the Greek economy, the energy sector included, Greece appears to be emerging from the economic crisis stronger, both as a significant energy hub for the South East European region and also a serious point of reference for major energy companies from around the world (Europe, America and Asia) which are seeking an entry into the European energy market. The energy market in Greece, which has been liberalised for many years, has taken advantage of the opportunities presented in the economic crisis in order to adopt many necessary reforms. In addition, areas of the energy market which have been underutilised in previous years are becoming active, while foreign investors are increasingly confident in investing in the Greek energy market, a fact evidenced in part by the interest in the privatisation of major Greek energy assets.

PRIVATISATION OF ENERGY COMPANIES

In the field of the privatisation of energy companies, the Greek government has made significant strides, overcoming many obstacles (which required making structural changes and overcoming domestic political opposition), where, as of this writing, the first major energy privatisation project is being concluded and the second such project is close to the selection of a successful bidder.

The first major energy privatisation project is the National Natural Gas TSO ("DESFA"); after almost three years since the commencement of the process, and almost one year since the selection of Azeri company Socar as the strategic partner of the Greek state and the signing of the relevant agreement to transfer a 66% majority stake to Socar, all national licences and certifications have been issued. In order to conclude the transaction (valued at €400million), the Regulatory Authority for Energy ("RAE"), has certified DESFA as an Independent Transportation Operator ("ITO") while also taking into account the European Commission's concerns and including a clause for suspension of the new owner's voting rights if it were deemed that the security of supply in Greece or the European Union was being threatened. Subsequent to the certification of DESFA as an ITO, all that remains for the sale to be finalised is its approval by the European Commission's Director-General for Competition.

Following on the heels of the privatisation of DESFA is the privatisation of the Independent Power Transportation Operator ("ADMIE"). Taking advantage of the experience gained from the DESFA privatisation process, the Greek state has been seeking to adhere to an ambitious timetable for the privatisation of ADMIE. The Invitation to Submit an Expression of Interest was published in April 2014; the submission of the binding bids by the interested parties, which was originally required within eight (8) months (December 2014), has only received minor delays at the request of the interested parties and, as of the time of writing, is expected in late 2014 or early 2015, and the signing of the relevant agreement is expected to take place shortly thereafter. The four candidates for ADMIE are the State Grid Corporation of China ("SGCC"), Terna, the Italian operator, Elia, the Belgian operator, and PSP Investments, a Canadian fund which already has a presence in Greece with a 40% stake in the Athens international airport.

In addition to DESFA and ADMIE, other energy companies which are to be privatised in some form or another include the Public Gas Company ("DEPA"), the Public Power Corporation ("PPC"), and Hellenic Petroleum ("ELPE"). The first attempt to privatise DEPA was unsuccessful; however, as natural gas continues to increase its market share, DEPA is expected to be well positioned to play an important role in the region, and it is therefore expected that the second privatisation attempt will be successful. The fact that DEPA has implemented a number of actions to allow for increased competition in the field of natural gas and to make its responsibilities and obligations clear to all market players should increase the chances of a successful privatisation.

Finally, the position of PPC in the Greek energy market is vital; it is the dominant electricity producer and supplier, and therefore a very appealing investment opportunity. More particularly, the plan for the restructuring and privatisation of PPC includes (i) the establishment of a new subsidiary electricity company to be privatised ("Small PPC") which will "inherit" about 30% of the overall portfolio of PPC; and (ii) the additional privatisation of the Greek state's 17% stake in the parent company PPC.

HYDROCARBONS RESEARCH

The first decisive step towards the commercial exploitation of possible oil reserves in Greece through the "open door" process was made by the Ministry of Environment, Energy and Climate Change ("MEECC"), when in July 2013 it announced that consortiums led by Energean Oil and Hellenic Petroleum won the tenders for exploration and exploitation of hydrocarbons in the areas of Ioannina and Katakolo, and the Gulf of Patra in western Greece, respectively. These tenders were met with significant international interest and were considered to be a success. Following several delays, in September 2014, the Hellenic parliament ratified the agreements between the Greek state and the concessionaires, which means that the exploration activities will commence shortly.

Early forecasts estimate the oil reserves for the three locations for the above concession agreements amount to 305 million barrels, a quantity that could generate revenues of up to $27billion over a 35 year period. In this event, the Greek state's earnings can be estimated to reach between $5billion to $8billion. The three consortiums have committed to investing €60million each during their respective first stage drilling procedures and, based on the agreements, these investments would reach €700million to €800million if hydrocarbon discoveries are made.

1. The consortium of Greek firm Energean Oil & Gas and Canadian-based oil and gas company Petra Petroleum has been awarded concession for an onshore site in Ioannina, north western Greece. Based on its agreement, the consortium has committed to staging the first drilling effort within the next four years, with a follow-up effort within the ensuing six years. Should the exploratory work prove successful, production in the Ioannina area can be expected to begin after 2021.
2. The consortium of Energean Oil & Gas and UK firm Trajan Oil, has been awarded concession for the area of Katakolo, western Peloponnese. Production phase should come considerably sooner at the Katakolo site, where a relatively small oil reserve was confirmed in 1981. The consortium plans to reevaluate existing data for the spot and begin producing in 2017.
3. The consortium of Greek firm ELPE, along with Italy's Edison and Irish firm Petroceltic has been selected to work an offshore location in the Gulf of Patras. This consortium has already approached firms active internationally in seismic research and one of these will be chosen to prepare detailed data. Seismic study results are expected in spring in 2015, while initial drilling is anticipated to take place in mid-2017. Depending on the results, two or three drilling efforts are expected in the Gulf of Patras, each at a cost of between €20 and €35 million.

In order to capitalise on the success of the "open door" process and the experience gained through it, the Greek state has announced a new round of international tenders for exploration and exploitation of an additional 20 offshore blocks south of Crete and in the Ionian Sea, as well as of three onshore sites in western Greece. The area south of Crete is believed to be the country's most likely prospect for the discovery of a major petroleum reservoir of international proportions, while the onshore sites (in the Arta-Preveza region, Aetoloakarnania, and northwest Peloponnese) have already drawn interest from major international players such as ENEL. The offered offshore blocks have considerable water depth levels and they are larger than the blocks previously offered, which means that advanced technical capabilities and extensive capital support will be needed for the exploration activities; this practically means that only large and mid-sized firms will be capable of staying in the race for the award of concession.

The timeline for the procedures of this round of oil exploration deals will be considerably swifter than that of the "open door" process given the experience already gained. The interested parties have a six-month deadline from the date of publication of the announcement of the tender in the Official Journal of the European Union to submit their offers; these offers will then be evaluated over a period of at least three months before the successful bids are selected and the relevant agreements are expected to be signed in the fall of 2015. This means that the entire process from the publication of the tenders to the signing of the agreements will take approximately twelve months from the launch of tender procedures; an aggressive, yet attainable goal. To further highlight the seriousness with which the timetable is approached, assurances that drilling operations will be swiftly conducted once deals have been signed are likely to accumulate higher scores during the tender's evaluation stage.

In order to be able to follow through with this timetable, the Greek state has taken on in parallel several related activities: a) the preparation of a study to examine the environmental impact of the exploratory work; b) publication of a joint ministerial decision on the distribution of provincial tax between provincial governments and local councils; and c) new appointments of specialised staff at the Greek Hydrocarbon Management Company ("EDEY") aimed at making tender procedures more efficient. The president of EDEY has been appointed, its BoD was formed into corpus in September 2014 and EDEY will be hiring at least twenty additional staff members, all specialised energy sector officials, to bolster its efforts and overall efficiency.

THE ELECTRICITY MARKET REFORM

Implementation of the European Target Model

Currently, the structure of the operation of the Greek wholesale electricity market is primarily based on a mandatory pool model regulating power exchanges between market participants (ie producers, electricity suppliers and eligible customers) according to which energy generated is mandatorily placed on the national grid through its mandatory sale to the sole electricity off-taker in Greece, ie the Electricity Market Operator ("LAGIE"), without the ability to use bilateral contracts for physical delivery between producers/importers and load representatives. Within the framework of this mandatory pool model, all power producers are required to submit to LAGIE energy injection offers for each of their power units in order to become eligible for dispatch by the operator and receive the payments corresponding to the energy injected into the grid, which are calculated on the basis of the SMP[1].

Greece is currently in the process of restructuring its wholesale electricity model in order to conform to the rules for market integration based on the European Target Model for electricity, with the aim to participate efficiently in a single European electricity market. The fact that the Target Model is strongly influenced by the markets of north-western Europe raises significant challenges for the Greek market, the design of which is fundamentally different from the approach used in north-western Europe. In order to reach a decision on the options available for the Target Model, RAE, ADMIE and LAGIE instructed an international consultant to develop a study entitled "Basic Planning Principles and Action Timetable for the Adjustment of the Internal Electricity Market with the Requirement of the Target Model". The results of this study were placed in public consultation until November 2014.

The general themes of this study include (i) the creation of a market for forward contracts, (ii) the creation of an intra-day market in which the participants will be able to adjust their net positions so that they will not be penalised due to deviations from the purchased in real time quantities, (iii) the creation of a balancing market with offers for the increase and decrease of production and/or consumption in order to balance the production and consumption of the system in real time, (iv) the change of rules of the daily market as well as of the manner of submission of offers by the participants (eg, by examining the types of offers made in other European markets, such as blocks or complex offers), etc.

In addition to the above, the study provides for the introduction of bilateral agreements between producers and alternative electricity off-takers. Furthermore, in order to protect the liquidity of the daily market, the bilateral agreements which the dominant supplier may enter into will be restricted. Especially in relation to the renewable energy ("RES") market, the option for bilateral agreements is also supported by the "Guidelines on state aid for environmental protection and energy 2014 to 2020" released by the European Commission. While the Commission expects that energy produced by RES will become "grid-competitive" in the period between 2020 and 2030 and that, by that point, subsidies and other forms of aid to energy from RES will be phased out, state aid may be permitted for RES projects until this takes place. However, such aid will only be authorised for a maximum period of ten years and will only be considered appropriate under specific circumstances and conditions, which in principle contribute to the integration of renewable electricity in the market, such as requiring the beneficiaries of the relevant aid sell their electricity directly in the market and are subject to market obligations[2].

The introduction of bilateral agreements for RES producers will also be in compliance with the obligation of the Greek state, under the provisions of its recent loan agreements, to reexamine the viability of the currently existing RES support schemes and make them more compatible with the current economic and market conditions (see also next section on the RES New Deal). However, it should be noted that the implementation of the bilateral agreements option would require significant investments for the upgrade of the national Grid in order to become compatible with the European networks and enable also the exportation of RES energy under bilateral agreements with foreign off-takers[3].

NOME auctions

Another measure which is close to being introduced in the Greek energy market is the use of auction procedures for the purchase of electricity packets (comprised of lignite and hydro production) by independent suppliers in order to cover the needs of their clients. This mechanism is based on the French NOME model facilitating low-cost energy. These auctions will be based on a starting price, although, as of the time of writing, specific details have not been made known.

The preparations for these auctions in the electricity wholesale market are close to being finalised in terms of regulatory details. RAE has made the necessary revisions based on the public consultations which took place as well as comments of the country's creditor representatives, the Troika. Taking into account the steps which have to be taken (the approval by the European Commission's Directorate-General for Competition and the submission to the Greek parliament for legislation processing) the first round of auctions is expected to take place in early March 2015.

THE RES NEW DEAL

The unprecedented and unexpected expansion of the RES sector in Greece and more particularly photovoltaic solar ("PV") projects due to the very favorable Feed In Tariff (FIT) granted to this technology created a high degree of financial obligations by the Greek state towards RES producers, which in turn led to an onerous shortfall in the RES Special Account, a special account from which payments to RES producers for the energy which they inject into the system are to be made. However, as this account had been underfunded over the years, coupled with the abovementioned favorable FIT granted to PVs, LAGIE has been late in making the required payments, which in turn affects the ability of RES producers to meet their own financing and loan obligations.

Due to this reason, and in light of the commitment of the Greek state towards its international lenders to completely eliminate the deficit in the RES Special Account, a new set of retroactive measures called "New Deal", applicable to all RES systems, was announced in March 2014 by the MEECC. Apart from eliminating the RES Special Account deficit, these retroactive measures also aim to reduce the cost of electricity for the end customers and to adjust the projects' internal rates of return (IRR), so that all RES power producers have similar investment returns.

The New Deal has been based on the following three main axes:

a) The readjustment of the currently applicable RES FITs, in order for the internal rate of return ("IRR") of the investments in all types of RES technologies to converge between 12% and 15% for all RES power projects. The loss caused to RES producers by this reduction of the FITs is then counterbalanced with the extension of the duration of the Power Purchase Agreements ("PPA"s);

b) The protection of the investors by taking into consideration the loan agreements entered into with local and international financing institutions; and

c) The compatibility of the new RES FITs with the current needs of the Greek electricity market (reducing the cost for energy production in Greece and securing reasonable investment rates of return).

The readjusted RES FITs have been calculated on the basis of specific criteria which have been proven to have a significant impact on the investment rates of return, such as the project's installation and operation cost, its installed capacity, the date of its connection to the system and its operational period, as well as whether it has received any kind of subsidy by the Greek state or through funds made available by the EU for the materialisation of the investment (either in the form of a direct grant or through tax exemptions). It has been calculated that the average FIT reduction which will be applied to commercial PV projects will amount to approximately 33%, whereas the respective reduction for wind park projects is not expected to exceed 6.4%. By applying a "haircut" of the RES FITs for all types of RES technology the MEECC aims to secure the operability of the RES FIT system in the future and to prevent a deficit being created again.

In order to counterbalance the abovementioned reductions, the New Deal provided that the PPAs for RES projects which have operated for less than 12 years as of 1 January 2014 shall be automatically extended by seven years and, in the cases where such extension applies, the producers shall have to choose one of the following options:

a) the sale of the produced energy on market terms (ie, under SMP driven prices) and on the basis of the contribution of each RES technology to the stability of the electricity system; or

b) the sale of the energy produced by priority at a price of €90/MWh up to a specific quantity of energy provided for by an equation set out in the law depending on the type of RES project.

The decision on which of the above options the producer chooses must be made no later than six months prior to the beginning of the extension period. After the expiration of the term of the PPAs (including the extension period), and on the condition that a valid production licence still exists, the sale of the energy which is produced by RES power plants will be injected into the system on market conditions and prices.

In addition, the suspension period for the licensing of new PV projects and the connection of already licensed ones is terminated and replaced by a maximum annual capacity which may be entered into the electricity system by PV power plants of 200MW (a limitation applicable until 2020). Any capacity exceeding the above limit will be compensated on market terms (ie, under SMP driven prices) for the year within which the maximum allowed PV capacity was exceeded and at the applicable FIT for the year in which it was not exceeded.

CONCLUSION

The Greek energy market has been utilising the lessons learned and the opportunities which arose from the financial crisis, and is in the process of instituting a wide range of reforms and utilising sectors of the energy market which had been previously dormant. The movement seen in hydrocarbons exploration and the international interest which it has sparked, the success stories of the first major energy privatisations in Greece, the structural reforms which have been and are being made in the electricity and RES sectors, all of these show the reflexes and care which the Greek government has shown in responding to the pressing needs of the energy market.

The use of a more comprehensive energy policy which seeks to align the legal and regulatory framework with that of other European countries, the promotion of existing clean energy projects, the modernisation and expansion of the energy related infrastructure, the diversification of sources of energy by exploring new energy possibilities through hydrocarbons research, and the creation of new job opportunities and technological innovations can only mean that Greece is taking the necessary steps in becoming the energy hub of South East Europe which it can be, as well as the entry point for major international energy players.

ENDNOTES

1. RES producers are exempted from the above obligation since the energy generated enjoys dispatch priority to the Grid and the payments are calculated on the basis of a guaranteed fixed FIT.
2. As of 1 January 2016, all new aid schemes and measures will require that, among other conditions, aid is granted as a premium in addition to the market price ("SMP"), indicating a shift from the typical and currently applicable FIT scheme to the feed-in premium scheme, whereby, the RES producers will be obliged to sell electricity directly in the market. Wind parks with an installed capacity of up to 3MW are exempt from this condition.
   As of 1 January 2017 aid will be granted through a competitive bidding process, unless specifically shown that it is otherwise necessary (ex. for diversification purposes, for new and innovative technologies, for reasons of grid stability) or it relates to small RES projects (such as wind parks with an installed capacity of up to 6MW). The abovementioned competitive bidding process must be open to all RES producers on a non-discriminatory basis in order to be considered proportionate and not distorting of the competition of the internal market; failure to adhere to this would lead to the aid granted not being compatible with the internal market rules.
   If an installation is commissioned prior to 1 January 2017 and had received confirmation of the aid before such date, the aid could be granted on the basis of the scheme in force at the time of confirmation.
3. The abovementioned Commission Guidelines also allow for the option to allow investment aid to energy infrastructure up to 100% of the eligible costs in the cases of Projects of Common Interest, smart grids and infrastructure in assisted regions.

ENERGY LAW IN HUNGARY

Recent developments in the Hungarian energy market

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TWO NEW NUCLEAR BLOCKS TO BE CONSTRUCTED BY ROSATOM

Pursuant to a set of international treaties entered into by and between Hungary and the Russian Federation in January 2014, the Russian state-owned Rosatom has been granted the right to construct two new nuclear blocks at the sole nuclear power plant in Hungary located at Paks. As a result of the development, the built-in capacity of the Paks nuclear power plant will be increased to a total capacity of 2,400MW. The current total capacity of the four existing nuclear blocks that are expected to operate until 2030 is 2,000MW. The first new block is expected to become operational in 2023 and the construction is planned to be completed in 2026. The investment cost is approximately €10-12 billion. Up to 80% of the costs are to be financed by a credit facility granted by the Russian Federation to Hungary specifically in connection with the nuclear construction project. The project is held to be the most significant investment in the Hungarian economy for a century. Pursuant to the international treaties concluded by Hungary and the Russian Federation, Rosatom is obliged to make all reasonable efforts in order to involve Hungarian entrepreneurs as subcontractors for the completion of at least 40% of the project.

SIGNIFICANT MANDATORY CUT OF HOUSEHOLD ENERGY PRICES

The Hungarian government has mandated a significant reduction in household gas, electricity and district heating prices from the beginning of 2013. This initiative has been continuously carried out in 2014. As a result of the initiative, the household prices of the following products have been reduced as follows: (i) gas – by 26.5%, (ii) electricity – by 25.7%, and (iii) district heating – by 23.3%. This has been achieved by reducing the constituent elements of the end price (eg, service charges, network usage fees, etc) by different proportions. The mandatory price cut has put suppliers under significant pressure. As a result, investments in the energy sector dropped significantly in 2013 and 2014. Since household gas, electricity and district heating prices are regulated prices, the price cuts are compliant with the applicable Hungarian laws. However, it is questionable whether the reduced prices are practicable in the medium-term or long-term from an economic point of view. The Commission has not expressed as yet its opinion that the price cuts are non-compliant with EU law.

STATE-OWNED PUBLIC UTILITY SERVICE PROVIDER TO BE SET UP BY MARCH 2015

In line with the recent energy policy of the Hungarian government that aims at restoring a larger state control over the energy sector, the Hungarian government plans to set up a wholly state-owned public utility service provider company by March 2015. Pursuant to government plans, the new company would supply end-users with electricity, gas and district heating in the framework of universal services by competing with existing market players. The above plan fits into the long-term initiative of the government to obtain a larger market share in the energy sector. As a result of that initiative, the wholly state-owned MVM Zrt purchased from the RWE group the universal gas services provider Főgáz Zrt which in turn has a share of 15% in the market of universal services in the gas sector. As it has been confirmed by a letter of intent signed by MVM Zrt, the next target of acquisition would be E.On Energiaszolgáltató Kft that supplies gas and electricity to end-users. The state-owned public utility service provider company will be controlled by the Hungarian Development Bank. Therefore, as a first step, the shares of Főgáz Zrt will be transferred to that bank. Due to the significant cuts of household energy prices and the increased taxes in the energy sector introduced in the last couple of years, many market players may be easily convinced to sell energy supply companies to the Hungarian state. However, it is doubtful whether the state will be able to operate companies providing universal services under those hard circumstances that in fact encourage private companies to leave the market.

HUNGARY SUPPORTS THE CONSTRUCTION OF SOUTH STREAM WITH AMENDED PERMIT REQUIREMENTS

Pursuant to a recent amendment of Act XL of 2008 on natural gas supply (*a földgázellátásról szóló törvény*, the "Natural Gas Act"), a company may be entitled to construct natural gas transmission lines on the basis of a transmission line construction permit meaning that no transmission system operator permit is required for such an activity. The most important consequence of the above provision is that the constructor of a natural gas transmission line does not qualify as a transmission system operator. Therefore, the construction of a natural gas transmission line does not fall under the scope of the ten-year network development plans. As a result, the construction of a natural gas transmission line, such as the South Stream, is not subject to consultation with the actual or potential system users. Furthermore, such a construction would not fall within the scope of the ten year EU-wide network development plan. In practice, the above amendment of the Hungarian Natural Gas Act means that the Hungarian section of the South Stream pipeline could have been commenced on the basis of the sole permit of the Hungarian energy regulator. However, following an announcement of the Russian government in late 2014, the South Stream pipeline has been cancelled.

REGIONAL ELECTRICITY MARKET INTEGRATION

On 11 November 2014, the Romanian power exchange joined the already integrated power exchanges of the Czech Republic, Slovakia and Hungary. The most important innovation of the integrated power exchanges is that the former two-steps process relating to cross-border capacities (ie, daily explicit cross-border capacity auctions followed by power trading on local exchanges) has been replaced by a simpler, more effective mechanism. Under the integrated trading system, the trade algorithm takes the energy flow and the cross-border capacities simultaneously into account, thus making it possible for cross-border capacities to be managed implicitly together with the power trading processes. As a result, the reservation of cross-border capacity by the means of daily explicit capacity auction is no longer necessary.

Poland seems to be interested in the regional market coupling initiative. Therefore, Poland participated in the above process as an external observer. However, no exact step plan or timing in connection with the Polish integration has been determined so far.

MET POWER AG EXPANDS IN HUNGARY

MET Power AG, a company owned by MOL Nyrt and by Hungarian individuals, has completed two major acquisitions in Hungary in 2014.

In the first quarter of 2014, MET Power AG acquired from GDF Suez 74.8% of the shares in Dunamenti Erőmű Zrt. 25% of the shares in Dunamenti Erőmű Zrt are owned by the wholly state-owned MVM Zrt.

Dunamenti Erőmű Zrt owns a gas-fired power plant having a built-in capacity of 1,900MW of electricity and 1,000MW of heat, which makes it the gas-fired power plant with the largest capacity in Hungary. As such, the power plant is of strategic importance in terms of security of supply. In spite of its strategic importance, the power plant recently suffered major losses in the range of €30 million.

The second major transaction carried out by MET Power AG is the acquisition of the retail electricity trade division of GDF Suez. As a result of the transaction, only the gas distribution, universal services and retail sale of gas remains in the Hungarian portfolio of GDF Suez.

In 2013 and 2014, the state was the main player in the field of transactions in the energy sector. The transactions completed by the MET group show a trend that private investors are also starting to take part in transactions in the energy sector.

URANIUM AND COAL MINING PLANS CANCELLED BY WILDHORSE ENERGY LTD.

The Australian company Wildhorse Energy Ltd had planned to re-launch uranium and coal mining at Mecsek Hills in South Western Hungary, at a site that was shut down in 1997 for inefficiency reasons. The mineral resource of the Mecsek Hill exploration area amounts to approximately 65Mlbs U_3O_8. Taking into account further unexplored areas in the region, Wildhorse Energy Ltd held the exploration area as one of the largest uranium metal fields in the region. Further to the uranium and coal mining, the company has assessed the possibilities of an underground coal gasification plant in the area. Although Wildhorse Energy Ltd planned to carry out exploration and exploitation for a period of 20 years, in the third quarter of 2014 it has practically stopped all exploration activities due to the difficult financial position of the company. Wildhorse Energy Ltd had intended to sell the underground coal gasification project to a Singapore-listed company, Linc Energy, but the deal was cancelled.

LAST UNDERGROUND COAL MINE CLOSES BY THE END OF 2014, THE RELATED POWER PLANT IS TO BE RESTRUCTURED

The last underground coal mine of Hungary located at Márkushegy, North-Western Hungary will be closed by the end of 2014 with re-cultivation to be completed by 2018. Due to the closure of the mine, the operation of Vértes power plant that utilized the coal supplied by the mine needed to be restructured. Therefore, the wholly state-owned MVM Zrt decided to develop the power plant into a biomass power plant with a total built-in capacity of 108MW.

MOL OFFERED FOUR NORTH SEA LICENCES

Hungarian oil and gas company MOL Nyrt announced in November 2014 that it was offered four licences in the UK continental shelf in a licensing round. The operator tagged the licenses as "highly prospective" and they concern areas in the North Sea. The process will be concluded after MOL and its partner formally accept the licences following further reconciliation with the UK Department of Energy & Climate Change (DECC), MOL said.

HUNGARY AND AZERBAIJAN SIGNED A DECLARATION ON STRATEGIC PARTNERSHIP

On 11 November 2014, the Hungarian Prime Minister said it was in the interest of both Hungary and Europe to bring Azeri gas to Central Europe. Existing contracts guarantee the delivery of Azeri gas to Southern Europe, but Hungary intends to negotiate terms for the delivery of Azeri gas to Central Europe.

HUNGARIAN HEATING PROVIDER LAUNCHES HUF672 MILLION BIOMASS PLANT

Bioenergy-Duna, a unit of municipally-owned district heating provider Mohács-Hő Hőszolgáltató Kft, completed the construction of a biomass-fuelled heating plant, through its investment of HUF672 million in Mohács in southern Hungary in October 2014. The 4.5MW plant is expected to generate 60,000GJ of energy annually, covering 75% of the town's district heating needs with renewable fuel from January 2015.

ECOSOLIFER BUILDS HUF15 BILLION SOLAR PANEL PLANT

EcoSolifer, a solar panel producer using Hungarian know-how, is building a HUF15 billion solar cell plant in Csorna, north-west Hungary. The Hungarian State would support the investment with a HUF1 billion grant. Construction of the plant, which is expected to employ 212 people, should be finished by the second half of 2015. Production of solar energy panels is on the rise in the country. Two Hungarian companies, Jüllich Glas and Agulhas-Solar, recently announced that they were also boosting production of electricity by way of installation of solar panels.

PANNERGY INAUGURATES 30MW GEOTHERMAL POWER PLANT

Hungarian geothermal energy company PannErgy inaugurated a 30MW thermal power production unit in the city of Miskolc, in northeastern Hungary in September 2014. An expansion of the PannEnergy's KUALA power plant, the new production unit supplies electricity to downtown Miskolc and the city's University. This is the second leg of the company's geothermal energy project in the city. KUALA's new unit was supported with a HUF1 billion state grant. PannErgy saw net losses of HUF165 million in the first half of the year, down about two thirds year-on-year. However, its revenue totalled HUF1.27 billion in H1, growing approximately three-and-a-half times higher from H1 of last year.

GAZPROM PLANS TO EXPAND ITS CNG AND LNG PORTFOLIO IN HUNGARY

Pursuant to current plans, Gazprom intends to put into operation its first CNG refuelling station by the beginning of 2016, at the latest. In Hungary, the use of CNG as motorfuel is rather underdeveloped since there are only approximately 4,000 vehicles using that kind of fuel. In order to boost the use of CNG and LNG as motorfuels, Hungarian legislation needs to be significantly overhauled because the current legislation leaves several questions regarding that topic unregulated.

ENERGY LAW IN ICELAND

Recent developments in the Icelandic energy market

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PARTICULARITIES OF THE ICELANDIC ENERGY MARKET

What is unique about the Icelandic energy market is the high level of renewable energy generation and consumption. Iceland has established a target for 2020 of 72% share of renewable energy in the gross final energy consumption in the National Renewable Action Plan in accordance with its obligations under Directive 2009/28/EC. Already in 2011, the share of renewable energy was 76%.[1] The Icelandic energy model is sustainable, with respect to electricity generation and heating; nearly 100% of electricity and energy for heating comes from renewable sources.

As Iceland has an abundance of hydro and geothermal resources, the Icelandic energy market is based on the sale of electricity to high energy consuming industries. In 2013, 68.4% of all electricity produced in Iceland was consumed by the aluminium industry and 8.7% by the ferrosilicon industry.[2] This is the result of a government policy to attract foreign investors by offering affordable electricity. Landsvirkjun, the national power company of Iceland, is currently offering long term power purchasing agreements where the price per MWh is US$43. This is a highly competitive price compared to other energy producers in Europe.[3] In 2014, Landsvirkjun signed two new power purchase agreements ("PPA") with silicon metal plants, one in the north east region of Iceland and one in the south west region. The first agreement was with PCC Bakki Silicon hf. for the delivery of 58MW of power and the second one with United Silicon hf. for the delivery of 35MW of power.[4]

THE STRUCTURE OF THE ICELANDIC ENERGY MARKET

Today, three companies are the main producers and distributors of electricity in Iceland. Landsvirkjun is the biggest energy provider, generating 75% of all electricity in the Iceland. The other main generators are Orkuveita Reykjavíkur (13%) and HS Energy (9%). The remaining 3% electricity comes from multiple private producers of electricity.

The total installed capacity of power plants in Iceland was 2,767MW in 2013, of which 1,986MW (71.8%) was from hydro power plants, 665MW (24%) from geothermal power plants, 114MW (4.1%) from fuels and 2MW (0.1%) from wind. Iceland's total electricity production in 2013 amounted to 18,116GWh, where 12,863GWh (71%) came from hydro power, 5,245GWh (29%) from geothermal power, 5GWh from wind power and 3GWh from fuels. Geothermal energy was utilised in 2013 for space heating (43%), electricity production (40%), fish farming (5%), swimming pools heating (4%), snow melting (4%), industries (2%) and greenhouses heating (2%).[5]

NEW INSTALLATIONS AND POWER DEVELOPMENT LICENCES IN ICELAND

The Búðarháls Hydro Electric Station came into operation in March 2014. It has an installed capacity of 95MW and a generating capacity of approximately 585GWh per year. This power station is owned and operated by Landsvirkjun and is built to complement other stations already operating in Þjórsá in order to maximise the potential outputs and value of the natural resources entrusted to the company.[6]

The National Energy Authority ("NEA") issued a power development licence (a licence authorising the holder to construct and operate a power plant) to Landsvirkjun for a geothermal power plant in the north-east of Iceland (Þeistareykir). The permit was issued in March 2014 and remains valid for 60 years. Planned installed capacity at Þeistareykir is 45MW with a generating capacity of 1,476GWh per year.[7]

The NEA also issued a power development licence to Biokraft ehf. for the operation of two 600kW windmills in the south of Iceland (Þykkvibær) in July 2014 with a generating capacity of up to 3GWh per year.[8] Energy produced by the windmills reached consumers in September.[9] Þykkvibær was chosen as a suitable place for the windmills due to its topography and wind stability. Landsvirkjun erected two wind turbines for research purposes in 2012, each having a 900kW capacity with a combined generating capacity of up to 5.4GWh per year. Landsvirkjun chose to erect the wind turbines far inland to explore the conditions there in comparison to windmills by the shorelines. Locating the windmills this far inland may result in possible problems such as icing at the altitude of 250 to 270 meters above sea level.

INTERCONNECTOR BETWEEN ICELAND AND THE UK

The Icelandic Minister of Industry and Commerce established a working group in June 2012 with the objective of examining the possibility of establishing an interconnector between Iceland and the United Kingdom. The working group was instructed to examine whether an interconnector cable would be economically viable and to further explore technical and environmental issues with respect to legal obligations and bilateral agreements. The group published a report in June 2013 concluding that it is still uncertain whether such a cable would be a viable option. The group set out in detail what issues required further examination, in order to determine whether the project would be viable.

On 30 January 2014, the business committee of the Icelandic parliament (Alþingi) published its opinion on the report. The committee points out that there are several issues which need to be examined in detail before a decision can be made on whether a sub-sea power cable should be built. According to the committee the following matters need to be examined in detail:

(i) the effect a sub-sea cable will have on energy prices in Iceland,

(ii) future electricity consumption in Iceland;

(iii) number of new power plants needed to serve the sub-sea cable and how energy production of existing power plants can be enhanced;

(iv) what effect such a cable might have on the value of land held by land owners in Iceland and further what opportunities land owners in Iceland might have to enhance the value of their land by building smaller power plants;

(v) the future of energy market in Europe; and

(vi) the cost and risk associated with constructing such a cable. Moreover, ownership, liability and operational risk of the cable must be established.

Finally the Committee deems it important to engage in discussions with potential buyers of energy and their participation in the building and operation of the cable. The Minister of Industry and Commerce is currently setting up working groups that are supposed to address these issues.

THE TRANSMISSION GRID NEEDS TO BE STRENGTHENED

Landsnet, the operator of Iceland's electricity transmission system, published a system plan and an environmental report on the system plan for the period from 2014 to 2023 in October 2014. The objective of the system plan is to assess and provide an overview of the necessary structural changes needed to be made to the transmission grid to ensure that transmission operators will in the future be able to carry out their tasks. The main conclusions are that the transmission system needs to be upgraded to meet future demand, in particular in areas outside of Reykjavik. Furthermore, a stronger connection is needed between the largest energy production areas. Finally, further developments for transmission of 132kV were deemed unrealistic and it was concluded that the focus should be on voltage of 220kV or higher.

OWNERSHIP UNBUNDLING

The ownership unbundling of electricity generation and transmission assets has been a hot topic in Iceland in recent years. The Icelandic national grid company (Landsnet hf.) is currently owned by (1) Landsvirkjun (ie, national power company) 64.73%; (2) RARIK (ie, state electric power works) 22.51%; (3) Orkuveita Reykjavíkur (ie, Reykjavik Energy) 6.78%; and (4) Orkubú Vestfjarða (ie, Westfjord power company) 5.98%. The unbundling of the production and transmission of electricity has been proven difficult given the large share of ownership held by Landsvirkjun in Landsnet. Landsvirkjun cannot sell its share in Landsnet without renegotiating the terms of outstanding loan agreements as disposal of such large assets would result in default of these agreements.[10] Currently Article 8 of the Electricity Act no. 65/2003 states that transmission system operators shall be in majority held by the state, municipalities and/or public undertakings. The Minister of Industries and Innovation however established a committee to explore the possibility of changes in ownership of Landsnet in 2011. The committee has not published its proposals.

A greater emphasis has been placed on unbundling the public utility company (distribution system operator), Orkuveita Reykjavíkur ("OR"), which produces electricity from geothermal energy, provides geothermal water for heating and cold water for consumption and firefighting. The services of OR cover 67% of the population of Iceland. A new Act no. 136/2013 on Orkuveita Reykjavíkur came into force on 1 January 2014, where OR was provided with the ability to establish subsidiaries and to assign them concessions and other specific rights in order to comply with the obligation of unbundling set out in the Electricity Act no. 65/2003.

OIL AND GAS

The NEA issued three hydrocarbon exploration licences for the Dragon Area (located on the Jan Mayen Ridge) in 2013 to:

- Faroe Petroleum Norge AS, Íslenskt Kolvetni ehf. and Petoro Iceland AS;
- Ithaca Petroleum ehf., Kolvetni ehf. and Petoro Iceland AS; and
- Eykon ehf., CNOOC International Ltd. and Petoro Iceland AS.

The validity of the licences ranges from 7 to 12 years. Each licence has a predefined phase of studies. At the end of each phase the licensees must determine whether or not they will commit to the next phase of study. Two of the licensees, CNOOC International Ltd. and Ithaca Petroleum, have committed to reviewing existing data and 2D measurements whereas the third licensee, Faroe Petroleum, only committed to reviewing existing data. Ithaca Petroleum has until 2017 to complete the first phase of study and CNOOC until 2018.[11] Faroe Petroleum handed in its hydrocarbon exploration licence in December 2014 following its first phase of study.[12]

ENFORCEMENT

The EFTA Surveillance Authority ("ESA") received a complaint against Iceland for incorrect implementation of the Second Electricity Directive. ESA has requested information from the Icelandic government on the tasks and surveillance authority of the NEA in particular in relation to the operation of Landsnet. When this chapter was written, ESA was still awaiting a response from the Icelandic authorities.[13]

ESA has also launched infringement proceedings against the Icelandic government for failing to implement Directive 2010/30/EU establishing a framework for the harmonisation of national measures on labelling and standard product information regarding energy consumption by 1 June 2013.[14]

ESA has adopted new state aid guidelines for environmental protection and energy which correspond to the European Commission guidelines on state aid for environmental production and energy 2014-2020.[15] The ESA guidelines came into force on 16 July 2014.[16]

ENDNOTES

1. *The Icelandic National Renewable Energy Action Plan for the promotion of the use of energy from renewable sources in accordance with Directive 2009/28/EC and the Commission Decision of 30 June 2009 on a template for the national renewable energy action plans,* December 2012. This number varies from 76% to 85% depending on the calculation method.

2. National Energy Authority, Energy Statistics in Iceland 2013, http://os.is/gogn/os-onnur-rit/orkutolur_2013-enska.pdf, accessed on 15 October 2014. The share of energy consumption by the ferrosilicon industry has increased by 2.7% between the years 2012 and 2013. See for comparison: National Energy Authority, Energy Statistics in Iceland 2012, http://os.is/gogn/os-onnur-rit/orkutolur_2013-enska.pdf, accessed on 26 October 2014

3. Landsvirkjun, Annual report 2013, http://annualreport2013.landsvirkjun.com/energy-generation-and-business-opportunities, accessed on 16 October 2014

4. Landsvirkjun, Landsvirkjun and United Silicon sign a power purchase agreement, http://www.landsvirkjun.com/company/mediacentre/news/news-read/landsvirkjun-and-united-silicon-sign-a-power-purchase-agreement, accessed on 17 October 2014 and Landsvirkjun, Landsvirkjun and PCC Bakki hf. sign a power purchase agreement, http://www.landsvirkjun.com/company/mediacentre/news/news-read/landsvirkjun-and-pcc-bakki-silicon-sign-a-power-purchase-agreement

5. National Energy Authority, Energy Statistics in Iceland 2013, http://os.is/gogn/os-onnur-rit/orkutolur_2013-enska.pdf, accessed on 15 October 2014

6. Landsvirkun, Búðarhálsstöð, http://www.landsvirkjun.is/Fyrirtaekid/Aflstodvar/Budarhalsstod, accessed on 15 October 2014

7. Landsvirkun, Þeistareykir, http://www.landsvirkjun.is/rannsoknirogthroun/virkjunarkostir/theistareykir/, accessed on 15 October 2014

8. National Energy Authority, Power development licence for operation of windmills in Þykkvibær, http://www.orkustofnun.is/orkustofnun/frettir/nr/1584, accessed on 15 October 2014

9. Our nature, The energy of the nature is now available from Icelandic wind, http://www.on.is/frettir/orka-natturunnar-nu-faanleg-ur-islensku-roki?gclid=Cj0KEQjw8aeiBRCknPXk-u_V_4gBEiQAD2-mgR0ZEgPt-wKJZNbwL__duIfAyWTairIfx7gH4kTsv9waAgMj8P8HAQ, accessed on 15 October 2014

10. Committee opinion concerning proposed amendments to Act no. 42/1983 on the National Power Company, Act no. 139/2001 establishing the partnership of Reykjavík Energy, Electricity Act no. 65/2003 and Act no. 19/2011 amending the Electricity Act, nr. 65/2003, as amended (the owners' guarantees, ownership transmission and delaying corporate separation), available on the homepage of Alþingi (http://www.althingi.is/altext/140/s/0537.html)

11. National Energy Authority, Research at the Dragon Area on schedule, http://www.orkustofnun.is/orkustofnun/frettir/nr/1592, accessed on 13 October 2014

12. National Energy Authority, Research at the Dragon Area on schedule, http://orkustofnun.is/orkustofnun/frettir/nr/1622, accessed on 2 January 2014

13. Directive 2003/54/EC of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC [2003] OJ L176/37

14. Directive 2010/30/EU of 19 May 2010 on the indication by labelling and standard product information of the consumption of energy and other resources by energy-related products [2010] OJ L153/1

15. Communication from the Commission – Guidelines on state aid for environmental protection and energy 2014-2020 [2014] OJ C200/1

16. The guidelines are available on the homepage of the EFTA Surveillance Authority at www.eftasurv.int

ENERGY LAW IN IRELAND

Recent developments in the Irish energy market

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There have been a number of significant commercial and legal developments to Ireland's energy market in 2014. This article provides an overview of the key developments in the supply industry and in government policy, with a particular focus on the redesign of the existing wholesale electricity market for the island of Ireland (Ireland and Northern Ireland) known as the Single Electricity Market (the "SEM"), so as to bring it into line with the European Target Model.

STRUCTURAL CHANGES TO THE ENERGY SECTOR

The international financial crisis has had a significant impact on Ireland's economy and its public finances. Ireland enjoyed a period of economic prosperity and growth, followed by a severe economic downturn affecting both the private and public purse. According to the Green Paper on Energy Policy in Ireland published by the Department of Communications, Energy and Natural Resources (the "DCENR") in May 2014 (the "Green Paper"), the overall primary energy use in Ireland has decreased by 19%. This decrease may be attributed to both the economic downturn as well as gains in efficiency. The consequent reduction in demand means that Ireland has a sufficient level of capacity for the coming years, if not a structural overcapacity issue in the short term. However, a decrease in demand has not necessarily led to a reduction in prices for consumers. Gas and electricity prices in Ireland are heavily influenced by international fossil fuel markets due to Ireland's relative geographic isolation and its low level of indigenous production. As with the rest of the EU, prices paid by residential and business consumers have been increasing since 2007 as existing conventional plant has remained on the bars.

A large proportion of the impact on public finances stems from the circa. €64 billion which has been invested by the Irish state to stabilise the Irish banking sector. Ultimately Ireland required support from the EU and the International Monetary Fund ("IMF") in November 2010. Ireland exited the Programme of Support in December 2013 with a restructured banking system and in October 2014 announced its first post-austerity budget. The October 2014 Quarterly bulletin from the Central Bank of Ireland predicts growth in GDP of 4.5% in 2014 with 3.4% in 2015.

The Green Paper notes that the energy market is inextricably linked to the broader economic landscape and has an integral role to play in enabling future growth in Ireland. In this context the Green Paper states that investment has been made in energy research and infrastructure despite the downturn and strain on public finances, particularly in relation to finances allocated to improve the Irish electricity transmission network and the Irish gas network.

The EU/IMF bail-out placed a number of obligations on the Irish government, including in respect of reducing the budget deficit and national debt. The Irish state is committed to realising value from state-owned assets and this has led to acquisitions in the energy sector.

The state-owned Bord Gáis Éireann (now Ervia) owns the entire gas transportation system (transmission and distribution) in Ireland and has been the dominant domestic gas supplier (through its subsidiary Bord Gáis Energy) as well as having a significant electricity generation and supply business. In March 2014 it was announced that Ervia had entered into an agreement to sell Bord Gáis Energy to a consortium comprising Centrica plc, Brookfield Renewable Energy Partners LP and iCON Infrastructure. The transaction had a value of €1.1 billion.

As a result of this transaction, Centrica plc acquired Bord Gáis Energy's generation, trading and retail supply businesses in Ireland. Brookfield acquired Bord Gáis Energy's renewable generation business and iCON acquired Bord Gáis Energy's gas distribution and retail supply businesses in Northern Ireland. Ervia will focus on its responsibility for the delivery of gas and water infrastructure and services in Ireland through its subsidiaries, Gas Networks Ireland and Irish Water.

The state-owned Electricity Supply Board was also asked to privatise certain assets including its interest in power projects in the United Kingdom and Spain. It was also required to dispose of two peat fired power projects in Ireland at Lough Ree and West Offaly, but these assets were withdrawn from the sale in the first half of 2014.

REDESIGN OF THE SEM

The SEM was introduced in 2007 and its key characteristics include a gross mandatory pool with central commitment, a single system marginal price, transmission-constraint payments and the introduction of an explicit capacity remuneration mechanism.

EU Member States have been tasked with implementing electricity markets that are consistent with the EU Target Model by 2014. The SEM faces certain challenges in this regard, in particular insofar as it does not provide for an ex ante price nor does it permit widespread intra-day trading. However, a two year derogation has been granted to implement the necessary SEM reforms. The Commission for Energy Regulation ("CER") in Ireland and the Utility Regulator in Northern Ireland ("UREG") (together the "Regulatory Authorities") have now sought to extend that date further to late 2017.

The development of a revised Integrated Single Electricity Market ("I-SEM") has moved forward in 2014. In February 2014, a consultation paper on possible options for the design of the I-SEM was issued by the SEM Committee (being the Committee of the Regulatory Authorities with responsibility for governance of the SEM) and a draft decision paper was issued in June 2014.

The SEM Committee has been given responsibility for developing I-SEM further by the DCENR in Ireland and the Department of Enterprise Trade and Investment ("DETI") in Northern Ireland.

Most recently in September 2014, a final decision paper (the "Decision Paper") was published by the SEM Committee in respect of the design of the I-SEM alongside a detailed impact assessment. It should be noted that this is a high level design decision only, and its purpose is to set out a series of recommendations which may, if the CER and UREG agree, be ultimately incorporated into binding legislation.

The Decision Paper provides that the I-SEM will be focused on liquid and transparent markets, while ensuring security of supply, meeting environmental requirements and maximising benefits for consumers in the short-term and the long-term. The Decision Paper sets out two decisions made by the SEM Committee: (i) the I-SEM Trading Arrangements, which are set out in more detail below ("Decision 1"); and (ii) an explicit capacity trading remuneration mechanism to help deliver secure supplies for consumers in the all-island market in light of increasing variable generation ("Decision 2").

Decision 1: I-SEM Trading Arrangements

Decision 1 provides that there will be four markets or timeframes for market participants to trade: (i) the forward market; (ii) the day-ahead market ("DAM"); (iii) the intra-day market ("IDM"); and (iv) the balancing market ("BM"). There will also be an imbalance settlement where market participants will be required to balance their trades and physical power at a single imbalance price.

Forward market: The SEM Committee has decided that (i) the I-SEM will have only financial trading instruments for within zone trading; (ii) subject to further discussions and agreement with neighbouring markets, cross-zonal trading will be supported only by Financial Transmission Rights ("FTRs").

Consistent with current arrangements within the SEM, trading in the forwards timeframe is to be carried out using financial contracts with no right for physical settlement. It is expected that contracts for differences ("CfDs") will be used for this purpose, with the day ahead market (discussed below) as reference market. CfDs should enable hedging against variations in the reference price. Where permitted by the detailed design of the I-SEM, aggregation (or portfolio bidding) may operate.

In respect of cross zonal hedging, the SEM Committee has stated its preference for the use of FTRs – described as effectively a CfD where the holder receives a payment based on the difference in the day-ahead price in the two zones. The Decision Paper highlights that the use of FTRs will be subject to agreement with authorities in the other zone, for example Ofgem in the UK. The auction rules and the decision as to whether FTRs are options or obligations will be considered at the detailed design stage.

The SEM Committee states in its non-technical summary of the Decision Paper that in order to support the day-ahead and intra-day markets, financial trading will support the formation of robust and transparent prices within these markets, and this will ensure that liquidity in these markets is not reduced through physical trading in the forwards timeframe and tying up of interconnector capacity.

Day-ahead market ("DAM"): The SEM Committee has decided that: (i) the European Day Ahead Market will be the 'exclusive' route to a physical contract nomination at the day ahead stage; and (ii) unit-based participation for generation in general, with gross portfolio aggregation arrangements for demand-side units and specified variable renewable generation will be introduced.

The Decision Paper indicates that bidding generation or demand into the European day-ahead price coupling process will be the only route to take a forward position in the DAM to offset balancing responsibility. There will be no mandatory entry for participants into the DAM however the Decision Paper provides that the delivery of a very liquid DAM is an important focus for the detailed design stage. The SEM Committee expects that participation will be incentivised so as to provide robust reference prices for forward trading and to facilitate efficient trading across interconnection with the UK market.

In certain circumstances, aggregated bidding from generation may be permitted (this will be specified in the detailed design stage). However, the default rule will be that unit-based bidding by generation will be required in the interests of transparency and promoting effective competition. Gross portfolio bidding will be permitted from suppliers and demand-side units subject to restrictions in the detailed design phase. As a consequence, even where aggregation is permitted, it is highlighted that ordinarily separate bids must be submitted for demand, demand side units and generation. The Decision Paper provides that de minimis levels for portfolio bids of generation and supply (currently existing in the SEM) are not precluded in the high level design and will be addressed in the detailed design phase.

Intraday market ("IDM"): The SEM Committee has decided that:

(i) continuous intraday trading will be the exclusive route to intraday physical contract nominations (with scope to introduce periodic implicit auctions as/if these develop at the European level); and

(ii) unit-based participation for generation in general, with gross portfolio aggregation arrangements for demand-side units and specified variable renewable generation will be introduced.

As with the DAM, the European coupling process will be the exclusive mechanism to participate in the intraday timeframe. The IDM will employ products available through the EU central platform. Further detail will be provided in the detailed design phase in respect of the timing and format of bids/offers. The Decision Paper indicates that the IDM will be continuous with a first come first served basis used to allocate cross-zonal capacity to match cross-zonal bids and offers. Periodic intraday auctions will be allowed under the detailed design and rules. In terms of aggregation, the Decision Paper approach to the IDM tracks the approach to the DAM.

Balancing Mechanism: The SEM Committee has decided that: (i) the starting point for dispatch is detailed and feasible physical nominations required for all market participants following the DAM; (ii) there will be mandatory participation in Balancing Mechanism after day-ahead stage; (iii) there will be unit-based participation in Balancing Mechanism in general; (iv) marginal pricing for unconstrained energy balancing actions will be introduced; and (v) pay as bid for non-energy actions (possibly combined with local market power mitigation measures) will be introduced.

The Decision paper provides that the TSOs are responsible for ensuring a feasible dispatch of plant that delivers a safe and secure system, including having sufficient reserve. As set out above, the starting point for dispatch will be the physical nominations from the day-ahead stage, as updated to reflect developments in the intraday stage. The SEM Committee states in its non-technical summary of the Decision Paper that market participants will be responsible for balancing their positions and will be mandated to participate in the balancing market through incremental and decremental bids which will determine the costs of balancing actions.

Imbalance: The SEM Committee has decided that: (i) all market participants will be responsible for balancing; (ii) imbalance settlement will be unit-based for generation; and (iii) there will be a single imbalance price.

Participants in the I-SEM will be balance responsible, meaning that they are responsible for the difference between actual generation or load and the volumes traded. This means that the intraday market will be crucial to correct volumes in light of developments after the DAM such as anticipated demand. The single imbalance price will reflect the marginal cost of the imbalance and payments will be at the same price to those who generated more than contracted for those who produced less.

The SEM Committee has also included detail in its Decision Paper in respect of participation in the market for small players, and means to encourage forward financial market liquidity, including facilitation of a centralised forward trading platform.

Decision 2: I-SEM Capacity Remuneration Mechanism

The SEM Committee has decided that the I-SEM will include an explicit capacity remuneration mechanism ("CRM"). The I-SEM Decision Paper provides that a CRM is required because an energy-only market will not in practice deliver long term generation adequacy. In effect, the CRM will be used to ensure that power is available in times of stress. The SEM Committee note that the explicit CRM will be implemented in such a way as to avoid distorting cross border trade in the EU Internal Energy Market.

The explicit CRM would work alongside any targeted contracting mechanisms that are put in place as a back stop measure to address specific security of supply concerns. The explicit CRM will be a quantity-based mechanism, and will take the form of Reliability Options, which are financial call options issued to capacity providers by a centralised party through a competitive auction. Market participants will receive a capacity payment in the form of an option fee. The Decision Paper indicates that capacity payments will be quantity-based and paid to bidders in a competitive process such as an auction. In return for the annual capacity payment, market participants undertake to provide capacity at a pre-determined strike price when demand is high and prices are rising. The Reliability Options will have a strike price and a reference price – when the market reference price is above the strike price, all holders of the option have to make a payment equal to the difference between the market reference price and the strike price.

The methodology for setting the strike price and any additional penalty arrangements for non-delivery of capacity will be developed in the detailed design phase of the market, in addition to market power mitigation measures, equitable treatment of different capacity resources regarding access, cross border participation, ensuring the requirement for physical capacity is consistent with appropriate access for providers that use all technologies of all sizes, as well as the treatment of renewable supports in the I-SEM.

Next Steps

The next phase in developing the I-SEM is the detailed design followed by the implementation stage. The SEM Committee has published a document alongside the Decision Paper setting out the next steps with further detail.

ENERGY POLICY DEVELOPMENTS

Energy Green Paper

In March 2007, the Irish government published a White Paper entitled 'Delivering a Sustainable Energy Future for Ireland', setting out the government vision for the future development of the energy sector for 2007 to 2020. This focused on the central pillars of increasing security, sustainability and competitiveness of energy supply. As noted above, the DCENR launched the Green Paper in May 2014. The purpose of this consultation is to invite submissions from stakeholders in relation to the future development of Ireland's energy policy. It is anticipated that the government will publish a new Energy White Paper following completion of this consultation process.

The Green Paper provides that the developments in technology, the economic landscape and climate change commitments precipitate the development of new policy priorities towards 2030. The Green Paper sets out six policy priority areas for consultation and consideration, namely (i) empowering energy citizens; (ii) markets, regulation and prices; (iii) planning and implementing essential energy infrastructure; (iv) ensuring a balanced and secure energy mix; (v) putting the energy system on a sustainable pathway; and (vi) driving economic opportunity.

Offshore renewable energy development plan

In February 2014, the Irish Minister for Communications, Energy & Natural Resources launched the Offshore Renewable Energy Development Plan ("OREDP") to provide a framework for the sustainable development of Ireland's offshore renewable energy resources. The OREDP is designed to facilitate the development of offshore renewable energy in Ireland's expansive offshore resource. In particular, it provides for co-ordination amongst relevant government stakeholders so that environmental sustainability, technical feasibility and commercial viability are taken into account.

DEVELOPMENTS IN RENEWABLES AND ENERGY EFFICIENCY

While the Green Paper provided an opportunity to consider the longer term policy options, Ireland continues move forward in respect of the integration of renewables and energy efficiency. There have been developments in this area in 2014.

DS3

The two TSOs for the SEM are implementing a programme for 'Delivering a Secure, Sustainable Energy System', known as DS3. The aim of DS3 is to ensure that existing electricity infrastructure can operate with the increase in variable, nonsynchronous renewable generation which is expected.

DS3 seeks to achieve this by the inclusion of financial incentives for improved plant, the adoption of policies and tools to ensure optimisation of generation and the electricity system and the procurement of additional system services which may create interesting opportunities for new investment in the Irish energy sector.

National Smart Metering Programme

In October 2014, the CER published its decision paper on the high level design of the smart metering solution for Ireland. The paper outlines the decisions of the CER in respect of: (i) core design for the smart metering architecture to enable information flow between supplier and consumer; (ii) the regulatory framework for the introduction of time of use tariffs for domestic consumers and small businesses; (iii) information provision to consumers in relation to energy use; and (iv) how pay as you go processes will operate when gas and electricity smart meters have been installed.

The next steps in the programme include network procurement of necessary components and the detailed design of market systems changes required to support smart meters. The CER decision paper provides that the rollout of electricity and gas smart meters is currently scheduled to commence in 2018, although it notes that this depends on many factors.

Energy efficiency

The Irish government launched its third Energy Efficiency Action Plan in August 2014 setting out its policy for the achievement of 20% energy savings by 2020, including a requirement for public sector use to reduce by 33%. In January 2014, the government introduced the European Union (Energy Efficiency Scheme) Regulations 2014 which allow the government to impose binding energy savings targets on suppliers. Failure to comply with the targets imposed may be penalised and suppliers may be required to contribute to the National Energy Efficiency Fund established in 2013. The National Energy Efficiency Fund was established to support the delivery of energy efficiency improvement programmes.

In March 2014, Sustainable Development Capital LLP was appointed by the DCENR as the Investment Advisor to the National Energy Efficiency Fund and to provide a source of finance to the public and private sector when undertaking energy efficiency projects.

CONCLUSION

The energy market in Ireland has undergone some significant changes in 2014. As Ireland's economy recovers from the financial crisis, the government has continued to support investment in energy infrastructure, energy efficiency and market design. The SEM Committee has made substantial progress in the design of Ireland’s Integrated Single Electricity Market in line with the European Target Model, and this design process will continue to develop in 2015/2016.

ENERGY LAW IN ITALY

Recent developments in the Italian energy sector

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ELECTRICITY MARKET: GENERAL DATA

The Italian energy market is experiencing significant changes due to the continuing reduction in electricity demand (3% in 2014)[1] and the over-capacity (currently over 25GW) of the system. Talks of Enel S.p.A. (the largest electricity utility company) being forced to close some thermoelectric plants become more insistent every day. In 2014 national production met 86.7% of the demand, while the excess (13.3%) was covered by imports, mainly through the interconnectors at the Northern border. Figures make Italy the largest electricity importer in Europe.

Thermoelectric generation saw a further decrease of 10.2%, while renewable energy sources significantly increased their production to 39% of the national demand.[2] Photovoltaic sources covered 8.5% of the total electricity demand, marking an 8.9% increase compared to the previous year. However, as a consequence of the recent legislation limiting subsidies for new PV projects, estimates forecast a reduction of more than 50% in new installations: 800MW installed capacity compared to the 1.7GW that has been installed in the last year.

KEY TRANSACTIONS

Notable transactions in the Italian energy sector include the sale from Cassa Depositi e Prestiti (the Italian state-controlled lender ("CDP")) to the State Grid Corporation of China of a 35% stake in CDP Reti (the Italian energy-grid holding company) for €2.1bn. The transaction is considered to be the biggest investment a Chinese company has ever made in Europe.

The sale by Germany's E.ON of its Italian assets (6GW of installed power, around 900,000 gas and electricity clients and a stake in an offshore liquefied natural gas terminal) has drawn interest from many energy companies. Some bidders submitted final offers for selected segments (eg, the hydro business) at the beginning of December 2014. To date Edison is the only potential single player considering to buy all of the assets.

The Ilva plant in Taranto, Europe's largest steel plant by output capacity, has been placed into "special administration" by the Italian coalition government following an environmental scandal. The aim of the procedure is to avoid job losses (the site employs 11,000 workers). According to the latest sources the government is considering issuing a law decree giving wide powers to a special commissioner in charge for the remediation plan in accordance with prescriptions drawn by public authorities. Afterwards the company could be sold, similarly to what happened to General Motors in USA, to private investors including ArcelorMittal (the world's largest steel maker) and Marcegaglia group which already showed their interest subject to dismissal of plant seizure. JSW Steel is also in talks to buy parts of Italy's second-largest steel plant, Lucchini.

CHANGES TO RENEWABLES ENERGY SUPPORT SCHEMES

The overall cost for renewables has registered an exponential growth in the last few years. In 2011, the Gestore dei Servizi Elettrici ("GSE") (the state-owned entity in charge of promoting the development of renewable energy sources and energy efficiency in Italy, mainly by granting economic incentives) paid out €6.3bn, while in 2013 public expenditure grew to €11bn and in 2014 the Italian Regulatory Authority for Electricity Gas and Water estimates total expenses of €12.5bn,[3] of which €12bn is attributable to the "A3" component of the energy bill regarding renewable energy incentives.

As a result, the newly elected Prime Minister Matteo Renzi's government identified the subsidies for the photovoltaic sector as an area where cuts were to be made for the purpose of reducing the load of electricity bills, which are among the highest in Europe, for small and medium-sized enterprises.

The measures studied by the government caused serious complaints among national and international investors as they are considered to have retroactive effects. On 5 August 2014, law decree no. 91/2014 (the "Decree") was converted into law by the Italian parliament. The Decree, among other measures to boost the economy, revised the feed-in tariff scheme for photovoltaic plants.

It is stipulated that, by 30 November 2014, operators of photovoltaic plants (with a capacity higher than 200kW) shall elect one of the following options, which will apply as from 1 January 2015:

a) extend the feed-in-tariff term from 20 to 24 years and receive a reduced tariff (ie, a reduction ranging from 17% to 25%) depending on the residual operational years (with a higher reduction for those plants entered into operation earlier);

b) maintain a 20-year feed-in-tariff period, receive a reduced tariff at an earlier stage and then an increased tariff (by the same amount) at a later stage (the magnitude of the decreases and increases are provided by an *ad-hoc* formula issued by means of ministerial decree); or

c) maintain the feed-in-tariff for the original 20-year term, with a flat cut on the tariff varying by plant size (6% for 200kW to 500kW plants, 7% for 500kW to 900kW plants and 8% for plants over 900kW).

Starting from the second half of 2014, GSE will pay the feed-in tariffs relating to photovoltaic plants through monthly instalments for an amount equal to 90% of the estimated average annual output for the relevant calendar year and, by 30 June of the following year, adjust payments on the basis of the actual output.

The Decree further introduces the possibility for photovoltaic operators to have access to bank loans for a maximum amount equal to the difference between:

- the incentive calculated as at 31 December 2014 on the basis of the pre-existing rules; and
- the revised incentive.

Such loans may benefit from the intervention of CDP, by means of either dedicated funding or (jointly or alternatively) a guarantee provided by CDP on the basis of "*specific arrangements with the banking system*". The liabilities incurred by CDP in connection with the above shall be secured by the state in accordance with terms and conditions yet to be defined. Such provision aims to mitigate any cash-flow shortfalls arising from decreased feed-in-tariffs, by allowing photovoltaic operators access to bank loans under favourable credit conditions. Many criticisms of the Decree have been raised due to the generic language used in the text and the repeated references to a forthcoming ministerial decree, which leaves a significant degree of uncertainty on the effectiveness of such provisions. The abovementioned opportunities are indeed subject to a decree of the Ministry of Economy and Finance, which has not yet been issued and, as of today, there are no indications on the actual role of CDP in this respect.

Similarly to other European countries, Italy has been criticised by national and foreign investors for the retroactive cuts of incentives. Several companies submitted an official complaint to the European Commission with a view to ascertaining whether the provisions of the Decree are in line with the EU law (ie, the Renewable Energy Directive). The European Commission is yet to provide an answer. Whilst the Commission does not have an obligation to reply to every report and only proceeds where the relevant violations are found to be substantial, the Commission can, at its discretion, decide whether or not to continue and escalate the matter by providing the Member State with a reasoned opinion and deciding to appeal to the Court of Justice.

A number of Italian investors have raised constitutional concerns. However, under Italian law it is not possible to lodge direct appeals with the Constitutional Court. Thus around fifty operators brought legal actions in the national administrative courts challenging the provisions introduced in October 2014 by the implementing decrees. The aim is to lead the judge to raise a constitutionality objection before the Constitutional Court, as the provisions at issue (as far as they apply retroactively) are regarded as a breach of the legitimate expectation and legal certainty principles provided under the Italian Constitution. The term for filing the claim is 60 days from the publication in the Official Gazette of the MED implementing decrees (ie, 23 December 2014). Among the operators which already filed a "domestic" claim against the decree, according to Italian press and media, major players in the energy sector, such as Enel Green Power S.p.A. are included. In a hearing in November, all claimants waived their request of suspension of decree provisions as a urgent and precautionary measure. As a consequence, the judge referred the dispute to the merit hearing, scheduled in March 2015 where parties will discuss the grounds of the claims (including the alleged unconstitutionality of the re-shaping provisions) and it is possible that in the same hearing the judge may decide whether to submit the case to the Constitutional Court.

Foreign investors have threatened legal actions pursuant to the Energy Charter Treaty, claiming an alleged breach by Italy of the obligation under Article 10 to accord to investments fair and equitable treatment. Whilst to date, the only Energy Charter Treaty case pending against the Italian Republic is the ICSID arbitration referred below, the majority of foreign investors in Italian solar projects have reportedly instructed counsel with a view to filing ECT claims in late December 2014 or January 2015. The Service for Legal Affairs, Diplomatic Disputes and International Agreements of the Italian Ministry of Foreign Affairs and International Cooperation has informally confirmed the receipt of numerous letters of complaint by foreign investors threatening future legal actions.

In particular, they rely on the dispute settlement provision of Article 26 which grants recourse to arbitration under the International Centre for Settlement of Investment Disputes (ICSID), the UNCITRAL or the Stockholm Chamber of Commerce (SCC) rules. The awards of such arbitrations (which normally last one to three years) are final and binding upon the disputing parties and are enforceable internationally.

It is worth noting that, while several claims have been brought against Spain and the Czech Republic as a result of modifications to the energy regulatory framework in those countries, claims against Italy have been slower to materialise and Italy is currently only subject to one ICSID arbitration.

With reference to non-photovoltaic RES, a recent decree provides that the indicative cumulative annual cost of incentives for non-photovoltaic RES may not exceed €5.8bn. To date, the "cost counter" provided by GSE amounts to €5.4bn. It has been generally acknowledged in the market that the counter will touch the overall threshold in January 2015. A mechanism similar to that one applying to PV operators was offered to RES producers previously in 2013. Pursuant to Section 1, paragraph 3, of Law decree no.145/2013 (the "Destination Italy Decree") RES producers benefiting from incentives (green certificates, feed-in tariff or premium tariff) have the option to modify the residual duration and amount of the incentive to be collected. More particularly, RES producers have the option to:

- extend the incentive period for an additional seven years, subject to a reduction of the incentive amount dependent on the type of plant/source; or
- continue to benefit from the current incentive regime until the actual expiry date, in which case the plant owners would be excluded from the opportunity to benefit from any new incentives due for any kind of intervention on the same site, for a 10-year period starting from the original expiry date of the incentive regime.

Another issue concerning the RES sector has been widely discussed in 2014: the effectiveness of the Dutch auction mechanism set forth by the Ministerial Decree of 6 July 2012 providing for the assignment of the incentives through a competitive auction process. With specific regard to the wind sector, the results of such mechanism have been quite disappointing. Data[4] on the 2012 and 2013 auctions report that over 60% (550MW) of the 900MW capacity awarded, at the present time, is not even in the construction phase. The absence of any prior selection procedure based on a projects' feasibility and bankability criteria, together with a lack of proper monitoring on the works progress, generate even greater doubts for the 2014 auctions, where more than 1.2GW have registered to the auction and the annual contingent is limited to 365MW. Awarded projects have bid extremely high discounts ranging from 26.38% to 30% (ie, the maximum allowed) on the base price which was set at

€127/MWh, meaning that winning projects have agreed to accept a feed-in-tariff as low as €88.9/MWh. A debate on the opportunity to change the legal framework is currently ongoing and wind industry is expecting some changes in the forthcoming MED decree which shall set out the power quotas for the 2016 to 2020 period.

CAPACITY MARKET

The Ministry of Economic Development has approved[5] the regulatory framework to create a "capacity market" that ensures the availability of electricity production capacity over the long term to address developments in consumption, avoids problems in terms of security and protects final customers against risk-pricing.[6]

Under the new scheme, the capacity is auctioned four years in advance of the beginning of a three-year delivery period. This long lead period is intended to maximum competition and bidding on the market, including allowing effective participation by plants that are yet to be built. When the capacity market is in place, producers will have to ensure the availability of electricity production capacity to protect the system from the risk of deficits in generation or critical situations. The quantity of capacity to be made available will be determined by Terna (the TSO) based on the expected consumption and reserve requirements.

The new capacity market is intended to serve as a profitable mechanism to support electricity producers from conventional sources, which are facing a serious crisis, but which are considered strategic by the Italian government for their production predictability and in terms of employment.

The new mechanism provides that Terna must arrange specific supply auctions for each relevant area network (ie, each portion of electricity network into which the national territory has been divided), with voluntary participation, for negotiating options on real production capacity (the so-called "standard contracts").

For each MW of committed capacity, operators will receive an annual premium, but will have to pay Terna any positive differences between the price of the electricity sold on the spot and services markets (the "reference price") and the price of service referenced in the contract. These differences will serve to "discount" consumer electricity bills.[7]

The new capacity market left some scepticism among interested operators, in particular in relation to:

- the funding of the mechanism (the law expressly provides that the electricity bills cannot be influenced by the introduction of the mechanism); and
- the real number of plants that will effectively be authorised to take part to the capacity market (Terna set out strict flexibility performance requirements for the plants to participate in the market and the challenging market conditions make it very difficult for producers to invest in plant refurbishment).

NATURAL GAS MARKET

Provisional data provided by SNAM Rete Gas S.p.A. (the national TSO) confirms the latest trends, showing a decrease in demand of 3.0%[8] compared to the previous year, much of which is attributable to the sharp reduction of gas consumption in the thermoelectric sector. Further to the Ukrainian crisis, one of the most debated issues in 2014 has been the strong dependence on foreign importation of natural gas. In 2014, Italy's imports of natural gas fell, for the first time in many years, under 90%.

More particularly, Russia remains the primary natural gas supplier with a share of 38% (+ 3% from the previous year), Algeria follows with 21%, while Libya registers a 9% share (a cautious increase from the previous year but remaining far from the supply levels achieved prior to the war in Libya) and Qatar supplies 8% of the overall imported gas.[9]

The diversification in national supply and the development of strategic infrastructure in order to secure supply and stock of natural gas represented the fulcrum of a lively debate among operators and policy makers.

GAS INTERCONNECTORS

With the view of becoming the "main southern European Hub", a crucial role is played by the development of cross-border interconnectors. The Trans-Adriatic Pipeline ("TAP")[10], with a maximum capacity of 24.68 million m^3/day, will transport Caspian natural gas to Europe across Greece, Albania and the Adriatic Sea before coming ashore in Southern Italy to connect to the Italian natural gas network.

In September 2014 the Ministry of the Environment issued the environmental impact assessment decree and on 1 October 2014 the preliminary inquiry by the Ministry of Economic Development for the issuance of the single authorisation for construction and operation of the pipeline started.

However, there are concerns regarding works completion (53km of pipeline in Italy (45km offshore, 8km onshore) and the onshore terminal) due to strong local opposition carried out by certain local authorities. The municipality of Melendugno (LE) issued legislation which successfully interrupted the preliminary drilling activities that were being carried out in its territory.

A second strategic interconnector project for the Italian gas sector, the Gazprom sponsored[11] natural gas South Stream pipeline, has suffered significant slowdowns during 2014 after the EU Commission raised concerns over potential EU law infringements. Allegedly, the Bulgarian government committed to provide a more favourable tax regime to Gazprom, which according to the EU Commission is in breach of the EU's state aid rules. The pipeline would run under the Black Sea to Bulgaria, and continue through Serbia, Hungary and Slovenia before reaching the Italian city of Tarvisio (UD). The planned capacity is 63 billion m^3/year, which would make it one of the greatest gas pipelines ending up in Italy. At the beginning of December 2014, the Russian President announced that Moscow would abandon the South Stream project. Diplomatic attempts to rescue the project are currently underway and the situation remains fluid.

SIMPLIFICATION IN HYDROCARBON EXPLORATION AND GAS INFRASTRUCTURE LICENSING

Law decree no. 133/2014 (the "Unlock Italy" decree) was approved in September 2014 and amended and converted into Law no. 164 dated November 11, 2014 . The decree is aimed at improving the security of national natural gas supply and provides that national gas infrastructure (eg, gas interconnectors, LNG terminals, natural gas storages) and connected activities (including the preliminary activities necessary for the draft of the relevant projects), due to their strategic importance, are declared urgent and of national interest for expropriation purposes.

The Unlock Italy decree further provides that hydrocarbon prospecting, research, and production activities are declared to be of "public interest" and a single concession for those activities is now provided. Moreover, the administrative procedure for awarding concessions has been consistently centralised at ministerial level; should the a region not complete the current Environmental Impact Assessments by 31 December 2014, the decision will be taken by the Ministry of Environment, who will be the authority in charge for the issuance of the concession after that time.

ENDNOTES

1. Provisional data provided by Terna in its monthly report on the electricity market. Data refers to January to September 2014

2. *Idem*

3. 2014 AEEGSI Annual Report on the status of services and the regulation of electricity and gas, p. 50

4. Associazione Nazionale Energia del Vento (ANEV), <http://www.anev.org/?news=aste-competitive-per-leolico-un-vero-fallimento> accessed 7 October 2014

5. Ministerial Decree of 30 June 2014, pursuant to paragraph 153 of article 1 of law 147/2013 ("Stability Law 2014")

6. AEEG, press release available at <http://www.autorita.energia.it/it/com_stampa/13/130910.htm>, accessed on 20 October 2014

7. *Idem*

8. Data on the January-September period processed by REF-E for Quotidiano Energia available at <http://www.quotidianoenergia.it/#id_news=378975,dest=news-body,pos=1,id_categ=7701,no_navi=true,affinity,_page=qe_news_show,__m=qe_news>, accessed on 23 October 2014

9. AEEGSI *Annual Report on the status of services and the regulation of electricity and gas*, 2014

10. After months of rumours regarding possible changes within the group of sponsors consortium, on 30 September the company announced that Spain's Enagas has joined the Trans Adriatic Pipeline consortium with a participation of 16% and Belgium's Fluxys has increased its stake to 19% after the two companies bought out France's Total and Germany's E.ON from the pipeline project

11. Gazprom is the project's main sponsor. The Italian company ENI is present with a 20% participation in the *consortium* financing the offshore part of the pipeline

ENERGY LAW IN KAZAKHSTAN

Recent developments in the Kazakhstani energy market

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GENERAL OVERVIEW OF ENERGY LEGISLATION AND MAIN LEGISLATIVE TRENDS

When considering Kazakhstan's legislation on energy resources, the starting point is the state ownership of mineral resources as provided by the Constitution of 1995 (the "Constitution"). Legislative provisions for investment, tax, banking, corporate, currency, antitrust, land and other areas also impact on the energy sector. It is also necessary to consider enforcement standards in both administrative and criminal branches of the law. An understanding of this legislation creates a more complete picture of the regime governing energy resources in Kazakhstan.

We will focus on subsoil use legislation that directly regulates relations in the sphere of subsoil use and on prospects for alternative energy in Kazakhstan.

General overview of the energy legislation

Since the proclamation of independence of Kazakhstan in 1991 a comprehensive law for the energy sector has been created. While the law is often subject to change, the relevant amendments are usually aimed at solving specific problems rather than making global changes. The main sources of regulation are national legislation and international agreements.

Legislative trends

Most recently the investment policy of the state has changed significantly as it endeavours to attract investors into the Kazakhstani economy. This includes the latest legislative amendments in the subsoil use and investments sectors, as well as in the business environment in general. At the same time, favorable conditions for local companies are in place with the reinforced local content obligations imposed on investors, especially in the subsoil use area.

Legal regime of subsoil use

Under the Constitution, natural resources, including minerals and oil, are state owned. These can be extracted from both public and private property, as permitted by subsoil use contracts.

Under the current legislation, the government grants subsoil use rights to companies, permitting, as the case may be:

- state geological studies;
- exploration;
- production;
- combined exploration and production; and
- construction and maintenance of underground facilities not related to exploration or production (eg, oil reservoirs and underground storage facilities).

The Kazakhstani government grants subsoil use rights by way of contract, entered into with the authorised government body acting on behalf of the state (the "Competent Body"). The Competent Body is a public entity designated by the government to implement and conclude contracts for subsoil use, and is currently the Ministry of Energy of the Republic of Kazakhstan.

Kazakhstan has steadily intensified efforts to increase the use of local personnel and Kazakhstani producers in subsoil use operations in recent years. Recent changes in legislation have led to more rigid regulation aimed at maximising the use of goods and services of Kazakhstani producers, as well as reducing foreign personnel, by encouraging the training and employment of equivalent local personnel by subsurface users.

RECENT CHANGES TO THE LAW ON SUBSOIL AND SUBSOIL USE

On 29 December 2014 the Law on Amendments and Additions to Certain Legislative Acts of the Republic of Kazakhstan on Subsoil Use ("Law") was enacted. It came into legal effect on 10 January 2015.

An overview of key changes is outlined below.

Terminology

The Law amends some older and introduces a number of newer terms and definitions to be used in the subsoil use sector, such as "under-studied subsoil area", "auction", "model contract for exploration", "financial liabilities", "physical volume of commitments", "tender" and others.

Geological information

The subsoil user retains the ownership right for geological information only for the duration of the contract.

National companies performing state geological studies at their own expense are now considered as potential holders of geological information.

Geological information on vacant subsoil areas is available for review upon request of an interested person subject to statutory requirements on state secrets.

Limited priority right

One of the landmark changes in this Law is the limitation of the government priority right, which is now exercised only in relation to subsoil use areas of strategic significance (so called "strategic deposits"). Previously, the priority right applied to nearly any disposal of rights to exploration and/or production of hydrocarbons and hard minerals or objects associated with subsoil use rights.

At the same time, the law retains the government's right of consent in relation to any transfer of participating interests/shares of legal entities that are subsoil users or those that have the ability to directly or indirectly influence decisions made by subsoil users, if the main activity relates to subsoil use in Kazakhstan. There are certain exemptions to these rules, eg, in the case of an IPO, if the transaction is between affiliated companies owned by the same parent company in 99% interest, etc. This requirement applies to both Kazakhstani and foreign investors. The statutory timeline for obtaining the consent is 20 business days, and an additional 50 business days must be factored in if the government exercises its priority right in relation to strategic deposits. Notwithstanding the statutory timeline the entire process may take longer in practice. The consent is granted for six months. If a transaction is not completed within that period, an extension must be obtained, or a new consent must be sought. There is a requirement to notify the Competent Body within five days of the completion of the transaction for which consent was granted, otherwise the transaction may be deemed invalid. It should be noted however that the recent legislative changes have not been tested in practice and may be subject to various interpretations.

Strategic deposits

In order to ensure sustainable development and security of the Republic of Kazakhstan certain subsoil areas are recognised as strategic deposits.

A list of strategic deposits, as well as qualification criteria, are approved by the government of the Republic of Kazakhstan.

Fast-track procedure for granting an exploration right

The Law envisages a simplified procedure for granting a subsoil use right for exploration of understudied deposits (each deposit with no more than 10 blocks). Subsoil users who obtained a subsoil use right under the simplified procedure are released from local content obligations.

Under this procedure a subsoil user independently approves the project of exploration works and is not required to have a work programme in place.

Auction as a new method

The Law introduces a signature bonus based auction as a new method of identifying a tender winner. All other terms and conditions, committed to by the winner when an auction is announced, remain intact and are automatically included in the contract for granting subsoil use rights.

Cure period for contract breach

The cure period for contract breach with respect to physical commitments should not exceed six months; with respect to financial commitments should not exceed three months; and with respect to other terms of the contract should not exceed one month from the date of receipt of the written notice.

The above cure periods may be extended upon the written request of the subsoil user.

Subsoil use right assignment restriction applies only to hydrocarbons

According to the Law, the restriction on assignment of subsoil use rights within two years after the contract effective date now applies only to hydrocarbons.

Concept of contract area conversion introduced

A subsoil user exploring solid minerals is entitled to apply for permission to convert the contract area by spinning off certain areas/blocks for further exploration or production under a separate subsoil use contract.

Oil accounting information system

The oil accounting information system is designed for automated collection, processing, storage and use of the information on the oil volume of production, manufacture, preparation, processing, transportation, storage, sale, shipment, loss, importation into the territory of the Republic of Kazakhstan and export from the territory of the Republic of Kazakhstan.

THE POTENTIAL FOR RENEWABLE ENERGY SOURCES IN KAZAKHSTAN

Kazakhstan has a large potential for renewable energy. It was the first Central Asian country to develop a strategy for the transition to a low carbon economy focused on the development of renewable energy sources. Kazakhstan has accepted voluntary obligations to reduce greenhouse gas emissions by up to 15% by 2020 and by up to 25% by 2050, relative to the level of 1992.

Hydroelectric power

Today hydroelectric power plants account for approximately 12.3% of the generating capacity of Kazakhstan. Moreover, 68% of hydroelectric power plants have been in operation for over 30 years. This will change with the completion of several major hydroelectric power plant projects in coming years, namely Moinak hydroelectric power plant (with a determined productivity of 300MW), Kerbulak hydroelectric power plant (with a determined productivity of 49.5MW), and Bulak hydroelectric power plant (with a determined productivity of 68.25MW).

Wind energy

The wind energy potential of Kazakhstan is estimated at between 0.929 to 1.82 billion kWh per year. Studies that were carried out in the framework of the United Nations Development Programme ("UNDP") project on wind power[1] showed a total area of about 50,000km^2 with an average annual wind speed of more than 6m/s, making this area profitable for wind energy development. The most significant wind power resources are concentrated in the Zhungar tunnel (17,000kWh per km^2).

Two major projects, the Zhanatas wind power complex (400MW) and the Shokpar wind power complex (200MW) were launched in the Zhambyl region in March 2011. The amount invested in their construction will be approximately US$1 billion.

A number of wind power complexes are planned by 2015, supported by the government: near the Shelek tunnel (with determined productivity of 51MW); near the Zhungar tunnel (with productivity of 50MW in the first stage); in the Ulan district of East Kazakhstan (24MW), along with a number of others.

Solar energy

The potential for development of solar energy is estimated at 2.5 billion kWh per year.

Despite the fact that Kazakhstan is located on the northern latitudes, the potential of solar radiation is quite significant (1,300 to 1,800kWh per km^2 per year, the number of hours of sunshine per year being 2,200 to 3,000). Solar energy can also be used to generate heat, which leads to the possibility of the introduction of solar installations in areas far from the main electricity and heat supply.

By 2015, solar power plants with total productivity of 91MW are planned, mainly in the Almaty region. In addition, practical measures are being taken to create a manufacturing base for production of silicon and photovoltaic cells which are necessary for the development of solar energy.

Biofuels

It should be noted that the use of biofuels has certain potential. In particular, 35 billion kWh of electricity and 44 million Gcal of heat energy can be obtained every year through processing agricultural waste.

Current situation

Despite efforts taken at the state level, renewable and alternative energy sources (excluding large hydroelectric power plants) are not well developed in Kazakhstan. At present no single major project has been completed in the country, despite a number of attempts to construct wind energy complexes.

According to official data, in 2010 alternative energy sources made up between 0.03% and 0.46% of the total power generation. The Kazakh Research Institute of Energy held that the operating productivity of renewable energy sources is mainly represented by several mini hydropower plants.

State support

Legislative support for the development of renewable energy sources and several sectoral programmes have been adopted in Kazakhstan in the last few years.

There is increased interest from investors, including interest from foreign investors (primarily from China and Germany), in renewable energy projects in Kazakhstan due to the adoption of key provisions in the relevant legislation.

The law of the Republic of Kazakhstan "On supporting the use of renewable sources of energy", adopted in 2009, established a legal, economic and organisational basis for promoting the use of renewables for production of electricity and heat, and specified measures of support.

In particular, the law provides investment preferences for renewables and prioritises the use of "clean" electricity on the market, supporting its transmission through lines and through a state-controlled system of certificates.

In accordance with the "Strategic Plan of the Republic of Kazakhstan until the year 2020", by 2015 alternative energy sources should account for 1.5% of total energy consumption, and more than 3% by 2020. Priorities set by the state programme for forced industrial development of Kazakhstan from 2010 to 2014 set the volume of electricity to be generated by renewable energy sources in 2014 at 1 billion kWh per year.

According to the programme for development of electric power in the Republic of Kazakhstan for 2010 to 2014, electricity generation in 2014 should reach 97.9 billion kWh with the forecast consumption of 96.8 billion kWh.

PROBLEMS WITH THE KASHAGAN FIELD

Kashagan is very important in Kazakhstan's economy. Experts estimate that more than half of all oil is extracted from mature fields that have already passed peak production, or are in the final stages of development. This has led to stagnation, caused by the absence of new fields, in the Kazakhstani oil and gas industry over the past two years. However, there are reasonable hopes that oil production at Kashagan will grow in the future, along with associated revenues. Recoverable oil reserves at this field are estimated at 760 million tons.

Oil extraction at the Kashagan field started on 11 September 2013. However, on September 24 exploitation of the field was stopped after a gas leak was detected from the onshore pipeline coming from the island of D to Bolashak, and the Department of Emergency Management and the relevant regulatory authorities were immediately informed. Extraction resumed, but on October 9 was repeatedly suspended after detection of further gas leaks. Hydrotesting was carried out which identified other potential leaks.

Experts found that an unforeseen increase in hardness of the metal in small areas of the pipeline had caused sulfide to crack under stress and this was the direct cause of the pipeline leaks. Consequently, the oil and gas pipelines required complete replacement. The operator of Kashagan North Caspian Operating Company B.V. is developing a plan to replace the pipeline, which is planned to be finished by early 2015.

The plan under development would involve tendering for contractors and determining material specifications using existing basic equipment. The main goal is to replace the pipelines and resume extraction as soon as possible. As a precautionary measure, and to save time, the consortium of the Kashagan field has launched a tender process for the procurement of pipe segments.

ENDNOTE

1. UNDP/GEF project "Kazakhstan – Wind Power Market Development Initiative" (2004-2011)

ENERGY LAW IN LATVIA

Recent developments in the Latvian energy market

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E.ON RUHRGAS AG EXITS FROM AS LATVIJAS GĀZE

E.ON Ruhrgas AG ("E.ON") is set to sell its shareholding in AS Latvijas gāze ("LG"), which has a monopoly in the natural gas market in Latvia.

E.ON has been a shareholder of LG since acquiring a minority shareholding during LG's privatisation in 1997. Since then, E.ON has increased its shareholding in LG to 47.23%, making it LG's largest shareholder. LG's other major shareholders are currently Russia's Gazprom (34%) and Itera Latvia (16%).

E.ON's exit from LG is part of a plan to withdraw from the Baltic and Central and Eastern Europe region. In the first half of 2014, E.ON sold its shares in an Estonian gas company AS Eesti Gaas to the Finnish power group Fortum, and its shares in a Lithuanian gas company AS Lietuvos dujos, AmberGrid and Lesto to two state-owned companies.

According to publicly available information, in 2014 the Latvian government rejected a direct offer by E.ON to sell its shareholding in LG to the government for €220 million. Later that year, E.ON organised an open bid process for all parties interested in acquiring its shareholding in LG and the government decided to participate. However, E.ON publicly announced that the government did not qualify for further participation in the bid process. Possible purchasers of E.ON's shareholding in LG include Lithuanian state-owned companies Lietuvos Energija and Epso-G, and the Marguerite Fund. E.ON is expected to complete the divestment of its shareholding in 2015.

HOUSEHOLDS TO JOIN ELECTRICITY MARKET

In 2015, households in Latvia will finally join the electricity market.

Until now, domestic residential electricity tariffs in Latvia have been regulated and the government has repeatedly postponed the liberalisation of the market. According to AS Sadales tīkls, a local DSO, three electricity companies have already published their proposed household tariffs, and at least three more are planning to do likewise.

However, SIA Enefit, the second largest electricity seller in Latvia after the state-owned AS Latvenergo, has announced that it will not enter the residential market, citing what it considers to be unnecessary restrictions on cross-border electricity transmission between Latvia and Estonia and anti-competitive conditions for electricity traders as the reasons for its decision.

IMPLEMENTATION OF THE ENERGY EFFICIENCY DIRECTIVE DELAYED

The Energy Efficiency Directive[1] obliged Latvia to adopt measures to implement its provisions by 4 June 2014.

However, implementation has been delayed due to the Latvian government's failure to reconcile the diverse viewpoints of concerned stakeholders including heating and electricity producers and the transport sector. One of the most contentious aspects concerns the implementation and funding of energy efficiency schemes. It has been initially proposed by the state that heating producers should be solely obliged to fund improvements in energy efficiency in the residential sector. However, heating companies have rejected this proposal and suggested instead that investment in energy efficiency should be proportionate across all sectors, so that improvements in energy efficiency in a particular sector are funded by consumers of that form of energy.

Investments in the energy efficiency sector in Latvia have an estimated value of €3 billion, so any decision as to implementation is likely to have a significant impact on both current and potential market players.

ENDNOTE

1. Directive 2012/27/EU of the European Parliament and Council of 25 October 2012 on energy efficiency, amending Directives 2009/15/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC.

ENERGY LAW IN LITHUANIA

Recent developments in the Lithuanian energy market

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NATURAL GAS SECTOR

TSO Unbundling and restructuring

On 12 February 2014 the Ministry of Energy of Lithuania transferred its stake of 17.7% in Lithuanian natural gas DSO Amber Grid AB to the Lithuanian company EPSO-G UAB. On 21 May 2014, EPSO-G UAB acquired a 38.9% shareholding of Amber Grid AB from E.ON Ruhrgas International GmbH (Germany), thus increasing its stake in Amber Grid AB to 56.6%.

In a parallel transaction, the Ministry of Finance of Lithuania transferred its stake of 17.7% in Lietuvos Dujos AB (the Lithuanian natural gas supply and distribution company) to Lietuvos Energija UAB on 21 February 2014.

After the acquisition of the shareholding from E.ON Ruhrgas International GmbH on 21 May 2014, Lietuvos Energija UAB held a stake of 56.6% in Lietuvos Dujos AB.

On 19 June 2014, upon the mandatory takeover bid implementation, OAO Gazprom sold its stake of 37.1% in Amber Grid AB to EPSO-G UAB and a stake of 37.06% in Lietuvos Dujos AB to Lietuvos Energija UAB. This transaction enabled Lithuania to implement fully the Third Gas Directive.

The above transaction has resulted in the following ownership structure of Amber Grid AB: EPSO-G UAB holds a 96.58% stake and minority shareholders hold a 3.42% stake. The ownership structure of Lietuvos Dujos AB is now as follows: Lietuvos Energija UAB holds a 96.64% stake and minority shareholders hold a 3.36% stake.

Lietuvos Energija UAB has unbundled its natural gas supply activities from its natural gas distribution business by establishing a new company "Lietuvos dujų tiekimas UAB". On 13 October 2014, the National Control Commission for Energy and Prices granted Lietuvos dujų tiekimas UAB a licence for the supply of natural gas which is commenced on 1 November 2014.

LNG

On 10 February 2014 the Ministry of Energy approved LITGAS UAB, part of Lietuvos Energija energy company group, as a designated supplier responsible for liquefied natural gas ("LNG") supply and trading via a LNG terminal under construction in Klaipėda. From the start of 2015, LITGAS UAB will be required to supply a specified minimum volume of 540 million m^3 of LNG to support the continued operations of the LNG terminal. Therefore, on 21 August 2014 LITGAS UAB signed a LNG supply contract with the Norwegian company Statoil ASA. Under the mid-term contract signed with Statoil ASA, the first LNG cargo is expected to be delivered to the Klaipėda LNG terminal at the end of December 2014 so that the terminal may commence commercial operations from 1 January 2015. Each year Statoil ASA will be required to deliver between six and seven LNG cargoes to Klaipėda port.

LITGAS UAB is currently able to supply more gas than anticipated by legislation. The company has already entered into 12 non-binding Master Sale and Purchase Agreements ("MTA/MSPA") with global suppliers. These agreements enable LITGAS UAB to trade on the spot market and to offer natural gas to the Lithuanian market from companies whose aggregate supply accounts for more than half of total global LNG supply.

On 18 April 2014, Klaipėdos Nafta AB, the owner of the Klaipėda LNG project, approved the regulations for use of the LNG terminal in Klaipėda following the pre-approval by the National Control Commission for Energy and Prices. The regulations set out the requirements for third party access to the LNG terminal's infrastructure.

The LNG terminal was launched on 3 December 2014 and started its commercial operations from the first day of 2015.

Underground gas storage

In 2010, Lithuania began assessing the viability for the construction of an underground gas storage facility in Syderiai, a village in the area of Telšiai. The analysis of seismic data of the Syderiai geological structure has shown that the Cambrian layer occurring at a depth of approx. 1450m contains a large formation suitable for gas storage.

KBB Underground Technologies GmbH carried out the works of Syderiai geological structure research data processing and preparation of the storage reservoir model. This model allowed an assessment of the reservoir's properties and its distribution through the whole infrastructure of the underground gas storage facility, the determination of sealing properties and integrity of the caprock, the calculation of the volume of storable gas, the assessment of injection/extraction scenarios, and the quantification of approximate investments necessary to complete the project as well as providing a wealth of other vital data. The Lithuanian government is yet to decide on the future of the project.

NUCLEAR POWER PLANT PROJECT

On 30 July 2014, the Ministry of Energy and Hitachi Ltd. (a strategic investor in the new nuclear power plant ("NPP") in Visaginas), signed a Memorandum of Understanding for joint actions in the preparation for the establishment of an interim project company. After signing this memorandum, the parties are now considering further steps in the preparatory works to:

- Establish the interim project company to ensure the NPP project's maturity;

- improve the competitiveness; and
- the implementation conditions of the NPP project.

Once the preparatory works are finished, a proposal for the establishment of the interim project company will be submitted to the potential investors.

Taking into account the finding of the governmental Working Group for Refining the National Energy Independence Strategy that the continuity of NPP is viable only if additional financial and contractual conditions are implemented, the Strategic Investor Hitachi Ltd. has submitted proposals for the improvement of the financing conditions of the project with the support of Japanese export credit agencies. The government is yet to respond to such proposals.

On 29 March 2014, all seven Lithuanian political parties currently operating in the Lithuanian parliament signed an agreement on foreign, security and defence policy for 2014-2020 and committed to the implementation of several strategic energy and infrastructure projects, including the Visaginas NPP project. However, the perspectives of this project are still questionable, as the state authorities have not reached a firm agreement on further implementation of the Visaginas NPP project.

SYNCHRONISATION WITH THE EUROPEAN CONTINENTAL NETWORK ("ECN")

In cooperation with Latvian and Estonian electricity TSOs, namely Augstsprieguma Tikls and Elering, Litgrid undertook a feasibility study that provided a detailed analysis of the technical conditions and possibilities for the Baltic States' energy system interconnection with the ECN. The results of the study were released at the end of 2013; they revealed that, technically, interconnection with the ECN is possible, however, in order to achieve this, the current electric transmission systems of the Baltics, Poland and Kaliningrad require improvements including the modernisation of the methods of control and reserves. In addition, several new B2B converters with Russia and Belorussia are required. Special attention was drawn to the technical features of Visaginas NPP; the study concluded that there were no major legal or regulatory obstacles for the synchronisation with the ECN. The study also found that it is possible to synchronise the Latvian and Estonian transmission systems with the ECN until 2020. The study was not optimistic about reducing the time needed by eliminating the Kaliningrad link, as it found that synchronisation eliminating the Kaliningrad link will take longer than if the synchronisation included Kaliningrad. The synchronisation of the Baltic States with the ECN is expected to be completed by 2020.

ELECTRICITY INTERCONNECTOR PROJECTS

The development of energy infrastructure links with the EU energy market is essential to overcome the isolation of the Lithuanian energy market. It goes without saying that Lithuania's electricity links with Sweden (NordBalt) and Poland (LitPol Link) are key projects.

(i) NordBalt

The objective of the NordBalt project is to build an interconnection system between the electricity transmission systems of Lithuania and Sweden with a capacity of 700MW. The length of the link is expected to be approximately 450km. It would consist of high voltage direct current underwater and underground cables as well as converter stations in Lithuania and Sweden. The project is expected to be completed by 2016.

Technical specifications for the public procurement of "Nordbalt" electric power link's converter stations and cables were provided by Vattenfall Power Consultant following the request of the Swedish TSO Svenska Kraftnät. The studies of the Baltic Seabed were completed by AB Marin Mätteknik. AB STRI performed the measurements of harmonics in Klaipėda substation and performed the calculations of harmonic resistance. Documents of territorial planning of the territory of Lithuania were completed by UAB "Sweco Lietuva".

On 11 April 2014 the "Topaz Installer", a specialist vessel for constructing underwater cables, laid the first metres of cable into the Baltic Sea, approximately 600m off the coast of Kuršių Nerija. The 800m long steel pipes were used to transport the cables from the Baltic coast.

The 250km section of the NordBalt submarine cable has been laid on the bed of the Baltic Sea. The construction of the 13km land cable going through the town of Alksnyne, under the Curonian Spit and the industrial part of Klaipeda to the Klaipeda transformer substation was finished in November.

The 450km NordBalt power interconnection should start operating at the end of 2015.

(ii) LitPol

The LitPol Link interconnector will consist of approximately 150km of high voltage double-circuit 400kV overhead lines from Elk (Poland) to Alytus (Lithuania) where a back-to-back station will be built. The 500MW interconnector between Poland and Lithuania is expected to become operational in 2015. In 2020, the link capacity is expected to be increased up to 1,000MW. The total cost of the project is estimated to be €250 million.

RENEWABLE ENERGY SOURCES

In 2012, 21.72% of all energy in Lithuania was produced using renewable energy sources, with this index gradually increasing. In 2013 this percentage increased to 22.95% and is going to be even higher in 2014.

The 10kW installed capacity plant, using renewable energy sources, must participate in the auction if it wants to receive a feed-in tariff. The auctions are organised provided there is a free promotion quota which is set by the government. Currently, only the auctions for allocation of quotas for hydro power plants can be organised. Auctions for allocation of quotas for biomass, solar and wind energy power plants cannot be held due to the fact that targets for total installed capacity of these plants prescribed by the government are already achieved:

- target for the total installed capacity of wind power plants is 500MW (target is already achieved);
- target for the total installed capacity of solar power plants to 10MW (target is already achieved);
- target for the total installed capacity of hydro power plants to 141MW; and
- target for the total installed capacity of biofuels power plants to 105MW (target is already achieved).

Four companies, UAB Feodus, UAB Baltic Energy Group, UAB Renerga and UAB AVEC have publicly declared an interest (with no specific projects yet) for developing the wind farms in the Baltic Sea. The wind power plants could be installed in the Baltic Sea, the territorial waters of Lithuania and the Lithuanian exclusive economic zone. These companies are considering installing turbines with a capacity of approximately 10MW – 350MW. There are two possible methods of connecting the wind power plants with the electric power transmission system of Lithuania: a disintegrated and integrated option. The latter option corresponds both with the strategy of the EU and with the electric power link project between Lithuania and Sweden. However the territorial planning documents, including impact assessment, have not been prepared to date. Moreover it is expected that these documents will probably need to be approved by both the parliament and the neighbouring countries.

ENERGY LAW IN LUXEMBOURG

Recent developments in the Luxembourg energy market

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MARKET RESTRUCTURING

After ArcelorMittal divested its 23.48% stake in Enovos International SA ("Enovos") in July 2012 to a fund managed by the then Axa Private Equity (now known as "Ardian"), two other major shareholders in Enovos, RWE and E.ON, announced in April 2014 that they are interested in the sale of their participation of 18.36% and 10% respectively.

Enovos was formed in 2009 as a result of a fundamental restructuring of the Luxembourg energy market with the merger of three historical players of the "Greater Region"[1]: Cegedel SA (Luxembourg electricity incumbent), Soteg SA (Luxembourg gas incumbent) and Saar Ferngas AG. Apart from Ardian, RWE and E.ON, the state of Luxembourg holds directly and indirectly 35.45% of the capital of Enovos, and the City of Luxembourg and GDF Suez (Electrabel) own 8% and 4.71% respectively.

In his response to a parliamentary question[2], the Minister for Economy, Etienne Schneider, indicated that according to the information provided to the Luxembourg state, RWE's and E.ON's decisions were taken in the frame of their respective group strategy and divestiture programmes. Furthermore, the Minister for Economy explained that the articles of incorporation of Enovos foresee a preemption right in favor of the remaining shareholders and that the City of Luxembourg and the Grand Duchy of Luxembourg state have the common intention to acquire 50% plus 1 share of Enovos' capital, so that the majority of the shares would be held by public shareholders.

The acquisition of a majority shareholding in Enovos by the public sector should indeed be considered as being of strategic importance for Luxembourg. A modern, competitive and high quality supply of energy is a major attraction for its economy.

According to the Minister for Economy, in addition to the public sector's involvement, it remains important that Enovos' share capital continues to be held by private investors, either from the financial or industrial sector, who would be interested in contributing their experience and knowledge to the development of Enovos.

Since the announcement of RWE's and E.ON's intention to sell their participation in Enovos in April 2014, no new information about possible negotiations with the Luxembourg state or with potential private investors has been published.

NEW POWER PLANTS AND POSSIBLE CLOSURES

On 19 September 2014 the Kiowatt trigeneration plant was commissioned in Bissen. Kiowatt is a joint venture between the Luxembourg company LuxEnergie and the Belgian "Groupe François".

This first trigeneration plant in Luxembourg combines production of wood pellets with production of electricity and heat. Waste wood is used in order to produce up to 21GWh of electricity annually which is injected into the public network. According to Kiowatt[3], this is enough to supply the electricity needs of about 3,500 households.

The thermal energy produced (about 11.5MW or 93GWh per year) is used for three different applications:

- by a dryer system used in the production of the wood pellets;
- by injection into the future district heat network of Bissen; and
- by refrigeration production for the adjacent LuxConnect Data Centre using absorption refrigerating machines.

Public attention was drawn to the possible closure of the combined-cycle gas turbine power plant operated by TWINerg in Esch. Issues relating to unintentional emissions of dust containing rust particles have caused concern in the media and with local residents for some time during the temporary closure period.

The Belgian company Electrabel GDF-Suez, the main shareholder of TWINerg, announced in August 2014 that the plant, which was commissioned in 2002, would be closed and mothballed on 1 October 2015. The declining profitability of the plant, with a loss of more than €13 million in 2013, had already led to several temporary closures of operation and a declining rate of operation of the facility. While the plant operated more than 7,000 hours per year until 2010, the operating hours dropped to 3,000 in 2013[4]. As the electricity produced by TWINerg is injected into the Belgian grid, discussions about its future status, eventually as balancing and reserve capacity are ongoing with the Belgian authorities. The impact of a closure on the district heating grid of Sudcal is expected to be minor.

Several restarts of the plant following temporary closures have been blamed for causing two incidents of pollution from "yellow dust" (containing rust and sulphur) in the neighbourhood of the TWINerg plant, resulting in up to 500 complaints by residents to the police[5].

SECURITY OF SUPPLY

Creos Luxembourg S.A. ("Creos") is the TSO for electricity and gas in Luxembourg.

Currently, Creos' electricity transmission system is directly connected to the German grid operated by Amprion. In order to ensure and enhance security of supply, Creos announced in a report published in July 2014[6], that it plans to introduce a permanent interconnection with the Belgian grid operated by Elia by 2023. Furthermore, Creos plans to invest €103 million in its high voltage electricity grid infrastructure from 2014 – 2023.

ELECTRICITY – CWE FLOW-BASED MARKET COUPLING LAUNCH POSTPONED

On 26 September 2014, Creos announced that the partners of the flow-based project in Central Western Europe ("CWE": Belgium, France, Germany, Luxembourg and the Netherlands) decided to avoid a launch before or during the winter 2014/2015 and to reschedule the target date of flow-based market coupling to 31 March 2015[7].

The reason for the postponement is the extraordinary situation in Belgium where the shutdown of several nuclear power plants may lead to power shortages and imbalances in the transmission system during the winter 2014/2015. Governments decided that a postponement was necessary so that an additional factor of uncertainty could be avoided during this time frame.

INTEGRATION OF THE LUXEMBOURG AND BELGIAN NATURAL GAS MARKETS

On 22 May 2014, Creos and Fluxys[8] announced that they had entered into a cooperation agreement aimed at integrating the two countries' gas markets[9].

The Minister for Economy, Etienne Schneider, stated:

> "*Luxembourg, which is located between the ZTP market (Zeebrugge Trading Point) in Belgium and the NCG market (Net Connect Germany) in Germany, aims to contribute actively to market integration in Western Europe. We approve the initiative by Fluxys Belgium and Creos Luxembourg to develop a single Belgian-Luxembourg market in close collaboration with the national regulatory authorities in both countries. This cooperation project is fully in line with the spirit of European Directive 2009/73/EC, i.e. to get the Member States to evolve towards creating a barrier-free single market with competitively priced gas and enhanced security of supply.*"

Subject to the approval of their respective national regulatory authorities, Creos and Fluxys aim to merge the two countries' natural gas markets in 2015.

NEW FEED-IN TARIFFS FOR ELECTRICITY PRODUCED FROM RENEWABLE ENERGY SOURCES

Luxembourg uses feed-in tariffs in order to promote energy from renewable sources. In the frame of the National Action Plan adopted by Luxembourg in 2010 pursuant to the Renewable Energy Directive, a review and adaptation of the existing feed-in schemes was planned[10].

A new grand-ducal regulation on the production of electricity based on renewable energy sources was adopted on 1 August 2014[11]. Except for electricity produced from photovoltaic installations (-9%), the injection tariffs of all other renewable sources were increased (biogas +31%, wind +13%, biomass +11%). These injection tariffs for new installations are guaranteed for 15 years and the additional costs are borne by the end-consumer through a compensation system managed by the national regulatory authority.

Although the new regulation was approved by the Commmission on the basis of article 107 (3) (c) of the TFEU and the Environmental Aid Guidelines 2008 – 2014, the Minister for Economy, Etienne Schneider, announced a more fundamental review of the feed-in schemes even before the final adoption of the grand-ducal regulation of 1 August 2014[12]. It appears necessary to adapt the existing system in order to conform it to the European Commission's new "Guidelines on State aid for environmental protection and energy 2014 – 2020" published on 28 June 2014[13].

COSTS AND BENEFITS OF FUEL TOURISM

Historically, taxation on gasoline and diesel fuel sales is low in Luxembourg compared to its neighbouring countries. While cross-border commuters certainly use the opportunity to fill up their fuel tanks in Luxembourg, fuel tourism is mainly due to long distance trucks transiting through Luxembourg. As a result, around three quarters of the fuel sold in Luxembourg is consumed outside the country's borders[14].

Taxes levied on fuel sales are an important source of income for Luxembourg as up to 10% of the State's budget is generated by them. If the fuel industry also largely contributes to the economy in terms of employment, Luxembourg's energy taxation policy comes under increasing pressure due to its environmental impact.

Indeed, the largest share of energy-related CO_2 emissions is emitted by the transport sector (up to 64.2% in 2012[15]). Former governments have in the past aimed to reduce this negative impact by various fiscal measures (for instance the "Kyoto Cent" which is a special tax on road fuel sales) or by buying emission certificates.

As it becomes more and more difficult for Luxembourg to meet its commitments to reducing CO_2 emissions under the Kyoto Protocol and in the frame of the European Union, the current government consisting of the liberal Democratic Party, the centre-left Luxembourg Socialist Workers' Party and the Green Party (led by Prime Minister Xavier Bettel since December 2013) is now considering reviewing its energy taxation policy in detail. For this purpose, the government, under the auspices of the Environment Ministry, launched a study in 2014 in order to assess the costs and benefits of fuel tourism in Luxembourg[16].

JUDICIAL REVIEWS

The application for judicial review brought by Greenpeace Luxembourg and several local residents against the building permit authorising the construction of an underground high voltage power line by Sotel to connect its industrial grid to the French transmission grid ("RTE") was dismissed. The Administrative Tribunal[17] held that the municipal building regulations had to be interpreted in light of the national law on nature conservation. Even in nature conservation areas, the Tribunal held that municipal regulations could not render developments authorised under national legislation as "impossible", such as the construction of a power line. The Tribunal thus rejected Greenpeace's claim that a strict application of the municipal regulations prohibited construction of a power line through the protected area. Maintaining its opposition to the supply of French nuclear power through this line, Greenpeace is appealed the Tribunal's decision. The Administrative Court of Appeal confirmed the first decision thus bringing an end to a legal battle initiated by Greenpeace in 2008[18].

ENERGY PRICES

In its annual report published in October 2014[19], the national regulatory authority, Institut Luxembourgeois de Régulation ("ILR"), analysed the structure and evolution of natural gas and electricity prices offered by suppliers to households. The ILR concluded that these prices were reasonable and non-discriminatory, although the prices for the supply of natural gas remain difficult to compare.

Furthermore, the prices for integrated supply[20] of electricity and natural gas remain below the integrated prices offered in

Germany, France and Belgium. The price difference is mainly due to the low level of taxes applied in Luxembourg, as the energy prices themselves are close to the prices applied in the neighboring countries.

RESEARCH

The Luxembourg public research centre (*Centre de recherche public*) Henri Tudor has developed an online tool allowing companies to assess their greenhouse gas ("GHG") emissions.

Known as "Betriber & CO2", the free web based application, takes into account the amount of energy consumed by a company, the distances travelled and materials consumed. Based on emission factors associated with the various activities, results of GHG emissions are calculated and given in kg CO_2 equivalent. The figures can be presented in four categories: infrastructure, transport, catering and waste. The application also presents the emission figures according to the three targets proposed by the ISO 14064-1 standard. This standard specifies principles and requirements at the organisation level for quantification and reporting of GHG emissions and removals, including requirements for the design, development, management, reporting and verification of an organisation's GHG inventory[21].

The tool is intended to increase awareness of GHG emissions and to encourage industry to consider pursuing further analyses on emissions[22].

RENEWABLE ENERGY

Enovos Luxembourg S.A. continued its investments in renewable energy projects.

The Alcoutim photovoltaic power plant, located in the south of Portugal, was inaugurated in October 2014. The plant is based on concentrated photovoltaic ("CPV") technology and is capable of an annual power generation of 1,900MWh. Enovos holds 34.09% of the capital of the project and collaborated with Soitec, the supplier of the CPV, and three other Portuguese project partners[23].

Through its majority owned subsidiary, NPG Energy S.A., Enovos Luxembourg participated in a biogas plant NPG BIO II in the port of Antwerp in Belgium. The facility has a capacity of 3MW and will produce 21GWh. This plant represents the second investment by NPG Energy in biogas, following the commission of its first biogas plant in Tongeren (also in Belgium)[24] in 2012.

The commissioning in September 2014 is expected to be followed by two additional biogas plants over the next twelve months.

CLIMATE PACT AND EUROPEAN ENERGY AWARDS

Since its inception in January 2013, the municipalities wishing to pursue climate change policies can sign a "climate pact" with the Ministry of Sustainable Development. For its second Climate Pact Day in May 2014, 87 municipalities (out of a total of 106) had signed such an agreement, thus committing themselves to restructure their local climate and energy policies in exchange for technical assistance from "myenergy", a national body created for the promotion of renewable energies and energy efficiency. As of October 2014, 10 communes had been audited and had received the "European Energy Award"[25]. Further certifications are expected, with best practice being promoted among the communes.

ENERGY PERFORMANCE CERTIFICATES

A study by the University of Luxembourg showed that the energy ratings mentioned in the energy performance certificates vastly overstate the energy consumption. The analysts studied the energy performance certificates of 125 individual homes and 105 apartment buildings totalling 870 lodgings and compared them to the heating combustibles consumed by these lodgings over the course of three years. The University of Luxembourg found that the certificates exaggerated the energy consumption by up to 74% for homes and even up to 103% for apartment buildings. The study found that the older the buildings, the greater were the differences between the certificates and the actual consumption. The University expressed its wish that the study would be seen as a constructive contribution to render the energy performance certificates more reliable[26].

ENDNOTES

1. The Greater Region is composed of Saarland (Germany), Lorraine (France), Luxembourg, Rheinland-Palatinate (Germany), Wallonia (Belgium).
2. Question parlementaire No 214 du 11 avril 2014 de Monsieur le Député Fränk Arndt.
3. www.kiowatt.lu.
4. www.chd.lu – answer by the Minister for Economy to the parliamentary question number 492 of 29 August 2014.
5. http://www.lequotidien.lu/le-pays/60388.html.
6. http://www.creos-net.lu/creos-luxembourg/infrastructure/reseau-delectricite.html.
7. According to the information provided by APX Spower Spot Exchange, "*the Flow Based model is a methodology which describes the network in order to take into account the impacts of cross-border exchanges on network security constraints when optimising the market flows (i.e. the match of offer and demand) for the concernedregion, thus offering more capacity and maximising the social welfare generated*". https://www.apxgroup.com/services/research-projects/cwe-flow-based-market-coupling/
8. Natural gas DSO in Belgium.
9. http://www.fluxys.com/belgium/en/NewsAndPress/2014/140522_Press_Creos.
10. Exposé des motifs, 6575 – Projet de règlement grand-ducal relatif à la production d'électricité basée sur les sources d'énergie renouvelables et modifiant :1. le règlement grand-ducal du 31 mars 2010 relatif au mécanisme de compensation dans le cadre de l'organisation du marché de l'électricité; 2. le règlement grand-ducal du 15 décembre 2011 relatif à la production, la rémunération et la commercialisation de biogaz, page 4.
11. Règlement grand-ducal du 1er août 2014 relatif à la production d'électricité basée sur les sources d'énergie renouvelables et modifiant: 1. le règlement grand-ducal du 31 mars 2010 relatif au mécanisme de compensation dans le cadre de l'organisation du marché de l'électricité; 2. Le règlement grand-ducal du 15 décembre 2011 relatif à la production, la rémunération et la commercialisation de biogaz.
12. Réponse à la question parlementaire No 413 du 18 juillet 2014 de Mesdames les Députées Octavie Modert et Martine Hansen et de Monsieur le Député Aly Kaes.
13. http://eur-lex.europa.eu/legal-content/FR/TXT/?uri=OJ:C:2014:200:TOC.
14. http://www.wort.lu/en/politics/emissions-vs-tax-revenue-the-pros-and-cons-of-fuel-tourism-53df4e68b9b398870804fcb3.
15. Energy Policies of IEA Countries, Luxembourg 2014 Review, page 28.
16. http://www.wort.lu/en/politics/emissions-vs-tax-revenue-the-pros-and-cons-of-fuel-tourism-53df4e68b9b398870804fcb3.
17. http://www.justice.public.lu/fr/jurisprudence/juridictions-administratives/index.php: judgment of 31 March 2014, number 32152. http://www.greenpeace.org/luxembourg/fr/news/Jugement-Sotel/ press release 22 April 2014.
18. http://www.justice.public.lu/fr/jurisprudence/juridictions-administratives/index.php: judgment of 13 November 2014, number 34521C.
19. The report is published on the website www.STROUMaGAS.lu.
20. These prices include apart from the supply also the costs for the access to and the use of the network.
21. http://co2tool.tudor.lu/Tool_CFP/.
22. http://www.tudor.lu/fr/actualite/faire-un-bilan-de-ses-emissions-et-decouvrir-des-champs-dactions.
23. http://www.chronicle.lu/categoriesbusinessenergy/item/8825-enovos-inaugurates-its-1st-photovoltaic-power-plant-in-portugal.
24. http://www.renewableenergymagazine.com/article/enovos-and-npg-energy-inaugurate-biogas-plant-20140922.
25. www.pacteclimat.lu.
26. http://wwwfr.uni.lu/universite/actualites/a_la_une/passeports_energetiques_une_surevaluation_de_la_consommation_finale – press release 27 May 2014.

ENERGY LAW IN THE FORMER YUGOSLAV REPUBLIC OF MACEDONIA

Recent developments in the Macedonian energy market

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INTRODUCTION

There have been no major regulatory amendments in Macedonian energy related legislation over the past year. Macedonian legislation is still only compliant with the Second Energy Package. Although Macedonia is part of the Energy Community Treaty, the Ministerial Council of which decided to require Energy Community Treaty members to adopt the Third Energy Package by January 2015, no legislative amendments in respect thereof had been put before the Macedonian Assembly at the end of 2014.

Currently, the Macedonian energy market is predominantly focused on the project of gasification (ie, developing an internal primary and secondary gas pipeline infrastructure) of the country, as well as the topic of electricity market liberalisation.

THE GASIFICATION OF MACEDONIA

The Skopje region

The Macedonian government started the process of gasification in February 2014, when it published a tender for the award of a public-private partnership for financing, designing, constructing, operating, maintaining and developing a natural gas distribution system in the Skopje region (one of the three regions in which Macedonia has been divided for the purpose of the gasification; the other two being the western region and the eastern region). According to the estimation of the Macedonian government the investment value for the gasification of the Skopje region will amount to somewhere ca. €98 million.

Of the companies that registered their interest with the Macedonian government, the Turkish company Akso Enerji, as well as the Italian company CPL Concordia, were selected in July 2014 to continue to the second phase of the public-private partnership awarding procedure.

The western and eastern regions

On 6 September 2014 the Macedonian government published two new tenders for the award of a public-private partnership for financing, designing, constructing, operating, maintaining and developing a natural gas distribution system for the two remaining regions (the western and eastern regions) of the country.

It is the Macedonian government's estimation that the investment value for the western region (officially named "Region 3") will be ca. €22.2 million, whereas the estimation for the eastern region (officially "Region 2") investment value is ca. EUR €27.5 million.

Gas supply/connection to a major gas pipeline

In July 2013 the governments of Macedonia and Russia signed a bilateral cooperation agreement on the construction of the South Stream gas pipeline section in Macedonia. Following an announcement by the Russian government in late 2014, it seems that this pipeline project might be stopped or suspended.

In light of this, and in a quest to find a steady supply of natural gas, it seems that Macedonia might now turn its attention to the Trans Adriatic Pipeline (the "TAP"). The Macedonian Vice Prime Minister and Finance Minister Mr. Stavreski stated in an interview given in September 2014 that Macedonia plans to officially file a request to join the TAP project soon. It is not yet clear whether Macedonia would be connected to the TAP in the Greek section or in the Albanian section of the TAP, but what is clear is that the pipeline will cross only tens of kilometres from Macedonia's southern border, thus making Macedonia's inclusion relatively practicable and cost effective.

ELECTRICITY MARKET LIBERALISATION

The electricity market liberalisation in Macedonia has been implemented in several phases so far. Back in 2007, the liberalisation was initiated by giving a dozen large industrial consumers the right to purchase their electricity on the free market. The second phase of the electricity market liberalisation came into force on 1 January 2014, when another 220 large Macedonian companies were given the status of "qualified consumers", and gained the right to purchase electricity on the free market.

It should also be noted that although there is an increased number of competitors trying to get a market share of the companies that are part of the first two phases, EVN Supply (a daughter company of EVN Macedonia, which operates the distribution and supply of electricity in Macedonia and is part of the EVN Austria group) is dominant on the market, with over 70% of the market share.

The third and final phase of the process is expected to achieve a full liberalisation of the national electricity market by giving all remaining companies, as well as Macedonian households, the right to choose their electricity supplier.

This final phase was originally planned to come into effect on 1 January 2015. However, in October 2014, the Macedonian government unexpectedly proposed, and the Macedonian Assembly adopted, amendments to the law on energy delaying the third phase of the electricity market liberalisation due to a likely rise in electricity prices for households by up to 20%.

The final phase will now be implemented in five different stages (each for a different group of consumers based on their electricity consumption). The final group of consumers (ie, domestic households) will now gain the right to purchase their electricity on the open market as late as 20 June 2020.

Mr. Janez Kopač, Director of the Energy Community Secretariat noted that the delay of the full liberalisation of the electricity market until 2020 is a clear breach of the Energy Community Treaty, which stipulates that the market should be open as of 1 January 2015 at the latest. It is not yet clear if Macedonia will face any consequences as a result of this breach. It is expected that any such consequences will become known in the course of 2015.

CHEBREN HYDROELECTRIC POWER PLANT

After ten unsuccessful tenders, the Macedonian government has continued to try and find a company interested in constructing the "Chebren" hydroelectric power plant ("HPP").

It should be noted, however, that in the previous tenders the "Chebren" HPP was offered in a package with the "Galishte" HPP. The latter was deemed unprofitable by potential investors and was cited as one of the reasons why investors lost interest in the project. The current public call only refers to the "Chebren" HPP.

Apart from this, the last tender also provided more favourable terms for potential investors with respect to the height of the dam, the percentage that the Macedonian government must have in the newly established company that will hold the concession, as well as a better and fixed price for electricity transmission.

On the bid deadline on 30 June 2014 the only bid received was that of the Greek company Public Power Corporation. The construction of the "Chebren" HPP is expected to last around 7 years and should cost approximately €300 million.

CONCESSION OF 400 SMALL HYDROPOWER PLANTS

The government of Macedonia has a long term energy plan which includes the building of 400 small hydropower plants in different locations in Macedonia. Seventy water concession agreements for the construction of small hydropower plants have already been concluded.

In February 2014 the Macedonian government published a new tender for the award of a water concession for an additional 80 small hydropower plants. Out of these, 48 locations are offered as packages of 2, 3 or 4 hydropower plants, while the other 32 locations are offered individually. The projects are envisaged to be constructed in the valleys of Vardar; Treska; Bregalnica; Strumica; and Black Drin Rivers in Macedonia.

According to the Minister for the Environment, a total of 49 offers both from domestic and foreign companies have been filed with the Ministry. The overall investment for all 80 hydropower plants is estimated to be around €170 million and their overall installed capacity will amount approximately 63MW. According to the tender, the best bidders will receive a concession agreement with a length of 23 years, out of which 3 years should be used for the construction of the plant(s).

AMENDMENTS TO THE LAW ON CONSTRUCTION

A number of investors have publicly noted that they face major bureaucratic setbacks which delay the construction of their projects in Macedonia. This especially represents an issue for energy projects in which investors and lenders are confronted with set timeframes to construct the facilities. Some of the biggest problems often arise from real estate related matters, such as land ownership and other land title related disputes.

The government of Macedonia recently proposed, and the Assembly adopted, certain amendments to the law on construction. These amendments should allow the project developers investing in (i) oil, product and heat pipelines; and (ii) energy production facilities using renewable sources to obtain a construction permit and start the construction of such facilities without first resolving real estate ownership issues. However, the real estate ownership issues do need to get resolved prior to obtaining an approval for use of the facility (which can be obtained after the construction works have been entirely finished).

It seems that these amendments might make the entire process of investing in energy related projects in Macedonia easier and could perhaps stimulate more interest from both domestic and foreign investors, especially in the renewable energy sector.

ENERGY LAW IN MALTA

Recent developments in the Maltese energy market

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MALTA-AN ENERGY HUB IN THE MEDITERRANEAN

International trading hub

Malta aims to become an energy hub in the Mediterranean region. In September 2014 the Maltese government announced its intention to exploit the possibility of trading renewable energy across borders and Malta's potential to become a gas supply hub with a link to gas fields in North Africa to Europe. To achieve this objective in November 2014 a joint venture was formed between Malta Enterprise, the national development agency responsible for promoting and facilitating international investment in Malta, and International Energy Group, a Singaporean company, with the aim of developing Malta as a trading hub for energy products between Europe and Asia. While initially the joint venture will be using Malta as an oil trading hub there are plans to extend its activities to oil blending and bunkering.

Climate change action

During the UN Climate Change Summit held in New York in September 2014 the Maltese government announced that as part of its climate finance commitments it intends to offer technical support to states most vulnerable to climate change. Furthermore, in October 2014 the government approved: (i) a draft Climate Action Act which aims to formalise and rationalise international and European legal requirements for the preparation of inventories on emissions of green house gasses; (ii) the national low carbon development strategy; (iii) the establishment of a Climate Action Board; and (iv) a Climate Action Fund[1].

GAS

Euro – Mediterranean gas platform

During the 'Malta Energy Conference' held in July 2014 and co-hosted by Malta and Cyprus Energy ministers from EU Member States, African and East Mediterranean countries announced their agreement, in principle, to establish a Euro-Mediterranean platform on gas supply in order to bring together policy makers, industry representatives and regulators. This platform will aim to assist the development of Euro-Mediterranean relations in the gas sector, to encourage greater convergence between the policies of various countries and to promote investment in pipelines, LNG terminals, and other energy infrastructure. In view of the possibility that the EU internal gas supply will be exhausted in the next 20 years, the southern Mediterranean corridor is considered to be an important part of the EU's strategy for the diversification of its gas supplies. The then European Energy Commissioner, Günther Oettinger, has stated publicly that he believes that Malta is in the perfect geo-strategic position to act as broker on gas issues between the Mediterranean's Northern and Southern shores. In December 2014 the Maltese government signed a memorandum of understanding with SOCAR, the Azerbaijani oil and gas state agency, on strategic cooperation in the oil and gas sector.

New gas plant

In December 2013 the state-owned utility company, Enemalta Corporation ('Enemalta'), awarded the tender for the supply and development of a Combined Cycle Gas Turbine ('CCGT') power plant, a LNG floating storage unit and an onshore regasification unit in Delimara to ElectroGas Malta Consortium ('ElectroGas'). In March 2014 the Malta Environment and Planning Authority ('MEPA') issued the planning permits required for the construction of a new 215MW gas-fired electricity plant and related LNG storage facilities at the Delimara Power Station. These planning permits will enable the construction of a CCGT plant including three gas-fired turbines and a fourth turbine to feed off the steam generated by the first three units. This new plant will be supplied through a regasification unit receiving LNG from a floating storage unit moored to a jetty. This facility will also aim to supply the Delimara Phase 3 plant (Enemalta's existing 149MW plant commissioned in 2012) which will be converted to operate on natural gas as opposed to heavy fuel oil.

The Maltese government had originally pledged to commission this plant by March 2015[2] to coincide with the government's declared intention to reduce utility rates for businesses by 25%. In December 2014 the government announced that the construction of this plant will be delayed and that as a result electricity generated from gas-fired plants will start reaching end consumers by June 2016. Although the reduction in utility rates is dependant on the savings which are expected to be made from this new facility, in March 2014 the government fulfilled its electoral promise to reduce utility rates for domestic households by 25%.

LPG sector

The Ministry for Energy and the Conservation of Water has introduced a price stabilisation mechanism for LPG and propane. With effect from June 2013 the price of LPG and propane was fixed by the Malta Resources Authority ("MRA")[3]. This price stabilisation mechanism was subsequently extended for further periods[4], with prices currently being fixed for the quarter ending on 31 December 2014. The government has also launched a public consultatation on the sale of LPG cylinders as a Service of General Economic Interest ("SGEI") and is currently reviewing the responses it has received to this consultation[5].

The Qajjenza gas storage and filling plant which had been in operation since 1959 has been decommissioned over the last two years and in June 2014 a permit was issued by MEPA for the final phase of decommissioning and the removal of 20 LPG storage tanks and gas filing facilities. The decommissioning is to be carried out by Gasco Energy Limited ("Gasco"), a joint venture between the Maltese company Multigas Limited and the Italian company Liquigas SpA established for the management and operation of Enemalta's LPG activities, in terms of Gasco's obligations under the 2008 concession agreement entered into with Enemalta.

OIL

Exploration

Mediterranean Oil & Gas ("MOG"), which holds a licence from the government to explore oil in Maltese waters, has been granted a six month extension to the production sharing contract it holds with the Maltese Government. The first exploration period of this contract ended on 17 July 2014. MOG's licence covers four contiguous blocks in Area 4 located in the southern part of Maltese offshore territory adjacent to acreage in Libya. MOG together with its partner Genel Energy, started drilling the "Hagar Qim 1" exploration well in May 2014 using the deep-water semi-submerisble drilling rig Paul Romano. After exploration reached the Eocene (rock level) MOG plugged and abandoned this well as no indication of hydrocarbons in commercially exploitable quantities was found. This was the 11th well to be drilled off the coast of Malta and the first exploration well since 2002.

Inland fuel market

In September 2013 the Ministry for Energy and the Conservation of Water announced that Enemalta would be fixing the price of petrol and diesel with a view to increasing price stability in the inland fuel market[6]. The price (including VAT) of unleaded petrol was fixed at €1.44 per litre and that of diesel was fixed at €1.36 per litre until 31 December 2014[7].

In October 2014 the government declared that Enemalta sold its petroleum division to two newly formed state-owned entites, Petromal Company Ltd and Enemed Company Ltd for around €83 million. This consideration has been set off against the €150 million Enemalta owes the government in excise duties.

ELECTRICITY

Decomissioning of Marsa power station

Enemalta remains the main producer, distributor and supplier of electricity in Malta, with the exception of a small contribution from a number of small producers generating electricity from renewable energy sources ("RES"). The four boilers at the Marsa Power Station were due to be decommissioned at the same time as the commissioning of Phase 3 of the Delimara Power Station in 2012. However, the decommissioning of the Marsa power station has been delayed. While the European Commission is aware that a new generation plant at Delimara has been put into commercial operation and that the ongoing Malta-Sicily electricity interconnector project is nearing completion, it continues to monitor progress in relation to the decomissioning of the Marsa plant. Meanwhile, the government has imposed a daily fine on the operator, Enemalta, for operating the Marsa power station. As at July 2014 the fines imposed on Enemalta reached approximately €2.5 million. Enemalta has also been required to pay a €50,000 lump sum penalty in respect of each of the four Marsa boilers, which by 2011 had already exceeded the 20,000 hour limit of operation imposed for the period 2008 – 2015 under the Large Combustion Plants Directive. So far two boilers at the Marsa Power Station have been decommissioned and the other two will be closed down when the interconnector is activated.

Agreement with Shanghai Electric Power

In March 2014 the government announced that a preliminary strategic investment agreement was signed with the international energy company Shanghai Electric Power ("SEP"). On 12 December 2014 the government of Malta and SEP signed the final agreement pursuant to which SEP will be investing a total of approximately €320 million: €100 million for a 33% stake in Enemalta €150 million for a 90% stake in D3 Power Generation Limited, a new company established to take over the Delimara Power Station Phase 3 plant and in which Eenmalta will retain a 10% stake, and approximately €70 million to convert this recently built plant to operate on natural gas instead of heavy fuel oil[8]. This plant is expected to be converted to gas by June 2016. While Enemalta will, initially, be able to generate approximately 150MW of electricity from its two Delimara power plants, Enemalta will eventually be required to purchase electricity from third parties to meet its required generation capacity. Enemalta will, however, continue to retain ownership of the distribution grid. The government has announced that the Delimara Phase 1 plant will be decommissioned while the Phase 2 and 3 plants will be run on diesel until Phase 3 is converted to natural gas. Enemalta plans to purchase around 50% of Malta's required electricity from ElectroGas, around 30% from D3 Power Generation Limited, and around 20% from the European Grid through the interconnector with Sicily. The government has announced that a seven-year business plan for Enemalta has been agreed in principle with SEP and that by virtue of the 18-year power purchase agreement entered into with ElectroGas, the price of electricity for Enemalta has been fixed for five years, linking the electricity price to an international index. The deal between the government of Malta and SEP is also reported to include an agreement for Enemalta and SEP to form a number of joint ventures to sell alternative energy equipment, including photovoltaic panels, to the European market and to provide energy maintenance services for SEP plants in the Mediterranean region.

Smart meters

As of August 2014, eighty-seven per cent of the electricity meters connected to the national grid were replaced with new smart meters. It is anticipated that the remaining meters will be installed in the subsequent months[9].

INTERCONNECTOR

Electricity interconnector

The 200MW HVAC interconnection between Malta and Sicily is at an advanced stage of construction[10]. In March 2014 Enemalta completed the excavation of a 4.56km tunnel from Maghtab to Pembroke, to improve the electricity distribution in this area. 132kV cables from the Interconnetor's Maghtab terminal will be channelled through this tunnel to connect to the national grid via the new 132kV distribution centre at Kappara as well as to a new distribution centre currently under construction at Pembroke[11]. Apart from the construction of the interconnector, the Norweigan company Nexans will be constructing two terminal stations including necessary switchgears and transformers, one in Malta and the other in Ragusa, where electricity imported through the interconnector will be fed to the national grid though a new 132kV distribution centre located in Kappara. This project is expected to be commissioned in early 2015 as works on the interconnector are in their final stages.

Gas interconnector

The government has applied for EU funding under the Connecting Europe Facility to develop a new gas link by building a submarine gas pipeline between Malta and Gela in Italy. The proposed link will involve an offshore Floating Storage and Re-gasification Unit ('FSRU') moored some 12km outside Marsaxlokk Bay. This proposal will involve the pumping of approximately 1.1. million cubic metres of re-gasified gas per day to the new gas-fired powerstation in Delimara to be built by the ElectroGas.

RENEWABLE ENERGY

As at the end of 2012 generation capacity from RES connected to the grid stood at 18MW. Solar photovoltaic installations were the main contributor to the increase in total RES capacity over previous years, with the largest uptake taking place in the residential sector due to the scheme launched in July 2011[12]. Since 2012, a new generator producing electricity from landfill gas was also connected to the grid[13]. Malta has an obligation to derive 10% of its gross energy consumption from RES by 2020. The National Renewable Energy Action Plan ("NREAP") submitted by Malta in 2009 projected that by 2017 the electricity generation capacity from RES would reach 155MW[14]. In June 2014, the government declared that 3% of energy generated in Malta by end 2014 would be from RES.

Malta's first solar panel farm was set up by Medserv, an oil and gas logistics services company listed on the Malta Stock Exchange, at its Malta Freeport headquarters. This consists of an 8000-panel farm spread over 20,000 square metres and costing approximately €4 million. This was connected into the national grid and will produce 2MW of electricity which will be sold to Enemalta. Furthermore, a total of 32 organisations have benefitted from the latest €1.2 million scheme issued for photovoltaic panel projects for religious societies.

In November 2014 MEPA together with the Ministry of Energy and Health published a proposed policy to: (i) define a 'solar farm'; (ii) provide guidance for the location of new solar farms; and (iii) identify environmentally relevant design criteria and mitigation measures that need to be integrated into solar farm development to address their potential impact[15]. Eventually this policy is expected to become entrenched in the NREAP currently under revision. MEPA calculates that potentially there is just under 0.7km^2 of available area for solar wind farms. This could theoretically accommodate around 50MWp of PVs and would contribute almost one third of the projected PV capacity necessary to meet Malta’s 10% RES target by 2020 in a scenario which assumes no major wind farm projects.

The partnership between SEP and Enemalta is expected to identify more than 30 potential solar and wind farm projects in Europe with a capacity of 600MW, exceeding Malta's maximum demand of 400MW required to power the entire island on a hot day. The project is expected to start by the beginning of 2015 and aims to achieve the projected capacity within three years from inception.

Under a scheme implemented by the government in 2014, vehicle owners may benefit from a government grant to convert their vehicle to autogas. As at June 2013, the stock of licensed motor vehicles in Malta stood at approximately 329,000 (compared to a population of approximately 447,000). 79.3% of motor vehicles were passenger cars, 14.2% were commercial vehicles, 5.4% were motorcylces and less than 1% were busses[16]. In 2011, emissions in the transport sector accounted for 19% of total emissions in Malta. Road transport accounted for 87.5% of GHG emisions, marine and aviation transport modes accounted for 6.6% of emissions while the remaining 5.8% were emitted by off-road vehicles and other transportation modes[17]. There is an increasing trend of emissions coming from the transport sector due to the increase in passenger vehicle stock, more frequent use of passenger vehicles, ageing vehicle fleet, greater traffic congestion and a steady decline in the use of public transport[18]. As part of the EU funded DEMO-EV (demonstrating the feasibility of electric vehicles towards climate change mitigation) initiative during 2014, 20 new electric vehicles were introduced for use by different individuals and organisations, including Enemalta's Distribution Section, for a period of one year on a test basis. The use of these vehicles is being monitored and usage data is being collected from each vehicle's on-board computer and from the public charging pillars[19]. However, no data has been published as of 31 December 2014.

WASTE

In January 2014 the government published a Waste Management Plan for the Maltese Islands[20]. Malta recognises the need to meet its targets to reduce the generation of waste and to increase source separation including the promotion of recycling and reduction of landfilling. Malta has undertaken to:

- recycle 50% of paper, plastics, metal and glass waste from households by 2020;
- landfill only 35% of biodegradable municipal waste by 2020;
- recover 70% of construction and demolition waste by 2020;
- collect 65% of the average weight of electrical and electronic equipment placed on the national markets by 2021;
- for electrical and electronic equipment placed on the national markets, achieve 55%, 70%, 80% and 85% re-use and recycling and 75%, 80% and 85% recovery by 2018;
- reach 45% of collection rates for waste portable batteries by 2016;
- re-use and recover 95% of the average weight per vehicle per year by 2014.

The National Waste Management Plan proposes initiatives to review the existing collection system in order to provide the existing and upcoming mechanical biological treatment ('MBT') plants with source separated waste. This restructuring is intended to be completed by 2015 in order to coincide with the completion of the Malta North MBT. Other measures proposed include the introduction of clear organic waste collection; measures to improve the quality of waste to be directed to the Sant' Antnin Waste Facility; development, through the state-owned WasteServe Malta Limited, which is responsible for organising, managing and operating integrated systems for waste management, of basic infrastructure to deal with the various waste streams generated in Malta coupled with additional infrastructure and services developed and operated by the private sector. Furthermore, apart from the current facilities in operation, the government is planning, designing and constructing additional facilities partly funded under the Cohesion Fund 2007 – 2013, which include[21]:

- a waste transfer station in Gozo for waste originating in Gozo and Comino;
- a mechanical biological treatment plant in the North of Malta for the treatment of animal manure and municipal solid waste;
- a sixth civic amenity site in 'Ta' Qali' to cater for waste generated by the vegetable market;
- the rehabilition of the former 'Maghtab' and 'Qortin' Dumps;
- the rehabilitation of the former 'Zwejra' landfill;
- the upgrading of the Marsa Thermal Treatment Facility which will include, amongst other facilities, the introduction of dedicated storage of clinical waste, the establishment of a shredder and storage area for shredded wood and refuse derived fuel; and the establishment of wastewater treatment plant.

The €60 million Sant Antnin Waste treatment plant being built in Maghtab benefitted from €43 million in EU funding and will be commissioned in 2016. This will be the largest treatment plant in Malta. The plant currently handles one-third of Malta's 240,000 tons of waste collected each year. The new plant will treat 66,000 tons of domestic waste, 47,000 tons of commercial waste and 39,000 tons of manure every year. This plant, which will be the first to treat manure in Malta, will convert manure to compost releasing biogas which will in turn produce 9GW of electricity per year, which is enough to power 2,000 houses. The power generated from this treatment plant will be fed into the national grid.

WATER POLICY

In 2014, the Sustainable Energy and Water Conservation Unit was established by Ministerial Order[22]. This Unit is an Agency appointed to carry out functions related to the design, implementation and dissemination of water, conventional energy and alternative energy policy.

A total of 20,703 tons of sewage sludge from urban waste water treatment plants was landfilled in 2011. While no official figures for 2014 have been released so far, this figure is expected to increase since the Urban Waste Water Treatment Plant in the South of Malta has been fully operational since mid-2011[23].

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ENERGY LAW IN MONTENEGRO

Recent developments in the Montenegrin energy market

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ENERGY SECTOR REFORMS

The Montenegrin government has dedicated itself to implementing the Third Energy Package in its legal framework.

The unbundling of the generation, distribution and supply of electricity are to date being conducted by the Montenegrin integrated national electric utility company, the majority-state-owned Montenegrin National Electric Enterprise (*Elektroprivreda Crne Gore AD Nikšić*) ("EPCG"). Unbundling of the three elements in terms of accounting has been completed. However, Montenegro still needs to comply with its unbundling obligations in as far as distribution activities are concerned.

NEW PRIORITY PROJECTS

In February 2014 the Government of Montenegro adopted a document entitled Information on the Priority Energy Development Projects. In accordance with this document, there are currently six key projects on the Montenegrin energy market:

Offshore exploration and exploitation of hydrocarbons

The public invitation for the tender on hydrocarbons exploration and exploitation was published by the Ministry of Economy in August 2013. The tender relates to 13 blocks of 3,000 km² in the Adriatic Sea and was closed in May 2014. The bids were submitted by the following six companies: Marathon Oil Corporation (USA), OMV (Austria), Eni S.p.A. (Italy), Novatek (Russian Federation), Energean Oil and Gas (Greece) and Mediterranean Oil and Gas (United Kingdom). The intention of the State of Montenegro is to increase the knowledge of the offshore potential, which has not been sufficiently explored to date.

The concession is divided into two phases:

- the exploration phase, and
- the exploitation phase.

The exploration phase together with reserve-verification cannot exceed a period of six years for a block on the land, or seven years for a block on the sea. Upon the concessionaire's request and only in cases provided by law, the exploration phase can be extended by up to two years.

The exploitation phase starts from the date of the first extraction of hydrocarbons from the reservoir and lasts until the deadline established by the concession contract, which cannot exceed 20 years from the moment of the first extraction activity. Also, the exploitation phase upon the request of the concessionaire may be extended for half of the exploitation phase period (ie, not more than 10 years).

This project is currently one of the top priority projects of the Ministry of Economy. Apart from the fact that the exploitation of hydrocarbons will diversify the energy system of Montenegro, potential exploitation may bring significant revenues to the State of Montenegro. Under the recently adopted Hydrocarbons Tax Act (*Zakon o porezu na ugljovodonike*) ("Official Gazette of Montenegro", no. 31/2014) the tax rate for hydrocarbon upstream operations is 54%.

Ionian Adriatic Pipeline Project ("IAAP")

Montenegro has entered into a gas pipeline project with Albania and Croatia, the IAPP. It is planned that the pipeline will connect Croatia to Albania through Montenegro with the flow capability going from north to south. An intergovernmental declaration in relation to the IAPP was signed by Albania, Croatia and Montenegro in 2007. Bosnia and Herzegovina acceded to this declaration in December 2008.

In May 2013, Montenegro and the other countries involved in the project signed a memorandum of understanding for support and cooperation on the realisation of the IAPP.

In September 2013, competent Ministers from Croatia, Albania, Bosnia and Herzegovina and Montenegro agreed on the steps to be taken for realisation of the project. Preliminary estimates show that construction expenses of the section in Montenegro would amount to approximately €100 million. The planned construction period is three to four years.

The official ground breaking ceremony of the construction of the IAPP was held in Baku on 20 September 2014.

Construction of second block of TPP Pljevlja

Under the EU Directive on Industrial Emissions which is binding on Montenegro based on its membership in the Energy Community, the block of TPP Pljevlja currently in operation is not running in accordance with the prescribed emissions' limits and, as a result, needs to be closed until 31 December 2022.

EPCG is planning the construction of the second block of TPP Pljevlja. The new block is planned to have the capacity in the range of 200–300MW. The energy efficiency of the new block shall be at least 38% and the project shall also provide the heat supply to the municipality of Pljevlja. The new block is to be built in accordance with the high environmental protection standards.

The tender for the construction of the second block of TPP Pljevlja closed on 31 October 2014. At the time of writing four companies are considered as potential partners in this project: Škoda Praha (Czech Republic), Powerchina Hubei Electric Power Survey & Design Institute (China), Istroenergo Group IEG Slovakia-SES Tlmace (Slovakia) and China Machinery Engineering Corporation (CMEC) (China). The announcement regarding the best ranking bidder is expected by the end of 2014.

Small hydropower plants (SHPP)

As a result of the public tenders announced in 2013 the following companies were awarded with concession contracts:

- consortium "Plava Hydro Power" (Peć, Kosovo) for construction of two SHPPs on the Djurička river;
- company "Hidroenergija Montenegro" d.o.o. (Berane, Montenegro) for construction of one SHPP on the Kaludarska river;
- consortium "Interenergo" (Ljubljana, Slovenia) for construction of two SHPPs on the Vrbnica watercourse;
- consortium "Hydro Bistrica" (Podgorica, Montenegro) for construction of one SHPP on the Bistrica watercourse; and
- consortium "Kutska i Mojanska" (Podgorica, Montenegro) for construction of one SHPP on the Kutska river and three SHPPs on the Mojanska river.

The contracts provide for the construction of ten SHPPs with a total capacity of 23MW and an annual production of 86GWh. The total investment for these SHPPs is estimated at approximately €50 million.

Undersea power transmission link between Italy and Montenegro

In 2010, Crnogorski elektroprenosni sistem ("CGES"), the Montenegrin TSO, entered into an agreement with Italian company Terna S.p.A. on laying a high-voltage underwater cable under the Adriatic Sea that will connect the coasts of the two countries. The cable will run 390km under the sea and an additional 25km onshore. It will stretch from the initial point in the Italian city of Pescara on one side to the Montenegrin town of Tivat on the other side. The capacity of the cable is planned to be 1000MW. The construction should last for four years and the cable is expected to be completed and operational by 2018.

The tenders for parts of the works on the project were held in 2014. CGES concluded the agreement on the construction of power station Lastva with Siemens (Austria) and construction of 400kV Lastva-Cevo transmission line with Iberdrola (Spain). Energoinvest (Bosnia and Herzegovina) was awarded the contract for the construction of 400kV Cevo-Pljevlja transmission line.

The entire project is worth approximately €750 million. It is expected that the interconnection project will generate an annual income of around €40 million.

According to the information provided by the Ministry of Economy, CGES and Terna have further joint investment plans to construct 400kV transmission lines from Montenegro to Serbia and/or Bosnia and Herzegovina. This would create a grid ring across Montenegro that would optimise the Montenegrin transmission system.

After its completion, the interconnection will give south-eastern European countries access to the Italian energy market.

Wind Projects

Development of the following two wind power projects is underway:

- WPP Možura, with an installed capacity of 46MW and planned yearly production of approximately 100GWh, a project to be realised by the Spanish company Fersa Energias Renovables and Montenegrin company Čelebić d.o.o; and
- WPP Krnovo, with an installed capacity of 72MW and planned yearly production of approximately 160GWh, a project to be realised by the consortium of the Austrian Ivicom Consulting and the French Akuo Energy.

These will be the first wind power plants in Montenegro.

The investors applied for the construction permit for WPP Možura on 30 June 2014, while the construction permit for WPP Krnovo was issued in May 2014. Currently the investors are negotiating the conditions of participation in the financing of the Krnovo project with the European Bank for Reconstruction and Development.

MARKET LIBERALISATION

Currently all energy consumers, except households, may choose their electricity supplier. In accordance with the obligations that Montenegro has undertaken with respect to the membership in the Energy Community, the households are to be granted the right to choose their supplier from 1 January 2015.

FINANCIAL CRISIS IMPACT

In July 2013 the Commercial court in Podgorica commenced bankruptcy proceedings against the Aluminum Combine Podgorica ("KAP"), the major aluminium producer in Montenegro and one of the biggest single electricity consumers in Montenegro. The total debts of KAP reached approx. €380 million. In June 2014 Montenegrin company Uniprom purchased the business of KAP through an asset deal in the bankruptcy proceedings. However, due to the high production costs and unstable aluminium prices, maintenance of previous production levels is currently uncertain.

NEW COMPETITION AUTHORITY AND REGIONAL COOPERATION

In 2012 Montenegro adopted the new Competition Protection Act, which implemented a number of legal solutions in order to fulfil the EU standards. Establishment of the Montenegrin Competition Protection Agency ("Competition Agency") as an independent body[1] for the creation of conditions for progress and development of free-market competition and security of conditions for free conduct of business, was one of the key requests of the European Commission during the EU accession process.

The Competition Agency has rendered two decisions (in 2011 and 2012) against Jugopetrol a.d. Kotor, one of the major players on the Montenegrin oil and gas market, for abuse of the dominant position on the oil products storage market on the territory of the Bar harbour.

The Competition Agency has signed the cooperation agreements with the Secretariat of the Energy Community and competition authorities of Bulgaria and Austria. It is planned that such cooperation agreements will be also signed with the relevant competition authorities of Croatia and Serbia.

RECENT MERGERS AND ACQUISITIONS AND THEIR IMPACT ON THE MARKET

There have not been any recent mergers or acquisitions in the Montenegrin energy market. However, the Government of Montenegro in its Strategy of the Development of Energy Sector in Montenegro for the period up to 2030 ("Strategy") prescribes the merger of Thermal Power Plant ("TPP") Pljevlja, with the capacity of 218.5MW with Coal Mine Pljevlja as the best strategic solution for both entities. The merger is intended to occur in light of the planned construction of a new block of TPP Pljevlja, which would require doubling the Coal Mine's capacity. Currently, TPP Pljevlja is in the ownership of EPCG whereas the State owns a 31% stake in the Coal Mine Pljevlja.

PROCEEDINGS LAUNCHED

At the moment Montenegro is not a member of the European Union, but remains firm on the accession path. The European Commission Montenegro Progress Report for 2014 provides, *inter alia*, that the progress in the energy sector remains moderately advanced.

On 20 January 2011, the Secretariat of the Energy Community ("Secretariat") sent an opening letter to Montenegro in Case ECS-5/11. The case concerns the lack of the TSO's participation in a common coordinated congestion management method and procedure for the allocation of capacity to the market, according to the obligations pursuant to the Decision by the Ministerial Council of 2008.

In March 2014, the transmission system operators of Albania, Bosnia and Herzegovina, Croatia, Greece, Montenegro, Kosovo and Turkey established a Coordinated Auction Office which started operating on 27 November 2014.

On 11 February 2014, the Secretariat sent an opening letter to Montenegro, for failure to comply with Energy Community rules related to renewable energy. In the opening letter, the Secretariat addresses the failure of Montenegro to adopt and submit to the Secretariat a National Renewable Energy Action Plan. The deadline for submission expired on 30 June 2013.

NEW ENERGY ACT

The current Energy Act was enacted in 2010. Montenegro, as a member of the Energy Community is obliged to implement the Third Energy Package. To comply fully with this obligation, the Ministry of Economy of Montenegro has prepared a draft of the new Energy Act. The public debate on the new Energy Act lasted from 4 August to 15 September 2014. The Ministry received over 350 comments from the key players in the Montenegrin energy market. The draft was also delivered to the Secretariat of the Energy Community, who also provided number of comments and suggestions. At the moment the Ministry is in the process of considering and implementing the comments received.

The new Energy Act is planned to be adopted in the first quarter of 2015. One of the announced novelties would be the interim status of "preferential energy producer" for the producers of renewable energy. Such status can be granted from the moment the construction permit is issued for a maximum period of two years. It allows the energy producer, when it obtains the preferential energy producer status (after the use permit), to choose the feed-in tariff valid at the moment of granting either the interim preferential energy producer or preferential energy producer status. In this way the producers would have the guarantee that the same tariff would be applied both at the moment of commencement and completion of construction works. It may also choose a more favourable tariff, in case the tariff has been changed upward (although, this is not likely) in the meantime.

The Government of Montenegro has adopted a new Energy Strategy in July 2014, which provides the framework for development of energy sector up to 2030, as described above.

ACTIONS OF THE REGULATOR

The Regulatory Energy Agency of Montenegro ("REA") was established in 2004. The regulation shall be performed on a non-discriminatory and transparent basis in accordance with the relevant EU directives. Recently, the REA has revoked the licenses from Eco Gas d.o.o. Podgorica (the sale and transportation of oil products licence and the gas and oil transportation by road licence) and MGS Energy d.o.o. Podgorica (sale and supply of liquid petroleum gas licence) because of infringements of the energy regulations.

ENDNOTE

1. Under the previous Competition Protection Act, competition protection was monitored by a competent body within the Montenegrin Ministry of Economy.

ENERGY LAW IN THE NETHERLANDS

Recent developments in the Dutch energy market

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In this chapter, an outline is given of the most significant developments in the energy sector in the Netherlands. The Dutch energy market can be characterised as a mature market. The power and gas markets are fully liberalised and the Netherlands has a tradition of implementing European directives to a maximum extent. It has also adopted a forward pro-active approach when the energy market was liberalised. When the Third Energy Package was adopted by the European Union, most of the regulatory requirements contained therein were already covered by national legislation.

In terms of market organisation, an important difference between the Netherlands and most other European countries is that the unbundling regime is applied beyond transmission system operators (TSOs) only. The unbundling regime also applies to the distribution system operators (DSOs) beyond the scope of the Third Energy Package. The unbundling requirements for regional network companies have been the subject of fierce opposition by the incumbent integrated energy companies. Two of these companies, Eneco and Delta, remain horizontally integrated and have commenced legal proceedings against the unbundling requirement. Supreme Court judgment was expected on 9 January 2015.

Another specific aspect of market organisation in the Dutch energy sector is found in the gas market structure, where the Dutch State participates in the sector as legislator but also as a party to various agreements with Shell and ExxonMobil, as shareholders of the largest producer in the Netherlands (NAM). Additionally, the Dutch State is the sole shareholder of the gas TSO, GTS and the "state participant" (EBN) which, pursuant to the Dutch Mining Act holds a 40%[1] stake in all gas production, and holds 50% of the shares in GasTerra, the largest gas supplier in the Netherlands.

The abundant (but declining)[2] indigenous gas production, sophisticated and elaborate gas infrastructure and the ambition to be the gas roundabout of Europe have shaped the Dutch gas sector. Gas proceeds for the Dutch State are considerable and currently amount to approximately €13 billion per year (between 5% and 10% of the total state income of the Netherlands). This has an influence on Dutch gas market policies. The most obvious influence may very well be the relatively conservative approach of the Dutch government towards the promotion of renewable energy production, especially compared to our neighbour country Germany. Another example of this can be found by the fact that gas proceeds were very significantly weighed and considered when the government decided to limit production from the Groningen field, because it causes an increasing risk of large earthquakes.[3]

In the past fifteen years the most significant changes in the power and gas sectors were caused by the transposition of new (European) legislation (liberalisation of the power and gas markets, unbundling, implementation of greenhouse gas emission trading and the subsidies for renewable energy production) into national laws. This has transformed the European energy market from a regional monopolistic market model to an open integrated market model. The integration of the energy markets in the EU is not perfect or completed by any means, but new legislation will not have the same transformative effect on the market as the first three European energy directives.[4] For instance, the European Network Codes that are being developed with ancillary EU regulations are not expected to have a major impact on the energy sector in The Netherlands.

A perfect storm

In the wake of the financial crisis that occurred in 2008, Western Europe was hit by the worst economic recession since the Second World War. Around 2010, a steep increase of domestic gas production in the USA from unconventional sources became apparent and has often been referred to as the "shale gas revolution".

The power sector was particularly affected by these circumstances. Shale gas developments in the USA created additional domestic demand for gas, especially in the power generation section, at the expense of coal, which was then re-exported towards other markets, including Europe. The resulting oversupply of cheap coal on the Western European market combined with relatively high gas prices changed the economics of gas versus coal in the power sector. The situation was aggravated by the fall of the CO_2 price in the European Union emission's trading system.

Around 2007, many newly built power generation projects were initiated, which created a situation of overcapacity, when the economic recession led to a big drop in the demand for power and gas. At the same time, wholesale power prices are low and a surge of intermittent renewable energy sources promoted by elaborate subsidy schemes continues to displace coal and gas fired power generation. This put large pressure on the profitability of conventional power production and many gas fired power plants in the Netherlands are shut down frequently because of their inability to recoup running costs.

The difficult market circumstances could explain why the level of M&A in the Dutch energy sector is low. Significant acquisitions or divestments in the Dutch energy sector are not expected, although there have been rumours about a possible partial privatisation of the 100% State owned TSOs for gas (GTS) and power (TenneT). Furthermore, the two remaining publicly owned energy companies in the Netherlands, Eneco and Delta, have made public statements that talks about a possible merger between the two companies were aborted. Many projects (gas fired power plants, a new nuclear facility and several underground gas storage projects) have been cancelled in the last years.

What policies are the Netherlands adopting to address the situation?

The Dutch government is doing very little to help power producers cope with the changed circumstances. In some other European countries, a system of capacity payments for conventional power generation has been implemented or is seriously considered. This is not likely for the Netherlands in view of the political bias of most political parties towards renewable power generation.

In respect of its natural gas policies, the Dutch government originally focussed on the disposal of its considerable gas reserves and the optimal usage thereof. In a letter of 7 October 2014, the Minister addressed that security of supply is now high on the agenda as a result of gas production related earthquakes in the Netherlands, discussions on shale gas, high gas prices and the role of gas in the transition to a renewable supply of energy. Additionally, the recent developments in Ukraine and the increasing European dependence on Russian gas supplies, justifies a shift of focus towards security of supply.

In respect of climate change and energy policies, the Dutch government has recently stated that its goal is to achieve a fully renewable supply of energy by 2050. The Energy Agreement concluded in 2013 between the government and a variety of companies and non-governmental organisations plays a key role in the envisaged transition (see below).

These two broad policies are the basis for many recent regulatory developments and initiatives, which we cannot address all within the context of this article. Below we will consider the Supreme Court decision on unbundling regime, the recent climate changes policy and the Energy Agreement and other regulatory development.

UNBUNDLING REGIME IN THE NETHERLANDS

In the Dutch energy sector, the unbundling requirements imposed on integrated energy companies by the Independent Grid Management Act (*Wet onafhankelijk Netbeheer*), also referred to as the Unbundling Act (*Splitsingswet*), has been subject of debate for some years now. The debate in particular concerns the group prohibition (*groepsverbod*), which entered into force on 1 January 2011.[5]

Pursuant to this group prohibition, the operators of gas and electricity transmission and distribution networks are not permitted to be part of a corporate group[6] which is also active in production, supply and/or trade of gas or electricity (and vice versa), nor may there be any shareholders connections between companies that are active in production, supply and trade activities on the one hand, and the operation of the transmission and distribution networks on the other.

The group prohibition is similar to the most far reaching unbundling regime under the Third Energy Package, ie, the full ownership unbundling model. However, contrary to the unbundling regime under the Third Energy Package, which only applies at transmission level, the group prohibition also applies at the regional distribution level. Therefore, both TSOs and DSOs are bound by the group prohibition.

Three Dutch vertically integrated energy companies started proceedings against the Dutch State. In their opinion, the group prohibition is in conflict with (*inter alia*) the free movement of capital (article 63 of the Treaty on the Functioning of the European Union (the "Treaty"), because it would (*inter alia*) restrict the possibilities for cross-border investments, and article 1 paragraph 1 of the First Protocol with the European Convention for the Protection of Human Rights and Fundamental Freedoms ("ECHR"), which protects ownership rights.

Their claim was initially rejected[7] but, on appeal, the High Court (*Gerechtshof*) ruled that the group prohibition ndeed constitutes a restriction of the free movement of capital for network operators and foreign investors.[8] The dispute was finally submitted to the Dutch Supreme Court (*Hoge Raad*), who referred the matter to the Court of Justice of the European Union ("CJEU") for a preliminary ruling.[9] The CJEU agreed with the High Court on the matter that the *Splitsingswet* constitutes a restriction of the free movement of capital.[10] However, it also ruled that such restriction may be allowed by overriding reasons in the public interest. The CJEU stated that it is for the referring court to determine whether the restrictions are appropriate to the objectives pursued and do not go beyond what is necessary to attain those objectives.

On 3 October 2014, the Advocate General at the Dutch Supreme Court (*advocaat-generaal bij de Hoge Raad*) ("AG") delivered his opinion on the matter.[11] He advised the Dutch Supreme Court to set aside the decision of the High Court.[12] However, the AG also concluded that the High Court did not get around to assessing a claimed breach of article 1 paragraph 1 of the First Protocol with the ECHR. This caveat of the AG is expected to result in a referral by the Dutch Supreme Court back to the High Court for handling the open issue. The Dutch Supreme Court is expected to decide on the matter on 9 January 2015.

DUTCH CLIMATE AND ENERGY POLICY

Climate Agenda

On 4 October 2013, the Dutch Ministry of Infrastructure and the Environment presented a policy document on climate change, the 'Climate Agenda: resilient, prosperous and green' ("Climate Agenda"). The Climate Agenda set outs the opportunities and risks of climate change for the Netherlands and proposed measures to be taken at national, European and global level up to 2030.[13]

The Climate Agenda focuses on three main themes: (i) working together both on a national and international level to successfully approach climate change, (ii) adaptation to climate change in order to prepare society for the unavoidable consequences of climate change, and (iii) mitigation of climate change by reducing greenhouse gas emissions.[14]

On the State Opening of Parliament (*Prinsjesdag*) which took place on 16 September 2014, the Delta Decision Spatial Adaptation (*Deltabeslissing Ruimtelijke Adaptatie*) (the "Delta Decision") was presented. The Delta Decision is part of the Delta Programme 2015.[15] The aim of the Delta Programme is to ensure that the water safety and freshwater supply are sustainable and robust by 2050, so that the Netherlands will be better equipped to withstand weather extremes. In the Delta Decision Spatial Adaptation proposals have been made for making the spatial design of the Netherlands more 'water robust'.

On 9 October 2014, over 90 parties, amongst which included the government, a variety of companies, civil society organisations and knowledge and educational institutions, signed an letter of intent in which they have confirmed to form a 'coalition of the willing' for making the Dutch urban area in 2050 better equipped to deal with the consequences of heat, drought, excess water and flooding.[16] As a first step towards achieving this ambition, knowledge and experiences are shared.

Dutch Energy Agreement

The Dutch 'polder model', a consensus-driven and bottom up decision making process, shows to be one of the preferred manners to reach (high impact) decisions that relate to the Dutch energy and climate policy.

On 6 September 2013, the Energy Agreement for Sustainable Growth (*Energieakkoord voor duurzame groei*) (the "Energy Agreement") was concluded between over 40 parties, amongst which included a variety of companies, various representative organisations, such as employers' associations and unions, nature conservative and environmental organisations and other civil-society organisations, financial institutions and the (local) government(s). The Energy Agreement fits perfectly within the first and third theme of the Climate Agenda (working together and mitigation of climate change).

The parties to the Energy Agreement have agreed to strive to achieve the following objectives:

- a saving in final energy consumption averaging 1.5% annually;
- a 100 petajoule saving in the final energy consumption by 2020;
- an increase in the proportion of energy generated from renewable sources to 14% in 2020 and a further increase to 16% in 2023; and
- creation of at least 15,0000 full-time jobs.

The Energy Agreement comprises 10 basic components, all aimed at achieving the above mentioned objectives. The components are (i) saving energy in the built environment and increasing energy efficiency in industry, agriculture and the rest of the commercial sector; (ii) scaling up renewable energy generation, such as wind power, and various types of local energy general such as solar energy, and the use of biomass; (iii) increase decentralised generation of renewable energy by people themselves and by cooperative initiatives; (iv) making the energy transmission network ready for a sustainable future; (v) a properly functioning EU Emissions Trading System (through lobbying in Brussels); (vi) minimisation of capacity of coal-fired power stations (closing of coal-fired power stations from the 1980s); (vii) increase transport efficiency and make mobility more sustainable; (viii) increase of employment opportunities in the installation and construction sectors and in the longer term in the renewable energy sector; (ix) increase energy innovation and energy export; and (x) introduction of funding programmes for the investments needed for the transitions envisaged in the Energy Agreement.

One of the components of the Energy Agreement, the agreement on closing down coal fired power plants from the 1980s, has come under pressure as a result of an informal opinion issued by the Dutch Authority Consumer and Market (*Autoriteit Consument en Markt*) ("ACM") in this respect.[17] In its analysis of the planned agreement on closing down the coal fired power plants, the ACM concludes that the proposed agreement is likely to fall within the scope of section 6, paragraph 1 of the Dutch Competition Act (*Mededingingswet*) and article 101, paragraph 1, of the Treaty; ie it constitutes a violation of the cartel prohibition. According to the ACM, a private agreement to withdraw production capacity from the market constitutes a restriction of competition. If undertakings mutually coordinate their behaviour, which has been done through the Energy Agreement, thereby restricting competition, their actions constitute, in principle, a violation of the cartel prohibition. However, if enough benefits are associated such an agreement, it may be exempted from the prohibition. The ACM explained that the assessment as to whether the Energy Agreement qualifies for the statutory exemption should address the question whether the restriction of competition resulting from the agreement is objectively speaking necessary to realise the associated desired benefits, and whether those benefits sufficiently compensate buyers, who will be paying a higher electricity price because of the restriction of competition.[18] In the controversial[19] view of the ACM, the benefits of the agreement insufficiently compensate the higher price the Dutch electricity buyers will be paying.

Although the ACM's view gave rise to strong criticism, the ACM has not changed its initial analysis, and, if the Energy Agreement would be executed at this point, the ACM would have to undertake actions against it.

The discussion regarding this part of the Energy Agreement has notended yet. The parties to the Energy Agreement still intend to close down the power plants and are trying to find ways to make this happen, without violating the competition laws. However, at this moment, it is still unclear what will happen to this part of the Energy Agreement.

The execution of the agreements made in the Energy Agreement has started. In accordance with the Energy Agreement, the effects will be shown through the national energy review, which sets out the state of Dutch energy management and is conducted by the independent energy research centre, called ECN. The first national energy review was presented on 7 October 2014.[20] The national energy review 2014 describes the developments since the year 2000 and expectations for the further developments up to 2030.

From the national energy review, it appears that certain goals for renewable energy and energy savings as agreed in the Energy Agreement will not be achieved. Based on the current, already determined, and proposed measures (of which the latter includes many of the measures to be taken under the Energy Agreement), it is expected that in 2020, the share of renewable energy will be 12.4%, which is below the goal set on European level for the Netherlands. In 2023, it is expected to be between 13.1% and 15.9%. The goal set in the Energy Agreement for 2023, 16%, will therefore be difficult to achieve. With respect to energy savings, it is expected that in 2020, the savings rate will be 1.2% (average) per annum. The goal set in the Energy Agreement of a saving of 1000 petajoule in 2020, will not be achieved based on the current and proposed measures.

The results from the national energy review put pressure on the Energy Agreement. The responsible Minister of Economic Affairs stressed that it would be too early to conclude that the agreed goals will not be achieved and that the Netherlands are on track.

OTHER SIGNIFICANT DEVELOPMENTS

Heat Act

The Heat Act (*Warmtewet*) is one of the scarce laws that have been initiated and drawn up by the Dutch Lower House of Parliament (*Tweede Kamer der Staten-Generaal*). This perhaps explains why it has taken more than 10 years before the act has entered into effect since it was first proposed on 17 September 2003.[21] On 1 January 2014, the Heat Act entered into effect after many amendments in the legislative process. This puts an end to uncertainty about the regulatory framework for heat supply, which housing corporations, project developers, municipalities and other involved parties faced when structuring large and small heating projects (eg, district heating, central block heating, aquifer heating, etc). Various amendments are still foreseen but the main elements of the regulations stand.

The Heat Act applies to the supply of heat to small end users. The production of heat and supply to large (industrial) end users remains largely unregulated. The Heat Act provides protection to end users without alternative heating options, who are connected to a specific heating infrastructure (eg, district heating, aquifer heating, central block heating). The Heat Act contains, amongst others, tariff regulations (including maximum tariffs based on the principle that end users without alternative heating options do not pay more for heat than for conventional gas heating), licence requirements for the supply of heat and emergency procedures to safeguard the continuous supply of heat.

Legislative proposal for an offshore wind power act

In order to scale up offshore wind farm development, a legislative proposal for a new offshore wind power act was published on 16 October 2014[22] to implement the obligation in the Energy Agreement to provide for a robust legal framework for the development of wind farms at sea. The act provides for a new concession system that introduces a so-called plot decision (*kavelbesluit*). A permit will only be granted if the construction and exploitation of the relevant wind park can be commenced within four years after receipt of the permit. Another important improvement will be that the permit procedure is linked to the decision for granting subsidies under the SDE+ regulation, which is not linked in the current regulatory regime. Also of importance is the contemplated decision to make the TSO the designated offshore grid operator with a mandatory task to provide for an offshore grid and connection of wind farm.[23] Pursuant to the Energy Agreement, the legislative framework for offshore wind parks has to be in place by 1 January 2015. A legislative proposal has been presented to parliament on 16 October 2014 and the current expectation is that it will be adopted in the course of 2015.

Regulation of gas quality

As of 1 October 2014, the Dutch Gas Act provides that gas injected into a gas transport network or is made available by the TSOs or DSOs to the end user must meet the quality requirements laid down in the ministerial regulation regarding gas quality (*Regeling gaskwaliteit*).[24] In this ministerial regulation, several quality requirements for high calorific gas and low calorific gas are prescribed, for both injection and delivery.[25] Pursuant to the Dutch Gas Act, the TSOs and DSOs are required to refuse gas for injection into the gas transport network if it does not meet the gas quality requirements laid down in the ministerial regulation.[26] In addition, the TSO is required to treat and mix the gas that is injected into the national grid in order to ensure that the gas being made available at the exit points, meets the prescribed quality requirements.[27]

The obligation of the TSOs and DSOs to refuse gas that does not meet the prescribed quality requirements does not apply in respect of the gas produced from the Dutch small fields.[28] Consequently, the TSOs and DSOs will still be generally required to accept this gas for entry into the national grid, irrespective of the quality of such gas.

The regulation of gas quality has become more and more difficult as a result of the various upstream (future) developments, such as:

- the reduction in the production of high calorific gas from the Dutch small gas fields;
- the future reduction in the production of low calorific gas from the Groningen gas fields;
- the expected increase in the demand for gas from other countries; and
- the production of renewable gases, such as green gas.

The new provisions in the Dutch Gas Act and relating ministerial regulation regarding gas quality have been introduced in order to attribute and share responsibility for the composition of gas between the different parties that play a role in the transportation of gas (ie injectors, TSOs and DSOs and end users). Injectors are responsible for the composition of the gas when it is injected and the TSOs and DSOs are responsible for the composition of the gas when it is delivered to end users.

ENDNOTES

1. Under the old mining regulations, the mandatory participation of EBN was 50% and therefore production licenses granted under that old mining regulations are subject to 50% participation by EBN. This higher participation has been respected for existing licenses when the new Mining Act came into force in 2001. For this reason, some active production licenses are still subject to 50% participation by EBN.

2. Although there may be a substantial shale gas potential in the Netherlands and the state has not put a moratorium on shale gas development (as happened in France), shale gas development is not expected to be successful in a very densely populated country with stringent environmental and spatial planning regulations, especially since public opposition is strong after the earthquakes in Groningen.

3. In 2012, an earthquake of 3.6 on the Richter Scale occurred in the Province of Groningen. Other smaller earthquakes have occurred since and are connected with gas production of the Groningen Field. This caused great public concern, over 12,000 damage claims and was the subject of many emotional debates. The government has extensively researched the implications for the State budget if gas proceeds would decrease as a result of restricting production from the Groningen Field. Long term gas supply obligations of GasTerra were also explicitly weighed in the decision making. It took almost until 17 January 2014 to decide on several measures, including 80% decrease of Loppersum production, up 10 bln m3 total Groningen production restriction over a 3 year period as of 2014 and measures aiming at damages repair, compensation and damage prevention.

4. Directive 96/92/EC and Directive 98/30/EC (First Electricity and Gas Directives) Directive 2003/54/EC and Directive 2003/55/EC (Second Electricity and Gas Directives) and Regulation No 713/09/EC and Regulation, No 714/09/EC(Third Gas Directive and Third Electricity Directive).

5. Article 10b of the Dutch Electricity Act and article 2c of the Dutch Gas Act.

6. It concerns the 'group' concept under article 2:24b of the Dutch Civil Code, which describes a group as an economic unit in which legal persons and partnerships are united in one organisation.

7. Court of The Hague 11 March 2009 (LJN: BH5468, BH5469 and BH 5470).

8. High Court of The Hague 22 June 2010 (LJN: BM8494, BM8495 and BM8496).

9. Supreme Court 24 February 2012 (LJN: BQ9210, BQ9212 and BQ9214).

10. Court of Justice of the European Union 22 October 2013 in the joined cases C-105/12, C-106/12 en C-107/12.

11. Supreme Court public prosecutor's office (*Parket bij de Hoge Raad*) 3 October 2014 (ECLI:NL:PHR:2014:180, 1801 and 1802.

12. The High Court ruled that the *Splitsingswet* restricted the free movement of capital for network operators and foreign investors. The AG points out that this restriction indeed is imposed by the *Splitsingswet*. However, the energy companies are not network operators or foreign investors. Therefore, they cannot demand that the group prohibition is declared non-binding for them based on a restriction of the free movement of capital. The energy companies also based their claim on article 1 paragraph 1 of the First Protocol with the ECHR.

13. http://www.government.nl/news/2013/10/04/climate-agenda-mitigation-adaptation-and-business-sense.html.

14. Climate agenda: resilient, prosperous and green, Ministry of Infrastructure and Environment, September 2014 and http://www.government.nl/documents-and-publications/reports/2014/09/24/climate-agenda-resilient-prosperous-and-green-summary.html.

15. Delta Programme 2015, Ministry of Infrastructure and Environment September 2014.

16. www.rijksoverheid.nl/onderwerpen/klimaatveradneringen/nieuws/2014/10/09.

17. Analyses by the ACM of the planned agreement on closing down coal power plants from the 1980s, www.acm.nl.

18. www.acm.nl/en/publications/publication/12194.

19. The ACM view has given rise to strong criticism from the parties to the Energy Agreement. Their criticism focused mainly on two points. Firstly, the ACM only took this particular element of the Energy Agreement into account, while it should have looked at the full Energy Agreement. Secondly, the benefits of the Energy Agreement, both environmental and other benefits, are much greater than what the ACM stated them to be in its analyses.

20. National energy review (Nationale Energieverkenning) 2014, Energieonderzoek Centrum Nederland (ECN), Petten 2014.

21. Proposal of parliamentary members Ten Hoopen and Hessel for regulating the supply of heat to small end users dated 17-9-2003, Parliamentary Papers 29 048, nr 1.

22. Proposal for a new offshore windpower act (*Wetsvoorstel windenergie op zee*), Parliamentary Papers 34 058, nr. 2.

23. This designation and expansion of mandatory tasks will be outlined in a change to the Electricity Act and Gas Act, as foreseen in the legislative programme called "STROOM" that aims to integrate both acts and provide for one comprehensive energy act.

24. Article 11 of the Dutch Gas Act.

25. Regulation from the Minister of Economic Affairs dated 11 July 2014 for the adoption of regulations regarding gas quality (*Regeling gaskwaliteit*).

26. Article 10, paragraph 3, sub d of the Dutch Gas Act.

27. Article 10a, paragraph 1, sub n of the Dutch Gas Act.

28. This follows from the wording of the new article Article 10, paragraph 3, sub d of the the Dutch Gas Act. In the explanatory notes to the ministerial regulation it was further stated in this respect that the quality requirements as set out in the ministerial regulation, do not aim to restrict the obligation of the TSO under the so called 'small field policy'. The 'small field policy' has been laid down in articles 53, 54a and 54b Dutch Gas Act.

ENERGY LAW IN NORWAY

Recent developments in the Norwegian energy market

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OIL AND GAS: COST FOCUS AND DWINDLING OIL PRICE HALT FIELD DEVELOPMENTS, TRIGGERS DISPUTES

2014 has seen a significant drop in the price of oil, from around US$115/bbl in July 2014, to below US$70/bbl in the beginning of December 2014. This has already affected the outlook on the Norwegian upstream sector, which for the last three years has lived with oil prices well above US$100/bbl. Over the last year Norwegian Continental Shelf ("NCS") oil companies, led by Statoil, have increased their focus on reducing costs. Cost cutting initiatives were taken even before the oil price started its steep decline, and the focus on costs has been reinforced ever since. Many of the current field development projects on the NCS have break-even prices of around US$85 – 90bbl, and several projects have already been halted and some have been put aside. The giant Johan Sverdrup field is a profitable exception with its estimated break-even price of US$35 – 40bbl, but most other discoveries on the NCS are technically challenging and require a sustained high oil price in order to be profitable.

With oil companies looking for ways to reduce their costs, oil services companies are experiencing harder times. Amongst others, Statoil have made efforts to reduce their rig lease commitments by suspending or terminating rig contracts, sometimes triggering disputes in doing so. The rig market is adapting to an expected lower spend on exploration in 2015, and several drilling rigs have already left the NCS. During 2014 many oil service companies have been forced to shift focus from growth to downsizing.

NEW OIL AND GAS DISCOVERIES

2014 has been a moderately successful year in terms of discoveries on the NCS. While several oil and gas discoveries have been made, few are considered commercially viable. As an exception, Lundin continued its impressive track record by the Alta discovery in the Barents region, which according to the company could hold as much as 310 million barrels of oil.

BARENTS HESITATION

The Barents region (the northernmost part of the NCS) is considered as the area holding the largest undiscovered reserves on the NCS. In recent years several discoveries have been made, a trend that continued in 2014 with Lundin's significant discovery in the Alta prospect. However, only a few of the oil discoveries in the Barents are currently considered as real candidates for development. In 2014, both the Goliat development project and the project to mature the Johan Castberg discovery into a field development experienced setbacks. Delivery of the Goliat platform has been delayed and the project is subject to significant cost overruns. Much has been expected of the Johan Castberg discovery; however, the project has a high break-even price and concept selection has been postponed as Statoil is struggling to prove that the project can become commercially viable. Another uncertainty holding the Barents area back is that most discoveries mainly contain gas, and none of the gas discoveries are large enough to justify new export facilities such as a liquefied natural gas terminal or a dry gas pipeline to connect to the existing pipeline network.

ELECTRICITY MARKET: LOW PRICES

Due to the fact that Norway is still a net exporter of electricity, electricity prices remain low and are not expected to increase significantly over the next coming years. This is partly due to energy efficiency measures and partly due to the introduction of medium to small scale renewables projects, which is a result of the support schemes, in particular the green certificate scheme. In its proposal for the national budget for 2015, the government proposed to increase the depreciation rates for wind power facilities, making the Norwegian fiscal regime more competitive towards the Swedish regime. It is expected that this will strengthen the current trend, and secure relatively low prices in the near to mid-term future.

RELEVANT CONSULTATIONS BY THE NATIONAL REGULATOR

The Ministry of Petroleum and Energy has received the report from an expert group which was, amongst others, mandated to: assess which tasks the Norwegian transmission grid should have on a long term basis; to propose models for an appropriate organisation of the grid; to describe which assumptions need to be fulfilled and which measures the authorities might apply to realise a well organised grid organisation; to propose harmonisation of the tariffs between grid companies; to assess whether it is possible to implement the suggested changes to the grid organisation by 2020; and to propose a strategy for a possible implementation. The report has been subject to a broad consultation process, in which some of the proposals were slated by the grid companies. The Ministry is currently reviewing industry feedback and is expected to propose necessary regulatory changes during 2015.

The Ministry of Petroleum and Energy has proposed to repeal the so-called competence regulation, requiring, amongst others, power producers to secure in-house employment of a certain number of employees possessing the required level of competence in operating and maintaining the integrity of a power production facility. The regulation will be replaced by general provisions in the Energy Act providing more flexibility for power producers with respect to the choice between in-house or hired resources.

With the aim of transposing the EU directive on geological storage of CO_2 into Norwegian legislation, the Ministry of Petroleum and Energy and the Ministry of Environment has concluded a publication process relating to two regulations addressing transport and storage of CO_2. It is expected that the new legislation will enter into force in early 2015.

CARBON CAPTURE AND STORAGE

The Norwegian government just recently launched its renewed carbon capture and storage ("CCS") strategy, based on three different pillars: R&D projects, demo projects and full-scale projects. The government is maintaining its ambitions to contribute to the establishment of a full scale CCS project by 2020, but has applied a softer approach in terms of the geographical location of the project, implying that it can be either abroad or in Norway.

The CO_2 Technology Centre at Mongstad (owned by the Norwegian state, Statoil ASA, A/S Norske Shell and Sasol) is continuing its operations, and has concluded a test agreement with Shell Cansolv aiming at testing Shell Cansolv's technology. Previously, agreements have been entered into for testing of Aker's and Alstom's technologies.

SIGNIFICANT OTHER INDUSTRY DEVELOPMENTS

Norway's only independent gas fired power plant was shut down and mothballed due to low electricity prices and high gas prices (spark spread).

The Ministry of Petroleum and Energy granted concessions to Statnett SF, to construct, build and operate two high voltage interconnectors between Norway and Germany, and between Norway and the UK.

Statnett is continuing its investment program aimed at strengthening grid connections in particular in the western part of Norway.

MERGERS AND ACQUISITIONS

Electricity

Finnish-owned power supplier Fortum sold its grid and district heating business for a total of €340m. The district heating business was purchased by iCON Infrastructure Partners whilst the grid business was taken over by Hafslund, the largest owner of local and regional grid assets in Norway. The transaction increased the number of Hafslund's grid customers to 675,000. Fortum continues its end-user sales business through Fortum Markets, which supplies around 100,000 customers in Norway.

Oil and gas

During 2014, several major mergers and acquisitions have been made, and the most important are the following:

- Coherent with its global efforts to reduce capex exposure, Statoil have sold participating interests in several significant fields on the NCS during 2014. It has reduced its participating interests in the Aasta Hansteen field and the Polarled pipeline (both under development), and has exited from the Gjøa and Vega fields (both in production). This follows the trend from 2013, when Statoil reduced its participating interests in the Gullfaks and Gudrun fields.
- RWE AG announced in March 2014 that they have sold their oil and gas upstream activities (RWE Dea AG) to L1 Energy. One of the main assets is RWE Dea Norge AS. The transaction was approved by the Norwegian authorities in June 2014. However, the transaction is not yet completed.
- Det norske oljeselskap ASA has acquired Marathon Oil Norge AS for a cash consideration of US$2.1 billion. The transaction was completed in October 2014. In 2013, combined production from the two companies amounted to approximately 84,000 barrels of oil per day, making Det norske oljeselskap ASA one of the largest listed independent E&P companies in Europe in terms of output. Following the integration, the company will have close to 400 employees.
- The Canadian oil company Talisman Energy announced in 2013 that they are interested in selling all their Norwegian assets in the North Sea. Talisman Energy Norway has participating interests in several producing fields, like Brage, Varg, Veslefrikk and Gyda and has about 500 employees. The process is still ongoing.

GASSLED TARIFFS

By an amendment to the Tariff Regulation in June 2013, the regulated tariffs for the use of the upstream gas pipeline network at the Norwegian continental shelf (owned by the Gassled joint venture) were reduced by 90%. The reduction applies for capacity reservations made after 1 July 2013 and for transportation after 1 October 2016. The decrease in the cost for transportation and processing of natural gas is considered to strengthen the incentives for exploration and development of marginal fields, and was made to promote resource management. The government was also of the opinion that the owners of Gassled have received reasonable profits on their investment. During 2010 and 2011 some financial investors became owners in Gassled, and such investors have filed writ to the courts claiming that the amendment to the Tariff Regulation is invalid. The claimants have indicated that their total loss as a result of the amendment to the Tariff Regulation is about 34 billion NOK. The court hearings are scheduled to take place in April/May 2015.

ENERGY LAW IN POLAND

Recent developments in the Polish energy market

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LATEST TRENDS IN THE POLISH ENERGY SECTOR

In recent years there have been a substantial number of changes to the Polish energy sector ie, electricity and natural gas markets. However, in some cases discussions are still taking place and some of the issues important to the sector remain unsolved. In this context, there are several significant trends in the Polish energy market, which can be identified.

The total installed capacity in the Polish power system in 2013 amounted to 38,406MW and increased by 0.9% compared to 2012. Annual electricity consumption in 2012 amounted to 157,980GWh, a rise of 0.6% compared to 2012. However, the matter of new generation capacity remains an issue. A significant part of Polish energy assets were built in the seventies and the eighties, and therefore, with the advent of more restrictive emission standards and GHG policies, will need to be replaced by new units. Officials and sector representatives argue that new, cleaner carbon technologies are to be developed in Poland. Notwithstanding the above, coal stands to remain the basic source of energy for the Polish power system. In 2013, power plants based on coal (both hard coal and lignite) produced 87% of electricity in Poland. According to the document "Polish Energy Policy until 2030" (see below) and statements of government representatives, coal is to remain the basis of energy security of the Polish power system. Accordingly, there are capital projects for coal-fired assets both in the planning pipeline and already at the stage of implementation. For instance, 2014 saw the start of the construction phase of two new 900MW generation units in the Opole power plant, which belongs to PGE. These two units are expected to become fully operational in 2018. A similar project (one 900MW unit) was launched in Jaworzno by Tauron. Moreover, the Kozienice power plant belonging to Enea has advanced with its generation project expected to add approximately 1000MW of new capacity. On the other hand, the Polish hard coal sector has been facing challenges recently. In general, these challenges are related to a rather low market price of coal, growing imports of cheap coal, especially from the East, and the unfinished coal sector restructuring process. In consequence, most of the biggest coal companies are running at a substantial loss. One of the ideas to deal with the financial problems of coal companies is to merge them with the biggest energy companies. However, this idea faces opposition from the energy sector. The discussion on how to cope with coal sector difficulties continues.

The installed capacity of renewable energy sources ("RES") has grown significantly in recent years. In the two years between 2011 and 2013, the total power output of RES (including wind farms) has doubled from 2,833MW in 2011 to 5,895MW in 2013. In this context, we note that RES projects (especially wind) accelerated last year in connection with the new support system proposed in the draft Renewable Energy Sources Act ("RES Bill"). The new scheme, which in contrast to the current green certificate system is to be based on auctions, raises many doubts, and most of the developers are striving to finish their projects before entry of the new law into force. Due to time constraints (the new law will enter into force on 1 January 2016) only advanced projects have a chance of reaching completion within that time. Therefore institutional interests tend to buy ready and built wind farms rather than those still in development. The proposed legal changes influence the activity of RES investors. Most wind development activity has been recently seen within the biggest energy groups: PGE, Energa, Tauron, Enea.

One can also note some activity in the area of nuclear energy. Preparations for construction of the first Polish nuclear power plant continue. On 28 January 2014, the National Nuclear Power Plant Development Programme (the "Programme") was finally adopted by the government. The Programme, drafted by the Ministry of Economy, sets out deadlines for building nuclear power plants and preparing the regulatory and operational environment, as well as the roles of institutions responsible for Programme implementation. The first power unit is to become operational by the end of 2024, and the first power plant is planned to be completed by the end of 2030, and the second by 2035. The total installed capacity of the two plants is expected to reach approximately 6000MW. A special-purpose vehicle for the power plant project was founded by PGE under the name PGE EJ1. On 3 September 2014, PGE signed an agreement selling a 30% equity interest in PGE EJ1 to major energy companies ENEA and Tauron and to KGHM, the copper company. The agreement requires all the parties to act jointly in order to finance the nuclear power plant project within the next three years. It is expected that the choice of strategic partner, technology and fuel suppliers will be made and the project will have financing secured during that time.

As for the power and gas grids, both the TSO for electricity and the TSO for gas continue to invest in infrastructure. Some projects have been finished, some are still underway. According to the power system development plan, the construction of approximately 3226km of new transportation lines is expected to be completed or commenced by 2018. As regards the gas transportation system, the plan is to build or upgrade approximately 800km of pipelines by 2018. The overall aim of these projects is to strengthen energy security. In the case of the power system, the main reasons include the advanced age of most transportation assets, the increasing quantity of power generated by wind farms, the growing energy demand and the continuing development of the common European energy market (the latter is especially related to construction of interconnectors). In the case of the gas transportation system, the primary expansion drivers are diversification of supplies, market integration and growing demand.

Energy Policies

The currently applicable rules of Polish energy policy are set out in the "Energy Policy of Poland until 2030" ("2030 Policy"), adopted on 10 November 2009 by the government and amended on 29 September 2010. The 2030 Policy determines the following aspects of energy policy: energy efficiency improvement, enhanced security of fuels and energy supplies, introduction of nuclear energy, development of renewables and development of competitive fuel and energy markets. The 2030 Policy sets an expected share of 2030 energy mix at "more than" 15% for RES and at "more than 10%" for nuclear. Coal will continue to be the main source of energy guaranteeing the energy security and the security of supplies for the energy sector.

According to the Polish Energy Law, an energy policy is to be developed every 4 years. A draft energy policy of Poland until 2050 ("2050 Policy") was presented in August 2014 and is currently subject to the public consultations process. The 2050 Policy adopts a sustainable growth scenario assuming that the 2050 energy mix is to be: at least 15% RES and 15% nuclear, with the dominant role of fossil fuels. Moreover, the 2050 Policy presents two potential alternative scenarios: the nuclear scenario (share of nuclear at 45% to 60%) and the "gas+RES" scenario which would mean a combined share of gas and RES at 50% to 55%.

To sum up, at its current stage of development, the 2050 Policy is more an identification of core issues in the Polish energy sector than a document setting out any specific targets to be achieved by 2050. The document is in its early version and it still being discussed.

Significant changes to the legal framework

As mentioned before, a lively debate is taking place in the context of the Renewable Energy Sources Bill ("RES Bill"). After a long period of processing in the parliamentary Committee for Energy and Energy Sources and inter-departmental consultations within the cabinet, the RES Bill passed its first reading in parliament in July 2014. However, this resulted in it being sent back to the committee. September 2014 saw the end of the public hearing process on the bill. Almost 130 persons representing commercial chambers, energy companies, various associations, agencies and offices decided to participate directly and many stakeholders sent in written comments. In addition, a huge number of comments by different kinds of entities had been received earlier at the stage of public consultation. The range of participation and issues that have been raised can give an idea of the extent of RES Bill debate. From the perspective of investors, the major concerns are that the green certificate system is to be replaced by an auction system where various renewable sources will compete for financial support (the lower the price for the energy produced by a particular renewable source, the greater the chances of financial support). As a result, some renewable technologies may turn out to be economically unviable in Poland. Now the system grants support for each relevant RES installation, therefore investors are sure they will obtain support. In contrast, under the new system they will have to compete with each other and financial support is not provided if they do not win the auction. A different legal regime is proposed for prosumers ie, those who produce energy for their needs in micro-sources (meaning installations with a capacity of up to 40kW and connected to a grid with a rated voltage of below 110kV, or renewable sources of heat with a total capacity of up to 120kW) and sell any surplus to the grid. In general, the RES Bill maintains the current support system for prosumers. According to this system, the production of energy in micro-sources is not considered a business activity, prosumers are exempted from connection fees and the retail utility sellers must buy this energy at a price which equals 80% of the average sales price of electricity on the competitive market in the prior calendar year. However, some stakeholders are not fully satisfied with the proposed system, especially with the provisions that set the price of the purchase obligation at 80% of the market price, as this, in their opinion, makes micro-source development unprofitable.

Lively discussion is also on-going in relation to the Hydrocarbon Bill which was published on 17 September 2014 and is at the stage of public consultations. Its purpose is to regulate the exploration and mining of hydrocarbons while streamlining the related administrative proceedings. Among the projected changes, the Hydrocarbon Bill is expected to shorten the permitting timescales and replace the consent requirement by the requirement to obtain non-binding opinions. These changes are mainly driven by the current situation with the exploration of shale gas in Poland. Despite the fact that the main focus of Polish debate is on fiscal matters now, the environmental security of this activity is also a significant topic. By the end of every year Poland is required to prepare a report for the European Commission referring to its recommendation on this activity.

Certain (especially foreign) investors have recently decided to abort exploration of shale gas in Poland and withdraw from their concessions. Many commentators argue that one of the main reasons was that test drills that did not fully live up to expectations; whilst legal uncertainty and past plans to impose new taxes on the shale gas business also played a part.

Poland continues to liberalise its natural gas market. The changes are intended to improve the competitiveness of the Polish gas market, which is currently dominated by PGNiG Group. This led to the introduction of an exchange obligation which prescribes that specific proportions of natural gas are to be traded on the Polish Power Exchange (40% as of 2014 and 55% as of 2015). However, in fact, the dominant gas seller, PGNiG S.A., would have difficulties finding entities willing to buy gas from it on the exchange and would face the risk of financial penalties for failure to fulfil its exchange obligation. As a consequence, PGNiG S.A. formed a new daughter company PGNiG Obrót Detaliczny ("PGNiG Retail") which as a legal successor of PGNiG S.A. has taken over its retail consumers portfolio. PGNiG Retail will buy natural gas on the power exchange from PGNiG S.A. and sell it to retail consumers. The legislator approved this idea and even supported it by amending the Polish Energy Law in a way which made it possible for one company to take over the end-users of another.

In relation to energy efficiency, the Ministry of Economy presented draft new legislation (Energy Efficiency Bill) in June 2014. The new legislation (which is to replace the old one which is in force until 2016) implements the Energy Efficiency Directive, which still has not been fully implemented into the Polish legal system. Among other things, the new law will maintain the white certificate system.

It is also worth noting that the parliament is working on a new law on landscape protection which may have an impact on wind farm siting. The proposed legislation refers to the European Landscape Convention, which has not been implemented in Poland yet.

Additionally, in October 2014 the Ministry of Economy published draft assumptions to an amendment to the Energy Law Act concerning the introduction of smart metering in Poland. According to the assumptions, by 31 December 2024 DSOs will have to install smart meters for at least 80% of end customers connected to an electricity grid with a voltage of up to 1kV. However, an end customer will have the right to request a DSO to install a smart meter earlier than that.

LEGAL ACTIVITIES

Recent implementation of EU law

The most recent significant amendment of the Polish Energy Law (26 July 2013) resulted from infringement procedures launched against Poland by the European Commission for failure to implement the Third Electricity Directive and the Third Gas Directive. After the amendment, the Commission withdrew the relevant proceedings. With respect to environmental issues, in September 2014 new, more restrictive air emissions regulations became effective, implementing the Industrial Emissions Directive ("IED"). In the context of the CCS legal framework, in November 2013 an amendment to the Polish Energy Law regarding CO_2 capture and storage came into force as a result of implementation of the CCS Directive.

Infringement proceedings by the European Commission

As a result of the 26 July 2013 amendments to the Polish Energy Law, the European Commission withdrew in autumn 2013 its complaint against Poland for failure to implement the New Electricity Directive and the New Gas Directive. However, there are still proceedings pending against Poland for failure to transpose two EU directives related to the energy sector, ie the Renewable Energy Directive and Directive 2010/31/EU on the energy performance of buildings (the "EPB Directive").

As to the first of those, a reasoned opinion was sent to Poland in March 2012, and in March 2013 the European Commission announced taking Poland to the Court of Justice of the European Union for failure to transpose. In the complaint, the Commission proposed a daily penalty of €133,228.80. Some commentators argue that amendments to the Polish Energy Law made on 26 July 2013 do not resolve the incompatibility of Polish law with the EU renewables rules, especially because they do not grant sufficient grid access priority to renewable sources. The implementation could be considered successful when the RES Act comes into force, but, as said, this process is in delay. In the spring of 2014, a representative of the Ministry of Economy announced that Poland is applying for the Commission to withdraw the case for non-transposition of the Renewable Energy Directive. The application would be based on the argument that transposition was achieved through the 26 July 2013 amendments to the Energy Law and through amendments to the Biofuels Act. However, at the time of writing, the case against Poland is still pending.

As regards the proceedings for failure to implement the EPB Directive, a reasoned opinion was sent to Poland in June 2013, and the proceedings against Poland were launched in July 2014. The proposed daily penalty amounts to €96,720. According to the Commission, Polish law continues to lack, *inter alia*, measures relating to energy certificates, minimum performance requirements and nearly-zero energy buildings. In August 2014, the parliament adopted the act on the energy performance of buildings which will come into force in March 2015 in order to ensure compliance.

Consultations and market monitoring by the national regulator

Topics related to smart grid and smart metering are one of the highest interests of the National Regulatory Authority ("NRA"). A recent consultation lead by the Polish NRA concerns the model technical specification for procurement of metering infrastructure for AMI systems. The model technical specification has been prepared and drafted under the auspices of the NRA in cooperation with DSOs, electricity retail companies and technology suppliers. Its purpose is to provide relevant technical and compatibility requirements for smart metering devices.

Other consultations by the Polish NRA have been carried out in the context of the development of the natural gas market. After finalisation of the public consultations on the exchange obligation and after the obligation was enacted into law, further consultations have recently been undertaken regarding the exemption of some of the gas companies from the obligation. The Polish Energy Law provides certain conditions (related to capacity of interconnectors) under which some categories of gas companies are exempt from the exchange obligation. The purpose of these consultations is to clarify:

- how interconnector capacity will be calculated; and
- to determine the categories of exempt entities on that basis.

In addition, relevant consultations with ACER, the European Commission and ENTSO-E have also been carried out by the Polish NRA recently.

The Polish NRA continues to monitor electricity and natural gas markets. The monitoring, as in previous years, focuses on the number of end-users that have switched their electricity/natural gas supplier (the so-called "TPA end-users"). The figures show a continuous increase in the number of electricity TPA end-users (approximately 340,000 by July 2014) and a slowly growing number of natural gas TPA end-users (approximately 700 by June 2014).

MARKET ISSUES

Recent mergers, acquisitions

One of the most significant mergers in the electricity market recently was the merger of Polenergia SRL and Polish Energy Partners S.A. The transaction, worth PLN 240 million, involved the formation of a new company, Polenergia S.A. ("Polenergia"), which issued new shares that were acquired by the Chinese investment fund CEE Equity Partners. The board of Polenergia has set ambitious goals ahead. The company's aim is to become a strong alternative for big energy groups and a leader in the renewable energy sector. By 2016 Polenergia's portfolio of onshore wind farms is to increase by 369MW. The company has declared that it will also continue offshore wind development in the Baltic Sea and a gas interconnector project with a capacity of 5 billion m^3.

As regards the bigger energy groups, PGE Group has shown an increased acquisition activity recently. PGE Energia Odnawialna ("PGE Renewables"), a PGE group company, continues expanding its renewables assets by buying wind companies or building its own plants. For instance, in September 2014 the company acquired wind farm assets with a total capacity of 60MW. The aggregate capacity of PGE Renewables' wind farms currently amounts to 311MW.

In nuclear energy, as mentioned, Enea, Tauron and KGHM acquired a 30% stake in PGE EJ1, the Polish nuclear company. The transaction was approved by the Polish competition authority.

Privatisation process

Recently there have not been any significant changes in respect of privatisation in the energy sector. Privatisation is projected for PKP Energetyka, an energy company belonging to the Polish railways company. PKP Energetyka is to be sold to a private investor, and an invitation to the share deal is expected to be published by the end of 2014. However, the state treasury still holds at least 50% stakes in the major energy groups: PGE, Enea, Energa. Certain privatisation attempts in the recent years were made in relation to Enea and Energa. As to Enea, the Ministry of the Treasury said the privatisation process is postponed until "the Kozienice power plant project [belonging to Enea] reaches an advanced stage". In the case of Energa, it was partly privatised by offering 34% of its shares to the public. The company debuted on the Warsaw Stock Exchange in late 2013. According to official documents of the Ministry of the Treasury, Energa and Enea are on the list of companies that may be "involved in privatisation". Therefore it is not impossible that these companies will go through further privatisation over the next few years. In contrast, PGE and Tauron were put on the list of "strategic companies", therefore in their case, the Ministry of the Treasury has made a plain decision to keep a controlling stake.

NEW PROJECTS & RECENT UPDATES

Significant new facilities

The construction of the first LNG terminal in Świnoujście continues. Due to certain complications regarding the construction companies, there have been some delays and the LNG facility is currently scheduled to become operational at the turn of 2015, with the first LNG supplies to be delivered in 2015. In autumn 2014, the first tests of LNG containers were completed, successfully according to the Polish LNG company. The terminal will initially enable the re-gasification of 5 billion m^3 of natural gas annually, which is about one third of the Polish natural gas annual demand. Further on, it will be possible to increase the dispatch capacity up to 7.5 billion m^3, if the demand for gas goes up.

Pilot mobile facilities for capturing and removing CO_2 from fumes were installed in two coal-fired power plants (Łaziska and Łagisza) respectively. Tauron representatives have stated that the first performance results are satisfactory, however, this technology is still at the research stage with commercial application merely in the plans. CCS technology development has been recently abandoned by PGE and Kędzierzyn Nitrogen Factory (Zakłady Azotowe Kedzierzyn ("ZAK")). Both projects were to cost billions of zlotys, for which EU funding and preferential loans have been secured. However, PGE and ZAK gave up on the projects and returned the money. The companies explained the problem lies not in the construction process itself, but in the cost of continuous capture, transportation and storage of gas. The latter would require detailed geological research and the building of long pipelines. Taking into account the current carbon allowance prices, the projects were found to be financially unviable.

Shale gas

A "shale gas boom" started in Poland in 2011, when the U.S. Energy Information Administration announced that Poland's shale gas resources can amount potentially to 5 trillion m^3. One year later, the Polish Geological Agency published a report that estimated the probable resources of shale gas in Poland to be in the range 346-768 billion m^3.

In the last few years, drills were made by American and Canadian shale gas companies and by Polish gas/petrol companies. However, the results are generally below expectations. Experts say that Polish shale formations are difficult to access, and are mostly of low or medium quality, which implies a higher cost of such operations. Some experts add that legal uncertainty plays a part, too. In effect, we can recently observe a tendency of abandoning the drills and exiting the Polish market, as happened in the case of several significant foreign players. Exploration works are being continued by PGNiG and Orlen (the biggest Polish petroleum company) and some of the foreign companies which decided to stay in Poland. Yet, the number of drills continues to be insufficient to assess the Polish shale gas resources properly. Moreover, a further slow-down in the drilling activity can be observed in recent months. As a result, most experts claim that the production of shale gas in Poland will not start as soon as expected, and it is difficult to predict when this production will reach commercial quantities.

ENERGY LAW IN PORTUGAL

Recent developments in the Portuguese energy market

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POLITICAL ENVIRONMENT IN PORTUGAL

Due to the international economic crisis and the adverse social consequences, Portugal has been experiencing a period of major political upheaval. This led to the election of a new government in June 2011(*XIX Governo Constitutional*), with the result that Portugal is now led by a coalition government made up of the PSD (*Partido Social Democrata*) and CDS-PP (*CDS – Partido Popular*) (both centre-right parties), led by Pedro Passos Coelho. The next election will take place in 2015 (*XX Governo Constitucional*).

Following Council Regulation (EU) 407/2010 of 11 May 2010, which established the European financial stabilisation mechanism, the Portuguese state, the European Commission, the European Central Bank (the "ECB") and the International Monetary Fund ("IMF") entered into the Memorandum of Understanding on Specific Economic Policy Conditionality (the "MoU") on 17 May 2011. The MoU details the internal economic policy conditions which must be satisfied in order for Portugal to be granted financial assistance by the ECB and IMF. The coalition government is bound to follow the recommendations and instructions set out in the MoU.

ENERGY MOU

With respect to the energy market and renewable electricity and gas markets the Portuguese government has taken measures costing in excess of €3.4 billion in order to achieve an elimination of tariff debt by 2020. Having taken these steps, the focus should now be on limiting energy price increases. To this end, in the eleventh update of the MoU concluded in March 2014, Portugal committed to presenting additional concrete measures to tackle remaining excess rents and to deliver cost reductions to be reflected in energy prices. Accordingly, the government has prepared a number of measures that will deliver cost reductions to be reflected in end user electricity prices (for low income earners), bottled and natural gas, and fuel. Most of these measures will be implemented in the next few months.

Following the identification by the government of the problem of distortion on the system services market, which was also highlighted in the reports of the relevant regulators, Portugal will implement measures in line with these reports to prevent the risk of overcompensation in the adjustment calculations (*revisibilidade*) of maintaining the contractual balance costs (*CMEC – Custos para a manutenção do equilíbrio contratual*) scheme, including an independent audit on risk of overcompensation and the amount of past overcompensations. Finally, the exceptional energy levy introduced in 2014 will also be maintained in 2015 and Portugal will continue to ensure that this is not passed on to end users.[1]

OBJECTIVES IN THE ENERGY MOU

The MoU aims to:

- Complete the liberalisation of the electricity and gas markets, following the adoption of the legal framework regarding the scope of competence of the logistics operator for switching suppliers, and implement the plan to create a new gas and electricity logistics operator independent company, as presented in the seventh review.
- Ensure the sustainability of the national electricity system and avoid further increases in the tariff debt.
- Ensure that the reduction of the energy dependence and the promotion of renewable energies is made in a way that limits the additional costs associated with the production of electricity under the ordinary and special (co-generation and renewables) regimes.
- Ensure consistency of the overall energy policy, by reviewing existing instruments.
- Continue to promote competition in energy markets and to further integrate the Iberian market for electricity and gas (MIBEL and MIBGAS respectively).
- Implement the measure to eliminate distortion on the system services market and present an estimation of the associated result in terms of cost reduction.
- Take the necessary action to ensure that the impact of the energy sector levy, in any circumstances, will not be passed on to end users.
- Following the report on the CMEC scheme and the process for the extension of the concession of the public hydro resource by the former Contracts for the Acquisition of Energy ("CAE") hydro power plants, analyse the potential for correcting measures.
- Take the necessary measures to comply with EU regulations and decisions.
- Accelerate convergence to market-based pricing for co-generation operators in parallel with electricity market developments under the EU internal electricity and gas market legislation. The remuneration scheme for co-generation will be further revised to improve efficiency of the support system in ensuring continued guaranteed access of operators to electricity networks and markets, with the calculation of explicit subsidies based on relevant price factors in the context of a competitive electricity market. The revision should ensure that the design of the support scheme allows a dynamic correlation between electricity market prices and the efficiency premium when the values of avoided externalities are not adequately reflected in electricity and other factor prices. This revision will be undertaken in line with the framework of the transposition of the Third Energy Package. Ensure through annual audits that plants not fulfilling the requirements for co-generation do not receive the support, and report on the progress.

- For new contracts in renewables, revise downward the feed-in tariffs and ensure that the tariffs do not over compensate producers for their additional costs as compared to market prices. Continue to provide an incentive to reduce costs further, through digressive tariffs, contributing to the sustainability of the national electricity system. The above mentioned revision must be implemented through the legal regulations that remain to be adopted under the framework of the transposition of the Third Energy Package. For more mature technologies, develop alternative mechanisms (such as feed-in premiums). Decisions on future investments in renewables, in particular in less mature technologies, will be based on a rigorous analysis in terms of their cost and consequences for energy prices. International benchmarks will be used for the analysis and an independent evaluation will be carried out. The use of cooperation mechanisms to finance future renewables investment shall be explored. A report on actions taken will be provided.[2]

PRIVATISATION PROGRAMME

The government continues to implement the privatisation programme under the new framework law for privatisation. The programme target of privatisation proceeds of about €5.5 billion was exceeded. The sale of GALP Energiaand the small remaining stake in REN (*Rede Eléctrica Nacional*) on the free market will be completed when market conditions improve.[3]

ENDNOTES

1. Source: http://www.portugal.gov.pt/media/1394876/11R_MEFP.pdf and http://www.portugal.gov.pt/media/1452387/LoI%2012R%20PT.pdf.
2. Source: http://www.portugal.gov.pt/media/1397626/11R_MoU_EU_20140424.pdf.
3. Source: http://www.portugal.gov.pt/media/1397626/11R_MoU_EU_20140424.pdf.

ENERGY LAW IN ROMANIA

Recent developments in the Romanian energy market

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GENERATION FACILITIES IN THE PIPELINE

To increase security of supply and aid system balancing, the Romanian government is undertaking two ambitious new generation projects that will provide power from nuclear and pumped hydro sources.

A project to build Units 3 and 4 at the Cernavoda nuclear power plant, adding 1,400MW of new capacity, was initiated in 2006. Following the exit of six international investors in 2010/2011, the government decided to set-up a new public/private joint venture to continue with the project. Following a public selection procedure, China General Nuclear Power Corporation was chosen as the private investor to participate in the venture, along with state-owned Nuclearelectrica SA, the current owner and operator of Units 1 and 2 at the Cernavoda nuclear power plant. At the time of writing, negotiation of the investment agreement is on-going. It is anticipated that the project will benefit from state support under a contracts-for-difference scheme being put in place in Romania for low-carbon power. The likelihood of Romania successfully securing state aid approval for the project has increased given that the European Commission has cleared Hinkley Point C nuclear power station in the UK receiving state support via a similar contracts-for-difference mechanism.

The Tarnita-Lapustesti pumped hydro storage station is expected to comprise four 250MW turbines and be located in north-west Romania. A special purpose vehicle, Hidro Tarnita SA, was set up in 2013 by Energy Complex Hunedoara SA and SAPE SA (the latter being a newly established company managing the Romanian state's participation in privatised energy companies). The aim is to involve other state-owned companies, such as Energy Complex Oltenia SA and Nuclearelectrica SA, in the project as well as private investors.

DIVESTMENT OF ENEL'S SUPPLY AND DISTRIBUTION BUSINESS

During a financial consolidation process, the Enel group announced in July 2014 that it intended to divest its Slovakian energy generation business, as well as certain assets in Romania, hoping to realise revenue of approximately €4.4 billion from the sales.

The Romanian assets consisted of equity stakes of 64.4% in each of Enel Distributie Muntenia and Enel Energie Muntenia, 51% in each of Enel Distributie Banat, Enel Distributie Dobrogea and Enel Energie, and 100% of the service company Enel Romania.

The stakes in the distribution and supply companies Electrica Banat and Electrica Dobrogea were acquired by Enel from the Romanian state in 2005. Electrica Muntenia Sud followed in 2008. The companies were subsequently unbundled, with the Romanian state and Proprietatea Fund retaining a minority interest in each company.

The sales attracted a lot of interest from the Romanian state, which appears to have participated in the non-binding offer phase through Nuclearelectrica SA and Electrica SA.

TAKE-OVER OF AGIP FILLING-STATIONS BY MOL

In September 2014, the European Commission cleared the acquisition by Hungarian oil and gas group MOL of 208 filling stations located in Romania, the Czech Republic and Slovakia from regional subsidiaries of Italian Eni.

In Romania, MOL saw its holding of stations increase from 147 to 189 following the addition of the 42 Agip stations. Eni had been present in the Romanian fuel distribution market since 1995.

PRIVATISATION

In November 2014, the Energy Department within the Romanian government called for expressions of interest in relation to the privatisation of Energy Complex Hunedoara SA.

A generator of thermal and electric power from pit coal, Energy Complex Hunedoara SA was created in 2012 following the merger of Electrocentrale Deva and Electrocentrale Paroseni and the subsequent absorption, in 2013, of Societatea Nationala a Huilei.

END OF INFRINGEMENT PROCEEDINGS

In October 2014, the European Commission decided to withdraw two claims against Romania for failing to transpose the New Electricity and Gas Directives. The infringement proceedings were commenced in September 2011.

STATE AID FOR ENERGY-INTENSIVE USERS

A 10 year exemption for certain energy-intensive users from the requirement to make financial contributions to the renewable support scheme entered into force on 1 December 2014 and is due to expire on 31 December 2024.

The Romanian renewable energy support scheme consists of a mandatory quota obligation combined with the trading of green certificates. The cost of purchasing green certificates is passed on to end consumers.

The exemption seeks to preserve the competitiveness of companies that are heavy users of power, exposed to international trade and have faced increased electricity bills as a result of the support being provided to promote renewable energy production. It has been found to be compliant with EU state aid rules, including the European Commission's new Energy and Environmental Aid Guidelines.

To benefit from the exemption, which allows energy-intensive users to avoid paying 40%, 60% or 85% of their renewable energy contributions, applicants have to demonstrate an electro-intensity of between 5% and 10%, 10% to 20%, or more than 20%, respectively.

In addition, energy-intensive users need to (i) show that they cannot record debts to the state budget; (ii) carry out energy audits and implement energy efficiency measures; (iii) undertake not to lay-off more than 25% of their employees and to maintain activities in the European Economic Area; and (iv) enter into partnerships with educational institutions to help develop a skilled workforce.

ENERGY LAW IN RUSSIA

Recent developments in the Russian energy sector

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OVERVIEW

As a result of the political situation in Ukraine, the European Union, the United States and certain other countries have imposed sanctions against Russia, including restrictions on lending to and involvement in dealings with new debt/securities issued by certain Russian entities as well as on exporting dealings in certain equipment used in the Russian oil industry. Despite the sanctions, the Russian government and oil and gas companies remain optimistic and are seeking new opportunities in alternative markets. To this end, Russia has started shifting its investment and trade towards Asia. The signing of an unprecedented 30-year, US$400 billion deal for Gazprom to deliver Russian gas to China after almost a decade of negotiations demonstrates this historic shift.

In response to the sanctions against it, Russia also intends to fully substitute imported equipment and technology (both in the upstream and in other areas) with Russian-produced alternatives. The goal of such a switch is to make Russian oil and gas companies and the industry in general less dependent on foreign goods and technologies.

Apart from these sanctions, the Russian oil and gas sector did not see any significant changes in 2014. Offshore projects continue to be dominated by state giants Gazprom and Rosneft and the attempts of major independent companies (eg, Lukoil) to introduce more competition have not yet been successful. Russian authorities have also implemented a major tax reform which entered into force on 1 January 2015. The reform involves a gradual increase to the mineral extraction tax (the "MET") rates on crude from 2015 – 2017 with a simultaneous decrease to both the export customs duty rates on crude and also the excise on oil products.

Likewise, there were no significant developments in the power sector during the past year. Market participants still consider the power sector to be less attractive for investment than might be hoped. However, the introduction of a new market model based on long-term contracts, announced by the authorities for 2015, has been delayed. The heating market also needs significant reform to become attractive to investors. Nevertheless, market participants are optimistic about the future of the power and heating industries.

A positive development for foreign investors in Russia is the on-going structural reform of the Russian Civil Code, which will result in the Russian civil legislation becoming more investor-friendly. One example of this is the amendments which have been introduced to provide for more flexibility in corporate governance.

OIL ANG GAS

Sanctions and their consequences

Both the EU and the US have introduced "sectoral sanctions" restricting access to capital markets for certain Russian entities. Sanctions targeting specific energy projects in Russia have also been introduced.

Russian oil companies, Rosneft, Transneft and Gazprom Neft, are expressly captured by the finance restrictions. For instance, EU persons are prohibited from, directly or indirectly, purchasing, selling, providing investment services for or assistance in the issuance of or otherwise dealing with transferable securities and money-market instruments with a maturity exceeding 30 days that are issued after 12 September 2014 by Rosneft, Transneft and Gazprom Neft, by their non-EU majority owned subsidiaries or by any entities acting on their behalf or at their direction. These companies are also subject to lending restrictions. Pursuant to these restrictions, and subject to certain exemptions, EU persons are prohibited from directly or indirectly making or being part of any arrangement to make new loans or credit with a maturity exceeding 30 days available to these entities. All of the restrictions apply not only to the named entities but also to their non-EU majority owned subsidiaries and to any entities acting on their behalf or at their direction.

In addition to the finance sanctions, the US and the EU have restricted the provision and exportation of goods, services or technology in support of exploration for or production of deepwater, Arctic offshore or shale oil projects in Russia.

However, it is debatable to what extent these restrictions will affect the Russian energy sector. According to the Russian Ministry of Energy, up to 24% of equipment used in oil and gas production is imported. For oil refining and petrochemicals, the figure is as high as 35%. Still other sectors, such as offshore drilling and LNG, are 100% dependent on imported equipment.

The Ministry of Energy is seeking to ensure that within 3 – 4 years, all imported equipment will be replaced with Russian-made substitutes.

According to the Minister of Natural Resources and Ecology, Sergey Donskoy, the Ministry is considering amending terms of licences that are burdensome to implement, as a means of helping companies operate in light of their restricted access to imported technology and equipment. The Ministry is already considering approximately 100 amendment applications.

Shift towards Asia

In May 2014, Russian Gazprom and Chinese CNPC (both state-owned gas companies) signed a 30-year contract in the presence of their countries' leaders for the supply of 38 billion cubic meters of Russian gas each year to China. The total price of the supplies reportedly exceeds US$400 billion. Starting from 2019, natural gas will be delivered to China from greenfield Eastern Siberian gas fields, Chayandinskoe and Kovyktinskoe, via a new major pipeline called the "Strength of Siberia". The 4,000 km gas pipeline will transport the gas from the Eastern Siberian fields through Vladivostok to China. Gazprom started construction on the pipeline in September 2014 and the overall cost of construction is estimated to be US$25 billion.

Moreover, in October 2014, a memorandum for the supply of gas from Western Siberia to China via the Altay gas pipeline was signed. A 30-year contract for supply of 30 billion cubic meters of Russian gas each year is expected to be signed at the beginning of 2015 with further increases of supplies up to 100 billion cubic meters.

Rosneft has also continued its cooperation with Chinese companies in relation to the development of certain offshore and onshore projects. It has been recently announced that CNPC intends to acquire 10% in Rosneft's subsidiary Vankorneft, which holds a licence for the development of the largest oil field to be brought on-stream within the last 25 years. This could be the second major investment of CNPC in Russian projects after the company acquired a 20% stake in the major Yamal LNG project developed jointly by Novatek and Total.

Offshore projects

Gazprom and Rosneft, which hold more than 110 licences in aggregate, are dominating Russian offshore projects. Though experts raise concerns about whether these state companies will be able to develop all of their licence blocks in spite of the sanctions against them, the government continues issuing licences to Gazprom and Rosneft without tender or auction. Indeed, four new licences were recently issued to them in the Barents, Laptev and Okhotsk seas.

Currently, Russian law provides that offshore fields are allowed to be developed only by Russian state-controlled companies with at least five years presence and experience in operation on the Russian continental shelf. Effectively, only a few Russian companies such as Gazprom, Rosneft, arguably Zarubezhneft and their selected subsidiaries, meet these criteria. Therefore, foreign investors seeking to participate in the development of offshore blocks are prevented from acquiring equity in the licence holder and must instead execute special contractual operatorship arrangements with the Russian state-owned companies. Amendments aimed at somewhat relaxing this position have long been discussed.

One proposed reform is to permit the subsidiaries of state-owned companies to hold offshore licences. Such an amendment would allow state-owned companies to transfer their licences to newly incorporated SPVs in which foreign investors could directly participate. Both Gazprom and Rosneft have supported this proposed reform as a means of encouraging participation by foreign investors in offshore upstream development.

LNG export liberalisation

As a result of amendments introduced at the end of 2013, Gazprom's legal monopoly on gas exports has been relaxed and two additional types of companies are now permitted to export LNG:

- those holding a subsoil licence requiring LNG plant construction as at 1 January 2013; and
- those state-owned companies and their subsidiaries which hold offshore licences and either produce LNG from relevant offshore fields or use gas extracted under production sharing agreements.

In 2014, the Russian Prime Minister, Dmitry Medvedev, signed the formal order required by law to implement these amendments by granting the right to export LNG to certain companies meeting the criteria specified above, namely: Rosneft, subsidiaries of Novatek including Yamal LNG, Gazprom, and one of Gazprom's subsidiaries.

In addition to these reforms, the state Duma is currently considering further liberalisation of LNG exports. In particular, the draft amendment under consideration would extend LNG export authorisation to those companies which hold subsoil licences requiring LNG plant construction as at 1 July 2014 (as opposed to 1 January 2013). The amendments, if approved, would grant the right to export LNG to the Pechora LNG project, which Rosneft is reportedly expected to purchase a share in.

Lukoil had also proposed amendments to allow LNG exports by all companies holding a subsoil licence requiring LNG plant construction, irrespective of the date by which those licences required construction. However, this initiative was not approved by the authorities.

Decommissioning funds

A proposal to establish decommissioning funds is being actively discussed. If the proposal is adopted, Russian subsoil users may be required to create special funds from which decommissioning works will be financed. The procedure for the collection of funds for the financing of decommissioning works would be established by the government. However, the draft law stipulates that a corporate guarantee in certain cases may substitute for the payment of decommissioning funds.

Tax developments

As part of the on-going reform of the tax regime applicable to oil and gas companies, Russia introduced the following major changes to its tax legislation:

- A new specific tax regime for oil and gas projects on the Russian continental shelf. The new regime grants the offshore projects certain incentives relating to the MET profits tax, property tax and export duty;
- A tax reform as of 1 January 2015, which contemplates a gradual increase to MET rates on crude from 2015 – 2017 with a simultaneous decrease to both the export customs duty rates for crude and also to the excise on oil products. It should be noted that the general rule is that MET is payable by all companies extracting crude while export customs duties are paid only by exporters;

- New rules for MET on natural gas and gas condensate. The new formula for calculating MET is aimed at establishing fairer (market-oriented) tax rates for the gas industry. The formula takes into account export and domestic prices for natural gas and crude, applicable export customs duty rates for natural gas and crude, the level of complexity of minerals extraction at a specific field and the geographical location of the respective block, amongst other elements;
- MET incentives for producers of difficult-to-recover oil; and
- An increase in the excise for petrol and diesel fuel.

Most of the changes were introduced in 2013 and entered into force on 1 January 2014.

POWER AND RENEWABLES

New market model in the power market

The power sector remains high-risk due to the uncertainty of the current market model which cannot guarantee a predictable return on investment. The authorities seem to be aware of the issue and in 2013 announced plans to modify the existing market model. Reportedly, the proposed market model provides for power to be traded under direct long-term (up to 20 years) agreements between generators and consumers. The model was expected to enter into force in 2015. However, despite the hopes of the market participants, there have not been any developments in this area yet.

New HPPs to be constructed in collaboration with Chinese counterparties

It has been announced that RusHydro, one of the largest Russian energy companies, intends to attract at least RUB370 billion (approximately US$8 billion) through joint ventures ("JVs") with Chinese counterparties for construction of a number of hydroelectric power plants ("HPPs") in the Russian Far East. The relevant agreements for establishment of JVs with Chinese Sanxia and PowerChina have been signed recently. Part of the electricity generated by these HPPs will be exported to China.

Renewable energy developments

Historically, the renewable energy market in Russia has remained less developed whilst the country's focus has been on conventional energy sources. Despite this, the market has seen increased interest this year. Russia became part of International Renewable Energy Agency and Russia has started more active exploitation of renewable energy sources (especially geothermal energy in the southern regions of the country).

In September 2014, the Russian President launched the Kosh-Agach solar power plant. Kosh-Agach is the first solar power plant in Russia with a capacity of 5 megawatts. It is also the first power plant launched which benefits from recent amendments that introduce a long-awaited mechanism incentivising the use of renewable energy sources.

ENERGY LAW IN SERBIA

Recent developments in the Serbian energy market

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ENERGY SECTOR REFORMS

In 2014 the efforts of Serbia to reform its energy sector and to bring it in line with the Third Energy Package have continued at a faster pace.

However, the progress has not been uniform and has mostly related to the electricity sector while gas sector reforms lagged behind especially in terms of reforming the heavily-indebted state-owned integrated gas company, Srbijagas.

ELECTRICITY SECTOR DEVELOPMENTS

Market Liberalisation

Serbia is currently in the final stage of the electricity market liberalisation process.

The Energy Act from 2011 has provided for a three-phase market liberalisation process:

First phase

As of 1 January 2013, every end customer connected to the transmission system, which accounted for 9.5% of total consumption, had the right to be supplied by the public supplier Elektroprivreda Srbije ("EPS") at regulated tariffs.

Nonetheless, out of 27 large industrial consumers, only one, the German "Messer" plant, has opted to change its supplier.

Second phase

This phase has become effective as of January 2014. In this second phase only the households and small commercial customers kept the right to be supplied by the public supplier (EPS) at regulated tariffs.

In other words, customers who have:

(i) at least one place of delivery at medium voltage (voltage level below 1kV), and

(ii) all delivery places on the low voltage (0.4kV), if they have more than 50 employees or total annual revenue of more than €10 million,

no longer have the right to be supplied by the public supplier and are from now on supplied on the open market. As of June 2014, 300 customers connected to the distribution system and two large customers connected to the transmission system had opted to change their supplier.

Third phase

As the last phase in the liberalisation process, households and small commercial consumers will be able to freely choose their supplier as of 1 January 2015. However, no significant engagement of other suppliers is expected, given that currently EPS supplies these customers pursuant to prices below market value.

In order to benefit truly from the competition in the electricity sector, Serbia will need to put further efforts in price deregulation.

Generation

In general, electricity generation from local sources in Serbia is capable of meeting the domestic electricity demand. To that extent, it is recorded by the Energy Agency that the total net import of electricity in 2013 was 2,152GWh whereas the total net export amounted to 4,475GWh. The predominant use of coal explains this relatively low import dependency and also relatively high CO_2 emission.

Generation from hydro power plants amounts to approximately 30%, while generation from thermal power plants ("TPPs") amounts to approximately 70% of the total electricity generated in Serbia. In 2013, power plants in Serbia had generated electricity in the total amount of 37,537GWh[1], out of which 70.3% was produced in TPPs, 28.4% in hydro power plants, 1.1% in thermo-heating power plants and 0.2% in other small, mostly hydro power plants.

Serbia is under an obligation to close part of its thermal capacities pursuant to the EU Directive on the Large Combustion Plants ("LCP Directive"). The deadline for this has been extended from 2017 to 2023 by the Ministerial Council of the Energy Community. Serbia has to shut-down all power blocks of less than 300MW which are not subject to the projects of mitigation of emissions of hazardous substances. In other words, the total capacity to be closed until 2023 amounts to approximately 1,100MW.

Trading

Approximately 80 market players engage in wholesale electricity trading, including EPS, the public enterprise engaged in electricity generation, distribution and supply services, which was, until 1 January 2015, the only entity holding a licence to supply consumer tariffs (ie households and small consumers). Other licensed traders are active mainly in resale and cross-border trade, while only six of them are currently supplying final consumers.

The reason for such a low participation rate in the supply segment of electricity market is that the electricity prices in Serbia remain traditionally low for social policy reasons. Consequently, prices in Serbia are 30-40% lower than electricity prices in south east Europe.

Unbundling

The Public Enterprise Elektromreže Srbije (EMS), the Serbian TSO (also licensed as the electricity market operator), is the only legally unbundled entity. The remaining electricity sector in Serbia is organised and operated under the umbrella of EPS.

Modernisation of the Distribution Network

As of November 2014, Serbia has joined the paths of the USA, Italy, Canada, Sweden and Denmark in application of the modern equipment and solutions regarding the management of the electricity distribution network. In this respect, EPS has signed a letter of intent with "Schneider Electric", a European multinational corporation specialised in energy management, with an ultimate aim of reducing the losses on the distribution grid, which are estimated at 14.9% of the total electricity produced in 2013, and enhancing its reliability.

Forming a Power Exchange

The announced formation of the South East European Power Exchange (SEEPEX), expected to commence in the second half of 2015, will present a significant push towards receiving benefits from a true competitive market.

EMS (Serbian TSO), as one of the founders, has announced that SEEPEX will be based on the price market coupling model and the spot trading principle, which will enhance its capacity and productivity. Further, SEEPEX will increase the transparency of the energy market, gradually reduce electricity prices and, most importantly, it will attract new investors to construct new generation and transmission capacities.

In May 2014, EMS found a strategic partner in European exchange "EPEX SPOT" that will assist in the financial aspect of SEEPEX's functioning. EPEX SPOT now holds a minority 25% stake in SEEPEX. It is expected that after the adoption of the necessary legal acts (pursuant to the new Energy Act), SEEPEX will become fully operational in the third quarter of 2015.

GAS SECTOR

State-owned integrated company Srbijagas is the key player in the Serbian gas market. Serbiagas supplies all retail suppliers in Serbia with gas at an identical wholesale price. Srbijagas obtains all its gas from the Gazprom Neft. The only entry gas entry point in Serbia is at the Hungarian border. The only natural gas producer in Serbia is NIS, the Serbian national oil company which is majority owned by Gazprom Neft.

Srbijagas is licensed for gas transmission, distribution and supply, as well as being the supplier of last resort.

With respect to gas-market liberalisation, as of 1 January 2015 the right to be supplied by the public supplier pursuant to prescribed tariffs will only be granted to households and small consumers.

NEW CAPACITIES

Completed Projects (small hydro and PV)

Serbia has significant energy potential from renewable energy sources which is estimated to be over 4.3 million tonnes of oil equivalent ("TOE") annually of which 2.7 million toe per annum lies in the production of biomass, 0.6 million toe per annum in potential hydro-energy, 0.2 million toe per annum in existing geothermal sources, 0.2 million toe in wind power and 0.6 million toe per annum in solar. The utilisation of the available sources of renewable energy is one of the top priorities set out in the Serbian Energy Strategy.

According to the Renewable Energy Directive the national target for the share of renewable energy sources ("RES") in gross final energy consumption in Serbia for 2020 is 27%, out of which, 22% was achieved by 2014. Although the general climate in Serbia vis-à-vis RES investments is positive, up until now the only significant investments have been in small hydropower plants ("SHPP"). To that extent, the Serbian Government has launched a tender for the construction of the SHPPs on 143 different locations, for which over 400 investors have applied. Currently, the hydro energy potential in Serbia amounts to approximately 7,000GWh, whereas more than a quarter of that lies in the SHPPs of up to 10MW.

Currently, there are 44 SHPPs with the total power of 33.2MW that have the privileged producer status and are availing of the feed-in tariffs.

In addition to the SHPPs, one noteworthy RES project would be a 2MW solar power plant commissioned in November 2014. This is the biggest solar project in Serbia to date.

Stagnation in Wind Projects

The investments in the wind projects have stagnated for a number of years. At the heart of the problem lie permit issues and issues relating to the offtake agreement. Furthermore, there is an overall cap of 500MW for all wind-park capacity in Serbia which may benefit from feed-in tariffs. Given the cap, the investors need to be able to secure the use of feed-in tariffs at an early stage of the project (ie before significant costs are incurred).

It is expected that the new Energy Act, planned to be enacted by the end of 2014, will overcome these difficulties and resolve currently existing bankability issues.

2014 FLOODS

In May 2014 Serbia suffered disastrous floods and landslides that, *inter alia*, caused substantial damage and losses to electricity generation activities, social services and infrastructure. The estimated total damage amounts to €1.7 billion, out of which, 32% was suffered by the energy/mining sector of approximately €500 million.[2]

Overflowing water from Kolubara River and its tributaries have flooded the open-pit mines Tamnava Zapad, Veliki Crljeni, as well as fields B and D in the Kolubara coal basin. Overall, these open-pit mines amount to about two thirds of the coal produced in the country. By June, fields B and D were recovered, whereas Tamnava Zapad and Veliki Crljeni, in which volume of the water amounted to 200 million m^3, are still in the recovery process.

LAW ENFORCEMENT ACTIVITIES BY COMPETITION AUTHORITY

During 2014, the Serbian Commission for Protection of Competition ("Commission") did not initiate any proceedings in the energy market. However, it has continued the activities of reporting and conducting inquiries in oil and oil derivatives market (the latest report was published in December 2013). Although the Commission has not yet identified any infringements of competition law, in April 2014, it has reviewed the coal sales process conducted by subsidiaries of EPS, ie RB "Kolubara" d.o.o.

Lazarevac and "Termoelektrane i Kopovi" Kostolac d.o.o. that took place during 2010-2013.

In the information published on its website, the Commission has identified eight key characteristics that indicate potential limitations of competition, and that consequently may lead to infringements of competition law. Those characteristics relate to, *inter alia*, rigid application criteria that are to a great extent based on the previous cooperation with the seller. The Commission has expressed concerns that such mechanisms develop into the formation of the "favoured purchasers circle". Further, the coal sales process priority has been given to the state entities, irrespective of the number of points collected based on the criteria for participation, thus resulting in the discrimination toward the private purchasers. Lastly, the mechanism of coal selling, on the market where demand exceeds the offered quantities, facilitates attainment of the "extra profit" in the resale process, ie the Commission believes that direct purchasers and later their customers are setting the unreasonably high resale prices with unreasonably high margins.

For the said concerns, the Commission announced that it will proceed with monitoring activities of RB "Kolubara" d.o.o. Lazarevac and "Termoelektrane i Kopovi" Kostolac d.o.o., so that any potential restrictive behaviour may be prevented. So far, no measures have been taken in this respect.

PRIVATISATION

The Serbian government has announced that it intends to seek a strategic partner for EPS during 2015. The privatisation model would be based on the sale of a minority stake and a potential transfer of management rights to the strategic partner. The government has not yet decided on the terms and conditions for the tender procedure.

The announced model resembles the one undertaken in privatisation of Montenegrin electric integrated utility in 2009. The state of Montenegro transferred a minority stake and management rights to Italian investor A2A S.p.A.

INFRINGEMENTS OF THE INTERNATIONAL COMMITMENTS

Non-participation of EMS in Regionally Coordinated Capacity Allocation

By not adopting the common coordinated congestion management method and procedure for the allocation of capacity to the market, EMS is not participating in the regionally coordinated capacity allocation mechanism, and thus Serbia is currently in breach of Article 3 of the Regulation (EC) 1228/2003. In this respect, a concern has been expressed that such behaviour prevents the forward trading rules and that it contradicts the obligations undertaken by entering into the Energy Community Treaty and general EU trading criteria.

Consequently, the Energy Community Secretariat has ordered EMS to submit by the end of July 2014 a roadmap with concrete actions and timelines for participation in any regional body performing long-term capacity allocations, in order to achieve a forward trading mechanism by December 2014. Although EMS has submitted the roadmap, the Energy Community Secretariat was not satisfied with the level of detail.

If Serbia does not meet the said requirements on allocation of the capacity by December 2014, there is a reasonable chance that the Energy Community Commission will open the infringement proceedings.

Non-Compliance with Sulphur in Fuels Directive

In 2013, Serbia was accused that it hadn't yet transposed and implemented the requirements set forth by Directive 1999/32/EC and Annex II of the Energy Community Treaty, with regards to the aim of reducing the emissions of sulphur due to combustion of heavy fuel oils and gas oils. In this respect, the Energy Community Secretariat has issued an opening letter and is currently preparing a reasoned opinion against Serbia in Case ECS-4/13.

No Unbundling in Gas Sector

After the failure to remedy the breaches with respect to the two vertically integrated gas undertakings, ie Srbijagas and Yugorosgaz that do not comply with the unbundling requirements, Serbia has been found to be in the breach of the Second Energy Package as well as the Energy Community Treaty in 2014. The decision of Ministerial Council in this respect is expected.

SOUTH STREAM

History and Suspension of Development

Gas consumption in Serbia amounts to approximately 2.5 billion m^3/a, the majority of which is imported from Russia, whereas the local production satisfies approximately 15% of the total gas demand.

In 2009, Serbia and Russian Federation signed an international bilateral agreement, regulating the following three ventures: (i) sale of 51% stake in NIS (Serbian integrated oil company) to the Russian conglomerate Gazprom Neft; (ii) formation of large gas storage capacity in the north of Serbia ie, Banatski dvor and lastly, (iii) the construction of the South Stream gas pipeline that will *inter alia* pass through Serbia.

To date, NIS has been sold to Gazprom Neft and the gas storage Banatski dvor has been constructed.

The South Stream gas pipeline is a project for construction of the gas pipeline for the transport of the Russian natural gas under the Black Sea to Bulgaria and on to Greece, Italy and Austria, passing through, *inter alia*, Serbia. The total estimated value of the South Stream project exceeded €20 billion pursuant to the newest estimates, whereas the value for the 400km of the pipeline's section that is envisaged to pass through Serbia was estimated at €2.1 billion.

The project is of great significance for Serbia mainly because (i) the estimated annual income of Serbia from the gas transit is €250 million, (ii) the project provides gas-supply security, (iii) it would attract the new investments in the sector and (iv) the works on the project would engage approximately 25,000 employees and a significant number of local companies. Up to now, Serbia has invested approximately €30 million in the South Stream project.

However, after the European Commission has reviewed the bilateral agreements signed between Russia on the one side and Bulgaria, Serbia, Hungary, Greece, Slovenia, Croatia and Austria on the other side, it has pushed for suspension of implementation on the basis of a breach of the EU law (unbundling issues). Many signatory countries have suspended the works on the project and EU has required further renegotiation and amendments to the agreements so as to make them compliant with EU law.

Simultaneously, Bulgaria has blocked the construction works on the part of the pipeline on the Black Sea. Thereafter, at the beginning of December 2014, Russian Federation announced the cancellation of the project.

Alternative

An alternative for Serbia with regards to gas security would be the Trans Adriatic Pipeline ("TAP"), ie the approximately 870km long gas pipeline that connects Greece, Albania and Italy, and secures gas from Azerbaijan. Consequently, the Ministry of Energy has announced that the works on the gas pipeline Niš-Dimitrovgrad, the necessary link for accessing TAP, will be accelerated. This link would also enhance the possibility that Serbia has the potential to connect to the recently announced Russia-Turkey gas pipeline.

NEW LEGISLATIVE DEVELOPMENTS

New Energy Act

With regards to the EU energy rules, Serbia has not yet streamlined its energy rules with the Third Energy Package. This is intended to be accomplished with the new Energy Act planned to be adopted in December 2014 or the beginning of 2015.

The novelties introduced by the new Energy Act will facilitate planned investments in the trans-Balkan energy corridor, which is a condition for forming the new high-voltage transmission network for transport of electricity from Eastern European Countries to Italy.

The new Energy Act is also expected to resolve bankability issues with respect to larger RES projects.

New Energy Strategy

At the beginning of 2014, the former Serbian Government has adopted a draft of the new Energy Strategy of the Republic of Serbia until 2025, with projections until 2030. The adoption of the Strategy was postponed after the parliamentary elections held at the beginning of 2014.

The new Strategy is expected to be adopted at the beginning of 2015, after the adoption of the new Energy Act.

Pursuant to the existing draft of the new Strategy, Serbia shall invest approximately €9 billion in the development of the electricity sector until 2030 (€5.3 billion until 2020).

ENDNOTES

1. Data obtained from the Serbian Energy Agency.
2. Pursuant to a report from the World Bank.

ENERGY LAW IN THE SLOVAK REPUBLIC

Recent developments in the Slovak energy market

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SLOVENSKÉ ELEKTRÁRNE

Slovenské elektrárne, a.s. ("SE") is the largest electricity producer in the Slovak Republic. The company operates two nuclear power plants, two thermal (fossil) and biomass power plants, two photovoltaic power plants and 34 hydroelectric power plants. The total installed capacity of the power plants owned or operated by SE, as of 31 December 2013, was 5,739MW. The shareholders of the company are the Italian company Enel (66%) and the Slovak state (through the National Property Fund) (34%).

In July 2014, the management of Enel decided to sell its share in SE (in a bidding procedure) in order to decrease the debt of the group. The following companies are rumoured to be bidders:

- EPH (which already owns majority share in SPP, another major Slovak energy company, and also a majority share in the electricity distribution and supply company Stredoslovenská energetika, a.s., as well as in NAFTA a.s.);
- ČEZ (a Czech energy giant with activities mainly in Central and Eastern Europe and having the Czech state as majority shareholder);
- SLOVNAFT, a.s. (a Slovak company active mainly in oil refinery and a part of Hungarian MOL group) together with Hungarian company MVM (company active in electricity production, trade and transmission and also natural gas trade and storage services);
- Rosatom (a Russian nuclear power company (although it is rumoured that Enel is reluctant to sell to purchasers from Russia));
- a potential Chinese investor (rumours being that it could be the Chinese state nuclear company, CNNC); and potentially
- the Slovak state.

The last option (ie the sale to the Slovak state) seems unlikely to materialise due to the need for consolidation of public expenses of the Slovak Republic although the Slovak Minister of Economy has expressed an opinion that the Slovak state should at least try to increase its shareholding to 51% from the current 34%). There are also market rumours that the Slovak government prefers ČEZ as the new shareholder.

However, the on-going construction of the new units 3 and 4 of the Mochovce Power Plant (with planned installed capacities of 471MW each) is a major hurdle for Enel with respect to the sale of the SE shareholding. This construction was started in 2008 with planned introduction into operation in 2012; that was later repeatedly postponed, and the current plans are looking to the end of 2016. Also, the expected investment costs increased multiple times, currently being at the amount of €3.8 billion. In this context, EPH and ČEZ as bidders have made statements that due to necessary investments in the completion of the construction of the new Mochovce units, and also due to the very low current prices of electricity on international markets, the price tag for the shareholding of Enel in SE is zero or even negative. Therefore, it is possible that the nuclear power projects will be carved out from SE in order to enable Enel to sell its shareholding. The management of Enel has also noted that if they do not find a suitable bidder, they will simply not sell the shareholding. In addition, in December 2014 the Slovak state terminated its lease agreement with SE, on the basis of which SE had leased the biggest water energy facility in Slovakia (Gabcikovo).

In the beginning of 2015, the management of Enel expressed a wish to sell the SE shareholding until the end of June 2015 for amount of around €4 billion. According to publicly available information, ENEL received four preliminary bids by December 2014.

NAFTA

The Czech group EPH was also active in another acquisition in the Slovak gas sector, through the acquisition of a 40.45% share in the gas storage operator NAFTA a.s. from the German company E.ON in December 2013. Other shareholders of NAFTA a.s. are SPP Infrastructure, a.s. with a 56.15% share (with 1.91% being held by small shareholders and 1.49% being treasury shares). NAFTA is a leader in natural gas storage in Slovakia (with a market share of around 78%) and, at the same time, in the exploration and production of hydrocarbons. The storage capacity of natural gas underground facilities operated by NAFTA a.s. is currently 2.4 billion m^3. EPH is also an indirect shareholder in NAFTA a.s. through its 56.15% shareholding in SPP (a Slovak dominant vertically integrated gas company). Following the sale of shares in NAFTA a.s., E.ON remains active in Slovakia only in the electricity sector, holding a stake in the electricity distribution and supply group Západoslovenská energetika, a.s.

PPC

Another acquisition in the Slovak energy sector was connected with the PPC group, which is an operator of the two combined cycle gas turbine facilities in Bratislava, with an installed capacity of 218MW and 58MW, producing electricity as well as heat. The former indirect shareholder of PPC, belonging to the Penta investment group, has sold its shareholding to members of the Istroenergo group. Until this acquisition, the Istroenergo group has been active in the construction of energy facilities but not in the operation of them. PPC also has activities in the Czech Republic.

RENEWABLE ENERGY LEGISLATION AND DEVELOPMENT IN THE SLOVAK ENERGY SECTOR

New energy policy

In Slovakia electricity from renewable energy sources ("RES") is promoted through a support scheme, in which the main support mechanism is a fixed feed-in tariff. The feed-in tariff is guaranteed for a term of 15 years from the year in which the electricity facility was put into operation or the year of its reconstruction or upgrade. To begin with, the feed-in tariffs were set quite high and this generous support scheme was the main reason for the fast development of many RES projects in 2010 and 2011, especially in the solar sector. The government feared that such fast development would lead to an unstable electricity grid and high costs for consumers and therefore in July 2011, support for solar and wind projects was effectively terminated (or at least significantly decreased).

Currently, the government, as well as the relevant state authorities and system operators, are more willing to promote RES such as biomass and biofuels than solar and wind power. This is due to the perception of solar and wind energy being sources with a high fluctuation of electricity generation.

This is in line with the new energy policy, which was elaborated by the Ministry of Economy of the Slovak Republic (the ministry responsible for the energy sector) and which was approved by the Slovak government at the end of 2014. The new energy policy is the main official energy policy document setting out the aims of the state energy policy until 2035. Under the new energy policy, the RES target for Slovakia for 2020 (ie a 14% share) should be achieved mainly by heat production and not by generation of electricity, support of which should gradually be lowered and electricity generation from the solar facilities, with installed capacity above 10kW, should not be supported at all. The energy policy envisages mainly the use of biomass and water as RES. The energy policy also focuses on the use of biomass and biogas which is produced in Slovakia, rather than artificially imported from other countries only for the purpose of energy production, following the principle that energy should be produced from sources originating in the country in which such energy will be consumed. The policy also envisages a theoretical possibility for new wind energy facilities, however, these must be first approved by the Slovak electricity TSO (Slovenská elektrizačná a prenosová sústava, a.s.), which is currently against such energy facilities.

G-tariff

In autumn 2013 the Slovak energy regulator (the Regulation Office for Network Industries ("RONI")) effectively further decreased the main support method for RES projects (ie the guaranteed feed-in tariff) through the introduction of a new special fee via secondary legislation. From January 2014, each generator of electricity has to pay a levy (the so-called "G-tariff" or "G-component") to the system operator for reserved capacity of its energy facilities within the transmission or distribution system. It is to be noted that all energy generators are subject to the G-tariff, and not only those generating electricity from RES sources.

In the case of a connection to the distribution network, this special levy amounts to approximately €16,000 to €21,000 (depending on the distribution system operator) per MW per year in 2014. This in turn means that the support for the RES projects introduced in operation in 2010 or 2011 was in fact decreased by approximately 5% through the introduction of this G-tariff. The amount of the G-tariff is separately set by RONI each year, which makes changes of this amount possible.

Since its introduction, the G-tariff has been subject to widespread criticism (and the European Commission has also expressed concerns) as it is argued that it is in fact a so called "solar tax", the purpose of which is to effectively lower governmental support for RES facilities. RONI in turn argues that this fee is reflects the the electricity generators' participation in the costs of development and maintenance of the electricity grid and that it does not target the RES facilities, since it is to be paid by electricity generators from conventional sources too.

Nevertheless, electricity generators, especially from solar projects, are making use of all available legal means to fight against this fee. The G-tariff was challenged at the level of RONI and is also subject to various litigation proceedings inter alia before the Slovak Constitutional Court. The latter challenge currently seems the most promising "defence mechanism" as it could lead to the abolishment of the G-tariff from legislation. The argumentation for challenging the G-tariff on the national level is based mainly on the breach of principle of legal certainty or legitimate reasonable expectations of the operators of the solar plants, and its contradiction with the energy policy of Slovakia, especially with feed-in tariff being guaranteed for 15 years.

Changes in the feed-in tariffs

As mentioned above, the main support mechanism for RES generators of electricity is the guaranteed feed-in tariff, which is determined in the year the electricity facility was put into operation or the year of its reconstruction or upgrade. Since 2010, the amount of the guaranteed feed-in tariff for new energy facilities has been gradually lowered, with major changes introduced and effective in July 2011 (ie, a significant decrease of the feed-in tariff and also introduction of significant limitations with respect to the projects eligible for feed-in tariff).

As of 1 January 2015, the feed-in tariff will be decreased again. For example, in the case of solar plants (which are currently eligible for a feed-in tariff only in case of a solar facility up to 30kW, located on the roof or walls of a building connected to the earth by a firm basement) the feed-in tariff will be lowered from €98.94 to €88.89 per MWh. In the case of wind facilities (construction of which has currently stopped in Slovakia anyway), the feed–in tariff was lowered from €70.30 to €62.49 per MWh.

Market coupling in CEE electricity markets

Since September 2012, the Slovak, Czech and Hungarian electricity transmission operators have been operating an interconnection project of the three national markets through the daily organised markets. The cross border transmission capacity necessary for electricity transmission from one national market to another is allocated in the form of a daily implicit auction.

In addition to these three countries, there are plans to also include Poland and Romania into market coupling. In October 2014 it was announced that market coupling with Romania is almost completely finished. The accession of Poland to market coupling is envisaged in the next phase, as a part of Central East Europe Flow-Based Market Coupling ("CEE FBMC"), since the Polish authorities and market participants were not able to agree on the specifics of market coupling with the other counterparties in autumn 2014.

The supply and transport of gas to and from Ukraine

In the past, Slovakia was almost completely dependent on the supply of gas from Russia through Ukraine. However, the gas dispute between Russia and the Ukraine in 2009 (when Slovakia was left without gas for almost two weeks) has shown the vulnerability of the country’s gas supply. Since the reliability of the Russian gas supply through Ukrainian territory cannot be guaranteed, the Slovak government has sought alternative solutions. For instance, in 2009 a ten year agreement with E.ON Ruhrgas was concluded for the supply of 500 million m^3 per year. Other measures were taken to ensure that gas storage facilities in Slovakia held enough emergency gas to get through the winter in case of another gas dispute.

The situation worsened in 2014 due to the conflict between Russia and Ukraine. The conflict impacted the gas supply and the transit to and through Slovakia as, in June 2014, Russia stopped supplying gas to Ukraine and only sent gas intended for transportation to Europe, ie through Slovakia, to and through Ukraine's gas system. However, the gas system in Ukraine is not suitable for such a situation (as lowered amounts of gas in its network mean decreased pressure in pipelines) and part of the gas intended for transportation remains in Ukraine as the local transmission and distribution networks are not entirely separate systems. Therefore, in autumn 2014, Slovakia and Poland noted a decrease in the volumes of gas supplied to its borders, which occasionally amounted to only 50% of the usual flow. This situation also means that it is possible Ukraine would not be able to transport any gas to Slovakia (and in fact neither to Central and Western Europe) through its gas system in winter. As of the beginning of January 2015, the flow was reported to be in standard volumes.

In connection with the crisis between Russia and Ukraine, a new reverse Vojany (Slovakia)–Uzhorod (Ukraine) pipeline was put into commercial operation in September 2014, which can transport 10 billon m^3 of natural gas per year to Ukraine. The purpose of the new pipeline and generally of the whole reverse flow was to supply gas to Ukraine as a safeguarding measure against potential problems with supply from Russia. The full capacity of this pipeline (ie 10 billon m^3 per year (or 27 million m^3 per day)) was booked by TSO eustream's customers until the end of 2019. The pipeline was realised entirely from eustream's own funds and no funds from the Slovak state or the EU were obtained. For the use of this pipeline, a new interconnection point (Budince) in the vicinity of the existing interconnection point (Veľké Kapušany) was established to interconnect the transmission networks of both TSO eustream and Ukrtransgaz. The similar reverse gas flow was enabled between Hungary and Ukraine as well as from Poland to Ukraine. However, reverse flow from Hungary was stopped in September 2014.

The gas pipeline between Slovakia and Hungary

In September 2011, the Slovak and Hungarian governments agreed to build a 115 km long gas transportation connection between the Slovak Republic and Hungary by 1 January 2015. The interconnection pipeline should connect the Slovak compressor station in Velke Zlievce with Hungarian Vecses, aiming to secure capacity in the direction of Hungary up to 12 million m^3 daily. The Slovak part of the interconnection pipeline was finished in July 2014, while the Slovak TSO eustream is waiting for completion of the project on the Hungarian side, with potential operation still envisaged before 1 January 2015. The testing procedure of the pipeline should commence on 1 December 2014.

In addition, a new cross border interconnector should be built with Poland, as it was added as a priority to the EU list of of Projects of Common Interest and forms part of the European Energy Security Strategy. The project is now in the preparatory phase, with a plan for it to be put into operation in 2020.

Bratislava–Schwechat oil pipeline

The plan to enable transportation of oil from the Slovak Republic to Austria via the so-called Bratislava–Schwechat Pipeline has been discussed for several years between the government, the relevant system operators and environmental NGOs. The aim of this project is to ensure greater diversity for oil transportation routes and increase the transportation capacity. As such, this project is considered by the European Commission to be an important energy project and was listed in the list of European projects of common interest as a project which may receive an EU subsidy and be supported in future from EU funds.

The pipeline should be up to 152km long, while its construction costs could amount up to €112 million. The pipeline should be constructed within six years of the commencement of works.

The exact route of the pipeline has not yet been determined due to various reasons, although these are mainly environmental reasons. In addition, the relevant municipalities in Bratislava have refused to plan the route of the pipeline through the municipalities' territories in the past and requested the Slovak Ministry of Economy to choose another route for the project, which would not go through any part of Bratislava. In October 2014, information was published that the pipeline should be routed through the city borough of Petržalka (one of the most densely populated residential districts in Central Europe) and that the investor is already looking for suitable parcels and beginning with its inspections. There is, however, no official decision or statement from the state or municipality authorities with respect to such route.

New act on energy efficiency

At the end of October 2014, the Slovak parliament (National Council of the Slovak Republic) approved Act No. 321/2014 Coll. on energy efficiency, which has become effective as of 1 December 2014.

The main reason for the adoption of the new act on energy efficiency was the implementation of the Directive 2012/27/EU of the European Parliament and of the Council of 25 October 2012 on energy efficiency into Slovak law, and also the need for regulation of various practical issues with energy efficiency. The new act is focused on energy efficiency in the whole energy chain and it will also affect various entities which are not dealing primarily with energy efficiency, such as electricity generators. Nevertheless, the newly introduced obligations are imposed mainly on the owners or operators of larger buildings, as well as industrial buildings. The act also includes various obligations with respect to energy efficiency in the course of operation of central heating where, for instance, apartment buildings with their own heating systems are obliged to install authorised meters to its heating system up until the end of 2016.

Amendment to emission trading scheme in the legislative pipeline

The emission allowance trading in Slovakia is governed by Act No. 414/2012 Coll., on Emission Allowance Trading which transposes the New EU ETS Directive into Slovak law. This act mainly regulates the trading of greenhouse gases and contaminated substances emission allowances, and stipulates further rights and obligations of the operators of installations and other participants in the emission trading scheme.

An amendment to this Act implementing various EU laws, such as EU Regulation No. 421/2014 amending Directive 2003/87/EC, entered into force on 1 January 2015 (with some of the changes becoming effective in January 2016 only).

However, the main change that was introduced is locally driven. This amendment excludes trading with contaminated substances, eg sulphur dioxide and nitrogen dioxide in the Slovakia trading system. The system for trading with contaminated substances has been regulated in Slovakia since 2002 and the relevant emission limits were observed even without it. Since the new technical requirements for the operation of sources of emissions of contaminated substances are, in the view of the relevant state authorities, sufficient, there is no longer any need for a special system for trading with contaminated substances.

ENERGY LAW IN SLOVENIA

Recent developments in the Slovenian energy market

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THE ENFORCEMENT OF THE NEW ENERGY ACT

In early 2014, the Slovenian parliament finally adopted the new and long awaited Energy Act (*Energetski zakon*; the "EA-1"). The EA-1, a recast of the Slovenian energy legislation, implementing several pieces of the EU energy *acquis*, particularly the Third Energy Package, entered into force in March 2014 and has introduced significant changes to the legislative framework governing the Slovenian energy market. One of the main requirements, introduced with the EA-1, was the full ownership unbundling of the transmission of electric energy, required under the New Electricity Directive. Following the latter, given that the electricity transmission system operator ELES d.o.o. ("TSO") had been fully owned by the state, the EA-1 provided that the ownership unbundling requirement was deemed to have been met, provided that control over the TSO and the production/supply companies respectively, is exercised by two different public bodies (authorities). As a result, the EA-1 transferred supervision over the TSO (as well as SODO d.o.o. and BORZEN d.o.o., as the electricity distribution system operator and the electricity market organiser respectively) from Slovenska odškodninska družba d.d.[1] to the government of the Republic of Slovenia (the "Government") and the Ministry of Infrastructure. No changes have, however, been introduced to the unbundling regime of the transportation of natural gas, as the EA-1 maintained the Independent Transportation Operator ("ITO") model, established under the previous legislation, with Plinovodi d.o.o., being certified as the sole (independent) transportation system operator.

In context of administrative requirements for the start-up of new energy companies, the EA-1 abolished the energy licences system, which previously required the majority of companies in the energy industry (active *inter alia* in the fields of energy, gas or heat supply or which conducted activities as transmission or system operators) to acquire energy licences issued by the Energy Agency of the Republic of Slovenia (*Agencija Republike Slovenije za energijo*; the "Agency").

Further, the EA-1 introduced the obligation for large companies to undergo energy audits every four years, determining the existing energy consumption and identifying any energy saving opportunities for the company's buildings. Constituting another energy efficiency innovation, energy performance certificates are to be obtained for new constructions and buildings, and acquired by owners of new constructions and buildings being sold or leased after 22 March 2014. All new buildings constructed after 2020 (on 2018 for the buildings pertaining to the public sector) will, on the other hand, also have to fully observe the requirements of the Nearly Zero Energy Buildings principle set out under the Energy Performance of Buildings Directive.

On the end user level, the EA-1 adopts high standards of protection for household consumers and small businesses, particularly by facilitating the switch of electricity and natural gas suppliers, which are now to be performed by the system operator within a maximum of 21 days. In addition, the EA-1 provides for the protection of vulnerable customers by requiring system operators to continue with the supply of electricity and natural gas (and bear the costs thereof), despite non payment by the end user, should a suspension of supply pose a risk for the life or health of the respective consumer.

Given that the adoption of the EA-1 entirely invalidated numerous implementing acts, many of which are still to be replaced in the near future, Slovenian energy reform has yet to see a final conclusion.

FURTHER RESTRICTIONS ON THE RENEWABLE ENERGY SUPPORT

Despite the enforcement of the EA-1, the support scheme incentivising the generation or cogeneration of energy from renewable sources in Slovenia has retained its two basic forms, namely: (i) the financial support settling the difference between the production cost and the expected market price for electricity; and (ii) a guaranteed purchase of electricity for a set price by Borzen Center for Support (an integral part of the market operator Borzen d.o.o.).

The EA-1, however, provides for further restrictions on support for investments making use of renewable energy sources ("RES"). First of all, support from the guaranteed purchase price scheme is now limited to installations with a production capacity of a maximum of 1MW, which is considerably lower than the 5MW provisioned under the previous legislation. Secondly, the EA-1 implemented a new system for awarding support by authorising the Agency to publish a call to investors for allocation of funds for RES support. Investors are invited to present their projects for generating installations using RES and high efficiency cogeneration by 1 October each year. The EA-1 authorises the Government to determine (and possibly decrease) the scope of investments, having regard to the goals set in the national action plan for RES (the "Action Plan"), as well as the availability of resources.

Apart from the restriction laid down under the EA-1, further cut backs of renewable energy incentives, namely for the use of biofuels, were introduced with an amendment of the Excise Duty Act, which abolished the tax benefits of fuel distributers for (mandatory) marketing of biofuels, with effect from 1 May 2014.[2] Despite the abolition of the biofuel incentive, the obligatory annual minimum biofuel quotas, set under the Decree on the promotion of the use of biofuels and other renewable fuels for the propulsion of motor vehicles (*Uredba o pospeševanju uporabe biogoriv in drugih obnovljivih goriv za pogon motornih vozil*), and the Action Plan, remained in place.

INFRINGEMENT PROCEEDINGS AGAINST SLOVENIA

During the past years, several proceedings due to non-implementation of EU energy directives have been initiated against Slovenia before the European Commission (the "Commission") and Court of Justice ("CJ"). In 2012 and 2013, the Commission issued reasoned opinions to Slovenia for failure to transpose the Renewable Energy Directive and, respectively, the Energy Performance of Buildings Directive. Following the pre-litigation proceedings before the Commission, in early 2013 Slovenia was referred to the CJ for not (fully) implementing the New Gas and Electricity Directives, thereby facing the risk of the imposition of substantial fines.

The threat of monetary sanctions relating to the New Energy Package was, however, successfully obviated with the adoption of the EA-1, which led to the the withdrawal of the action against Slovenia in the second quarter of 2014.

DECREASE OF PRICES OF ENERGY PRODUCTS

Competition in the Slovenian energy supply market continues to grow and supplier switches, particularly amongst industrial consumers, remain on the rise, thus contributing to the decrease of net prices (excluding duties and taxes) of energy products.

Within the period of one year, the final retail prices of electricity for the average household customer have experienced a 0.3% increase, while the average prices for industrial customers have been decreased by 7.8%. The price of natural gas in the past year has fallen even more considerably, with the retail price for the average household and industrial customer in Slovenia decreasing by 12% and 9% respectively.

In the first collective electricity purchase/supplier switch in Slovenia, taking under the auspices of the Slovenian Consumers' Association in October 2014, consumers joined forces to negotiate lower electricity prices, resulting in an average annual saving of €164 per household. Similar projects, already outlined for the near future, as well as the high consumer protection standards laid under the EA-1 facilitating the switch of supplier by household consumers, may trigger further reductions of household electricity prices in the years to come.

INFRASTRUCTURE DEVELOPMENTS: HYDROENERGY, SOUTH STREAM AND TEŠ 6 IN THE SPOTLIGHT

In the context of energy infrastructure developments, the Slovenian energy market has seen the continued rise of hydroelectricity investments, with several hydropower ventures projected for the near future.

One of the hydroelectric ("HE") power plants located downstream on the Sava River downstream, the €118 million 41.5MW HE Power Plant Brežice, officially entered the construction stage in March 2014 and is expected to be completed by 2017. The HE chain of the downstream part of the Sava River comprising six power plants will, however, only be complete on completion of the 30.5MW HE Power Plant Mokrice, currently still in the planning phase. Further, the construction of one of the largest HE ventures comprising ten power plants planned for the midstream of the Sava River, with a cumulative capacity of 338MW and an estimated cost of €1.3 billion, is projected to take place between 2018 and 2034. While the build up for the pumped storage HE power plant Kozjak on the Drava river stopped in December 2013, other HE infrastructure developments include the first HE power plants to be built on the Slovenian part of the Mura River.

Apart from the recent infrastructure ventures in the area of hydropower, the spotlight of the Slovenian energy sector remains with two of the largest and most controversial infrastructure projects of recent years. In November 2009, Slovenia and Russia signed an intergovernmental agreement on the implementation of the South Stream gas pipeline project ("South Stream"), planned to deliver Russian natural gas to Europe via the Black Sea route. Following the respective agreement, in November 2012 the Slovenian gas transportation system operator Plinovodi d.o.o. and the Russian gas multinational Gazprom signed the central investment document, based on which the joint venture company (Južni tok Slovenija d.o.o.) was envisioned to construct a part of the South Stream pipeline to be routed across the territory of Slovenia. In December 2013, however, the European Commission announced that the six bilateral contracts negotiated between Russia and EU Member States were in serious violation of EU law, thereby postponing the construction and undermining the implementation of the project, including its Slovenian section, with an estimated value of over €1 billion. In late 2014, the Russian government announced the cancellation of South Stream.

After years of public discussion regarding its questionable environmental and financial viability, the construction of Unit 6 of the Šoštanj Thermal Power Plant ("TEŠ 6" and "TEŠ"), as one of the largest infrastructure projects of recent years, financed with a €550 million loan given by the European Investment Bank, which was secured with a €440 million state guarantee, has reached its final stages in 2014. TEŠ is a generator of electricity and thermal energy with an installed capacity of 779MW, which generates over 3,500GWh of electricity and over 400GWh of thermal energy annually. In 2004 the company operating TEŠ decided that a sixth production unit would be required in order to replace the old production units and meet future energy demand. The value of the TEŠ 6 investment was initially estimated at €600 million, however this figure has more than doubled to an estimated €1.43 billion.

In the wake of complex financial and criminal, as well as corruption, investigations of the operation of TEŠ which have taken place in recent years, numerous irregularities and fraudulent practices, resulting in unjustified increases to the cost of the project, have been identified. The investigations have shown, in particular, suspicion of criminal acts of abuse of authority and misuse of rights, as well as forgery and destruction of documents, referring to the reconstruction of Unit 5 of TEŠ, as well the construction of TEŠ 6. According to the assessment of the Slovenian criminal police, the cumulative amount of undue benefits conferred to the parties involved (particularly the foreign supplier) exceed €284 million. The investigations led to criminal complaints being filed with the State Prosecutor of the Republic of Slovenia against ten suspects in October 2014. While the criminal proceedings and investigations continue, TEŠ 6 was synchronised with the grid on a trial basis in September 2014, and reached its maximum effective rated output of 600MW in October 2014.

In the past years there have been ongoing public discussions on the constuction of a second block of the Nuclear Power Station Krško. While extensive geological and seismological research has already been conducted, no final decisions on the launch of the project have yet been made. Given the disappoval of the project by the new Slovenian government, the construction of the second block does not appear likely to be initiated in the near future.

CHANGE OF GOVERNMENT

Following the resignation of the (now former) prime minister and the subsequent parliamentary elections taking place in July 2014, the new Government was appointed in September 2014, thereby setting new strategic lines for energy policy.

According to the Coalition Agreement (*Koalicijska pogodba*), signed by the Party of Miro Cerar (*Stranka Mira Cerarja – SMC*), Social Democrats (*Socialni demokrati – SD*) and Democratic Party of Pensioners in Slovenia (*Demokratična stranka upokojencev Slovenije – DeSUS*), as the parties forming the coalition, the priorities of the new Government with regard to the energy sector, comprise *inter alia;* (i) the establishment of a sustainable RES support scheme; (ii) investments to hydroelectric energy; and (iii) the promotion of the use of natural gas (including a recast of legislation governing the distribution thereof).

REOPENING OF PUBLIC DISCUSSION ON PRIVATISATION IN THE ENERGY SECTOR

Despite the increase of private sector participation due to the growing number of privately owned energy suppliers in recent years, the majority of companies in the energy sector remain under full or partial state ownership. In 2014, the heated discussion on the privatisation of the state owned energy companies was reopened, with a part of the general public as well as the energy sector trade union expressing a distinctively disapproving position.

Given that the new Government is generally deemed to oppose privatisation of energy companies in Slovenia, it is currently not expected for such procedures to be initiated in 2014. Instead of selling the state owned energy companies, the government promotes public-private partnership by facilitating investments in new energy projects.

ENDNOTES

1. Slovenska odškodninska družba d.d., as one of the companies managing state capital investments, has, however since been restructured and renamed into the Slovenian Sovereign Holding (*Slovenski državni holding d.d.*).
2. Tax benefits for marketing biofuels in the prescribed minimum quantities, were firstly introduced in 2004, and were lowered to (a maximum of) 5% in 2006.

ENERGY LAW IN SPAIN

Recent developments in the Spanish energy market

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In this article, we will focus on the main developments introduced in the gas and electricity sectors in Spain during 2014. In particular, we will focus on the new framework for the production of energy from renewable energy sources approved by the Spanish Government, and the reform of the Spanish gas system focused on the remuneration applicable to transport, regasification, basic storage and distribution of natural gas.

ELECTRICITY

Introduction

On 12 July 2013 the Spanish Council of Ministers approved Royal Decree-Law 9/2013, of 13 July ("RDL 9/2013"), a reform of the Spanish energy sector, which implements a series of urgent measures to guarantee the financial stability of the energy system. RDL 9/2013 entered in force on 14 July 2013. This on-going energy reform required the implementation of a new electricity sector act, a decree-law, eight royal decrees and three ministerial orders. As of today, there are still some orders and royal decrees awaiting approval. Particularly, the orders developing the parameters for the remuneration of the transmission and distribution activities and the royal decree of energy self-consumption, which is expected to be approved by the Government in the third quarter of 2015.

During 2014, the Spanish Government approved the:

- Electricity Sector Act 24/2013 of 26 December;
- Royal Decree 413/2014 of 6 June which regulates the production of electricity from renewable energy sources, cogeneration and waste (the "RD 413/2014"); and
- Order IET/1045/2014 of 16 June which approves the remuneration parameters for standard plants that will apply to certain renewable energy, cogeneration and waste-to-energy generation plants ("Order IET/1045/2014").

In the following subsections, we will analyse in depth this new legal framework.

New legal and economic framework for the production of electricity from renewable energy sources, cogeneration and waste.

On 10 June 2014, Spain's Official State Journal published RD 413/2014, which entered into force on 11 June 2014. RD 413/2014 proposes a new system of specific remuneration (*retribución específica*), on top of the remuneration received for the sale of energy valued at market rates. It establishes the calculation formulas and remunerative parameters for each category of "standard plant", as classified by the RD 413/2014, while also establishing a reasonable rate of return.

The reasonable rate of return is defined in the RDL 9/2013 and RD 413/2014 as a return before tax of around the average yield of 10-year Spanish Government Bonds on the secondary market during the 24 months preceding the month of May in the year prior to the start of the regulatory period, plus a differential.

RDL 9/2013 and RD 413/2014 establish a differential of 300 basis points for the first regulatory period, ending on 31 December 2019.

Total Remuneration

RD 413/2014 establishes the methodology for calculating the specific remuneration, which applies to plants that do not reach the minimum revenues required to cover costs and to allow them to compete on an equal footing with other technologies in the market while obtaining a reasonable rate of return, with reference to each respective standard category of plant.

The specific remunerative regime is based on plants receiving an additional remuneration that supplements the revenues that they obtain from selling the electricity produced in the market to cover the investment costs if an efficient and well-run company is unable to recover only from the revenues obtained from the market.

Those plants are entitled to receive specific remuneration, throughout their regulatory useful life, on top of the revenues they obtain from selling their energy at market prices. Such specific remuneration is divided into two components:

- **the return on investment component:** measured per unit of installed power capacity that covers the investment costs for each category of standard plant that cannot be recovered by the sale of power in the market; and
- **the return on operation component:** which covers the difference, if any, between the plant's operating costs and the income generated by the applicable standard plant from its participation in the market compared to the applicable standard plant.

Exceptionally, the specific remuneration may include an investment subsidy covering the investment in non-peninsular power systems when the overall cost of electricity generation is reduced.

In addition, plants that participate in system adjustment services will receive the remuneration established by applicable regulations.

Scope of application

The specific remuneration applies to:

- Existing plants
  - To those plants that had already been awarded a premium-based remuneration when RDL 9/2013 entered into force; and
  - To solar thermal plants that were awarded the remunerative

regime established in Royal Decree 1565/2010, of 16 November, which regulates and modifies certain aspects of special-regime electricity production.

- New plants

  In general, plants will be awarded the specific regime by competitive tender process (other royal decrees will establish the specific terms, technologies or groups of plants that are able to participate in the competitive tender process). The specific remunerative regime will apply to:

  - electricity generation plants or modifications to those plants that have not achieved their output targets established in Royal Decree 661/2007, of 25 May, except to wind, solar thermal and photovoltaic technologies. This remunerative regime will only be awarded to a maximum of 120MW; and
  - New wind energy and photovoltaic plants, and modifications of existing wind energy and photovoltaic plants, connected to the power networks of non-peninsular territories, subject to the specific criteria established in the fifth additional provision of RD 413/2014.

Hybrid Plants

RD 413/2014 establishes that certain hybrid plants will be entitled to receive the specific remuneration in accordance to the criteria determined in such RD 413/2014.

Accrual and application period

The specific remuneration system will begin to accrue from the later of (i) the first day of the month following the date on which the plant receives its definitive authorisation to operate, or (ii) the first day of the month following the date on which the plant obtains its pre-allocation registration in the specific remuneration system register.

Plants will no longer be entitled to the specific remuneration when they reach the end of their regulatory useful life (subject to the exceptions established by Order IET/1045/2014). However, those plants will be entitled to continue operating and they will receive the remuneration from the sale of energy in the market at market prices.

Adjustment and limits

RD 413/2014 establishes a series of adjustments and limits to the specific remuneration (which have been implemented and specified by Order IET/1045/2014):

- Adjustment of annual revenues from the specific remuneration as a result of the number of equivalent hours of operation

  In this sense, when a plant's number of equivalent hours of operation does not surpass the minimum number of equivalent hours of operation determined for its reference standard plant, its annual revenues under the specific remuneration system will be reduced in accordance to the minimum number of equivalent hours and the operating threshold. If the plant's number of equivalent hours of operation does not surpass the operation threshold it will not receive any specific remuneration.

- Adjustment due to market price deviations

  Two upper limits and two lower limits are established for each standard plant on the basis of the estimated market price that was used to calculate the remuneration parameters and the average annual daily and intraday market price.

Review and update of remuneration parameters

The RD 413/2014 establishes consecutive regulatory periods of six years, each of them divided into two half periods of three years. The parameters will be reviewed as follows:

- all of the parameters except for the regulatory useful life and the standard value of initial investment will be reviewed every six years;
- the estimate of revenues from the sale of energy generated will be reviewed every three years; and
- the return on operation when the operating cost of a technology is dependent on fuel prices will be reviewed every year.

The first regulatory period runs from 14 July 2013 to 31 December 2019.

New remuneration parameters applicable to standard renewable energy, cogeneration or waste-to-energy plants.

Following the approval of RD 413/2014 Spain's Official State Gazette published Order IET/1045/2014 on 20 June 2014. This order completes the remuneration model applicable to renewable energy, cogeneration and waste-to-energy plants that began with the approval of RDL 9/2013.

In this regard, according to article 13 of RD 413/2014, the Spanish Ministry of Industry, Energy and Tourism (*Ministerio de Industria, Energía y Turismo* ("MIET")) shall issue an order in which it classifies and categorises the different standard plants, providing them with a specific code, on the basis of the technology they use, their installed power capacity, age, electricity system and other parameters that it believes are necessary to implement the new remunerative regime.

Purpose

The Order has the following purposes:

- To determine and define the different categories of "standard plant".

  A comparison is made between the categories, groups and subgroups defined before the enactment of RD 413/2014 and the new categories, groups and subgroups established in that RD 413/2014; Appendices I and IV establish different standard plants, and their corresponding codes are established for the latter categories, groups and subgroups for the purpose of calculating their applicable remunerative regime. Ultimately, there are total of 1,517 standard plant categories.

  No standard category applies to plants that have passed their regulatory useful life.

- To establish remunerative parameters.

  Order IET/1045/2014 sets specific remunerative parameters for each standard plant for the first regulatory half-period.

- To complete the criteria for calculating the remuneration applicable to hybrid plants

Scope of Application

Order IET/1045/2014 applies to existing plants and new plants as described for RD 413/2014.

Remunerative Parameters: regulatory useful life and standard value of initial investment for standard plants

As established by RD 413/2014, a set of remuneration parameters will apply to each standard plant. These parameters will make up the specific remuneration applicable to the plants falling under the umbrella of each standard plant.

The following parameters are the most significant: return on investment per unit of power; return on operation; regulatory useful life; the minimum hours of operation; the operating threshold; and the maximum hours of operation for the purposes of calculating the return on operation, if any.

The following factors are, among others, also relevant for the purpose of calculating the above parameters: the standard value of the initial investment for each standard plant; the estimated price on the daily and intraday market; the number of operating hours for each standard plant and the annual upper and lower market price limits; the estimate of future operating revenues; the estimate of the future cost of operation; the rate of return readjustment value; the adjustment coefficient of a standard plant; and net asset value.

As mentioned, all these parameters are established for each respective standard plant in the Appendices to Order IET/1045/2014.

Order IET/1045/2014 is also especially significant as it establishes the regulatory useful life for standard plants and quantifies the initial value of investment. Neither of these parameters can be reviewed.

Pre-allocation registration in the specific remuneration system register

New plants, or modifications to existing plants, that have not met the power capacity targets established in Royal Decree 661/2007 (technologies other than wind, solar thermal and photovoltaic, awarded to a maximum of 120MW) must submit an application for pre-allocation registration in the specific remuneration system register.

In case of existing plants, they will be automatically registered in the specific remuneration system register on the date specified by the MIET.

Allocation of standard plants by default

According to the First Transitional Provision of RD 413/2014, when it is not possible from the information at the register of electricity producers or the settlement system to ascertain what standard plant should be allocated to certain groups or subgroups under the classification system applicable at the time, standard plants will be allocated by default following a methodology included in such Transitory Provision of Order IET/1045/2014.

NATURAL GAS

The remuneration reform introduced by Royal Decree-Law 8/2014

Background of the reform

On 4 July 2014, the Spanish Council of Ministers passed Royal Decree-Law 8/2014, approving urgent measures to encourage growth, competitiveness and efficiency ("RDL 8/2014") with three primary aims: (i) to encourage competition and market efficiency; (ii) to improve access to credit and (iii) to boost employment and the job market. More specifically in relation to energy, RDL 8/2014 establishes a series of measures aimed at ensuring the sustainability and accessibility of the hydrocarbons markets, by establishing a system of energy efficiency in line with European directives.

The underlying reason behind these measures has been the deficit in the Spanish gas sector. As a result, RDL 8/2014 acknowledges that the lower demand for gas in recent years caused by the financial crisis (as well as increased capacity and infrastructure in the system) has generated an imbalance between revenues and costs in the gas system between 2002 and 2006. This, in conjunction with the ultimate failure of measures to apply significant increases in regulated costs, has made it necessary to adopt a deeper reform to halt what the RDL 8/2014 considers to be a structural deficit of the system.

Measures adopted

Chapter II of Title III of the RDL 8/2014 establishes measures to ensure the financial sustainability of the natural gas system.

The principle of financial and economic sustainability is defined as the ability of the system to cover all the costs it generates, a principle to which all the public administrations and participants in the natural gas system will be subject to. It establishes that the revenues generated by the gas system will be used exclusively to finance the system's costs. It also establishes that the system's revenues must be sufficient to cover its costs. In order to maintain the cost/revenue balance, any measures that trigger a cost increase or a reduction of revenues must be accompanied by an equivalent decrease in other cost items or an equivalent increase in other revenues. The system's costs that will be financed by its revenues are:

- the remuneration of transport, regasification, basic storage and distribution;
- the remuneration of the technical management of the system;
- the duty payable to the Spanish Markets and Competition Commission (Comisión Nacional de los Mercados y la Competencia ("CNMC")) and the MIET;
- if any, the cost differential of supplying liquefied natural gas or manufactured gas and/or propane-air other than natural gas in island territories that do not have a connection to the gas pipeline network or regasification plants, as well as the remuneration of the supply-at-tariff carried out by the distributors in those territories;
- demand management measures, if recognised by applicable regulation;
- annual payments for temporary imbalances, plus applicable interest and adjustment payments, as described below; and
- any other cost established expressly by a legal provision that is aimed exclusively at the gas system.

The following is also included:

- the accumulated deficit at 31 December 2014, which will be determined in the definitive settlement of 2014. Those parties subject to the settlement system shall be entitled to recoup those amounts in settlements corresponding to the 15 following years (plus interest in market conditions); and
- the imbalance resulting from the remuneration of natural gas aimed at the supply-at-tariff market resulting from the Algeria

contracts and supplied through the Maghreb pipeline, as a result of the award rendered by the International Court of Arbitration in Paris on 9 August 2010. This deviation has been quantified at €163,790,000, which will be recovered over a period of five years (2015 to 2019).

The principle of sustainability must be accompanied by a remunerative methodology that allows for an adequate remuneration for low-risk activities, such as regasification, basic storage, transport and distribution.

Thus, the remuneration parameters applicable to those activities will be established for regulatory periods of six months, although they may be adjusted every three years if costs and revenues change significantly. However, the rate of financial return may not be adjusted throughout each regulatory period and automatic update formulas will not be applied to the parameters used to calculate them.

RDL 8/2014 establishes different methodologies for determining the remuneration applicable to distribution, on the one hand, and to regasification, transport and basic supply, on the other.

In both cases, the first regulatory period will begin on the date on which RDL 8/2014 enters into force, ending on 31 December 2020. Three sub-periods are also established:

- a period before the start of the first regulatory period starting from 1 January 2014 until the entry into force of RDL 8/2014 (for period of 2014) for which the applicable remuneration will be the figure, proportional to that date, contained in sections of Appendix IV of Order IET/2446/2013, of 27 December, corresponding, respectively, to the companies that own transport, regasification and basic storage facilities and distribution companies;
- from the entry into force of RDL 8/2014 until 31 December 2014 (second period of 2014). In this period, the MIET will approve the remuneration for each company on the basis of a report prepared by the CNMC, according to the parameters and methodology contained in Appendix X of RDL 8/2014 in the case of distribution companies, or Appendix XI in the case of companies that own transport, regasification and basic storage facilities; and
- from 1 January 2015 to the end of the first regulatory period (31 December 2020) remuneration will be calculated according to Appendix X of RDL 8/2014 in the case of distribution companies, or according to Appendix XI of RDL 8/20104 in the case of companies that carry out transport, regasification and basic storage activities. For these purposes, the MIET will approve the remuneration applicable to each calendar year, at the proposal of the CNMC, which must be delivered before 1 October of each year.

It is estimated that that the overall impact of these measures will be in the range of €200 million, proportionately affecting the income generated by transport, distribution, regasification and basic storage and, within each activity, each one of the companies that perform them.

Methodology for calculating the remuneration of distribution

The remuneration due to distribution facilities is connected to customer increases and the new demand they generate. As such, each company will be remunerated, for the aggregate of its facilities, on the basis of the customers that are connected to those facilities and the volume of gas supplied. An incentive will also be offered for connecting new municipal districts to the gas system.

Distributors will receive the applicable remuneration in the previous year, which will then be adjusted according to a coefficient that reflects improvements in productivity. That remuneration will also be increased with payments due to each distributor for growing its market. This last parameter differentiates among different kinds of customers, accord to their connection to the network.

This methodology also applies to new secondary transport facilities.

Methodology for calculating the remuneration of transport, regasification and basic storage

A common methodology has been established for all facilities in the basic network, using as a basis the current net value of the assets, removing adjustments made during the regulatory period. The remuneration is composed of:

- a fixed component for the facility's availability, which includes: annual operating and maintenance costs, depreciation and a financial return; and
- a variable component for the continuation of supply, which allows the rebalancing of imbalances resulting from demand fluctuations, with which the owners of facilities are able to cover the risk of those fluctuations. This variable component is shared among all the facilities on the basis of the weighting of their replacement value with respect to all the facilities that perform the activity.

In the case of regasification, the gas used for operations is borne by the plant operator.

If a facility continues to operate beyond the end of its useful life, its fixed remuneration will be its operation and maintenance costs plus a coefficient, which will depend on the years by which the facility has operated beyond its useful life.

However, with regard only to the transport, regasification and basic storage facilities entitled to remuneration from the gas system, from the moment RDL 8/2014 enters into force and throughout the first regulatory period, the rate of return will be calculated as the average yield of Spanish government 10-year bonds on the secondary market among the holders of non-segregated accounts in the 24 months before the regulation entered into force, plus 50 basis points.

Other measures

Finally, it should be highlighted that RDL 8/2014 also includes measures to correct any short-term imbalances and to prevent another structural deficit from being generated. These are:

- If in a single year the deficit exceeds 10% of the revenues generated by the system, tolls and duties will be increased automatically in the following year to recover the amount by which the limit was exceeded; and
- If the accumulated deficit exceeds 15% of revenues, tolls and duties will also be increased automatically in the following year to the extent by which the limit was exceeded.

Future reforms in the natural gas sector

It is expected that the next expected package of reforms in the hydrocarbons sector will deal with the regulation of fracking in

Spain. The latest trends and news suggest that such new expected reforms will establish certain incentives and measures to facilitate the exploration and production of unconventional hydrocarbons using fracking techniques. Such measures could include incentives and benefits for the land owners and the local regions where such activities are performed.

Regarding the exploration and production of unconventional hydrocarbons, it is worth mentioning that, during 2014, the Spanish Constitutional Court has issued judgements declaring the absence of competence of the Autonomous Regions to pass regional laws prohibiting the use of fracking in their territories and therefore declaring null and void such laws.

Likewise, further developments on the creation and establishment of an Iberian gas wholesale market (the Iberian gas hub) are also expected for the following months.

ENERGY LAW IN SWEDEN

Recent developments in the Swedish energy market

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MERGERS AND ACQUISITIONS

Electricity network sale

In January 2013, Fortum, the Finnish energy group with approximately 900,000 customers connected to its Swedish electricity distribution network, announced that the company was considering the sale of all its electricity networks in Scandinavia as part of a change of strategy, in which the company would focus on generating and selling low carbon electricity.

The sales of the Finnish electricity network and the Norwegian network were finalized in late 2013 and in mid-2014, respectively. Details have not yet been made public in relation to Sweden, but Fortum has announced that it is proceeding with the sale, in spite of speculation that legislative amendments to the tariff system (discussed below), might lower the value of the network. Analysts estimate that Fortum could sell the Swedish arm of its distribution business in the first half of 2015.

SIGNIFICANT NEW INSTALLATIONS

Possible new nuclear reactor for research purposes

In 2012, three universities (Royal Institute of Technology, Chalmers and Uppsala University) submitted a report to the Swedish government proposing new research facilities in Oskarshamn, allowing for research into Generation IV nuclear reactors (*forskningsanläggning för fjärde generationens kärnkraftsystem: ELECTRA-FCC*, 2012).

The facilities would include a lead-cooled fast reactor, a recycling process and accompanying security systems, and cost approximately SEK1.5 billion. Generation IV reactors have the potential to use existing nuclear fuel 100 times more efficiently than current processes allow. This could reduce the challenges of high-level nuclear waste management and open up the possibility of using spent fuel to produce weapons grade material. The report states that the facilities could be operational by 2023 at the earliest.

After being consulted in the matter, the Swedish Research Council concluded, in an opinion dated 30 September 2014, that many aspects of the proposal require further research and that a further inquiry should be conducted before any decision is made on the project.

It is now up to the government to decide how to proceed. There is, however, political uncertainty regarding how the new Swedish government will address nuclear power. The coalition parties announced on 1 October 2014 that they have agreed not to pursue the decommissioning of nuclear power plants, but that the operators of those plants will be subject to increased costs. The exact details of this agreement have not yet been made public, but it seems that the voluntary decommissioning of nuclear power plants may follow.

European Spallation Source

The construction on a multi-disciplinary research centre (European Spallation Source, ESS) based on the world's most powerful neutron source is underway.

Research using neutrons has several applications within the energy field, particularly as it allows investigation into structural and dynamical processes important to materials design. Possible research fields include fuel cells, storage materials, battery materials, thermoelectrics and solar cells.

The centre is a European initiative with funding from 17 partner countries, hosted by Sweden and Denmark. The ESS main facility will be built in Lund, Sweden, and the Data Management and Software Centre will be located in Copenhagen, Denmark. The facility was granted a permit by the Land and Environment Court on 26 June 2014. The Swedish Radiation Safety Authority has also granted an initial permit, but the facility will be subject to further review at later stages. The facility is expected to be operational by 2020.

New LNG terminal

Swedegas AB, Göteborgs Hamn AB (Port of Gothenburg) and Vopak LNG (a subsidiary of Royal Vopak) are planning to build an LNG terminal in the port of Gothenburg, which will be the first in Sweden. It will operate according to the "open access" principle, by which any company interested in supplying LNG to the Swedish market can seek to contract capacity at the terminal. The terminal in turn will allow end customers to choose any gas supplier they wish, thus opening market competition and reducing LNG prices for consumers. According to the open access principle, ownership and operation of the infrastructure must be kept separate from the production and trade of energy. The operators, Swedegas AB and Vopak LNG, do not themselves engage in the trade of LNG.

The terminal will have a capacity of 30,000m^3 when fully scaled. The LNG will be freighted from larger terminals, such as the GATE terminal in Rotterdam. The Port of Gothenburg owns the quays planned to be used in the loading operations. From Gothenburg, LNG may be transported to other parts of Sweden by train and lorry. The terminal will also be able to connect to the Swedish natural gas system, owned by Swedegas AB. There is an ongoing open season process whereby prospective users of the terminal can announce their interest in services that will be provided.

An LNG terminal requires an environmental permit. A permit application was submitted in September 2013 to the County Administrative Board of Västra Götaland, and a decision granting the permit was announced on 23 May 2014. The decision has been appealed by Preem AB, but as the decision makes the environmental permit effective immediately, works may continue.

The terminal is planned to become operational in 2015. However, a concession is required for any natural gas storage facility, including LNG, that is connected to the Swedish natural gas system. No such application has yet been submitted to the government offices.

Large-scale investment in wave energy park

Sweden's first wave energy park is due to open in the municipality of Sotenäs, located on the western coast of Sweden. When fully scaled, it is expected to be the world's largest with over 400 interconnected wave energy units. The cable, which has already been drawn, is dimensioned for a park with 10MW of power: enough to provide electricity for approximately 100 households. The park is the result of cooperation between Seabased AB, which has developed the technology, and Fortum, one of the largest energy producers in Sweden. The technology does not require large waves and is therefore suitable for the Swedish coast. The project has been made possible partly by an investment grant of SEK139 million from the Swedish Energy Agency, approved by the European Commission.

A permit for the water operations that the project entails was applied for and granted by the Land and Environment Court on 24 June 2010. If the activities progress according to plan, construction of the park will be completed in 2015.

APPEALS OF EX ANTE DECISIONS ON REVENUE CAPS FOR ELECTRICITY GRID OPERATORS

Due to changes in the Swedish Electricity Act which entered into force on 1 January 2012, Sweden has moved from a network tariff system where the tariffs were regulated on an ex post basis to a system based on ex ante regulation. One of the purposes behind the shift to ex ante regulation was to bring the Swedish legislation in line with the Third Energy Package.

The Swedish Energy Markets Inspectorate (the ''Inspectorate'') now determines, in advance, the total revenues which may be collected by the grid operator during the regulatory period (four years). The first regulatory period for the new system started on 1 January 2012.

The revenue cap is intended to cover reasonable costs for network operations during the regulatory period and to provide a reasonable rate of return on the capital required to operate the grid. Factors such as the quality of the grid operations are taken into account in calculating the revenue cap. The grid operators submitted their applications in early autumn 2011, with the revenue caps eventually approved by the Inspectorate being considerably lower than those applied for.

To ensure that customers get low and stable tariffs, which the Inspectorate considers to be a requirement of the Electricity Act, the Inspectorate decided to introduce the new tariff system gradually from 2010 over a transitional period extending over four regulatory periods, totaling 18 years (the "Transition Period"). However, the majority of grid operators appealed against the Inspectorate's decision to the Administrative Court.

The judgments were published on 11 December 2013 and the Administrative Court ruled substantially in favour of the grid operators:

- The Inspectorate was not entitled to apply the Transition Period. According to the court, there were no legal grounds for decreasing the calculated reasonable revenue cap with reference to the consumer interest, especially given that this had already been taken into account through the revenue cap regulation. Furthermore, the court expressed that if the model does lead to an unreasonably high yield, which may be the case, this should be addressed by the legislator and not by adjusting the result of the model.
- The regulatory rate of return for the regulatory period was set to 6.5% before tax. The Administrative Court thus dismissed some of the calculations made by the Inspectorate, which had adjusted the WACC to 5.2% in its decisions.

The Inspectorate appealed against the rulings of the Administrative Court, but the appeals were dismissed by the Administrative Court of Appeal in November 2014. These rulings have in turn been appealed to the Supreme Administrative Court by the Inspectorate. The Supreme Administrative Court is expected to decide in the first quarter of 2015 whether a leave to appeal shall be granted.

CHANGES TO THE LEGAL FRAMEWORK UNDER DISCUSSION

Electricity network tariffs

The Electricity Act was amended on 8 May 2014 in respect of the mechanism and methodology for the determination of network tariffs. The changes entered into force on 1 July 2014 and introduced the possibility for the government to authorise the Inspectorate to issue regulations for how the tariffs are determined. Furthermore, the breadth of the Inspectorate's power to issue regulations was expanded. Instead of concerning only the calculation of the capital base when determining the revenue cap for a network operator, the regulations issued by the Inspectorate may now also consider other issues of importance for the calculation of what should be considered as a reasonable return for the network operator.

As a result of the amendments to the Electricity Act, the government instructed the Inspectorate to review and propose amendments to the Ordinance (2010:304) for determining the revenue cap according to the Electricity Act (1997:857) (the ''Capital Base Ordinance'').

The Inspectorate was instructed to evaluate different methods for calculating the capital cost. The government clarified that the previously adopted capacity-retaining approach was to be maintained. The Inspectorate was further instructed to pay particular attention to the investment incentives provided by different methods and the question of transparency between customers' charges and the actual cost of network operations. Proposed amendments to the Capital Base Ordinance were intended to facilitate a cost efficient roll-out of renewable energy, an efficient energy system and ensure reasonable tariffs for customers.

The Inspectorate presented a report in March 2014, detailing its proposed amendments to the Capital Base Ordinance. On 4 September 2014, the government decided to enact a new ordinance, Ordinance (2014:1064) on the revenue cap of network operators, largely reflecting the Inspectorate's suggestions, with a few adjustments. Broadly outlined, the changes consist of:

- Provisions for calculating capital consumption that will come into effect from the regulatory period starting in 2016, introducing a linear method by which a facility for the transmission of electricity is normally depreciated over 40 years and other components over 10 years (with a possible extension to 50 and

12 years, respectively). At the end of the facility's or component's economic life, the asset cannot be included in the capital base.

- Provisions for determining the age of a facility. Any facility older than 38 years in 2015 will be considered 38 years old. Without this rule, no capital costs could have been claimed for facilities more than 50 years old in 2015 since their value would already have been fully depreciated under the new provisions on depreciation described above. These provisions entail that such a facility has a maximum of 12 years of remaining economic life.
- Authorisation for the Inspectorate to define which costs the network operator has the ability to affect. Previously this was an unregulated matter that caused uncertainty. The authorisation does not, however, allow the Inspectorate to define what efficiency improvements are required by network operators.
- Rules for determining the cost when a facility has been financed through a government loan.
- Eliminating certain exceptions for Svenska Kraftnät, the publicly owned national grid.

Gas network tariffs

On 23 January 2014 the government enacted Ordinance (2014:35) on determining the revenue cap in the natural gas sector. It largely follows the pattern of the electricity sector in that it is the Inspectorate that is responsible for issuing regulations on how the costs of natural gas companies are calculated. However, it gives the Inspectorate wider discretion, in that it does not provide specific rules for depreciation.

In April 2014, the Inspectorate issued its regulations on revenue caps for gas companies (Ei R2014:11). The first regulatory period is 2015-2018. In October, 2014, the Inspectorate issued its decisions on revenue caps for the first regulatory period. The regulatory rate of return, WACC, was set at 6.26% (real pre-tax). The economic lifetime of assets was decided according to a table, for instance eight years for support systems and supervision systems, 50 years for distribution pipes and 65 years for transmission pipes. In November 2014, several affected natural gas companies appealed the revenue caps.

Tax reduction on micro production of renewable energy

The government has presented a bill aimed at facilitating private sector investment into the production of renewable electricity. The bill proposes a tax reduction on the amount of electricity consumed that corresponds to the amount of electricity put into the network by the consumer during a calendar year as a result of the micro production of renewable electricity. The intention is to strengthen the position of consumers and to increase the market share of renewable energy. The bill must receive European Commission approval, in respect of state aid, before it can come into effect. Subject to this approval, the proposed tax reduction is likely to take effect from 1 January 2015.

Amendments to the Natural Gas Act (SFS 2005:403)

The Natural Gas Act has been adapted to a changing gas market. Through changes in the Natural Gas Act that entered into force on 1 July 2014, the term "national gas system" has been changed to "Western Sweden's natural gas system". The term "national gas system" in the Natural Gas Act previously covered the network system that extends along the Swedish west coast from south of Malmö to north of Gothenburg. As independent regional gas networks are currently being planned in other parts of Sweden, the amendment aims to clarify that the proprietor of a natural gas pipeline that is not part of Western Sweden's natural gas system is responsible for the maintenance of the short-term balance between the infeed and outtake of natural gas in its system. This responsibility includes *inter alia* drawing up a balance agreement with objective and non-discriminatory conditions etc, and corresponds almost exactly with existing rules in the Natural Gas Act.

Consequential amendments have been made to other acts related to natural gas, such as the Act on Certification of Certain Natural Gas Companies (2011:711).

Implementation of the Energy Efficiency Directive

In March 2014, the government presented a bill on the implementation of the Energy Efficiency Directive. As a result, new legislation and amendments were introduced during the summer of 2014. On 1 June 2014 an act on energy measuring in buildings came into force with the purpose of aligning energy costs with the actual use of energy by measuring energy in each separate apartment, giving the end user an incentive to reduce energy use. Another act that entered into force on the same day concerns energy auditing (*energikartläggning*) in large companies so as to encourage improved energy efficiency.

ENERGY LAW IN SWITZERLAND

Recent developments in the Swiss energy market

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LEGISLATIVE DEVELOPMENTS

As a result of the referendum regarding the control and limitation of immigration (*Masseneinwanderungsinitiative*), which the Swiss people passed on 9 February 2014, the negotiations between Switzerland and the EU have stalled. The passing of the referendum has made it more difficult to answer the institutional questions relevant to an agreement on energy matters as the referendum questioned the future of the relationship between the EU and Switzerland. The sectoral agreement for the energy industry can thus no longer be expected to occur in the near future. It is understood that the Association of the Swiss Electricity Companies ("VSE") is looking into the possibility of negotiating individual agreements.[1]

These same difficulties encountered with regards to the sectorial agreement between Switzerland and the EU also affected the introduction of market coupling:[2]

In order to facilitate market coupling at the Swiss borders in the day ahead market, Swissgrid and the European energy exchange ("EPEX SPOT") signed an agreement on 7 November 2013. As a result of this agreement, EPEX SPOT opened its Swiss subsidiary in Bern on 14 May 2014.[3] Electricity is still traded over the same trading platforms (predominantly Paris, Leipzig and Frankfurt). Following the establishment of a subsidiary in Bern, EPEX SPOT will provide the Swiss Federal Electricity Commission ("ElCom"), the Swiss independent regulatory authority for the electricity sector, with access to the relevant data in accordance with Swiss legislation (see below). This means that ElCom is able to ensure that the trade takes place in a legally correct manner without price manipulation.[4]

Due to the impasse in the negotiations regarding the energy agreement between the EU and Switzerland, the introduction of market coupling, originally expected for February 2015, will be delayed.

The Swiss Federal Council has also announced that feed-in tariffs for solar PV installations would be reduced. The cuts will apply, specifically, to systems up to 29.9kW, between 30kW and 1MW, and larger than 1MW. The level of reduction will be 23%, 18% and 12% respectively. The 15% bonus that applies to building-integrated PV systems will not be affected.

Possible impacts of the reduction in feed-in tariffs for solar PV installations include a reduction in the quality of installation as developers look to cut costs in order to maintain profitability. In addition, the one-off payment for those projects under 30kW could, potentially, become more attractive than a feed-in tariff. Industry reaction suggests that the cuts may be too extreme.

There is also a new strategy being introduced for electricity grid development. It is being designed so that the information required for a decision whether to install overhead or underground cables can be considered appropriately. The strategy was adopted on 14 June 2013 and a consultation was launched in November 2014 to review the draft legislation. It is hoped that this strategy will improve security of supply.

OWNERSHIP UNBUNDLING[5]

ElCom, the Swiss Regulator, conducted administrative proceedings into the unbundling proposals by Swissgrid, which were closed in Autumn 2012 after a compromise was found.

The transaction itself was successfully completed on 2 January 2013 when the ownership of the 6700 km long transmission network was transferred to Swissgrid.[6] Since then, the Swiss Federal Tribunal has held that other parts of the line should be considered as forming part of the transmission line and thus also to be transferred to Swissgrid. At the time of writing, it was expected that such additional assets would be transferred to Swissgrid by the end of 2014.

REMIT AND THE SWISS WHOLESALE MARKET

The Federal Council has introduced new regulations, according to which data related to the wholesale electricity market have to be reported to ElCom in line with the requirements of REMIT.

For this purpose, on 30 January 2013, the Federal Council added a new chapter to the Electricity Supply Ordinance of 14 March 2008 (SR 734.71) concerning the provision of data related to the wholesale electricity market. The new regulations in the Electricity Supply Ordinance entered into force on 1 July 2013.

ENERGY STRATEGY 2050

The aftermath of the Fukushima incident is still being felt in Switzerland. The Mühleberg nuclear power plant is still expected to be taken off the grid in 2019. The remaining nuclear power plants also planned to be taken off the grid are: Beznau I (2019), Beznau II (2022), Gösgen (2029), and Leibstadt (2034).[7]

The Swiss Federal Council's Energy Strategy 2050, which was first submitted to the Swiss parliament in 2013, is based on, *inter alia*, the following principles:

- Reduction of consumption of energy and electricity: The Swiss Federal Council intends to reduce the consumption of energy and electricity. The average consumption of energy per year and person is high. It amounts to approximately 6400Watt (or, according to the most recent statistics approximately 31,000kWh[8]). According to the Swiss Federal Council's plan, it should, between 2000 and 2020, be reduced by 16% and between 2000 and 2035 be reduced by 43%. The consumption of electricity should, between 2000 and 2020, be reduced by 3% and between 2000 and 2035 be reduced by 13%[9] and be stabilised starting from 2020.

- More renewable resources: The share of energy obtained from renewable resources shall be increased. It is planned to increase the yearly output of hydro-electric energy to 37,400GWh until 2035. The output of other renewable energy resources should be increased to 4,400GWh until 2020 and 14,500GWh until 2035.[10] Until the energy demand can be totally covered by renewable resources there is the possibility to supply the demand, if necessary, by fossil power generation from eg cogeneration plants or gas-steam power plants and/or electricity imports.[11] There shall be swift authorization procedures for the construction of renewable energy plants and facilities.[12]
- The Swiss transmission network shall be connected to the European transmission networks.[13]
- Access to the international energy markets: A free and unimpeded access to the international energy market is important in order to be able to ensure energy supply. This is particularly true for matters regarding fuel. Ensuring a stable electricity supply requires the exchange of electricity abroad, as well as being able to equate temporarily the fluctuations depending on time of day or year and weather. In this regard, the Swiss Federal Council seeks to conclude a treaty with the EU over a secure and stable market entry to the internal European energy market regulated.[14]
- Intensify energy research: In March 2013, the Swiss Parliament adopted the action plan "Coordinated Energy Research Switzerland" which aims to improve and increase energy research.
- Role model function of the Swiss Federation, the cantons, cities and communities: The public sector sets energy standards for their own buildings as a good example and covers their own need for electricity and heat as far as possible with renewable energy. The labels "Energy City" or "Energy Region" assigned by the program "Energy Switzerland" play a major role in this regard.
- Intensify international cooperation: Switzerland is an important location for research and innovation. It may contribute to, but also benefit from, the creation of know-how and the transfer of technology in the energy sector. Switzerland's involvement in international crisis management mechanisms strengthens the security of supply to Switzerland.

PROMOTING PROJECTS IN DEVELOPING AND TRANSITIONING COUNTRIES

In June 2014, the Swiss Federal Office of Energy ("SFOE") set out Switzerland's commitment to the advancement of international sustainable energy policies and schemes.[15] Switzerland will contribute CHF6.8 million to the Renewable Energy and Efficiency Promotion in International Cooperation ("REPIC"). REPIC is an interdepartmental initiative consisting of the Swiss State Secretariat for Economic Affairs, the Swiss Agency for Development and Cooperation and the SFOE. Its mission, *inter alia*, is to increase Swiss involvement and assistance in helping transitioning and developing countries formulate renewable energy strategies. The funding will allow REPIC to provide funding for up to 20 projects each year. These projects will all focus on renewable energy.

Examples of the projects include:

- Energy City model in Morocco, led by IDE-E; and
- Caritas Switzerland is implementing an example of a waste-to-energy program, through a social enterprise in Indonesia. It will turn used cooking oil into biodiesel.

CONSUMPTION

Consumption increased by 2.5% in 2013, and in September 2014, the Federal Electricity Commission announced that in 2015 the average costs for electricity per household will increase to SFr931. Factors such as population growth, GDP increase and a rise in the number of vehicles on the road have all contributed to the increase. Further, power plant modernisation has also served to raise costs. Renewable energy consumption also increased in 2013.

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ENERGY LAW IN TURKEY

Recent developments in the Turkish energy market[1]

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It has been more than a decade since the Turkish energy market was opened to private sector participation. During this time, in parallel with economic growth and with the help of private investment, the Turkish energy market has grown rapidly. However, Turkey's energy demand has grown faster than the available supply, and a large amount of investment is needed for meeting Turkey's increasingly growing energy demand. Having realised this, the Turkish government set specific energy related targets for the Turkish Republic's centenary in 2023.[2] Since 2011, Turkey has taken several steps towards its centenary targets. In accordance with Turkey's targets, late 2013 and 2014 witnessed the following developments:

- Turkey enacted new pieces of legislation in order to further liberalise the energy market;
- significant energy generation assets have undergone privatisation;
- significant new installations were put into operation and have increased Turkey's total installed power; and
- important progress was achieved in some landmark infrastructure projects, such as the Trans Anatolian Natural Gas Pipeline ("TANAP") Project and two contemplated nuclear power plant projects.

In addition, several other significant developments affecting the Turkish energy market and its players occurred in late 2013 and 2014.

SIGNIFICANT LEGISLATIVE DEVELOPMENTS

Proposed amendments to the Natural Gas Market Law

In Turkey, downstream natural gas market activities are governed by the Natural Gas Market Law[3] (the "NGML"). In September 2012, the Ministry of Energy and Natural Resources (the "MENR") published the text of the draft law amending the NGML (the "Draft Amendment Law") and made the Draft Amendment Law available for public review and comments until 10 October 2012. On 4 August 2014, the Draft Amendment Law (with significant revisions) was submitted to the Turkish Grand National Assembly (the "Turkish Parliament"). As of the time this article was prepared, these amendments had not been enacted.[4] According to recent news in the Turkish press, the Draft Amendment Law is expected to be enacted in 2015.

The most significant difference between the Draft Amendment Law's former version and the version that was submitted to the Turkish Parliament is the elimination of the provision prohibiting companies to import natural gas from countries from which Boru Hatları ile Petrol Taşıma Anonim Şirketi ("BOTAŞ")[5] is already importing natural gas.[6] It is clear that the reasoning behind this change is to further liberalise the Turkish natural gas market and to make it more open to private sector participation.

Draft Nuclear Liability Law and draft Nuclear Law

In Turkey, nuclear energy is governed by the Law on Construction and Operation of Nuclear Power Plants and Energy Sale[7] ("Law No. 5710"). The main secondary legislation is the Regulation on the Principles and Procedures for Competition and Contracts within the Framework of Law No. 5710.[8] The MENR prepared:

- a draft law (the "Draft Nuclear Law"), which governs the licensing mechanism of nuclear power plants and provides the establishment of the Nuclear Regulatory Authority (the "NRA"), in early 2014; and
- a draft law on liabilities in the field of nuclear energy (the "Draft Nuclear Liability Law"), governing the liability regime in the event of a nuclear incident, in October 2013.

While the current legislation states that the Turkish Atomic Energy Authority (the "TAEA") is responsible for providing licences (ie, site licences, construction licences and operation licences) to nuclear power plants' operators, under the Draft Nuclear Law, the NRA will take over this duty. In addition, the Draft Nuclear Law increases the number of activities requiring a licence, and also introduces the "permit" mechanism. If the Draft Nuclear Law enters into force as it is, individuals and legal entities will be obligated to obtain the relevant licence from the NRA, in order to conduct the following activities:

- operating a nuclear power plant;
- operating a radioactive waste facility;
- conducting transportation activities of nuclear materials and radioactive wastes;
- performing duties determined by the NRA in nuclear power plants;
- establishing a radioactive waste facility; and
- conducting activities determined by the NRA regarding nuclear materials and radioactive wastes.

On the other hand, below is a list of notable activities which will require a permit from the NRA:

- constructing a nuclear power plant or radioactive waste facility;
- commissioning a nuclear power plant or radioactive waste facility;
- de-commissioning nuclear power plants or radioactive waste facilities; and
- importing or exporting nuclear materials and transporting them in Turkey.

The Draft Nuclear Liability Law provides an upper limit to the operator's liability.[9] In addition, it provides for the establishment of a nuclear damage determination commission, to determine the amount of damages exceeding the limits of the operator's liability. Further, the Draft Nuclear Liability Law states that operators and nuclear fuel carriers must provide a guarantee and insure the plant for possible damages.

New Electricity Market Law and new Turkish Petroleum Law[10]

In 2013, Turkey changed the primary legislation governing the Turkish electricity market and the Turkish upstream natural gas and petroleum markets. On 30 March 2013, the new Electricity Market Law[11] (the "EML") entered into force and abolished the former law of 2001. This law aims to address various new issues that have long been awaited in the market, such as the introduction of a "preliminary licence" mechanism for generation licence applications. This law also provides for the establishment of an electricity exchange, which will create a whole new market of its own and become a significant investment opportunity. Among some of the other novelties are the abolition of the auto-production licence system and introduction of the supply licence to the market.[12] In addition to the EML, on 2 November 2013, the new Electricity Market Licence Regulation was introduced.[13]

On 11 June 2013, Turkey enacted the new Turkish Petroleum Law[14] (the "TPL") and abolished the former law of 1954. Then, the Turkish Petroleum Law Implementation Regulation[15] entered into force in early 2014. The TPL brings a more liberal and investor friendly regime than the provisions that the former law imposed on upstream participants. Perhaps the most significant change brought by the TPL is the abolition of the "national interest" concept. Based on the "national interest" concept, Türkiye Petrolleri Anonim Ortaklığı ("TPAO")[16] had a statutory right to obtain exploration licences on behalf of the state, and by virtue of this right the TPAO had an advantage in respect of exploration licence applications. With the abolition of this concept, TPAO no longer has that privilege.[17]

Other legislative developments

In order to reach its centenary targets and further liberalise its energy market, Turkey enacted the following secondary legislation in late 2013 and in 2014 (so far):

- Regulation on Renewable Energy Resources For Electricity Generation;[18]
- Contest Regulation on Pre-Licence Applications Regarding Generation Facility Based on Solar and Wind Energy;[19]
- Electricity Market Distribution Regulation;[20]
- Electricity Market Connection and Use of the System Regulation;[21]
- Regulation on Electricity Market Activities of Organized Industrial Zones;[22]
- Electricity Market Consumer Services Regulation;[23]
- Electricity Market Import and Export Regulation;[24]
- Electricity Grid Regulation;[25] and
- Communiqué on Wind and Solar Measurements for Preliminary License Applications.[26]

According to news in the Turkish press, although the Electricity Market Connection and Use of the System Regulation was enacted on 28 January 2014, the Energy Market Regulatory Authority ("EMRA") has started drafting a regulation for amending this regulation in order to address certain issues such as: (i) regional generation capacity; (ii) access to distribution system; and (iii) facilities to be transferred to distribution companies. Furthermore, EMRA also prepared a draft regulation proposing amendments to the Natural Gas Market Licence Regulation,[27] which is the main secondary legislation regulating the Turkish downstream natural gas market.

Recent privatisations[28] and privatisation news

After completing the privatisation of all state-owned electricity distribution companies, previously owned by Türkiye Elektrik Dağıtım Anonim Şirketi ("TEDAŞ")[29] in 2013, Turkey started to place more importance on the privatisation of state-owned electricity generation assets. In 2014, several electricity generation assets owned by Elektrik Üretim Anonim Şirketi ("EÜAŞ")[30] have gone into different stages of privatisation. Below is a summary of privatisations that have been completed as of 1 January 2015:

POWER PLANT	CONTRACT DATE	APPROXIMATE BID VALUE (US$ MILLION)
Çatalağzı Thermal Power Plant	22 December 2014	350
Yatağan Thermal Power Plant	1 December 2014	1,091
Esendal, Işıklar (Visera) Hydroelectric Power Plants	10 November 2014	1.85
Kayaköy Hydroelectric Power Plant	3 November 2014	10.3
Kemerköy and Yeniköy Thermal Power Plants[31]	23 December 2014	2,671

The privatisation of Dere and İvriz Hydroelectric Power Plants (as a package) for US$ 2.3 million was approved on 7 August 2014. The contracts for this privatisation are still waiting for the parties' signatures, as of 1 January 2015.

In addition, the tender for the privatisation of Anamur, Bozyazı, Mut-Derinçay, Silifke and Zeyne Hydroelectric Power Plants as a package was held on 13 August 2014. The highest bid was US$8.85 million. This privatisation is currently in the approval phase. The privatisation of Tunçbilek and Orhaneli Thermal Power Plants for US$ 521 million is also in the approval phase. Finally, four companies applied for preliminary qualification until 19 December 2014 for the privatisation of Soma B Thermal Power Plant. It is expected that these companies will be invited to open bidding rounds in the near future. On the other hand, the tender for privatisation of İGDAŞ (Istanbul's natural gas distribution company) is expected to be announced after the enactment of the Draft Amendment Law.

Additionally, according to news in the Turkish press, four hydroelectric power plants with a total of 700MW of installed power, that were constructed by the private sector within the scope of a build – operate – transfer model, will be transferred to EÜAŞ between December 2014 and October 2016. Three of these power plants, namely Fethiye, Suçatı and Dinar 2 Hydroelectric Power Plants will be taken into the privatisation portfolio. The fourth ie, Akköprü Hydroelectric Power Plant with a total of 118.6 MW of installed power, has already been transferred to EÜAŞ in December 2014. Whether or not this power plant will be taken into the privatisation portfolio will be decided by the MENR.

Recently, the Minister of Finance, Mr. Mehmet Şimşek made a noteworthy statement to the Turkish press. According to Mr. Şimşek, certain amounts of public shares in (i) BOTAŞ; (ii) Türkiye Elektrik İletim Anonim Şirketi ("TEİAŞ");[32] and (iii) TPAO are planned to be added to the privatisation portfolio. In December 2014, the Energy Minister stated that a draft law on privatisation of TPAO was prepared.

SIGNIFICANT NEW INSTALLATIONS

One of Turkey's energy targets is to increase its installed power to 120,000MW by 2023. Below is a list of major power plants and plant units that were commissioned in 2013.

POWER PLANT	COMPANY	INSTALLED POWER (MW)
Samsun Natural Gas Combined Cycle Power Plant	OMV Samsun Elektrik	886.9
Gebze Natural Gas Thermal Power Plant	Ansaldo Energia & Unit	865
Denizli Natural Gas Combined Cycle Power Plant	RWE & Turcas	797.4
Artvin Deriner Hydroelectric Power Plant	EÜAŞ	670
Istanbul Ambarlı Thermal Power Plant		516
Denizli Natural Gas Combined Cycle Power Plant	AGE Enerji	205
Kandil Hydroelectric Power Plant	EnerjiSA	203.2
Köprü Hydroelectric Power Plant		155.2
Samsun OSB Natural Gas Combined Cycle Power Plant	Yeşilyurt Enerji	139.6
Tatar Hydroelectric Power Plant	Darenhes Elektrik	128.2
Karaburun Wind Power Plant	Lodos Karaburun	120

Although there have been a large number of new installations in Turkey in 2014, the following new installations (compared to others) can be considered significant in terms of installed power:

- Cengiz Enerji's Cengiz Natural Gas Combined Cycle Power Plant, with a total of 401MW of installed power, was put into operation in October 2014.
- In August 2014, a unit of Atlas Enerji's Atlas Thermal Power Plant, with 600MW of installed power, was put into operation.
- The commissioning of Ak Enerji's Egemer – Erzin Natural Gas Combined Cycle Power Plant, with a total of 904MW of installed power, was also completed in August 2014.
- In July 2014, İçdaş Elektrik's Bekirli Thermal Power Plant, with 600MW of installed power, was commissioned.
- EnerjiSA's largest hydroelectric power plant, the Arkun Hydroelectric Power Plant, with 237 MW of installed power, was put into operation in June 2014.
- İzmir Demir Çelik's İzdemir Import Coal Power Plant, with 350MW of installed power, was commissioned in April 2014.
- 2014 saw the commissioning of Turkey's largest wind power plant. Polat Enerji constructed the Geycek Wind Based Energy Power Plant (Geycek RES) in Kırşehir, with 150MW of installed power.

RECENT DEVELOPMENTS IN PENDING PROJECTS

Recent developments in the TANAP Project

On 24 July 2014, Turkey approved the environmental impact assessment report prepared for the TANAP Project. In September 2014, the Turkish Parliament approved:

- the "Memorandum of Understanding between the Republic of Turkey and the Republic of Azerbaijan Regarding the TANAP System"; and
- the "Text of Amendment to the Host Government Agreement between the Republic of Turkey and the TANAP Project Company".

The Council of Ministers' Ratification Decrees for these two texts were published in the Official Gazette on 21 October 2014.

In 2014, Minister of Energy, Mr. Taner Yıldız, once again reiterated the intention regarding Turkmen gas being transported through TANAP, along with Azeri gas, and stated that negotiations for this issue are still pending.

Recent developments in other international pipeline projects

Late 2013 and 2014 witnessed the following developments in other international pipeline projects:

- On 25 July 2013, Turkey enacted a Council of Ministers' Decree for the construction of a pipeline to transport natural gas from Iran to Germany through Turkey (ie, Iran – Turkey – Europe Natural Gas Pipeline Project). After this decree was published in the Official Gazette, the MENR commenced expropriation activities.[33] The easing of the embargo on Iran in November 2013 (and the possibility that it may be entirely lifted in the future) has increased the possibility of this pipeline project being realised.
- The Northern Part of Iraq – Turkey Crude Oil Pipeline Project was among the radical energy (as well as political) developments of 2013 in Turkey. In late November 2013, the Turkish government met with the administration of the Northern Part of Iraq to begin negotiations for the transport of petroleum from the Northern Part of Iraq. However, these negotiations seem to have ceased as the Iraqi central government insisted that it participates in the project, while the northern part disagrees. The fact that the Iraqi central government started an ICC arbitration against Turkey in an effort to prevent the export of Kurdish oil from Turkey shows the Iraqi central government's standpoint towards this project.
- 2014 witnessed the emergence of a possible new natural gas pipeline project. According to news in the Turkish press, in the first months of 2014, there have been talks between Turkish and Bulgarian officials regarding the construction of a natural gas pipeline between Turkey and Bulgaria.
- In July 2014, the Ministry of Environment and Urbanisation (the "MEU") approved the environmental impact assessment report for the South Stream Natural Gas Pipeline Project. However, during his visit on 1 December 2014, Russian President Vladimir Putin stated that the South Stream Natural Gas Pipeline Project was cancelled. It is reported that Russia and Turkey have started negotiations over a new pipeline project (ie, "Turkish Stream"), whose route has not been determined yet. Russian Gazprom and BOTAŞ signed a Memorandum of Understanding to build an offshore gas pipeline through the Black Sea to Turkey on 1 December 2014.
- In December 2014, Eustream officials stated that a new (bi-directional) pipeline, connecting Ukraine and Turkey will be included to the European energy distribution system in the near future.

Recent developments in nuclear power plant projects

After the developments of 2013, important progress was achieved for Turkey's first nuclear power plant, the Akkuyu Nuclear Power Plant. The environmental impact assessment report was approved by the MEU on 1 December 2014. The next phase is obtaining a construction licence from the TAEA and concluding an electricity sale agreement with Türkiye Elektrik Ticaret ve Taahhüt Anonim Şirketi ("TETAŞ"). US$2 billion have been invested in this project so far. According to the Minister of Energy, construction works for the Akkuyu Nuclear Power Plant will start in April or May 2015.

The discussions regarding the Memorandum of Understanding between Turkey and Japan regarding Turkey's second nuclear power plant project (the Sinop Nuclear Power Plant Project) was concluded and the Memorandum of Understanding was delivered to the Japanese Embassy for signature in August 2014. According to recent news in the Turkish press, the Memorandum of Understanding indicates that the host government agreement was agreed on at the end of August 2014. The intergovernmental agreement (signed in May 2013) and this Memorandum of Understanding were submitted to the Turkish Parliament on 8 December 2014. According to the authorities, the host government agreement will be attached to the intergovernmental agreement. The environmental impact assessment report regarding the Sinop Nuclear Power Plant Project is also expected to be submitted to the MEU in 2015.

Recent developments in thermic projects

After the Abu Dhabi National Energy Company ("TAQA"), deferred its investment decision on the construction and operation of a coal based power plant with a capacity of up to 8,000MW in Turkey's Afşin – Elbistan region, companies from the State of Qatar, Japan, China and South Korea started to compete for this project. This project is said to have an investment value of approximately US$ 12-14 billion. According to recent news in the Turkish press, during Mr. Yıldız's visit to the State of Qatar in September 2014, there were talks regarding this project.

In 2014, EÜAŞ's assessment works towards the use of a new coal reserve discovered in the Konya – Karapınar region have continued. According to recent news, EÜAŞ signed a confidentiality agreement with Italian Edison S.p.A., in order for the Italian company to conduct feasibility studies in the region. Approximately US$7 to 8 billion of investments are expected to be made in order to utilise an estimated amount of 1.8 billion coal in the region.

Recent developments in natural gas storage projects

One of Turkey's aspirations is to utilise its natural gas storage capacity. According to experts, Turkey has 2.6 bcm underground storage capacity and 535 million m^3 LNG storage capacity. Although there are six storage licences in force, Turkey has only four natural gas storage facilities.

One of Turkey's major pending projects is BOTAŞ's Tuz Gölü (salt lake) natural gas storage facility project. This project entails two phases, each of whose capacity is 500 million m^3. It is expected that first phase of this project will be completed at the end of 2016 and the second phase will be completed at the end of 2019. In July 2014, the environmental impact assessment process was completed. Construction works started at the end of 2012.

The second major natural gas storage project is Çalık Holding's project with a total capacity of 960 million m^3. As Çalık Holding's project is located near Tuz Gölü, negotiations took place among BOTAŞ, Çalık Holding and Arar Petrol, regarding the exact location of Çalık Holding's storage facility. The overlap problems have been resolved and Çalık Holding's natural gas storage licence application is currently pending before EMRA.

An ambitious new project: the largest solar energy power plant in the world

According to the Minister of Energy, Turkey has aspirations to build the world's largest solar energy power plant. This power plant, which will apparently have 3,000MW of installed power, is planned to be commissioned in Konya and expected to start electricity generation in 2018. In order to realise this project, an investment of approximately US$6 billion will be needed. According to recent news in the Turkish press, solar cells to be used in this project will be manufactured domestically.

SIGNIFICANT OTHER MARKET DEVELOPMENTS

Electricity

Conversion of auto-production licences

The EML, which entered into force on 30 March 2013, abolished the "auto-production licence" system. Accordingly, existing auto-producer licences were going to be *ex officio* converted to generation licences. The EMRA Board adopted its decree no. 4952-18, setting forth the general principles regarding termination of current auto-production licences and issuance of generation licences for the relevant entities. In accordance with these principles, the EMRA Board adopted another decree, no. 4969. According to Decree no. 4969, as of 1 May 2014, 260 of 274 auto-production licences were terminated and the auto-production licence holders were granted generation licences. According to the same decree, separate procedures will be carried out for the remaining 14 auto-production licences, due to their specific circumstances.

Termination of generation licences

Under Provisional Article 9 of the EML, if companies who obtain a generation licence do not fulfill their obligations to start construction (and submit relevant documents to EMRA) within six months following completion of the pre-construction period indicated in their licences, their generation licences will be terminated. Under Provisional Article 15 of the Electricity Market License Regulation, a six month period starting from 2 November 2013 was granted to companies whose pre-construction periods are completed, in order for them to fulfill the above mentioned obligations. Accordingly, if a company did not fulfill its obligations until 2 May 2014, its generation licence was to be terminated and the termination procedures were to be carried out by EMRA.

In order to extend the six month period to one year, EMRA proposed amendments to the EML. These were submitted to the Turkish Parliament on 16 June 2014. However, as these amendments have not yet been enacted, EMRA started to gradually terminate generation licences and, as of 15 September 2014, 31 generation licences were terminated. It is expected that the number of terminated generation licences will be more than 100 in the upcoming days.

Renewable energy

Renewable energy resource certificate

The Renewable Energy Resources Support Mechanism (the "RER Support Mechanism") was introduced in 2010, with the enactment of the amendments to the Law on the Utilisation of Renewable Energy Resources for the Purpose of Generating Electrical Energy (the "RER Law"). The RER Law provides a feed in tariff and additional incentives for each type of generation facility covered by the RER Support Mechanism (ie, hydroelectric, wind, geothermal, biomass including land fill gas and solar power). Additional incentives are provided if domestic equipment is used in facilities commissioned before 31 December 2020. In order to benefit from the incentives provided under the RER Law, facilities must obtain a renewable energy resource certificate (the "RER Certificate") from EMRA.

After the introduction of the RER Support Mechanism, renewable energy became much more appealing to investors. 38 companies obtained an RER Certificate for 2013 and 93 companies obtained an RER Certificate for 2014. Finally, 234 companies, which filed their applications by 31 October 2014, obtained an RER Certificate in order to benefit from the RER Support Mechanism in 2015.

Solar power and wind power generation licence applications

EMRA received applications for solar based energy generation licences between 10 and 14 June 2013. Although the designated total capacity for solar based generation licences was 600MW, applications were submitted for nearly 7,901MW. Thus, several contests were to be (and will be) organised in different regions, in order to decide who will obtain the generation licence for each relevant region. The first contests were held on 12 May 2014 for the Elazığ (for 8MW of total capacity) and Erzurum (for 5MW of total capacity) provinces. TEİAŞ announced the second (for Siirt-Batman-Mardin, Şanlıurfa-Diyarbakır, Antalya, Muğla-Aydın, Denizli and Burdur districts) and third (for Konya 1 and Konya 2 districts) contest packages. The contests within the scope of the second package will be held on 29 January 2015, whereas contests within the scope of the third package will be held on 30 January 2015. According to TEİAŞ, further contests to determine the candidates for solar based generation licences in other districts will be held in 2015.

As of December 2014, EMRA has not issued any solar power based generation licence. However, there are three solar power based preliminary licenses (for Şırnak, Elazığ and Erzurum districts) in force. The next window for submitting applications for solar based energy generation licences will be between 1 and 7 April 2015. On the other hand, as of 15 October 2014, 258 wind power based generation licences are in force. EMRA will receive applications for new wind power based generation licences between 24 and 30 April 2015.

Unlicensed energy generation

After the enactment of the Regulation on Generating Electricity without a Licence[34] in October 2013, abolishing the former regulation of 2011, the number of applications for unlicensed electricity generation has substantially increased. According to information available on the Unlicensed Electricity Generation Association's website, until 28 October 2014, a total of 4,846 applications have been submitted for unlicensed energy generation. While 2,142 applications have been approved, 849 applications have been rejected. 1,855 applications are still under evaluation.

Natural gas

In 2014, Turkish officials requested reduction for the price of natural gas that BOTAŞ imports from Russia and stated that, as of 1 January 2015, this price reduction is Turkey's right. Reportedly, Russia will grant Turkey a 6% discount on its gas imports from Russia in 2015. Turkey has started technical negotiations with Russian Gazprom regarding a volume increase in the natural gas imported through the Blue Stream Natural Gas Pipeline. These negotiations have been inevitable, as there is a risk that import of 4 billion m^3 natural gas via the Western Line could cease due to the crisis between Russia and Ukraine. The plan is to sign an additional contract with Gazprom and to increase the amount of natural gas being imported via the Blue Stream Natural Gas Pipeline from 16 billion m^3 to 19 billion m^3. According to recent news in the Turkish press, during the Minister of Energy's visit to Russia, the parties agreed in principle to increase the natural gas volume to 19 billion m^3. During his visit on 1 December 2014, Russian President Putin stated that the parties reached an agreement on this increase and Russia is ready to meet Turkey's energy demands.

Additionally, the term of the contract under which Turkey imports LNG from Algeria was extended for 10 years, in November 2014.

Shale gas

In September 2014, TPAO officials stated that negotiations between TPAO and Exxon Mobil for projects regarding shale gas reserves in the Thrace region of Turkey are continuing. TPAO also plans to sign an agreement with American Halliburton, for shale gas in the Thrace region. On the other hand, TPAO and Shell are conducting studies for shale gas reserves in the Diyarbakır province. However, according to TPAO officials, the first results of studies conducted for shale gas in Turkey will be available in 2015. According to experts, Turkey has 1.8 trillion m^3 shale gas reserves and these reserves could meet Turkey's 40 year gas demand.

EPİAŞ

One of the novelties of the EML is the establishment of an electricity exchange market, to be administered via a newly incorporated company, Enerji Piyasaları İşletme Anonim Şirketi ("EPİAŞ"). According to EPİAŞ's articles of association (the "AOA") (which was approved by EMRA but has not been published in the Trade Registry Gazette), EPİAŞ's shareholding structure will be as follows:

- 30% will be owned by TEİAŞ;
- 30% will be owned by the Istanbul Stock Exchange; and
- 40% will be owned by private energy companies.

After EMRA's announcement to private energy companies, 114 private energy companies applied to EMRA between 1 July 2014 and 29 August 2014, for subscribing to EPİAŞ's shares. Although a total of 24,629,108 shares were offered, private energy companies applied for a total of 63,887,716 shares.

On 16 December 2014, EMRA announced that the AOA had been finalised and the Regulation on the Organizational Structure and Working Principles of EPİAŞ had been prepared. According to the AoA, EPİAŞ's share capital is TRY 61,572,770 (approximately EUR 21,000,000 / USD 27,000,000) and while TEİAŞ and the ISE will hold Class A and B shares, private energy companies will hold Class C shares.

In its announcement, EMRA declared the list of 109 private companies that will hold Class C shares in EPİAŞ. According to the list, 39 private companies will hold the majority of EPİAŞ's Class C shares, each of which will hold 412,408 shares, if they pay their share capital contribution amounts.

CONCLUSION

The Turkish economy grew 4.3% in 2013. According to the International Monetary Fund, the Turkish economy will grow 2.3% in 2014 and 3.1% in 2015. Turkey's energy demand is expected to increase by approximately 7% each year, until 2023. In 2012, Turkey consumed over 119 million tonnes of oil and gas, and this volume is expected to increase to over 218 million tonnes by 2023.

Turkey's costs for importing crude oil and natural gas are currently as high as US$ 56 billion. This accounts for more than half of the country's foreign trade deficit. Due to insufficient domestic energy generation, Turkey's primary goal is to strengthen its security of supply. Turkey aims to diversify its energy supply routes and sources, and to reduce the import costs by using more domestic resources such as hydro power, other renewable energy resources and also coal, while initiating a nuclear power programme. According to the Minister of Energy, Turkey must receive approximately US$ 12 billion of investment each year until 2023, to meet its energy demands.

ENDNOTES

1. This article only includes certain significant developments until 1 January 2015.

2. For detailed information regarding Turkey's energy related targets for 2023, please refer to the Turkey Chapter of the European Energy Handbook 2014.

3. Published in the Official Gazette dated 2 May 2001 and numbered 24390.

4. For further information regarding the Draft Amendment Law, please refer to the Turkey Chapter of the European Energy Handbook 2014.

5. BOTAŞ is the natural gas transmission system operator.

6. BOTAŞ currently imports almost 80% of the total natural gas imported to Turkey. It imports natural gas from Russia, Turkmenistan, Azerbaijan and Iran in addition to LNG imports from Nigeria and Algeria.

7. Published in the Official Gazette dated 21 November 2007 and numbered 26707.

8. Published in the Official Gazette dated 19 March 2008 and numbered 26821.

9. There is no publicly available information on the amount of this upper limit.

10. Although these enactments took place in 2013, we will provide brief information on them in this chapter due to their importance.

11. Published in the Official Gazette dated 30 March 2013 and numbered 28603.

12. For detailed information regarding the EML, please refer to the Turkey Chapter of the European Energy Handbook 2014.

13. Published in the Official Gazette dated 2 November 2013 and numbered 28809.

14. Published in the Official Gazette dated 11 June 2013 and numbered 28647.

15. Published in the Official Gazette dated 22 January 2014 and numbered 28890.

16. TPAO is a state owned petroleum and natural gas company, which has both upstream and downstream (more generally, upstream) activities.

17. For further information regarding the TPL, please refer to the Turkey Chapter of the European Energy Handbook 2014.

18. Published in the Official Gazette dated 27 November 2013 and numbered 28834.

19. Published in the Official Gazette dated 6 December 2013 and numbered 28843.

20. Published in the Official Gazette dated 2 January 2014 and numbered 28870.

21. Published in the Official Gazette dated 28 January 2014 and numbered 28896.

22. Published in the Official Gazette dated 14 March 2014 and numbered 28941.

23. Published in the Official Gazette dated 8 May 2014 and numbered 28994.

24. Published in the Official Gazette dated 17 May 2014 and numbered 29003.

25. Published in the Official Gazette dated 28 May 2014 and numbered 29013.

26. Published in the Official Gazette dated 17 June 2014 and numbered 29033.

27. Published in the Official Gazette dated 7 September 2002 and numbered 24869.

28. Information under this section is obtained from the Privatisation Administration's website.

29. TEDAŞ is the state electricity distribution entity.

30. EÜAŞ is the state electricity generation entity.

31. This privatisation package also includes the Kemerköy Port Area.

32. TEİAŞ is the state electricity transmission entity.

33. According to the Council of Ministers' Decree, the Turkish part of the pipeline will pass through Ağrı, Erzurum, Erzincan, Gümüşhane, Sivas, Yozgat, Kırşehir, Kırıkkale, Ankara, Eskişehir, Bilecik, Kütahya, Bursa, Balıkesir, Çanakkale, Tekirdağ and Edirne. It is expected that Turkey's 1,720 km portion of the pipeline will cost approximately US$ 4 billion.

34. Published in the Official Gazette dated 2 October 2013 and numbered 28783.

ENERGY LAW IN UKRAINE

Recent developments in the Ukrainian energy market

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MAJOR REGULATORY DEVELOPMENTS

Ratification of EU-Ukraine Association Agreement

The association agreement between the European Union and the European Atomic Energy Community and Ukraine (the "Association Agreement") was simultaneously ratified by the European Parliament and Ukraine on 16 September 2014. The political provisions of this treaty were signed on 21 March 2014 and the economic part of the Association Agreement was signed on 27 June 2014. Chapter 11 (Articles 268-280) of the Association Agreement deals with the energy sector and, amongst other provisions, requires that the price for the supply of gas and electricity to industrial consumers be driven solely by supply and demand.

Furthermore, the Association Agreement: (1) introduces requirements regarding transit and transportation of electricity and gas, customs duties and quantitative restrictions, licensing exploration, development and production of oil and gas; (2) prohibits dual pricing; (3) determines the principles for functioning of the regulatory authority in the electricity and gas industries and; (4) establishes the relationship with the Energy Community Treaty. In addition, the relevant Annexes to Chapter 11 set forth an "Early Warning Mechanism" that outlines practical measures aimed at prevention of and rapid reaction to an emergency situation or to a threat of an emergency situation.

Reforms to the gas transportation system

On 14 August 2014 the Ukrainian Parliament voted to implement the reform of Ukraine's gas transportation system ("GTS"). As a member of the European Energy Community, Ukraine has to comply with the European Union's Third Energy Package (specifically, the Third Gas Directive and the New Gas Regulation), which introduces the requirement to separate production, transportation and storage of natural gas into separate companies. Thus, pursuant to these recent legislative changes, the functions of the operational and technological management of Ukraine's GTS should be transferred from the state-owned enterprise to an operating company, to be determined by the Ministry of Ukraine for Energy and Coal Industry. GTS' operator functions may be assigned to the entity, whose founder and owner can be either the state as a single shareholder (acting through the state national joint-stock company "Naftogaz Ukraine") or a group of shareholders consisting of the state (owning at least 51% of equity rights of the GTS operator) and companies located in the European Union, the United States or the European Energy Community. The GTS operator entity is supposed to function as a TSO for the gas-network and be a certified member of the European Network of Transmission System Operators for Gas (ENTSOG).

Simplification of the permit system in the alternative energy sources sector

On 9 April 2014 the Ukrainian Parliament amended the Law of Ukraine "On the Alternative Energy Sources". This law is aimed at eliminating excessive and unjustified regulatory and administrative barriers in the alternative energy sector by abolishing the requirement to obtain permits for:

- production, transportation and distribution of electricity, heat and mechanical energy from alternative sources;
- production of geothermal energy;
- installation of equipment, which uses solar radiation, wind or water-wave energy, to build alternative energy facilities;
- construction or reconstruction of hydro-electric power facilities that use the energy of small rivers; and
- creation of transportation networks for energy produced from alternative sources.

Creation of new regulatory authority for energy

On 27 August 2014, the President of Ukraine decided to dissolve the National Commission of Ukraine for Electric Energy Regulation and the National Commission of Ukraine for State Regulation of Utility Services and to create a new combined regulatory authority for the energy sector: the National Commission of Ukraine for Energy and Utility Services State Regulation ("NCEUSSR"). According to NCEUSSR's charter, approved on 10 September 2014, it is a state collegial body which acts as a regulatory body for energy and utility services, reports to the Ukrainian Parliament and is controlled by the President of Ukraine. In addition to the powers of the two previously existing agencies, NCEUSSR will have new powers under the Governmental Order No. 915-r (see below) regarding implementation of interim emergency measures in order to ensure the reliable and stable operation of Ukraine's integrated electricity system, and to prevent accidents and damage to the electric-power equipment and facilities. Furthermore, on 16 September 2014 the Ukrainian Parliament registered a bill that is supposed to provide a comprehensive legal basis for the operation of NCEUSSR, strengthen its independence and introduce preconditions for ensuring efficient state regulation in the spheres of energy and utility services.

Action plan on implementation of the Renewable Energy Directive in Ukraine

On 3 September 2014, the Cabinet of Ministers of Ukraine approved the action plan on implementation of Renewable Energy Directive. According to this action plan, between 2015 and 2016 the technical specifications for production and utilisation of biomass fuel and bio liquids must be elaborated as a step towards halving greenhouse gas emissions by 1 January 2017. Where facilities producing biomass fuel and bio liquids have become operational after 1 January 2017, their emissions should be reduced by at least 60% by 1 January 2018. In addition, the relevant regulatory authorities are obliged to develop and make public the methodology for calculation of indicators of reduction in greenhouse gas emissions for biomass fuel and bio liquids. Starting from 15 December 2014 and every two years Ukraine will prepare a report on the results of encouragement and utilisation of energy generated from renewable sources, which will be submitted to the Secretariat of the Energy Community.

Bill on specific functioning of the fuel and energy sector in the special period of time

On 4 July 2014 the Ukrainian Parliament considered, in a first reading, the draft Law "On the Special Period in the Fuel and Energy Sector", which empowers the Cabinet of Ministers of Ukraine and the Ministry of Ukraine for Energy and Coal Industry to operate and control directly the pipeline transportation of fuel and energy in a "special period", defined by the law as a time in which limited or no energy supply from outside Ukraine is available. In addition, during such a "special period", the Cabinet of Ministers of Ukraine will have the power to establish a special regime of operation in the fuel and energy sector; determine the functioning of a central supervisory (operational and process-enabled) control system of Ukraine's integrated electricity system and the GTS; and define the conditions for a possible termination or limitation of the electricity and/or gas supply to consumers.

PRIVATISATION IN THE ENERGY SECTOR

Government action to sell the state-owned shares in energy companies

On 17 July 2014, the Cabinet of Ministers of Ukraine approved a list of state-owned assets to be privatised in 2014. The list of 164 enterprises has a total market value equal to UAH 15 billion (US$1.3 billion) and includes state owned shares in 18 regional energy companies, four combined heat and power plants, 38 gas supply and gas infrastructure development companies, two oil trading companies, one coal company, and one coal mine. Authorities responsible for managing state-owned shares in these companies were obliged to transfer the state-owned shares to the State Property Fund of Ukraine within one month, in order to be offered for sale in the bidding process. Privatisation of the state-owned assets will be carried out pursuant to the schedule prepared by the State Property Fund of Ukraine. According to the Prime Minister of Ukraine, the privatisation of these assets will be considered on the basis of consultations with international partners. As reported by the Institute of Economics and Forecasting of the Ukrainian National Science Academy, the annual funding needed for modification of thermoelectric power stations is about US$1 billion. Ukraine can only get this amount from strategic investors by selling state-owned assets in the energy sector.

ELECTRICITY

Liquidation of state joint-stock company "Energy Company of Ukraine"

On 3 September 2014 the Cabinet of Ministers of Ukraine made a decision to liquidate state joint-stock company "Energy Company of Ukraine" and to place the state-owned share package of joint-stock companies in the energy sector, namely "Centerenergo (78.29% of shares), "Luganskoblenergo" (60.06% of shares), "Dnistrovska GAES" (87.4% of shares), under management of the Ministry of Ukraine for Energy and Coal Industry. Considering the fact that after this transfer state joint-stock company "Energy Company of Ukraine" will not own or manage any share, the governmental decision on the liquidation appears to be justified.

OIL AND GAS SECTOR

Termination of Russian gas supplies to Ukraine

In April 2014, the Russian Federation raised the price for supplying gas to Ukraine from US$268.5 to US$485.5 per thousand m^3 and stopped unilaterally to apply the gas cost allowance in the amount of US$100 per thousand m^3. Ukraine refused to accept this price. On 16 June 2014, the Russian state monopoly gas supplier Gazprom introduced a prepayment requirement for gas deliveries to Ukraine and stopped supplying gas to Ukraine as both sides failed to reach a compromise on price. On the same date, Gazprom submitted a claim against the Ukrainian state energy company Naftogaz to the Arbitration Institute of the Stockholm Chamber of Commerce, seeking US$4.5 billion for the supplied gas. Naftogaz also filed a claim in Stockholm, requesting the arbitral tribunal to establish a fair market price for the imported Russian gas. The claim includes a recovery from Gazprom of overpayment, which is estimated at US$6 billion. In addition, in October 2014 Naftogaz also appealed to the Arbitration Institute in Stockholm to review its contract with Gazprom for gas transit through Ukraine, to award compensation and to bring the contract into compliance with the Third Energy Package of the European Union.

Reverse gas flow from other countries

Due to the suspension of Russian gas supplies to Ukraine, Ukraine negotiated reverse gas flows from Poland, Slovakia and Hungary.

While trying to negotiate a solution with Russia, Ukraine continues to search for alternative suppliers. For example, Naftogaz signed an agreement with Norwegian energy company Statoil to supply 11 million m^3 of gas per day starting from 1 October 2014. According to recent official reports, Ukraine imported about 310 million m^3 of gas during the first 10 days of October and about 2 billion m^3 since the beginning of 2014.

New agreement on main terms for Russian gas supply

Several rounds of lengthy and tough negotiations between Ukraine and Russia led, at the end of October 2014, to an agreement on the main terms on which Russia would resume the gas supply to Ukraine. According to this agreement, Ukraine will pay USD365 per 1,000 cubic meters of gas in the first quarter of 2015. The parties also agreed that the price for the gas would be defined based on the formula specified in the gas supply contract, according to which the gas price depends on the oil price.

Government imposed limits on gas consumption

On 9 July 2014, the Cabinet of Ministers of Ukraine set the maximum quantity of gas that can be consumed before the end of the 2014 to 2015 heating season at 14.011 billion m^3. This limit was set following the suspension of Russian gas supplies to Ukraine, in order to reduce gas consumption, to ensure the continuing gas supply to the population and industries, and to maintain stable functioning of GTS and the gas distribution system. Specific limits in gas consumption are fixed at up to 0.626 billion m^3 for public offices, up to 7.532 billion m^3 for enterprises, and up to 5.853 billion m^3 for heat generating and heat distributing companies.

RENEWABLE ENERGY

Government intends to reduce the "green tariff"

On 18 June 2014 the Cabinet of Ministers of Ukraine recommended that NCEUSSR reduce the peak time ratio from 1.8 to 1.01 when calculating the feed-in tariff (known as the "green tariff") for producers of energy from alternative sources, with the exception of micro, mini or small water power plants. As a result, the overall payments of the "green tariff" guaranteed by the Law of Ukraine "On the Electricity" would be reduced by about half. However, some experts expressed doubts on the legality of this recommendation. One of the solar energy investors, "TEKT" Company, has filed a lawsuit against the governmental recommendation. NCEUSSR has not implemented the recommendations of the Cabinet of Ministers of Ukraine. According to the recent Resolution of NCEUSSR No. 1072, dated 31 July 2014 and amended on 7 August 2014, the "green tariff" was reduced by 2.86% simply to reflect the change in the euro exchange rate.

NUCLEAR ENERGY

Ratification of Guarantee Agreements

On 15 May 2014 the Ukrainian Parliament ratified the Guarantee Agreements in relation to the loan facilities that the European Bank for Reconstruction and Development (EBRD) and the European Atomic Energy Community (Euratom) will provide to Energoatom, the Ukrainian state company that operates all nuclear power stations in the country. The Loan Agreements and the Guarantees Agreements relating to the EBRD's and Euratom's loan facilities in the total amount of €600 million to be provided to Energoatom were signed on 25 March and 7 August 2013 respectively. The loan facilities will be used for safety improvements of Ukrainian nuclear power plants.

Ukraine diversifies sources of nuclear fuel supply

Westinghouse Electric Company and Energoatom agreed a contract extension for fuel deliveries to Ukrainian nuclear power plants through to 2020. The contract continues the companies' long-standing partnership to provide competitive and secure nuclear fuel supplies for Ukraine's reactor fleet. Westinghouse originally signed a contract for nuclear fuel in 2008 and postponed its fulfilment in 2011 while Ukraine preferred to purchase Russian nuclear fuel. Under the terms of the extended contract executed with Westinghouse Electric Sweden, Westinghouse will produce the fuel at its fabrication facility in Sweden. The first supplies will be shipped to Pivdennoukrainska nuclear power plant. Supplies to other Ukrainian nuclear reactors currently burning fuel from Russia's TVEL will follow. However, the contract will allow the Ukrainian nuclear energy sector to promote diversification of fuel supplies.

GENERAL ENERGY SECTOR ISSUES

Energy losses due to conflict

Following the Russian Federation's annexation of Crimea in March 2014, losses in Ukraine's energy sector are continuously increasing. Official data include not only assets of energy enterprises that were seized, but also the loss of potential revenues and state budget incomes. On 28 July 2014 the Minister for Energy and Coal Industry announced that such damage (including offshore hydrocarbon reserves) was estimated at about US$300 billion, including the loss of: 15 oil and gas fields; three upside fields of oil and gas; underground gas storage; more than 1200km of gas transportation lines; 43 gas stations; two gas filling compressor stations; 15 marine gas producing platforms and conductors; and four floating self-lifting drilling rigs. With regard to the hydrocarbon deposits, Ukraine no longer has access to production fields of about 50 billion m^3 of gas, about 3.5 million tons of oil, and about 1 million tons of natural gas liquids.

In addition, coal mines with a combined output of about 300 thousand tons of coal per month have been destroyed during the military operations in the territory of Donetsk and Lugansk Regions (the "Donbass Region"). As of beginning of October 2014, 83 of a total of 155 Ukrainian coal mines are located within territory that is not under the control of Ukrainian Government. Accordingly, about 30% of all coal that was supposed to be used for production of electricity is not available. The volume of coal extraction decreased by 3.1 times in Donetsk Region and by 2.7 times in Lugansk Region in comparison to September 2013. To resolve this problem at least partially, Ukraine signed an agreement with the Republic of South Africa to purchase 1 million tons of coal.

ENERGY LAW IN THE UNITED KINGDOM

Recent developments in the UK energy market

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There were significant developments during 2014 in the UK power and oil and gas sectors, with the implementation of various support schemes and transitional arrangements, under the Energy Act 2013, putting into effect the UK's strategy for Electricity Market Reform and publication of the final report by Sir Ian Wood in relation to maximising economic recovery from the UK Continental Shelf and the initial responses from industry and government. The UK government has held the first round of Capacity Market auctions and begun the first allocation process for generic contracts for difference. Key terms have been agreed in relation to a bespoke contract for difference for the new nuclear project at Hinkley Point C and this arrangement has received State aid approval from the European Commission. The Commission has also granted approval of the UK's capacity market mechanism and generic contract for differences ("CfDs") schemes (except in relation to biomass). There has been greater clarity in relation to the forthcoming transition from the existing renewables scheme, the Renewables Obligation, to the new support mechanism, CfDs, which, as noted in our previous issue, has been a cause for concern for the renewables sector. 2015 will see significant regulatory change in relation to the management of the UKCS. Further, in the Autumn Statement, the UK government has announced a number of significant reforms to the oil and gas fiscal regime. There have also been developments in relation to the nascent UK shale gas industry.

ELECTRICITY MARKET REFORM

The Energy Act 2013 (the "Act") received royal assent on 18 December 2013, with most provisions, save as to nuclear regulation, entering into force on that date or 18 February 2014. The Act provided the powers for the UK government's Electricity Market Reform ("EMR") proposals, setting out a framework for new incentives for investment in low carbon electricity generation and a capacity market aimed at ensuring sufficient gas and other flexible plant (including demand side reduction) is available to maintain system security. Secondary legislation implementing the detail of the reforms came into force in August 2014. State aid clearances for the Capacity Market process and the enduring CfD regime (see below) were awarded in July 2014.

The UK government Department for Energy and Climate Change ("DECC") has commissioned an independent evaluation of the Electricity Market Reform to assess its effectiveness in achieving the government's energy and climate change objectives and to provide practical insights for further refining the capacity market and contract for differences regimes.

CfDs

The Act provided enabling powers for the introduction of a feed-in tariff based on a CfD: a support scheme for low carbon generation (renewables, nuclear and fossil fuel plant fitted with carbon capture and storage technology), which will sit alongside and eventually replace the Renewables Obligation.

Eligible generators will enter into long-term contracts under which they are paid, or pay, the difference between a market reference price and a fixed strike price (being the price per unit of electricity generated, set at a level determined to be necessary to support the relevant generation technology). The counterparty pays the difference to the generator when the strike price is higher than the market reference price; the generator pays back to the counterparty the difference between the two prices when the market price is higher than the strike price. The counterparty to the CfD is the Low Carbon Contracts Company ("LCCC"), a government owned company which became fully operational on 1 August 2014. If the generator is able to sell power in the wholesale energy market at the market reference price, the CfD mechanism effectively "fixes" the price which the generator receives for its electricity.

Following consultation, the government has published a standard form ("generic") of CfD, which is structured as a front-end agreement incorporating a standard set of terms and conditions. Provisions have also been made for phased CfDs (designed to support phased offshore wind projects of up to 1,500MW) and dual scheme facilities, where facilities that have existing support for capacity under the Renewables Obligation can seek support under a CfD for new, but separate, capacity.

Each annual allocation round is announced by the Secretary of State, who also publishes an allocation framework, budget and standard CfD terms for that round. The CfD terms, allocation framework and budget, together with the Energy Act 2013 and implementing secondary legislation[1] form the legal framework for the CfD regime. Applications are initially assessed by the Delivery Body, National Grid, for eligibility, and qualifying applications can be included in the allocation process. The Secretary of State published the relevant notices and budget for the first CfD allocation round in October 2014 and applications were due in October. It was originally intended that the allocation round would begin in December 2014 with a sealed bid submission window of 5–9 January 2015; however, the Delivery Body received at least one appeal against a non-qualification decision and the appeal was assessed by Ofgem. Ofgem has now completed its assessment and bidders were invited to submit sealed bids for the auction between 29 January and 4 February. The winning bidders are likely to be notified in late February, and receive contracts in late March.

As well as the generic CfD allocation process, the Secretary of State is also enabled under the Energy Act 2013 to direct the LCCC to offer a CfD to an eligible generator, subject to Levy Control Framework (see below) budget constraints and State aid considerations. The Secretary of State has retained discretion as to the process for awarding such a contract, although the recipient generator must by 'eligible' as defined in the Contracts for Difference (Definition of Eligible Generator) Regulations 2014. As noted further below, the Secretary of State is currently in discussion with the operator of the Hinkley Point C nuclear plant, NNB Generation Company, in relation to award of a CfD under this 'bespoke' process for the new nuclear power plant at Hinkley Point C.

The UK government has also published a stakeholder engagement document on the possibility of Swansea Bay Tidal Lagoon being supported by the award of a CfD. Responses are sought on the matter until February 2015.

The government has recent published its response to its consultation on changes to the CfD supplier obligation and the introduction of non-delivery disincentives for the CfD.

Offtaker of last resort

Concerns from the renewables industry about the lack of a route-to-market led to the introduction of a "back-stop PPA" to renewable generators holding a CfD. Under the back-stop PPA, the offtaker of last resort mechanism (the "OLR") is intended to supplement and support the new CfDs by giving additional comfort as to the minimum revenues that a project will receive. It is designed to reduce the risk of market failure, boost competition and, ultimately, reduce costs passed down to consumers. Eligible generators (effectively, generators with a valid, 'live' CfD) will be provided with a guaranteed route-to-market for their power by way of a short-term 'Backstop PPA' ("BPPA") with an OLR. All licensed suppliers with a share of 6% or more of the GB electricity market are required to submit irrevocable management fee bids for each BPPA (Mandatory Offtakers). Ofgem will identify and notify the Mandatory Offtakers in each OLR year (running from 1 April to 31 March) by the preceding 1 September, based on suppliers' relative shares of the electricity market in the OLR year preceding the notification. Other licensed suppliers may voluntarily submit bids.

The government anticipates that providing this alternative to the current market practice (entering into a long-term PPA with a creditworthy entity) will reduce the difficulty and cost experienced by independent renewable generators when raising finance, as well as supporting new entry into the PPA market. Certain sections of the implementing legislation came into force on 14 October 2014, while the remaining provisions will enter into force on 1 October 2015. It is anticipated that generators will be able to apply for BPPAs from October 2015.

Capacity market

The Act contains the high level powers necessary to enable the design and implementation of a capacity market which is intended to increase the security of electricity supply, particularly in view of the expected increase in intermittent renewable and inflexible nuclear generation. The government confirmed the final design of the capacity market and auction arrangements in June 2014, the scheme received State aid approval from the European Commission in July and the implementing rules and regulations (the Electricity Capacity Regulations 2014 (the "Regulations") and the Capacity Market Rules 2014 (the "Rules")) came into force on 1 August 2014.[2] Later in August the government made some technical amendments intended to correct drafting errors in the Rules, which came into force for the first round of the Capacity Market auction. Ofgem has the power to make and amend the rules. The Secretary of State retains responsibility for certain aspects of the capacity market, such as the amount of capacity to procure, eligibility for capacity auctions and whether to hold an auction. Capacity "agreements" (the Capacity Market Rules 2014 use the term "agreement" to describe the rights and obligations which accrue to a capacity provider as a result of the Regulations and Rules) will be awarded through a competitive central auction in which it is envisaged that both generators and non-generation providers of capacity (such as demand side response and storage service providers) are eligible to participate and must opt-out of the pre-qualification stage by notice to the Delivery Body if they do not wish to do so. All generation plant, including existing plant, is eligible to participate in the auction, with some exceptions: plant receiving other forms of support, such as payment under a CfD or through the Renewables Obligation, those with Short Term Operating Reserve (STOR) contracts, interconnectors or interconnected generating plant not situated in Great Britain (non-GB plant) are not eligible. Providers of balancing services (except those with STOR contracts) are eligible to participate. The government is working towards expanding the capacity market to non-GB electricity capacity, and intends that interconnectors should be eligible to participate in capacity market auctions from 2015 onwards. The bidding parties will be interconnector owners and will hold capacity agreements up to the level of their de-rated capacity (the de-rated capacity will be decided on an individual basis, by the SoS). The government has stressed that this 'interconnector-led' approach is an interim measure, until a common approach is set at an EU-level for cross-border participation in national capacity remuneration mechanisms, at which point the government notes that it may be appropriate to move towards another structure such as a generator-led approach.

The government will hold four-year ahead and one-year ahead capacity auctions for each delivery year. The auction will follow a descending-clock format and is 'pay-as-clear', where all participants receive the clearing price. Existing generation, demand side response and storage providers will be offered one-year capacity agreements. New and refurbishing plant are eligible for 15 and 3 year contracts respectively.

The government is in the process of developing amendments to the Capacity Market Rules which it intends will clarify when an applicant can apply for a 15 year capacity agreement. It expects to reach its final conclusions around February 2015.

The one-year ahead auctions are intended to support the integration of demand side response ("DSR") and small-scale generation technologies which may have difficulties in committing capacity four years ahead. The government is also putting in place transitional arrangements to support these technologies and intends to hold the first such auction, which will focus on load following and time limited obligations (ie peak hours and days) in 2015. If required, there may be a second auction more closely aligned to the enduring regime requirements and parameters.

As with CfDs, National Grid, in its role as system operator, is the delivery body for the capacity market. As such, National Grid provides the government with analysis on the amount of capacity to contract for and administers the capacity market, assessing the eligibility of participants and running the auction process. It also publishes information regarding the capacity auctions and is required to maintain a register of Capacity Market Units (CMUs, which are generating or DSR units) that have been awarded capacity agreements.

The first four-year ahead capacity auction took place in December 2014 for delivery year 2018/19, the first year for which the Capacity Market will be running. The final results were announced in early January 2015: 49.26GW of capacity was procured at a clearing price of £19.40/kW/year (2012 prices). In total, 306 CMUs have been awarded capacity agreements, from 46 bidding companies. These represent 75.82% of the capacity which entered the auction.

Two challenges have been made to the European General Court maintaining that the Capacity Market is an unlawful subsidy, seeking to instigate a formal enquiry by the European Commission. It is thought the challenges, if successful, could have an effect on the first round auction which was held in December 2014.

The government is commissioning a review of the effectiveness of the Capacity Market arrangements and has acknowledged that it may wish to consult on further changes to the secondary legislation based on this review in spring 2015. The first phase of the review will cover the first pre-qualification round and December 2014 capacity auction.

It appears that the government intends, subject to Parliamentary approval, that the various proposed changes will be in force in time for the next four-year ahead auction, planned for December 2015. As the proposed changes may be relevant to the first transitional arrangements auction which is also scheduled for 2015, the government intends to run the first transitional arrangements auction concurrently with the enduring market auction in Q4 (December) 2015.

Levy Control Framework

The Levy Control Framework (the "LCF") is a mechanism designed to control spending on DECC's low carbon electricity levy-funded policies. The LCF is designed to ensure that public expenditure which is funded by consumers (through their energy bills) does not exceed a set limit. Within the overall cap of the LCF, DECC has set various 'budgets' for each policy or scheme (ie a budget for CfD allocation, the Renewables Obligation, small-scale Feed in Tariffs etc.). The annual cap rises to £7.6 billion in 2020/21 (in 2011/12 prices) and represents the maximum allowed expenditure through consumer bills on these schemes for the period 2014/15–2020/21. DECC can manage spend and deployment across all the schemes within the LCF, in order to ensure that an increase in costs in one area, resulting in a corresponding increase in consumer bills, can be matched by a decrease in costs or support elsewhere within the framework.

Electricity demand reduction pilot

Under this scheme, businesses and organisations can seek financial support for measures which enable them to make capacity savings through the installation of more efficient electrical equipment. Organisations will auction electrical savings in return for funding. The pilot scheme is intended to run for 2 years. Applications have closed for participation in the first phase (auction) of the scheme. Up to £10 million will be available for the first auction, which is scheduled for January 2015. The government has allocated £20 million to the scheme in total, however it has indicated that there may not be a second auction.

Emissions performance standard

The Act implemented a statutory limit on the amount of annual CO_2 emissions allowed from new fossil fuel power stations over 50MWe (receiving development consent after 18 February 2014, the date that the relevant provisions in the Act came into force), equivalent to 450g/kWh (or 450kg/MWh) at a load factor of 85%. In January 2015, the government published its response to its consultation on draft regulations implementing fully this emissions performance standard ("EPS"). The consultation and response set out proposals for: monitoring and enforcement of the EPS, time-limited exemptions for carbon capture and storage (CCS) projects and arrangements for where an existing coal generation unit is upgraded to supercritical technology or if a main boiler is replaced. The government does not expect the standard to apply in practice to any operational plants for 4-5 years, based on the typical timelines for construction of new fossil-fuel, commercial-scale plant. The level, which is intended to catch coal but not gas plant, is stated to apply until the end of 2044. The government has committed to reviewing the EPS every 3 years and the first review is due by the end of 2015.

Consumer redress orders

The Act amended the underlying gas and electricity legislation to grant formal powers to energy regulator Ofgem to enable it to compel licensed (and some unlicensed) gas and electricity businesses to offer redress to consumers, in addition to its existing powers to issue a financial penalty for breach of licence conditions or other relevant requirements. Ofgem is empowered to issue "consumer redress orders" which may provide for: (i) compensation to be paid directly to the consumer; (ii) publication of a written statement outlining the contravention and consequences; and/or (iii) imposing termination or amendment of the affected consumer's contract. The compensation, together with any financial penalty, is capped at 10% of the company's turnover.

Following a consultation earlier in 2015, Ofgem published a revised 'Statement of Policy in respect of Financial Penalties and Consumer Redress' setting out how it proposes to use its new enforcement powers.

Strategy and Policy Statement

The Act introduced powers for the government to formalise Ofgem's role in the energy sector in a Strategy and Policy Statement (the "Statement"), which will set out the government's existing energy policy statements. The Act requires Ofgem to submit plans for, deliver and report against policy outcomes set out in the Statement. The Statement is intended to remain in place for a full parliamentary term, but can be reviewed in the meantime, and must be reviewed every 5 years. The Statement may be reviewed: after a Parliamentary general election; if Ofgem has notified the Secretary of State that a specified outcome is no longer realistically achievable; or if there has been a significant change in the government's energy policy.

The government consulted on the proposed draft Statement in 2014. The consultation has closed and the government response is awaited. Following consultation, the Statement must be approved by Parliament before it can be designated. DECC has indicated that it plans to designate the Statement in early 2015.

CHANGES TO EXISTING RENEWABLES INCENTIVES

As noted above, the CfD regime is intended to replace the Renewables Obligation (the "RO"). Pursuant to the Act, the government has laid legislation closing the RO to new capacity and to additional capacity of 5MW or less, from 1 April 2017. Until this date, generators may choose whether to apply for support under the RO or the CfD scheme for new generation plant or additional capacity over 5MW. Where a plant has some capacity accredited under the RO and some under a CfD, the plant would be a "Dual Scheme Facility" and specific metering and fuel data arrangements would apply.

The government has confirmed that it will close the RO to new solar PV above 5MW and to additional capacity which would bring a solar PV generating station above 5MW, from 1 April 2015.

Where a generator is already accredited within the RO on 1 April 2017, it will continue to receive support under the RO until 31 March 2037 at the latest. The government proposes, subject to Parliamentary approval, to fix the price of a certificate from 2027 to 2037 in order to reduce market volatility as the scheme winds down. Generators would be able to sell their Renewable Obligation Certificates directly to the government at their long-term value.[3]

DECC and the Scottish government are introducing grace periods to enable generators to apply for accreditation under the RO after the closure date, in order to avoid an "investment hiatus" during the transition from the RO to CfDs.

RIIO: NEW FRAMEWORK FOR SETTING PRICE CONTROLS

Ofgem has introduced a new framework for setting price controls for gas and electricity transmission and distribution system operators. The new framework covers an eight year period and is called RIIO (Revenue = Incentives + Innovation + Outputs) and is described as a 'performance based model'. The price controls for electricity and gas transmission and gas distribution were set in 2013 for the period 2013 to 2021. In November 2014 Ofgem published its decision for the final determination for ten electricity distribution companies for the next price control period for the period 2015 to 2023. In December, Ofgem published the statutory consultation for implementation of its final determinations and intends to issue the revised licences in February 2015.

COMPETITION INVESTIGATION OF THE UK ENERGY MARKET

The Competition and Markets Authority (CMA) was established under the Enterprise and Regulatory Reform Act 2013 and became fully operational on 1 April 2014, replacing the Office of Fair Trading and the Competition Commission. Ofgem has concurrent powers with the CMA to enforce the Competition Act 1998 and Articles 101 and 102 of the Treaty on the Functioning of the European Union in the electricity and gas sector. On 26 June 2014, Ofgem referred the UK energy market to the CMA for a full market investigation. The investigation began immediately and the CMA is required to publish its final report by 25 December 2015. The CMA has indicated in its Issues Statement, published on 24 July 2014, that it will focus on the following 4 'theories of harm':

- that 'opaque prices and/or low levels of liquidity in wholesale electricity markets' may create barriers to entry in retail and generation, perverse incentives for generators and other market inefficiencies;
- that vertically integrated electricity companies might be adversely affecting the competitive position of non-integrated companies, to the detriment of customers;
- that holding a powerful market position in electricity generation may lead to higher prices; and
- that there are 'weak incentives' to compete on price and non-price factors in retail markets, particularly as a result of low consumer engagement, regulation and supplier behaviour

In its Issues Statement, the CMA indicated that it is minded not to investigate the wholesale gas markets, gas interconnection and storage and regulation of revenues from transmission and distribution, although it may review the incentives which arise from the transmission pricing regime.

The CMA has published its proposed 'case timetable': publication of relevant working papers and an annotated issues statement is expected in January/February 2015, further hearings will be in February/March 2015. The CMA intends to publish its provisional results in May to June 2015 and its final report in November to December 2015.

IMPLEMENTATION OF THE EU TARGET MODEL

Ofgem and various industry bodies have been working on issues arising from market coupling and the implementation of the EU Target Model. Ofgem's work has primarily focussed on developing the market arrangements around cross-border interconnectors and cross-border intraday market coupling. This has led to the proposed switch from the traditional electricity forward agreement (EFA) calendar for electricity trades to calendar months, and for the gas industry to work towards changing the GB traded gas day to fit in with the European gas day. In the UK, this would require the gas day to run from 5am-5am and not as currently from 6am-6am. The bodies that manage the industry codes and agreements for the gas and electricity sector are working with Ofgem to consider the impact of the Framework Guidelines and Network Codes. ACER is currently consulting on the impact of the proposed changes to the gas day, including a proposal by Oil & Gas UK as to the possible avoidance of this change in the UK.

NEW REGIME FOR INTERCONNECTORS

Ofgem has introduced a new regulatory regime for investing in interconnectors: a 'cap and floor' regime. This was originally co-developed with CREG, the Belgian Regulator, for Project NEMO, the proposed interconnector between Belgium and Great Britain. It forms part of the Integrated Transmission Planning and Regulation (ITPR) project in which Ofgem is analysing the arrangements for the planning and delivery of onshore, offshore and cross-border transmission networks. In summary, the cap and floor regulatory regime sets a framework for GB interconnector investment. This developer-led approach balances incentivising investment through a market-based approach, with appropriate risks and rewards for the project developers. The levels of the cap and floor, flat in real terms, are set ex-ante and remain fixed for the regime duration. The floor on returns is set by tracking an index with the idea that a notionally efficient financed interconnector developer should be financeable by considering the cost of debt through the index tracked when setting floor returns. The cap on returns is set by considering the cost of equity for a generation plant. Once the interconnector becomes operational, Ofgem and CREG will assess NEMO revenues every five years against the set cap and floor values. In December 2014, Ofgem approved the financing and regulatory regime for Project NEMO on the basis of this cap and floor regime. Ofgem is currently consulting on its 'minded-to position' in relation to the interconnector, NSN Link (owned by Statnett and National Grid NSN Link Limited), between Great Britain and Norway. It is understood that Ofgem is likely to apply the "cap and floor" approach to all near term interconnectors.

OIL AND GAS

Review of the UK's Oil and Gas Industry

The government commissioned senior oil & gas industry specialist, Sir Ian Wood, to conduct a review to consider how the UK could maximise the return it receives from its resources in the UK Continental Shelf (the "UKCS"). His final report, published in February 2014, set out the current state of the industry and identified the need for changes in government and industry stewardship of offshore activities in order to maintain the long-term viability of the industry and to halt decline. The report highlighted the large number of smaller fields in the UKCS, and that much of the extractive infrastructure is operating beyond its originally intended life span.

The report recommended a number of new measures, focussed on maximising the economic recovery ("MER") from the UKCS, including the creation of a new arm's length regulatory body focussed on both the economic and operational regulation of the UKCS, that is able to deal more effectively with disputes, impose sanctions and grant incentives, and ensure transparency and access to data.

In July 2014, the government published its response strongly in support of the findings of the Wood Review. It its response, the government set out its proposed approach to implementing the findings of the Wood Review and noted its intent to establish the principles of MER of the UKCS in statute, through the Infrastructure Bill. The government has formed an Interim Advisory Panel ("IAP") to advise on implementation of the Wood Review. The IAP is chaired by Sir Ian Wood and attended by government and industry.

As a result of the Wood Review, a new, arm's-length regulatory body, the Oil and Gas Authority (the "OGA"), will be set up and headquartered in Aberdeen. Its final corporate structure will be a government company, with the Secretary of State as sole shareholder. The government intends to establish the OGA initially as an Executive Agency, in spring 2015, and it will then transition to being a Government Company in 2016. Ultimately, the government intends that the OGA should be industry-funded; although it recently committed £3 million a year for the next five years to establishing and running the OGA. Andy Samuel (previously with BG Group) has been appointed CEO of the OGA and started in this role on 1 January 2015.

Oil and Gas Fiscal Review and Finance Bill 2015

In the 2014 Budget, the government announced a review of the oil and gas fiscal regime to ensure it continues to incentivise economic recovery as the UKCS basin matures, working with the OGA. In December 2014, the Treasury published the 2014 Autumn Statement (which sets out the next stage of the government's long-term economic plan) and, shortly after, published its conclusions from the fiscal review in a report titled "Driving investment: a plan to reform the oil and gas fiscal regime" (the Fiscal Review Plan). In the Fiscal Review Plan, the Treasury noted that the twin objectives of the fiscal regime should be to maximise the economic recovery of oil and gas whilst ensuring a fair return on those resources for the nation. To achieve these objectives, the government intends to apply the following principles:

- to be consistent with MER, the overall tax burden will need to fall as the basin matures;
- the government will consider the wider economic benefits of oil and gas production, when deciding on fiscal policy; and
- the government's judgement of what is a "fair return" will take into account global competitiveness of commercial opportunities in the UK and UKCS, acknowledging the global operations of many of the companies taking key investment decisions relating to the UK and UKCS.

The Treasury identified the government's plans for fiscal reform, which include the following immediate or near-term changes (some of which had already been announced as part of the 2014 Autumn Statement):

- a 2% reduction to the rate of the Supplementary Charge from 32% to 30% (taking effect from 1 January 2015 and to be legislated for in the Finance Bill 2015), and the government has expressed an aim to reduce the rate further. However, the price-based trigger point – a government commitment announced in 2011 as the Fair Fuel Stabiliser, which was supposed to reduce the Supplementary Charge if oil prices fell below $75 p/b – has been withdrawn;
- introduction of a basin-wide 'Investment Allowance' which would reduce the effective tax rate further for companies that invest in the future of the UKCS (this will be the subject of a consultation in early 2015);
- a new cluster area allowance will be introduced with effect form 3 December 2014 in relation to high-pressure, high-temperature projects (HPHT) to exempt a portion of a company's profits from the Supplementary Charge. The amount of profit exempted will be at least equal 62.5% of the qualifying capital expenditure a company incurs in relation to a cluster area, reducing the effective tax rate on those exempted profits to 30% (this change is being legislated for in the Finance Bill 2015 and is currently subject to consultation); and
- the existing ring fence expenditure supplement for offshore oil and gas, which adds an annual supplement to unused carried forward expenditure to preserve the time value of those costs, will be extended from six to 10 accounting periods in the Finance Bill 2015. This extension will only be available in respect of losses incurred on or after 5 December 2013.

Further changes identified are financial support for seismic surveys in underexplored areas of the UKCS (further detail expected in the Budget 2015) and work on options for fiscal support of exploration.

The Treasury is also considering options to improve access to decommissioning tax relief and reforming the fiscal treatment of infrastructure, and expects to consult on these with industry in 2015. This follows on from a number of changes in recent years relating to decommissioning tax relief, the principal one being the introduction in the Finance Act 2013 of legislation allowing the government to enter into Decommissioning Relief Deeds, under which the government provides contractual certainty as to the level of available tax relief for oil and gas decommissioning. Perhaps unsurprisingly therefore decommissioning costs were identified as being one of the OGA's top priorities in its first year of operation.

SHALE GAS

Operators' progress

On 16 January 2015 the Environment Agency granted Cuadrilla environmental permits for drilling, hydraulic fracturing and flow testing for natural gas of up to 4 wells within the Bowland Hodder shale formation at a site in Preston New Road, Plumpton in Lancashire, England. It still awaits determination of the planning application for the site as well as determinations of both planning and environmental consents for a second site in Lancashire. The report of the planning officer for both sites was however that planning consent should be refused on the grounds of unacceptable impacts from noise and traffic. The decision of the planning committee was awaited at the time of writing.

This followed an extended period of determination. The consultation period for comments on the environmental impact assessments for the sites was increased by several weeks to provide additional time for comment and there were further delays to the original schedule for the Minerals Planning Authority to receive and consider a Health Impact Assessment and for consultation on further information provided by Cuadrilla and its technical advisers. This has inevitably contributed to observations from some about the glacial pace of progress being made by the fledgling industry in the UK.

Celtique Energie meanwhile had its application to sink exploratory wells in the South Downs National Parks rejected. The unanimous recommendation of the South Downs National Park Authority to reject the planning application came after the government issued guidance that hydraulic fracturing should only take place in national parks in "exceptional" circumstances.

Shale gas players IGas and Dart underwent a merger and petrochemicals company Ineos acquired 80% of Reach Coal Seam Gas's licence in the Midland Valley of Scotland and announced the creation of Ineos Upstream with plans to invest US$1billion in shale.

UK Policy developments

Acknowledging the difficulties faced by operators and recognising the potential contribution of shale gas to the UK economy, the government did take some further steps in 2014 to promote and enable shale gas exploration and commercial development in the UK. Industry continues however to have some frustrations with the level of government support, particularly the need for a more proactive approach by the Office for Unconventional Oil and Gas, part of DECC that was created to co-ordinating the approach of the various governmental bodies involved.

Subterranean land access rights - trespass

Following a consultation on proposals, the government pressed ahead with amendments to the Infrastructure Bill to enable shale operators to drill horizontally beneath the surface and undertake hydraulic fracturing without the need for approval from the owner of the surface land interest. Without this right, drilling beneath the surface without the consent of the owner of that land constitutes a trespass. Analogous industries such a coal mining however have long enjoyed statutory rights attaching to their coal extraction licences.

The new right (if enacted) will extend not only to shale operators but also others conducting exploration or appraisal of petroleum or geothermal energy that involves accessing land at depths of 300m or more. It does not however alter the need to first obtain a petroleum licence, planning permission and environmental permits. It is likely that there will be additional provisions in the Bill, when enacted, imposing further restrictions on how and where shale gas operations can be conducted.

Development of the shale gas industry continues however to enjoy broad support from the major political parties as we move towards a May 2015 general election.

In the Autumn Statement, the Chancellor indicated that government intended to provide a new £5 million fund for the provision of independent evidence to the public about the robustness of the regulatory regime. It intends to allocate a further £31 million to create sub-surface research test centres led by the Natural Environment Research Council, with the objective of developing knowledge on technologies such as shale gas and also carbon capture and storage. Further, the government intends to set up a long-term investment fund for the North of England and other areas hosting shale gas development.

There have been a continuing string of Parliamentary Select Committee inquiries into shale. In July 2014 the House of Lords Economic Affairs Committee reported on the economic impacts of shale gas development. In December 2014, the Environmental Audit Committee launched an further inquiry into the environmental risks of fracturing which has already begun hearing oral evidence.

Europe

The European Commission is due to review by July 2015 the degree to which Member States have implemented their January 2014 Recommendations on shale and if found wanting could decide to reinvigorate the call for EU legislation of shale operations. There has however been a perceptible change of heart within the EU though following re-election of the Commission in late 2014 and particularly in reaction to the Russia - Ukraine crisis and continuing uncertainty in relation to Russian gas supplies to Eastern European countries. This has tended to result in the ascendance of energy security as the primary driver of EU energy policy, making the imposition of tough new requirements for indigenous shale gas exploration perhaps less likely than they appeared in 2013.

In Seville, the revision of the Reference Document for the determination of Best Available Techniques (BAT) for mining waste operations is underway. UK regulators and industry bodies are involved in that process, one objective of which is to make specific provision for determining BAT for management of waste resulting from shale gas operations.

Attempts to include shale gas exploration within the list of projects always requiring environmental impact assessment as part of the revision of the Environmental Impact Assessment Directive did not succeed. As a result of the agreed changes however, the scope of EIA under the Directive will in future expressly require consideration of climate change, the underground environment and the impact of natural disasters, all of which could be relevant to shale gas operations.

Industry initiatives

Industry body UKOOG published its own best practice guidelines for undertaking baseline monitoring for onshore hydrocarbons operations. It also undertook a major public communications exercise to allow members of the public to raise and receive answers to their concerns.

Ernst & Young authored a report into the measures necessary to encourage establishment of a sufficient supply chain for the industry in years to come and the creation of a National College was announced. The National College for Onshore Oil and Gas will be headquartered at Blackpool and The Fylde College and linked to colleges in Chester, Redcar and Cleveland, Glasgow and Portsmouth. The National College will provide high level specialist skills needed by the industry, provide training for teachers and regulators, carry out research and development, accredit relevant training and academic courses run by other institutions and work with schools to encourage children to consider careers in the industry.

Regulatory developments

In December 2013 DECC published a Roadmap designed to inform people how each of the principle regulatory regimes applicable to shale gas operations fits together.

14th Licensing Round and new model terms of licences

In June 2014, the government altered the model clauses for new onshore petroleum exploration and development licences. The new model clauses are designed to allow for the wide distribution of shale reserves across licence areas, clarify the process for extensions of time and provide for speedy dissemination of geological data and operational results from hydraulic fracturing. The new clauses are contained in the Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014 (the 2014 Regulations). These regulations apply to any licence granted on or after 17th July 2014, including those to be issued as part of the 14th licensing round which are pending determination by DECC.

The 14th Licensing Round was announced following the release by DECC of a strategic environmental assessment for further onshore oil and gas licensing, as required by EU legislation. This identified extensive areas of England & Wales that would be made available for licensing. and was complimented by the release of long awaited reports by the British Geological Society providing completed shale resource estimates for the following areas in the UK: Midland Valley of Scotland; Wales; Jurassic shale of the Weald Basin; and Bowland Shale.

DECC introduced the amendments to the model clauses in response to industry's warning that the previous clauses applied to shale operations would seriously inhibit or potentially prevent the shale gas industry developing. While the new clauses allow undrilled acreage and related licences to be retained for longer (supporting this need for flexibility), DECC has the ability to claw back areas not being worked actively. DECC expects the changes to make shale gas development more economically viable. United Kingdom Onshore Oil and Gas (UKOOG) have welcomed them.

The Environment Agency is expected to issue a new version of its technical guidance for the sector in the first quarter of 2015.

Public Health England released a report of the potential for health risks from shale exploration, concluding that such risks exist but are very low provided the industry is properly regulated.

Shale gas and tax

Finance Act 2014

Also, as expected, the Finance Act 2014 contained new measures designed to promote onshore oil and gas projects. The measures comprise:

- a new onshore tax allowance, which has the effect of removing a proportion of the profits from onshore oil and gas projects from the scope of the additional 32% rate of supplementary charge; and
- the extension of the ring-fence expenditure supplement from six to 10 years for onshore oil and gas activities, which has the effect of increasing the value of carried forward expenditure or losses for such projects (the supplement compensates companies for the decline in the value of unutilised losses in real terms, ie where they do not have sufficient taxable income at the start of field development to utilise those losses until later periods).

These new measures apply to onshore oil and gas projects generally, including shale gas projects. The Finance Act 2014 received Royal Assent in July 2014, although the two measures described above took from 5 December 2013.

EU OFFSHORE SAFETY DIRECTIVE

The deadline for the implementation of the EU Offshore Safety Directive in UK law is July 2015. The UK government has consulted on aspects of changes to UK regulations required to achieve the Directive's objectives. Once enacted, operators of offshore installations will need to amend, and re-apply within a short window for approval of, extended "safety and environmental management systems" documents in accordance with the new regime, or cease operating. Arrangements with industry have been made to schedule this process to avoid overloading the Health & Safety Executive. A final conclusion is also awaited on the future set up of the environmental regulator for the offshore industry which the Directive requires to be separated from economic regulation by DECC (current it is within the remit of DECC Environment).

NUCLEAR POWER

Office for Nuclear Regulation

In March 2014 the Office for Nuclear Regulation (ONR), which was set up as a non-statutory agency of the Health and Safety Executive (HSE) on 1 April 2011, was made into a statutory body under the Act. Under the Act, the statutory ONR has responsibility for five key areas: nuclear safety; nuclear security; nuclear safeguards; the transport of nuclear material; and health and safety on nuclear sites.

New nuclear build

Substantial progress was made during 2014 in relation to the building of a new 3,260 MW nuclear plant at Hinkley Point in Somerset, following the granting of a nuclear site licence in November 2012, the first new site licence for a UK nuclear power station in 25 years. NNB Generation Company (an EDF Energy company) obtained a development consent order for the plant in March 2013, and government announced in October 2013 that it had reached agreement on the strike price for the contract for difference that will support the financing of the plant and that the project would be eligible for support under the UK infrastructure guarantee scheme. The strike price will be reduced if plans for a second plant, at Sizewell in Suffolk, proceed. On 8 October 2014, the European Commission announced that it had approved the State aid for the Hinkley Point C CfD.

The government has indicated that it intends that future CfDs for nuclear projects should if possible be awarded through a competitive project selection process, although it also reserves the ability to allocate a CfD through bilateral negotiation, as with Hinkley Point C.

Horizon Nuclear Power (now owned by Hitachi) is also progressing its plans for a potential 2,600 MW plant at Wylfa, Anglesey and, during 2014, completed the first stage of a formal public consultation (required prior to applying for a development consent order). In August, the Regulators concluded step 2 of the Generic Design Assessment for the Hitachi-GE's UK Advanced

Boiling Water Reactor (UK ABWR). The Regulators are aiming to complete the GDA of the UK ABWR, if all goes well, in December 2017. Horizon has also signed a deed with the Office for Nuclear Regulation (ONR) giving the ONR oversight of its procurement arrangements as a step towards obtaining a nuclear site licence.

In June 2014, Toshiba Westinghouse acquired a 60% stake in NuGeneration Ltd from GDF Suez, which retained 40%. Following this, Westinghouse AP1000 design was resubmitted to the GDA process and the ONR has recommenced work on closing out certain outstanding GDA issues for the design.

CARBON CAPTURE AND STORAGE

The government is seeking to support development of commercial-scale carbon capture and storage (CCS) technology, through EMR and the UK Carbon Capture and Storage (CCS) Commercialisation competition. Up to £1 billion capital funding is available through the competition and, as part of this programme, the government signed front end engineering and design (FEED) agreements with White Rose (in December 2013) and Peterhead (in February 2014). The government has invested around £100 million and is negotiating with the two companies in relation to granting the remainder of the available £1 billion. DECC hope that these negotiations will enable the companies to take their final investment decisions towards the end of 2015. The arrangements will be subject to State aid approval. The government is also consulting on development of a generic CfD and CfD allocation process for CCS.

REPORTING BY EXTRACTIVE COMPANIES ON GOVERNMENT PAYMENTS

The final Regulations and rules for the UK implementation of the requirements for reporting by extractive companies on payments to governments have been published and are in force for accounting years beginning on or after 1 January 2015.

The new EU regime for disclosure of government payments by the extractive industries is derived from two EU Directives, which are required to be implemented in each EU member state:

- Chapter 10 of the new EU Accounting Directive (2013/34/EU) (published in June 2013), which applies to large companies and any 'public interest entities' (that is any company with securities traded on an EU regulated market) incorporated in an EU Member State ("AD"); and
- Article 6 of the amended EU Transparency Directive (2004/109/EC, as amended by 2013/50/EU) (published in November 2013), which extends the regime to all companies with securities (debt or equity) listed on an EU regulated market, therefore including non-EU incorporated companies with an EU listing ("TD").

The UK has decided to implement the requirements early, with effect for financial periods beginning on or after 1 January 2015 through:

- The Reports on Payments to government Regulations 2014, which implement the AD provisions; and
- new Disclosure and Transparency Rule 4.3A, which implements the amended TD provisions.

REGULATION ON WHOLESALE ENERGY MARKET INTEGRITY AND TRANSPARENCY (REMIT)

DECC has consulted on the introduction of two new criminal offences of energy market manipulation and insider trading. This is intended to strengthen the existing civil regime and meet the government's commitment to create criminal sanctions for energy market abuse. In the consultation, the government proposes to put in place criminal penalties of up to 2 years imprisonment for the offences of market manipulation and insider dealing. It has been noted in the press that this is less than the 7 year maximum penalty for certain offences under corresponding legislation for the financial markets. In order to put the regime in place quickly (the government has suggested it would be in place by March 2015), the government has proposed to implement the sanctions through the European Communities Act (1972), and this has limited the maximum term of imprisonment that could be imposed by the courts. The government intends to monitor the relationship between the energy market and financial market regulations, with the aim of 'increasing their alignment over time'.

In December 2014, Ofgem opened a consultation on proposed to changes to its REMIT Procedural Guidelines (which explain how Ofgem carries its powers under REMIT) and the REMIT Penalties Statement (which explains how and when Ofgem will enforce a penalty if an individual or company breaches REMIT). The consultation closes on 19 February 2015.

LOOKING FORWARD

A number of developments are expected in 2015 in relation to the UK oil and gas and power sectors. In relation to oil and gas, the government has indicated that it intends to implement as quickly as possible the reforms to the offshore oil and gas sector recommended by the Wood Review, and that it expects industry to do the same. Much of the legislative arrangements formally putting in place the new regulator, the OGA, and setting its objectives, derived from the MER UK strategy, are scheduled to take place throughout 2015 and early 2016. There will be significant interest, from the market and industry participants alike, in the impact of the results of the first capacity market auction and, once completed, the first allocation round for CfDs. Industry participants will also be following the further developments in the government's EMR programme, in particular the proposed expansion of the capacity market to interconnector capacity and the introduction of the transitional arrangements for DSR. Further significant developments may emerge as a result of the CMA competition enquiry, with the CMA's conclusions due in December 2015. Finally, it is likely there will be keen interest in the results of the general election scheduled for 7th May 2015, and the differing strategies for the UK energy sector that may be proposed by the competing parties in the run up to the election.

ENDNOTES

1. Currently, the: Contracts for Difference (Allocation) Regulations 2014; the Contracts for Difference (Definition of Eligible Generator) Regulations 2014; Contracts for Difference (Electricity Supplier Obligations) Regulations 2014; Contracts for Difference (Standard Terms) Regulations 2014; Allocation Framework; the Electricity Market Reform (General) Regulations 2014 and the CfD (Counterparty Designation) Order 2014.
2. The government subsequently has also brought into force the Electricity Capacity (Supplier Payment etc.) Regulations 2014.
3. 'Planning our low carbon future: a white paper for secure, affordable and low carbon energy', dated 12 July 2011.

OVERVIEW OF THE LEGAL AND REGULATORY FRAMEWORK IN EUROPEAN JURISDICTIONS

ALBANIA

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Enti Rregullatori I Sektorit Te Energjise Elektrike (Regulatory Body Of The Electric System) ("ERE")
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Independent System Operator
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Hydro powerplants
	TRANSMISSION SYSTEM OPERATOR(S)	Operatatori I Sistemit Te Transmetimit (Transmission Operator System) ("OST")
	ELECTRICITY DISTRIBUTOR(S)	Operatori I Shperndarjes Se Energjise Elektrike (Electricity Distributor Operator) ("OSHEE")
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Korporata Elektro-Energjetike Shqiptare (Albanian Electro-Energetic Corporation ("KESH")
	INTERCONNECTORS	Albania Montenegro Greece
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer
	TRANSPORTATION SYSTEM OPERATOR(S)	Albpetrol Sh.A.
	GAS DISTRIBUTOR(S)	Albpetrol Sh.A.
	PRINCIPAL GAS SUPPLIER(S)	Albpetrol Sh.A. And From Imports
	INTERCONNECTORS	NA

AUSTRIA

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Energie-Control Austria
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Austria has implemented all four models (FOU, ISO, ITO, ITO+)

AUSTRIA (CONTINUED)

PRINCIPAL ELECTRICITY GENERATOR(S)	Verbund Hydropower AG Tiroler Wasserkraft AG Vorarlberger Illwerke AG Kelag Kärntner Elektrizitäts AG Steweag Steg ImWind GmbH
TRANSMISSION SYSTEM OPERATOR(S)	Austrian Power Grid AG TIWAG Netz AG VKW Netz AG
ELECTRICITY DISTRIBUTOR(S)	More than 130 Wiener Netze GmbH Netz Niederösterreich GmbH Steweag-Steg Netz Burgenland Strom GmbH KNG-Kärnten Netz GmbH Salzburg Netz GmbH Vorarlberger Energienetze GmbH Netz Oberösterreich GmbH TINETZ-Stromnetz Tirol AG
PRINCIPAL ELECTRICITY SUPPLIER(S)	Verbund AAE Naturstrom Vertrieb GmbH MyElectric Energievertriebs-u.dienstleistungs GmbH oekostrom Vertriebs GmbH switch Energie Burgenland AG Energie AG Oberösterreich EVN AG KELAG Salzburg AG TIWAG Wien Energie GmbH
INTERCONNECTORS	Austria has interconnections with the Czech Republic, Hungary, Italy, Germany, Slovenia and Switzerland

AUSTRIA (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Austria is an importer of gas, mainly from Russia
	TRANSPORTATION SYSTEM OPERATOR(S)	Gas Connect Austria TAG GmbH
	GAS DISTRIBUTOR(S)	Wiener Netze GmbH Netz Niederösterreich GmbH Gasnetz Steiermark
	PRINCIPAL GAS SUPPLIER(S)	Wien Energie Erdgas OÖ. Gas-Wärme GmbH switch Energievertriebsgesellschaft mbH My electric Energievertriebs-u.dienstleistungsGmbH Unsere Wasserkraft Kelag Kärntner Elektrizitäts-AG
	INTERCONNECTORS	Trans-Austria-Gas-Pipeline (TAG) South-East-Gas-Pipeline (SOL) West-Austria-Gas-Pipeline (WAG) Hungarian-Austria-Gas-Pipeline (HAG) PENTA-West-Pipeline

BELARUS

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	The President of The Republic of Belarus The National Assembly of The Republic of Belarus The Council of Ministers of The Republic of Belarus The Ministry of Energy of The Republic of Belarus The Ministry of Economy of The Republic of Belarus The Ministry of Natural Resources And Environmental Protection of The Republic of Belarus
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	N/A

BELARUS (CONTINUED)

PRINCIPAL ELECTRICITY GENERATOR(S)	Lukomlskaya Gres Beriozovskaya Gres Minsk Tec-4 Minsk Tec-5 Gomel Tec-2 Minsk Tec-3 Novopolotsk Tec Mogilev Tec-2 Svetlogorsk Tec Mozyr Tec Bobruysk Tec-2 Grodno Tec-2 (High-Pressure Power Plants)
TRANSMISSION SYSTEM OPERATOR(S)	RUP "ODU" (Affiliate of the state industrial group GPO "Belenergo")
ELECTRICITY DISTRIBUTOR(S)	RUP "Brestenergo" RUP "Vitebskenergo" RUP "Gomelenergo" RUP "Grodnoenergo" RUP "Minskenergo" RUP "Mogilevenergo" (Regional affiliates of the state industrial group GPO "Belenergo")
PRINCIPAL ELECTRICITY SUPPLIER(S)	RUP "Brestenergo" RUP "Vitebskenergo" RUP "Gomelenergo" RUP "Grodnoenergo" RUP "Minskenergo" RUP "Mogilevenergo" (Regional affiliates of the state industrial group GPO "Belenergo")
INTERCONNECTORS	Russia Ukraine Lithuania Poland

BELARUS (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer (from Russia) No shale gas in the jurisdiction
	TRANSPORTATION SYSTEM OPERATOR(S)	OJSC "Gazprom Transgaz Belarus" State Industrial Group GPO "Beltopgaz"
	GAS DISTRIBUTOR(S)	OJSC "Gazprom Transgaz Belarus" State Industrial Group GPO "Beltopgaz"
	PRINCIPAL GAS SUPPLIER(S)	OJSC "Gazprom" (Russia) "Belneftekthim" Concern
	INTERCONNECTORS	OJSC "Gazprom Transgaz Belarus" The "Yamal-Europe" main gas pipeline low-capacity interconnections with Russia Ukraine Lithuania Poland

BELGIUM

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	CREG (Federal Regulator) VREG, BRUGEL, CWAPE (Regional Regulators)
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Full Ownership Unbundling ("FOU")
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	EDF Luminus, Electrabel (GDF SUEZ), E.ON
	TRANSMISSION SYSTEM OPERATOR(S)	Elia System Operator S.A.
	ELECTRICITY DISTRIBUTOR(S)	Aieg, Aiesh, Gaselwest, Ores (Namur), Ores (Hainaut Electricité), Ores (Est), Ores (Luxembourg), Ores (Verviers), Ores (Brabant Wallon), Ores (Mouscron), Pbe, Régie D'electricité De Wavre, Tecteo
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Electrabel (gdf suez), EDF Luminus, eneco, eni gas & power, e.on Belgium, lampiris, Essent Belgium, OCTA+, Poweo, Mega, belpower, energie2030
	INTERCONNECTORS	France, Luxembourg, Germany, The Netherlands, United Kingdom (forthcoming, expected to be finalised in 2018)

BELGIUM (CONTINUED)

GAS

IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer (the main suppliers are: Norway (36% in 2012) and the Netherlands (26% in 2012) with other supply from: Russia and the United Kingdom, Qatar (12% in 2012) is the main source of LNG imports
TRANSPORTATION SYSTEM OPERATOR(S)	Fluxys
GAS DISTRIBUTOR(S)	Gaselwest, Imea, Imewo, Intergem, Iveka, Iverlek, Interelectra, Pbe, Iveg, Wvem, Ideg, Ieh, Igh, Interest/Ost, Interlux, Intermosane, Sedilec, Simogel
PRINCIPAL GAS SUPPLIER(S)	Eni Gas & Power (41% in 2012), Electrabel/GDF Suez (28% in 2012), EDF Luminus (10% in 2012) Other gas suppliers include: Belgian Eco Energy (BEE), Coretec, Direct Energie, Electrabel Customer Solutions, Elexys, Eneco België, Enovos Luxembourg, Essent Belgium (RWE), Etrim – Energy Cluster, Gas Natural Europe Belux, GDF Suez, Groene Energie Administratie (Greenchoice), Lampiris, Mega Power Online Sa, Natgas, Octa+, Powerhouse, Scholt Energy Control, Total Gas & Power Belgium, Wingas Gmbh
INTERCONNECTORS	France/Spain/Italy, Germany, Luxembourg, The Netherlands, Russia, Norway, United Kingdom

BOSNIA AND HERZEGOVINA ("BH")

GENERAL

NATIONAL REGULATORY AUTHORITY (-IES)	**I Electricity sector** 1. At Central level – State Electricity Regulatory Commission ("SERC") 2. In the Republic of Srpska (RS) – Regulatory Commission for Energy of Republic of Srpska ("RCERS") 3. In the Federation of Bosnia and Herzegovina ("FBH") – Regulatory Commission for Electricity of Federation of Bosnia and Herzegovina ("FERC") **II Other energy sectors** In RS, RCERS is the regulator for other energy sectors. In FBH, the Ministry of Energy, Mining and Industry is the regulator for the oil and gas sector.
UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	In the electricity sector, the unbundling of the transmission system will take place by the establishment of an independent system operator at the state level. The unbundling has not yet been completed. In the gas sector unbundling is not yet implemented.

BOSNIA AND HERZEGOVINA ("BH") (CONTINUED)

PRINCIPAL ELECTRICITY GENERATOR(S)	In the RS: Mixed Holding Electric Power Company of the Republic of Srpska ("EPC") In the FBH: Electric Power Company of BH ("EPBH"); and Electric Power Company of Croatian Community of Herceg Bosnia ("EPHB").
TRANSMISSION SYSTEM OPERATOR(S)	Independent System Operator of Bosnia and Herzegovina ("ISO") Transmission Company "Elektroprenos"
ELECTRICITY DISTRIBUTOR(S)	In the RS: 5 subsidiaries of the EPC: Elektro Doboj Elektro-Bijeljina Elektrokrajina Elektrodistribucija Elektro-hercegovina In the FBH: EPBH and EPHB
PRINCIPAL ELECTRICITY SUPPLIER(S)	In the RS: 5 subsidiaries of the EPC: Elektro Doboj Elektro-Bjeljina Elektrokrajina Elektrodistribucija Elektro-hercegovina In the FBH: EPBH and EPHB
INTERCONNECTORS	Serbia Croatia Montenegro

BOSNIA AND HERZEGOVINA ("BH") (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer The origin of the gas is the Russian Federation.
	TRANSPORTATION SYSTEM OPERATOR(S)	In the RS: Gas Promet a.d. Istočno Sarajevo Sarajevo Gas a.d. Istočno Sarajevo In the FBH: BH GAS d.o.o Sarajevo
	GAS DISTRIBUTOR(S)	In the RS: Sarajevo Gas a.d. Istočno Sarajevo Zvornik Stan a.d. Zvornik In the FBH: Sarajevo Gas d.o.o. Sarajevo Visoko Gas
	PRINCIPAL GAS SUPPLIER(S)	In the RS: Zvornik Stan a.d. Zvornik Sarajevo Gas a.d. Istočno Sarajevo In the FBH: Sarajevo Gas d.o.o. Sarajevo Visoko Gas
	INTERCONNECTORS	BH has an interconnection with Serbia BH GAS is competent for import of the gas on the territory of Bosnia and Herzegovina.

BULGARIA

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	State Energy And Water Regulatory Commission Minister Of Economy, Energy And Tourism Agency For Sustainable Energy Development
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	ITO

BULGARIA (CONTINUED)

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Nuclear Power Plant Kozloduy (2,000Mw) Thermal Power Plant Aes Maritza East I (670Mw) Thermal Power Plant Maritza East Ii (1,556Mw) Thermal Power Plant Maritza East Iii (906Mw) Cez Thermal Power Plant In Varna (1,260Mw)
	TRANSMISSION SYSTEM OPERATOR(S)	Electricity System Operator EAD (a wholly-owned subsidiary of the Bulgarian energy holding EAD)
	ELECTRICITY DISTRIBUTOR(S)	EVN Electrorazpredelenie AD (EVN Grid) ČEZ Razpredelenie Bulgaria AD (CEZ Grid) Energo-Pro Mrezhi AD (Energo-Pro Grid)
	PRINCIPAL ELECTRICITY SUPPLIER(S)	NEK EAD EVN Electrosnabdyavane AD ČEZ Electro Bulgaria AD Energo-Pro Prodazhbi AD
	INTERCONNECTORS	Greece (1) FYROM (3) Romania (4) Serbia (3) Turkey (2)
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer Russia
	TRANSPORTATION SYSTEM OPERATOR(S)	Bulgartransgaz EAD
	GAS DISTRIBUTOR(S)	Local distribution companies, most of them being subsidiaries of Overgas AD
	PRINCIPAL GAS SUPPLIER(S)	Bulgargaz EAD
	INTERCONNECTORS	Greece FYROM Romania Serbia Turkey

CROATIA

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	The Croatian Energy Regulatory Agency (*Hrvatska energetska regulatorna agencija*) ("HERA")
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Electricity – ITO (unbundling certification is still pending) Gas – FOU (unbundling certification is still pending)

CROATIA (CONTINUED)

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	According to HERA's licence registry a total of 30 companies are licensed as electricity generators, among which the two most important are: HEP Proizvodnja d.o.o. TE Plomin d.o.o.
	TRANSMISSION SYSTEM OPERATOR(S)	Hrvatski operator prijenosnog sustava d.o.o. ("HOPS")
	ELECTRICITY DISTRIBUTOR(S)	HEP Operator distribucijskog sustava d.o.o. ("HEP-ODS")
	PRINCIPAL ELECTRICITY SUPPLIER(S)	According to HERA's licence registry a total of 22 companies are licensed as electricity suppliers, among which the most important are: HEP – Opskrba d.o.o. GEN-I Zagreb d.o.o. RWE ENERGIJA d.o.o.
	INTERCONNECTORS	Slovenia Serbia Bosnia and Herzegovina Hungary
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Until 31 March 2014, the company PRIRODNI PLIN d.o.o. (owned by INA-INDUSTRIJA NAFTE d.d.) was the 'supplier of suppliers' under the public service obligation (PSO) of gas procurement at regulated prices On 1 April 2014, the company HEP d.d. was appointed the new wholesale gas supplier to other Croatian suppliers with PSOs for the needs of household customers for the period until 31 March 2017
	TRANSPORTATION SYSTEM OPERATOR(S)	PLINACRO d.o.o.
	GAS DISTRIBUTOR(S)	According to HERA's licence registry a total of 36 companies are licensed as gas distributors, among which the two most important are: HEP Plin d.o.o. GRADSKA PLINARA ZAGREB d.o.o.
	PRINCIPAL GAS SUPPLIER(S)	PRIRODNI PLIN d.o.o. (merged with INA -INDUSTRIJA NAFTE d.d. in July 2014) GRADSKA PLINARA ZAGREB – OPSKRBA d.o.o. HEP-PLIN d.o.o. MEĐIMURJE-PLIN d.o.o. PRVO PLINARSKO DRUŠTVO d.o.o. ENERGO d.o.o.
	INTERCONNECTORS	Rogatec between Croatia and Slovenia (Geoplin) Slobodnica-Donji Miholjac-Dravaszerdahely-Bata-Városfold between Croatia and Hungary (Földgázszállító Zrt.)

CYPRUS

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Cyprus Energy Regulation Authority ("CERA")
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Liberalised 100% in 2014

CYPRUS (CONTINUED)

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Electricity Authority Of Cyprus ("EAC")
	TRANSMISSION SYSTEM OPERATOR(S)	The transmission system operator which was established pursuant to electricity market regulation law
	ELECTRICITY DISTRIBUTOR(S)	The distribution system operator which remains under EAC
	PRINCIPAL ELECTRICITY SUPPLIER(S)	EAC
	INTERCONNECTORS	Cyprus currently has no cross-border links
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	N/A
	TRANSPORTATION SYSTEM OPERATOR(S)	N/A
	GAS DISTRIBUTOR(S)	N/A
	PRINCIPAL GAS SUPPLIER(S)	N/A
	INTERCONNECTORS	N/A

CZECH REPUBLIC

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Energy Regulatory Office ("*Energetický Regulační Úřad*")
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	FOU in the electricity sector ITO in the gas sector
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	ČEZ (72% of overall electricity production)
	TRANSMISSION SYSTEM OPERATOR(S)	ČEPS
	ELECTRICITY DISTRIBUTOR(S)	ČEZ, EON, PRE
	PRINCIPAL ELECTRICITY SUPPLIER(S)	ČEZ
	INTERCONNECTORS	Germany Austria Slovakia Poland
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME, ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer Russia Norway
	TRANSPORTATION SYSTEM OPERATOR(S)	NET4GAS
	GAS DISTRIBUTOR(S)	RWE, E.ON, VČP NET, SMP NET, JMP NET, PRAŽSKÁ PLYNÁRENSKÁ DISTRIBUCE
	PRINCIPAL GAS SUPPLIER(S)	RWE
	INTERCONNECTORS	Five international transfer stations: Brandov, Hora Sv. Kateřiny, Waidhaus, Lanžhot, Mokrý Háj and Cieiszyn Six Compressor Stations

DENMARK

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	The Danish Energy Regulatory ("DERA") (*Energitilsynet*)
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Electricity and gas: FOU already completed
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	DONG Energy A/S, Vattenfall A/S
	TRANSMISSION SYSTEM OPERATOR(S)	Energinet.dk
	ELECTRICITY DISTRIBUTOR(S)	Approximately 70
	PRINCIPAL ELECTRICITY SUPPLIER(S)	DONG Energy Energi Danmark Nordjysk Elhandel SE (former Sydenergi) SEAS-NVE Danske Commodities
	INTERCONNECTORS	Sweden Germany Norway The Netherlands: All approvals are set for a new cable with a capacity of 700 MW with planned commission in 2019

DENMARK (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Exporter In June, the City Council in Frederikshavns approved the Environmental Impact Assessment (EIA), as well as the district plan, which means that Total and the Danish North Sea Fund are now allowed to commence test drilling for shale gas (this is the first ever drilling for shale gas on Danish soil)
	TRANSPORTATION SYSTEM OPERATOR(S)	Energinet.dk
	GAS DISTRIBUTOR(S)	DONG Gas Distribution A/S HMN Naturgas I/S NGF Nature Energy Holding A/S (formerly Naturgas Fyn) Aalborg Municipality
	PRINCIPAL GAS SUPPLIER(S)	DCC Energi A/S DONG Naturgas Energi Danmark Energi Fyn Handel Energi Nord Engros Gas E.On Gashandel Danmark gasel. HMN Gassalg Nordjysk Elhandel Detail OK a.m.b.a. NGF Nature Energy Tre-For Energi SE (formerly Sydenergi) Sydfyns Elforsyning Wingas
	INTERCONNECTORS	Sweden and Germany

ESTONIA

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Estonian Competition Authority
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Electricity sector: FOU Gas sector: Estonia is exempt from unbundling requirement; however, it has decided to apply FOU as of 2015
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Eesti Energia Narva Elektrijaamad AS (approximately 85%)
	TRANSMISSION SYSTEM OPERATOR(S)	Elering AS
	ELECTRICITY DISTRIBUTOR(S)	In total there are 36 electricity distributors Elektrilevi OÜ has the largest market share (approximately 87%)
	PRINCIPAL ELECTRICITY SUPPLIER(S)	In total there are 15 electricity suppliers Eesti Energia AS has the largest market share (approximately 58%) followed by Elektrum Eesti OÜ (approximately 15%)
	INTERCONNECTORS	Finland Latvia Russia Synchronously interconnected with IPS/UPS

ESTONIA (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	All gas supplies are imported from Russia (either directly or via Latvia) No shale gas
	TRANSPORTATION SYSTEM OPERATOR(S)	AS EG Võrguteenus
	GAS DISTRIBUTOR(S)	In total there are 25 gas distributors AS Gaasivõrgud has the largest market share (approximately 69%)
	PRINCIPAL GAS SUPPLIER(S)	AS Eesti Gaas (approximately 89%) All other suppliers purchase gas for re-selling from AS Eesti Gaas
	INTERCONNECTORS	Russia and Latvia

FINLAND

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	In Finland the national supervisory authority for electricity markets is the Energy Authority (before 1.1.2014 the "Energy Market Authority"). In addition to the Energy Authority, the electricity market is supervised by the Finnish Competition and Consumer Authority.
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Electricity: The Energy Market Act requires legal and operational unbundling for both the TSO as well as large and mid-size DSOs. For small DSOs that have distributed less than 200 GWh annually through their 400 v network during the previous three calendar years, unbundling through separate accounts is sufficient. Gas: Finland has made use of an exemption from the unbundling requirements under the Third Gas Directive

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	In 2013, 27.1 per cent of the electricity was produced with nuclear power, 15.2 per cent with hydro power, and 18.7 per cent was imported Major electricity generators in Finland are Fortum Oyj, Pohjolan Voima (including Teollisuuden Voima), Helsingin Energia, and Kemijoki Oy, as well as Vattenfall and E.ON
	TRANSMISSION SYSTEM OPERATOR(S)	Fingrid Oyj
	ELECTRICITY DISTRIBUTOR(S)	In 2014, the largest DSO in Finland, Caruna Oy, had approximately 640 000 customers The 15 largest DSOs in Finland cover over 70 per cent of the electricity distribution network, network users, and revenue The majority of Finland's 83 distribution network companies are owned or controlled by municipalities Please see <http://energia.fi/en/electricity-market/eletricity-network/electricity-network-companies> for more information
	PRINCIPAL ELECTRICITY SUPPLIER(S)	There are approximately 120 companies producing electricity and approximately 400 power plants, from which over half are hydro power plants (the largest hydro power producer is Kemijoki Oy)
	INTERCONNECTORS	Sweden, Norway, Estonia, Russia

FINLAND (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer (Russia)
	TRANSPORTATION SYSTEM OPERATOR(S)	Gasum Oy Major shareholders are Fortum, Gazprom, the Finnish State, and E.ON
	GAS DISTRIBUTOR(S)	Contrary to most of Europe, the distribution of natural gas to private households and other minor consumers is not significant in Finland. In 2011, there were less than 25 local DSOs. Most of the DSOs are owned by municipalities, while some are owned by industrial users of natural gas.
	PRINCIPAL GAS SUPPLIER(S)	Approximately 95% of gas consumed in Finland is transmitted directly by Gasum Oy to end-users, which are mainly industrial operators. In Finland, the retail sale of natural gas accounts for only 5% of total sales. Selling natural gas does not require a licence, but the vendor must nevertheless fulfil certain requirements.
	INTERCONNECTORS	There are two pipelines between Finland and Russia, both operated by Gasum Oy. Gasum together with other natural gas companies in the Baltics are investigating the possibility of developing interdependent transmission systems. A submarine interconnector, *BalticConnector* would involve construction of a gas pipeline between Finland and Estonia, compressor stations on both sides of the Gulf of Finland, as well as connecting onshore pipelines to the existing gas grids. The Baltic Connector project is on the European Commission's list of 250 key energy infrastructure projects.

FRANCE

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Ministry of Energy Regulatory Commission of Energy (*Commission de régulation de l'énergie*) ("CRE")
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	ITO model

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	EDF Compagnie du Rhône E.ON
	TRANSMISSION SYSTEM OPERATOR(S)	Réseau de transport ("RTE")
	ELECTRICITY DISTRIBUTOR(S)	Electricité Réseau Distribution France ("ERDF") and approximately 160 local distributors
	PRINCIPAL ELECTRICITY SUPPLIER(S)	EDF, GDF Suez, E.ON, Alpiq, Enel, Poweo, Direct Energie
	INTERCONNECTORS	Italy UK Germany Spain Belgium Switzerland

FRANCE (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer, notably from Norway, the Netherlands, Algeria and Russia
	TRANSPORTATION SYSTEM OPERATOR(S)	GRTgaz TIGF
	GAS DISTRIBUTOR(S)	GRDF and approximately 25 local distributors
	PRINCIPAL GAS SUPPLIER(S)	GDF Suez Direct Energie EDF E.ON Eni Iberdrola Gazprom
	INTERCONNECTORS	Belgium Germany Switzerland Spain

GERMANY

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Federal National Agency (*Bundesnetzagentur*); Network Agencies of the Federal States
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	FOU, ISO and ITO

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	EnBW, RWE, Vattenfall, and municipality owned companies (*Stadtwerke*)
	TRANSMISSION SYSTEM OPERATOR(S)	50Hz Transmission, Amprion, enbw Transportnetze, TenneT TSO
	ELECTRICITY DISTRIBUTOR(S)	Approximately 850; more than 700 have < 30,000 customers
	PRINCIPAL ELECTRICITY SUPPLIER(S)	EnBW, RWE, Vattenfall, and municipality owned utilities (*Stadtwerke*)
	INTERCONNECTORS	Austria, Switzerland, France, Luxembourg, Belgium, Netherlands, Denmark, Poland, Czech Republic

GERMANY (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer (35% from Russia, 25% from Norway, 20% from the Netherlands). The remaining 20% is produced domestically.
	TRANSPORTATION SYSTEM OPERATOR(S)	Bayernets Eni Gas Transport Deutschland Erdgas Münster Transport EWE Netz Gasunie Deutschland GRTgaz Deutschland GVS Netz ONTRAS – VNG Gastransport Open Grid Europe Statoil Deutschland Transport Thyssengas Wingas Transport
	GAS DISTRIBUTOR(S)	Over 700, including many municipality owned companies (*Stadtwerke*)
	PRINCIPAL GAS SUPPLIER(S)	E.ON Ruhrgas, Shell, Exxon, VNG, RWE, Wngas, Erdgas Münster and municipally owned utilities (*Stadtwerke*)
	INTERCONNECTORS	Austria, Switzerland, France, Luxembourg, Belgium, Netherlands, Denmark, Poland and the Czech Republic

GREECE

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Regulatory Authority for Energy ("RAE")
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	ITO
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Public Power Corporation ("PPC"), Heron Thermoilektriki I, Heron II Viotia, Motor Oil, Elpedison and Protergia
	TRANSMISSION SYSTEM OPERATOR(S)	Hellenic Transmission System Operator ("HTSO")
	ELECTRICITY DISTRIBUTOR(S)	Hellenic Distribution Network Operator ("HDNO")
	PRINCIPAL ELECTRICITY SUPPLIER(S)	PPC and Heron Thermoilektriki
	INTERCONNECTORS	Albania, Former Yugoslav Republic of Macedonia, Bulgaria, Turkey and Italy
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer (piped gas from Russia and Turkey and liquefied natural gas ("LNG") from Algeria)
	TRANSPORTATION SYSTEM OPERATOR(S)	National Natural Gas Transmission System Operator ("NNGTS Operator" or "DESFA" as per its Greek initials)
	GAS DISTRIBUTOR(S)	Gas Distribution Companies ("EPAs" as per their Greek initials)
	PRINCIPAL GAS SUPPLIER(S)	Public Gas Company ("DEPA" as per its Greek initials), M&M
	INTERCONNECTORS	Turkey and Bulgaria

HUNGARY

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Hungarian Energy And Public Utility Regulatory Authority (*Magyar Energetikai És Közmű-Szabályozási Hivatal*)
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	ITO
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Mvm Zrt. (*Paksi Atomerőmű Zrt.*) Met Power (*Dunamenti Erőmű Zrt.*) Rwe (*Mátrai Erőmű Zrt.*) Alpiq (*Alpiq Csepeli Erőmű Kft.*) Aes (*Aes-Tisza Erőmű Kft.*) Edf (*Budapesti Erőmű Zrt.*)
	TRANSMISSION SYSTEM OPERATOR(S)	Mavir Zrt.
	ELECTRICITY DISTRIBUTOR(S)	Elmű Hálózati Kft. E.ON Dédász Zrt. E.ON Édász Zrt. E.ON Titász Zrt. EDF Démász Hálózati Elosztó Kft. Émász Hálózati Kft.
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Aes Hungary Energiaszolgáltató Kft. Alpiq Energia Magyarország Kft. Elmű Nyrt. E.ON Enrgiaszolgáltató Kft. EDF Démász Zrt. Émász Nyrt. Dalkia Energia Zrt. Mász Kft. Mvm Trade Zrt.
	INTERCONNECTORS	Slovakia Ukraine Romania Croatia Serbia Austria An interconnection between Slovenia and Hungary is anticipated for 2016.

HUNGARY (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer, primarily from Russia.
	TRANSPORTATION SYSTEM OPERATOR(S)	Földgázszállító Zrt.
	GAS DISTRIBUTOR(S)	Dbgáz Kft. E.ON Dél-Dunántúli Gázhálózati Zrt. Égáz-Dégáz Földgázelosztó Zrt. Isd Power Kft. Főgáz Földgázelosztási Kft. Magáz Kft. Oerg Kft. Tigáz-Dso Kft. E.ON Kögáz Zrt. Csepeli Erőmű Kft. Ngs Kft.
	PRINCIPAL GAS SUPPLIER(S)	Gdf Suez Energia Magyarország Zrt. Isd Power Kft. Főgáz Zrt. Tigáz Zrt. Magyar Földgázkereskedő Zrt. Alpiq Csepeli Erőmű Kft. Edf Démász Zrt. Ol Energiakereskedő Zrt.
	INTERCONNECTORS	Beregdaróc / Ukrtansgas (Ukraine) Mosonmagyaróvár / Omv Gas (Austria) Kiskundorozsma / Srbijagas (Serbia) Csanádpalota / Transgaz (Romania) Drávaszerdahely / Plinacro (Croatia)

ICELAND

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	National Energy Authority (*Orkustofnun*)
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Hybrid of ITO& FOU. An obligated to become FOU by 1 January 2015.

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Landsvirkjun, Reykjavík Energy (*Orkuveita Reykjavíkur*), Hs Energy (*Hs Orka*), Fallorka and Rarik.
	TRANSMISSION SYSTEM OPERATOR(S)	Landsnet
	ELECTRICITY DISTRIBUTOR(S)	Rafveita Reyðafjarðar, Hs Veitur, Norðurorka, Rarik, Reykjavík Energy (*Orkuveita Reykjavíkur*) and Orkubú Vestfjarða.
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Orkusalan, Reykjavík Energy (*Orkuveita reykjavíkur*), Hs Energy (*HS Orka*), Fallorka and Orkubú Vestfjarða.
	INTERCONNECTORS	No interconnectors in place, but several submarine cable projects are being considered.

ICELAND (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	N/A
	TRANSPORTATION SYSTEM OPERATOR(S)	N/A
	GAS DISTRIBUTOR(S)	N/A
	PRINCIPAL GAS SUPPLIER(S)	N/A
	INTERCONNECTORS	N/A

IRELAND

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Commission for Energy Regulation ("CER")
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Electricity sector: ISO Model Gas sector: ITO Model

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Electric Ireland ("ESB"), Airtricity ("SSE"), Viridian and Ervia (formerly *Bord Gáis Éireann,* renamed Ervia in 2014)
	TRANSMISSION SYSTEM OPERATOR(S)	Eirgrid
	ELECTRICITY DISTRIBUTOR(S)	ESB Networks Limited
	PRINCIPAL ELECTRICITY SUPPLIER(S)	ESB, SSE, Bord Gáis Energy Limited and Energia ("Viridian")
	INTERCONNECTORS	United Kingdom (operated as a single transmission system with Northern Ireland)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Net importer from the United Kingdom
	TRANSPORTATION SYSTEM OPERATOR(S)	Bord Gáis Éireann (now called *Ervia*) was certified as an ITO on 23 July 2013.
	GAS DISTRIBUTOR(S)	Gaslink (wholly owned subsidiary of Ervia)
	PRINCIPAL GAS SUPPLIER(S)	Bord Gáis Energy Limited, Viridian, ESB, SSE and Vayu
	INTERCONNECTORS	Two sub-sea interconnectors between Ireland and Scotland South-north pipeline connecting Ireland and Northern Ireland

ITALY

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Ministry of Economic Development Authority for Electricity, Gas and Water (*Autorità per l'Energia Elettrica il Gas e il Sistema Idrico,* "AEEGSI") Antitrust Authority (*Autorità Garante della Concorrenza e del Mercato*, "AGCM")
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	FOU model with reference to both the major Italian electricity (*Terna S.p.A.*) and gas (*Snam Rete Gas*) TSOs

ITALY (CONTINUED)

ELECTRICITY

PRINCIPAL ELECTRICITY GENERATOR(S)	ENEL Group (25.2%) ENI Group (8.5%) EDISON Group (6.0%) E.On Group (4.6%) A2A (3.1%) Erg Group (3.1%) Iren (3.1%) GdF Suez (2.9%)
TRANSMISSION SYSTEM OPERATOR(S)	Terna S.p.A.
ELECTRICITY DISTRIBUTOR(S)	Enel Distribuzione (86%) A2A Reti Elettriche (4%) Acea Distribuzione (3.2%) Aem Torino Distribuzione (1.4%) Remaining distributors with less than 1% of the volume of electricity distributed
PRINCIPAL ELECTRICITY SUPPLIER(S)	EDISON Group (67.34%) ENEL Group (34.9%) ENI Group (4.1%) Acea Group (3.9%)
INTERCONNECTORS	Italy imports approximately 13 to 14% of its electricity through the interconnection lines along the northern border. Italy is a major electricity importer in Europe. 22 cross-border interconnection lines are currently in operation with Switzerland, Austria, France, Slovenia and Greece.

ITALY (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Approximately 90% of gas consumed in Italy is imported from abroad, mainly from the following countries: Russia (about 38%) Algeria (about 21%) Libya (about 9%) Qatar (about 8%) Netherlands, Norway and Northern Europe (about 13%)
	TRANSPORTATION SYSTEM OPERATOR(S)	Snam Rete Gas S.p.A Società Gasdotti Italia Infrastrutture Trasporto Gas (formerly Edison Stoccaggio)
	GAS DISTRIBUTOR(S)	Snam S.p.A. (22.9%) F2i Reti Italia (16.6%) Hera Group (7.9%) Iren (6.2%) A2A Group (6.1%) Several municipally owned and minor private companies
	PRINCIPAL GAS SUPPLIER(S)	ENI (25.6%) Edison (6.6%) ENEL (6.4%) Edison Energia (5.2%) Iren Mercato (3.9%) Gdf Suez Energie (3.3%)
	INTERCONNECTORS	Gas cross-border interconnections currently in operation (managed by Snam Rete Gas) are connected to the Italian grid at the following entry points (5 pipelines and 3 LNG regasification terminals): Mazara del Vallo (Sicily) Tarvisio (Friuli Venezia Giulia) Passo Gries (Lombardy) Gela (Sicily) Gorizia (Friuli Venezia Giulia) Panigaglia (Liguria) Rovigo (Veneto) Livorno (Toscana)

KAZAKHSTAN

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Ministry of Energy
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	FOU

KAZAKHSTAN (CONTINUED)

ELECTRICITY

PRINCIPAL ELECTRICITY GENERATOR(S)	Ekibastuz GRES-1 LLP Ekibastuz GRES-2 JSC Eurasian Aksu TPP JSC GRES Kazakhmys Corporation JSC Jambul TPP JSC Bukhtarminsk HES Kazzinc LLP AES Ust-Kamenogorsk HPP LLP AES Shulbinsk HPP LLP Karaganda-Zhylu TPP LLP TPP-2 ArcelorMittal Temirtau JSC Rudnensk TPP JSC ("SSGPO") Balkhash TPP Zhezkazgan TPP of Corporation Kazakhmys LLP Pavlodar TPP-1 of Aluminium of Kazakhstan JSC Shymkent TPP-1,2 Yuzhpolimetal JSC
TRANSMISSION SYSTEM OPERATOR(S)	System Operator of the Unified Power System of Kazakhstan ("KEGOC")
ELECTRICITY DISTRIBUTOR(S)	Atyrau Zharyk JSC East Kazakhstan Regional Energy Company JSC Shygysenergotrade LLP Akmola Electricity Distribution Company JSC Kostanay Energocenter LLP Energy System Ltd Mangistauenergomunay LLP Taraz Electrical Networks LLP Nuclear Power Plant Mangistau Kazatomprom LLP
PRINCIPAL ELECTRICITY SUPPLIER(S)	Eurasia Energy Corporation JSC Karaganda Zharyk LLP KEGOC JSC Kostanay Heat Energy Company AES Ust-Kamenogorsk TPP JSC Shulbinsk HPP LLP
INTERCONNECTORS	Kazakhstan shares interconnectors with other members of the commonwealth of Independent States

KAZAKHSTAN (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Exporter No proven reserves of shale gas
	TRANSPORTATION SYSTEM OPERATOR(S)	KazMunaiGas JSC KazTransGas JSC
	GAS DISTRIBUTOR(S)	Karachaganak Tengiz Kashagan Fields Uzen Zhanazhol Zhetybay Aktoty Kalamkas Kalamkas-teniz Kaykan
	PRINCIPAL GAS SUPPLIER(S)	Tengizchevroil LLP Karachaganak Petroleum Operating BV PetroKazakhstan JSC CNPC-Aktobemunaigas JSC Mangistaumunaigas JSC
	INTERCONNECTORS	Uzbekistan Russia Kyrgyzstan

LATVIA

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Public Utilities Commission
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	ISO regime in the electricity market No unbundling in the gas market
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	AS Latvenergo
	TRANSMISSION SYSTEM OPERATOR(S)	AS Augstsprieguma tīkls
	ELECTRICITY DISTRIBUTOR(S)	AS Sadales tīkls
	PRINCIPAL ELECTRICITY SUPPLIER(S)	AS Latvenergo
	INTERCONNECTORS	Transmission system directly interconnected with Estonia, Lithuania and Russia. Indirect interconnection with Finland (via Estlink, the Estonia to Finland interconnector).
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer (JSC Gazprom) and exporter
	TRANSPORTATION SYSTEM OPERATOR(S)	AS Latvijas Gaze
	GAS DISTRIBUTOR(S)	AS Latvijas Gaze
	PRINCIPAL GAS SUPPLIER(S)	AS Latvijas Gaze
	INTERCONNECTORS	Transmission system directly interconnected with Estonia, Lithuania and Russia.

LITHUANIA

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	National Control Commission for Prices and Energy
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	FOU
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Lietuvos energijos gamyba AB (includes Lietuvos Elektrinė Power Plant, Kruonis Hydro Pumped Storage Power Plant and Kaunas Hydro Power Plant), Vilniaus energija UAB, Kauno termofikacijos elektrine UAB, INTER RAO Lietuva UAB (importer), Panevėžio energija AB.
	TRANSMISSION SYSTEM OPERATOR(S)	LITGRID AB
	ELECTRICITY DISTRIBUTOR(S)	LESTO AB
	PRINCIPAL ELECTRICITY SUPPLIER(S)	LESTO AB, INTER RAO Lietuva UAB, Enefit UAB, Electrum Lietuva UAB (previously known as Latvenergo Prekyba UAB), Energijos Tiekimas UAB, SBE Energy UAB, Lietuvos energijos gamyba, AB, Energijos kodas, UAB, Saurama, UAB.
	INTERCONNECTORS	Latvia Belarus Kalingrad system
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer from Russian Federation Importer from Norway commencing 2015
	TRANSPORTATION SYSTEM OPERATOR(S)	Amber grid AB
	GAS DISTRIBUTOR(S)	Lietuvos dujos AB
	PRINCIPAL GAS SUPPLIER(S)	Lietuvos dujų tiekimas UAB, Dujotekana UAB, LITGAS UAB
	INTERCONNECTORS	Minsk (Belarus) to Vilnius (Lithuania) pipeline, Riga (Latvia) to Vilnius pipeline, Kaliningrad (Russia) to Vilnius pipeline The LNG terminal starting from 2015.

LUXEMBOURG

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Luxembourg Regulatory Institute (*Institut Luxembourgeois de Régulation*)
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Exemption for small grids (Article 44(2) Third Electricity Directive / Article 49(6) Third Gas Directive)

LUXEMBOURG (CONTINUED)

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Société Electrique de l'OUR ("Seo") Twinerg
	TRANSMISSION SYSTEM OPERATOR(S)	Creos Sotel (Industrial Grid)
	ELECTRICITY DISTRIBUTOR(S)	Creos Electris Sudstroum Ville D'ettelbruck Ville De Diekirch
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Enovos Leo Electris Sudstroum Steinergy Eida Nordenergie
	INTERCONNECTORS	Germany Belgium
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer from Norway, Russia, Qatar and the Netherlands
	TRANSPORTATION SYSTEM OPERATOR(S)	Creos
	GAS DISTRIBUTOR(S)	Creos Sudgaz Ville De Dudelange
	PRINCIPAL GAS SUPPLIER(S)	Enovos Leo Sudgaz
	INTERCONNECTORS	Creos (Germany, Belgium and France)

FORMER YUGOSLAV REPUBLIC OF MACEDONIA ("FYROM")

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	The national regulatory body in the energy sector in the FYROM is the Energy Regulatory Commission (the "ERC").
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	In 2006 the Electric Power Company of Macedonia ("ESM") was transformed and the distribution of electricity was unbundled from the transmission and production of electricity. Today, the main producers of electricity are Macedonian Power Plants JSC Skopje ("ELEM"), the TSO ("MEPSO") and the DSO ("EVN Macedonia") are derived companies from ESM. The first two companies are 100% state owned.

FORMER YUGOSLAV REPUBLIC OF MACEDONIA ("FYROM") (CONTINUED)

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	ELEM operates two out of the three thermal power plants in the FYROM. ELEM also operates the most significant hydro power plants in the country. ELEM produces over 90% of the domestically produced electricity.
	TRANSMISSION SYSTEM OPERATOR(S)	MEPSO is a 100% state owned company with three main activities: (i) transmission of electricity; (ii) operation of the electricity market; and (iii) management of the power system in the FYROM.
	ELECTRICITY DISTRIBUTOR(S)	EVN Macedonia operates the electrical supply and distribution system in the FYROM. ELEM also has a licence to distribute electricity.
	PRINCIPAL ELECTRICITY SUPPLIER(S)	The market is liberalised only with respect to around 230 companies. All other entities and households get their electricity exclusively from EVN Macedonia. EVN Macedonia also dominates the liberalised part of the market with around 70% of the market share.
	INTERCONNECTORS	Serbia Bulgaria Greece MEPSO organises joint auctions with the neighbouring TSOs for the right to use the available cross border transmission lines. The right to use is granted on the principle of marginal price.

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	The FYROM is an importer of natural gas through the Russian transit gas pipeline on international corridor 8 which passes through Ukraine, Moldova, Romania and Bulgaria. No shale gas reserves have been discovered.
	TRANSPORTATION SYSTEM OPERATOR(S)	GA MA, the national operator of the natural gas network, is jointly owned by the government of the FYROM and local oil derivatives distribution company Makpetrol ad Skopje. The company operates and manages the natural gas transmission system and third party access.
	GAS DISTRIBUTOR(S)	The Directorate for Technological Industrial Development Zones is the licence holder for the implementation of energy related activities of natural gas distribution, natural gas distribution system management and natural gas supply to tariff based consumers within its scope which are connected to the natural gas distribution system. JP Kumanovo Gas and JP Strumica Gas also hold licences for natural gas distribution and supply to tariff-based consumers connected to the natural gas distribution system in their respective municipalities (ie Kumanovo and Strumica).
	PRINCIPAL GAS SUPPLIER(S)	Makpetrol-Prom Gas DOOEL Skopje and Bumak Primo DOOEL Skopje are both licenced to supply natural gas to tariff consumers. The Directorate for Technological Industrial Development Zones is also licensed to supply natural gas in the zones it manages. JP Kumanovo Gas and JP Strumica Gas also hold licences to supply natural gas in their respective municipalities.
	INTERCONNECTORS	The cross-border interconnection is on the border between the FYROM and Bulgaria in an area called Deve Bair. As the system operator, GA MA is authorized to grant the right to use available cross border transmission lines.

MALTA

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Malta Resources Authority ("MRA")
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	In relation to electricity, there is a derogation from the requirements of TSOs & DSOs and in relation to gas, there is a derogation TSOs to be unbundled.

MALTA (CONTINUED)

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Enemalta Corporation
	TRANSMISSION SYSTEM OPERATOR(S)	N/A
	ELECTRICITY DISTRIBUTOR(S)	Enemalta Corporation
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Enemalta Corporation
	INTERCONNECTORS	An electricity interconnector linking Malta to the European power grid in Italy is to be commissioned in 2015.
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Malta remains an importer of gas, though no data is currently available as to the origin of the imported gas. By June 2016 the Electrogas Malta consortium will be required to construct a combined-cycle gas turbine ("CCGT") power plant, on LNG floating storage unit and an onshore regasification unit at Delimara.
	TRANSPORTATION SYSTEM OPERATOR(S)	Easygas (Malta) Ltd and Liquigas Malta Ltd
	GAS DISTRIBUTOR(S)	Easygas (Malta) Ltd and Liquigas Malta Ltd
	PRINCIPAL GAS SUPPLIER(S)	Easygas (Malta) Ltd and Liquigas Malta Ltd
	INTERCONNECTORS	There is a proposal for the construction of a 150km gas pipeline between Malta and Italy (Sicily). This was included in the list of projects for EU funding.

MONTENEGRO

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Regulatory Agency for Energy
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	ITO
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	EPCG
	TRANSMISSION SYSTEM OPERATOR(S)	Crnogorski elektroprenosni sistem ("CGES")
	ELECTRICITY DISTRIBUTOR(S)	EPCG
	PRINCIPAL ELECTRICITY SUPPLIER(S)	EPCG
	INTERCONNECTORS	Serbia Bosnia and Herzegovina Albania
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	N/A
	TRANSPORTATION SYSTEM OPERATOR(S)	N/A
	GAS DISTRIBUTOR(S)	N/A
	PRINCIPAL GAS SUPPLIER(S)	N/A
	INTERCONNECTORS	N/A

THE NETHERLANDS

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Authority for Consumers and Markets (*Autoriteit Consument En Markt*)
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	FOU model, applicable to TSOs and regional grid operators
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Essent ("RWE"), Nuon ("Vattenfall"), Eneco, E.On, Electrabel and Delta
	TRANSMISSION SYSTEM OPERATOR(S)	Tennet
	ELECTRICITY DISTRIBUTOR(S)	Various regional grid operators owned by local authorities
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Eneco, RWE and Vattenfall
	INTERCONNECTORS	Interconnectors with Belgium, Germany, Norway and the United Kingdom. Interconnection with Denmark expected in 2019.
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Exporter No shale gas
	TRANSPORTATION SYSTEM OPERATOR(S)	GTS
	GAS DISTRIBUTOR(S)	Various regional grid operators owned by local authorities
	PRINCIPAL GAS SUPPLIER(S)	Gasterra
	INTERCONNECTORS	Various interconnectors with Belgium, Germany and the United Kingdom

NORWAY

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Norwegian Water Resources and Energy Directorate ("NVE") (not for upstream gas activities)
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	ISO (upstream gas sector) FOU (electricity sector)
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Statkraft SF Statkraft Energi AS
	TRANSMISSION SYSTEM OPERATOR(S)	Statnett SF
	ELECTRICITY DISTRIBUTOR(S)	About 140 companies are involved in grid operations at one or more grid levels. Hafslund Nett AS is the largest distribution grid company.
	PRINCIPAL ELECTRICITY SUPPLIER(S)	A large number of companies are involved in generation, supply and trading. Statkraft Energi AS is the largest supplier.
	INTERCONNECTORS	Sweden Denmark the Netherlands Finland Russia

NORWAY (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Norway is a gas exporter
	TRANSPORTATION SYSTEM OPERATOR(S)	Transmission system not developed. Gassco AS is an ISO for the upstream gas pipeline system on the Norwegian continental shelf.
	GAS DISTRIBUTOR(S)	N/A
	PRINCIPAL GAS SUPPLIER(S)	N/A
	INTERCONNECTORS	N/A

POLAND

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	The President of the Energy Regulatory Authority (*Prezes Urzędu Regulacji Energetyki*)
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	In practice, the FOU model has been adopted. The state treasury is the sole shareholder in gas and electricity TSOs and is also a major shareholder in trade and generation companies.
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Pge Polska Grupa Energetyczna S.A. Tauron Wytwarzanie S.A. Enea Wytwarzanie S.A. Ze Pak S.A. Energa S.A.
	TRANSMISSION SYSTEM OPERATOR(S)	PSE Operator S.A. (100% state owned)
	ELECTRICITY DISTRIBUTOR(S)	Pge Dystrybucja S.A. Tauron Dystrybucja S.A. Energa – Operator S.A. Enea Operator Sp. Z.O.O Rwe Stoen Operator Sp. Z.O.O
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Pge Obrót S.A. Energa-Obrót S.A. Enea S.A. Tauron Sprzedaż Sp. Z.O.O
	INTERCONNECTORS	the Czech Republic Germany Ukraine Slovakia Sweden Belarus

POLAND (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	PGNIG S.A. From Russia, Ukraine, Germany, Czech Republic
	TRANSPORTATION SYSTEM OPERATOR(S)	Gaz-System S.A. – Fully State Owned
	GAS DISTRIBUTOR(S)	One DSO – *Polska Spółka Gazownictwa Sp. Z O.O.* Fully Owned By PGNIG S.A.
	PRINCIPAL GAS SUPPLIER(S)	PGNIG S.A. (to industrial customers) PGNIG Obrót Detaliczny Sp. Z O.O. (to small retail customers)
	INTERCONNECTORS	Germany Belarus Czech Republic Ukraine

PORTUGAL

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Portuguese Energy Services Regulatory Authority: *Entidade Reguladora Dos Serviços Energéticos* ("ERSE") Governmental Directorate Of The Ministry Of Economy: *Dgeg – Direcção Geral De Energia E Geologia* ("DGEG")
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	N/A

PORTUGAL (CONTINUED)

PRINCIPAL ELECTRICITY GENERATOR(S)	Edp Gestão Da Produção De Energia, S.A. Iberdrola, S.A. Ren Trading, S.A.
TRANSMISSION SYSTEM OPERATOR(S)	REN – Rede Eléctrica Nacional
ELECTRICITY DISTRIBUTOR(S)	Edp Distribuição Energia, S.A. Cooperativa Eléctrica De Vale D'este Cooperativa Eléctrica De Vilarinho, C.R.L. Cooperativa Eléctrica De Loureiro, C.R.L. Cooproriz – Cooperativa De Abastecimento De Energia Eléctrica, C.R.L. A Eléctrica Moreira De Cónegos, C.R.L. A Celer – Cooperativa Electrificação De Rebordosa, C.R.L. Casa Do Povo De Valongo Do Vouga Junta De Freguesia De Cortes Do Meio Cooperativa Electrificação A Lord, C.R.L. Cooperativa Eléctrica S. Simão De Novais Electricidade Dos Açores Empresa De Electricidade Da Madeira
PRINCIPAL ELECTRICITY SUPPLIER(S)	Audax Energia, S.L. Axpo Iberia, S.L. Edp Comercial – Comercialização De Energia, S.A. Enat – Energias Naturais, Lda. Endesa Energia, Sucursal Em Portugal, S.A. Enforcesco,S.A. Galp Power, S.A. Iberdrola Generación, Energia E Serviços, Portugal, Unipessoal, Lda. Union Fenosa Comercial, S.L. – Sucursal Em Portugal Nexus Energia, S.A. The Main Supplier Of Last Resort Is Edp – Serviço Universal, S.A., Covering Most Of The National Territory
INTERCONNECTORS	N/A

PORTUGAL (CONTINUED)

GAS

IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer (From Algeria and Nigeria) Potential shale gas (Portugal has large oil shale deposits, but the issue still remains as to whether the gas exists in quantities sufficient to justify commercial extraction). Currently undertaking a preliminary study, with good indicators in the Algarve, Alentejo and in the municipalities of Bombarral, Cadaval and Alenquer)
TRANSPORTATION SYSTEM OPERATOR(S)	REN-Gasodutos, S.A.
GAS DISTRIBUTOR(S)	Operators Of Regional Distribution: Setgás, S.A. Lisboagás, S.A. Lusitaniagás, S.A. Agusgas S.A. Eiragas S.A. Edp Gás Distribuição, S.A. Operators Of Local Distribution: Dianagás – Sociedade Distribuidora De Gás Natural De Évora, S.A. Duriensegás – Sociedade Distribuidora De Gás Natural Do Douro, S.A. Medigás – Sociedade Distribuidora De Gás Natural Do Algarve, S.A. Paxgás – Sociedade Distribuidora De Gás Natural De Beja, S.A. Sonorgás – Sociedade De Gás Do Norte, S.A.
PRINCIPAL GAS SUPPLIER(S)	Edp Comercial – Comercialização De Energia, S.A. Edp Gás.Com – Comércio De Gás Natural, S.A. Endesa – Endesa Energia Sucursal Em Portugal,S.A. Galp Gás Natural, S.A. Galp Power, S.A. Gas Natural Comercializadora, S.A. Gold Energy – Comercializadora De Energia, S.A. Iberdrola Generación – Energia E Serviços Portugal, Unipessoal, Lda. Investigación, Criogenia Y Gas, S.A. – Sucursal (Incrygas) Molgás, Energia Portugal S.A. The Main Supplier Of Last Resort Is Galp Energia, S.A., Covering Most Of The National Territory.
INTERCONNECTORS	N/A

ROMANIA

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	The Romanian Energy Regulatory Authority – (*Autoritatea Nationala de Reglementare in domeniul Energiei* – ANRE)
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	ISO model
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Hidroelectrica S.A. Nuclearelectrica S.A. Complexul Energetic Oltenia S.A.
	TRANSMISSION SYSTEM OPERATOR(S)	Transelectrica S.A.
	ELECTRICITY DISTRIBUTOR(S)	CEZ Distributie S.A. ENEL Distributie Banat S.A. ENEL Distributie Dobrogea S.A. E.ON Moldova Distributie S.A. ENEL Distributie Muntenia S.A. FDEE Electrica Distributie Muntenia Nord S.A. FDEE Electrica Distributie Transilvania Sud S.A. FDEE Electrica Distributie Transilvania Nord S.A.
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Principal suppliers to end customers (both regulated and eligible) : Electrica Furnizare S.A. Enel Energie Muntenia S.A. Enel Energie S.A. E.ON Energie Romania S.A. CEZ Vanzare S.A. Alro S.A. Principal suppliers on competitive market : Alro S.A. Electrica Furnizare S.A. Tinmar Ind S.A. EON Energie Romania Repower Furnizare Romania SRL CEZ Vanzare
	INTERCONNECTORS	Existing interconnectors: Bulgaria Serbia Hungary Ukraine Moldova Projects: Overhead line 400 kV Romania – Serbia (Reșița - Pancevo) Overhead line 400 kV Romania – Moldova (Suceava - Bălți) Submarine cable (HVDC Link 400 kV) Romania – Turkey

ROMANIA (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER)	Importer (Russia; Western Europe through Hungary)
	TRANSPORTATION SYSTEM OPERATOR(S)	Transgaz S.A.
	GAS DISTRIBUTOR(S)	Congaz S.A. Distrigaz Sud Retele SRL E.ON Gaz Distributie S.A.
	PRINCIPAL GAS SUPPLIER(S)	Competitive market : OMV Petrom Gas SRL Romgaz S.A. GDF Suez Energy Romania S.A. Interagro S.A. Regulated market : GDF Suez Energy Romania S.A. E.ON Energie Romania S.A.
	INTERCONNECTORS	Hungary – Romania : Csanádpalota – FGSZ Bulgaria – Romania : Negru Voda I, II and III – Bulgartransgaz (only transit) Ukraine – Romania : Medieșu Aurit Import – Ukrtransgaz Isaccea Import (I, III and IV) – Ukrtransgaz (only transit) Romania – Moldova : Iasi – Ungheni Projects : Romania – Bulgaria : Ruse – Giurgiu – reverse flow

RUSSIA

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	There is no single authority regulating electricity and gas sectors in Russia. The major regulating bodies are: (i) the Ministry of Energy; (ii) the Federal Tariffs Service; (iii) the Federal Antimonopoly Service; (iv) the Federal Service for Ecological, Technological and Nuclear Supervision; (v) the Ministry of Natural Resources, including the Federal Service on Supervision in the Sphere of the Use of Natural Resources; and (vi) the Ministry of Economic Development
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	There is a prohibition for the generation and supply businesses to carry out the network businesses (except for isolated regions)

RUSSIA (CONTINUED)

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	5 wholesale generation companies (i.e. "OGK-1", "OGK-2", "OGK-3", "E.On Russia", "Enel Russia"); 14 regional generation companies (e.g. "TGK-1", "Mosenergo", "Quadra", "Rushydro", "Rosenergoatom")
	TRANSMISSION SYSTEM OPERATOR(S)	"Federal Grid Company of the Unified Energy System" (controlled by Russian Grids)
	ELECTRICITY DISTRIBUTOR(S)	11 regional distributional companies, a controlling stake in each of them is held by Russian Grids
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Many regional suppliers, e.g., "Mosenergosbyt", "Mezhregionenergosbyt", "Sverdlovenergosbyt", "Orenburgenergosbyt"
	INTERCONNECTORS	Finland Lithuania Latvia Estonia Norway Ukraine Kazakhstan Georgia Azerbaijan Belarus China

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Russia is an exporter of gas. Despite Russia's great potential for shale gas production, shale gas reserves remain undeveloped due to large conventional reserves
	TRANSPORTATION SYSTEM OPERATOR(S)	Gazprom
	GAS DISTRIBUTOR(S)	Gazprom
	PRINCIPAL GAS SUPPLIER(S)	Gazprom, Novatek, Rosneft
	INTERCONNECTORS	Blue Stream, Nord Stream, Yamal – Europe, Central Asia – Center

SERBIA

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Energy Agency
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	ITO

SERBIA (CONTINUED)

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	JP Elektroprivreda Srbije (EPS)
	TRANSMISSION SYSTEM OPERATOR(S)	Elektromreže Srbije (EMS)
	ELECTRICITY DISTRIBUTOR(S)	EPS (through five subsidiaries)
	PRINCIPAL ELECTRICITY SUPPLIER(S)	EPS (through one subsidiary)
	INTERCONNECTORS	Bulgaria Hungary FYROM Montenegro Albania Bosnia and Herzegovina Croatia Romania
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer (Russia)
	TRANSPORTATION SYSTEM OPERATOR(S)	Srbijagas
	GAS DISTRIBUTOR(S)	Srbijagas and 36 local distributors
	PRINCIPAL GAS SUPPLIER(S)	Srbijagas and 36 local suppliers
	INTERCONNECTORS	Hungary - annual capacity of 510 million m^3 Bosnia and Herzegovina – annual capacity of 80 million m^3

SLOVAK REPUBLIC

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	The Ministry of Economy of the Slovak Republic and The Regulatory Office for Network Industries
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	ITO
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Slovenské elektrárne, a.s.
	TRANSMISSION SYSTEM OPERATOR(S)	Slovenská elektizačná prenosová sústava, a.s.
	ELECTRICITY DISTRIBUTOR(S)	ZSE Distribúcia, a.s., Stredoslovenská energetika - Distribúcia, a.s., Východoslovenská distribučná, a.s.
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Západoslovenska energetika, a.s., Stredoslovenská energetika, a.s., Východoslovenská energetika, a.s.
	INTERCONNECTORS	Czech Republic Hungary Poland Ukraine

SLOVAK REPUBLIC (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer – mainly Russian gas
	TRANSPORTATION SYSTEM OPERATOR(S)	Eustream, a.s.
	GAS DISTRIBUTOR(S)	SPP – distribúcia, a.s.
	PRINCIPAL GAS SUPPLIER(S)	Slovenský plynárenský priemysel, a.s.
	INTERCONNECTORS	Austria Czech Republic Ukraine (with Hungary under construction)

SLOVENIA

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Energy Agency of the Republic of Slovenia Slovenian Environment Agency Energy Directorate within the Ministry of Infrastructure and Spatial Planning The Government office of the Republic of Slovenia of climate change
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Electricity: FOU Gas: ITO
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Holding slovenske elektrarne d.o.o. Nuklearna elektrarna Krško d.o.o. Termoelektrarna-toplarna Ljubljana d.o.o.
	TRANSMISSION SYSTEM OPERATOR(S)	Public company Elekto-Slovenija d.o.o. ("ELES")
	ELECTRICITY DISTRIBUTOR(S)	SODO electricity distribution system operator, d.o.o. Elektro Celje d.d. Elektro Gorenjska d.d. Elektro Ljubljana d.d. Elektro Maribor d.d. Elektro Primorska d.d.
	PRINCIPAL ELECTRICITY SUPPLIER(S)	SODO electricity distribution system operator, d.o.o. ELEKTRO CELJE ENERGIJA d.o.o. ELEKTRO GORENJSKA PRODAJA d.o.o. ELEKTRO ENERGIJA d.o.o. ENERGIJA PLUS d.o.o. E3 d.o.o. GEN-I d.o.o.
	INTER-CONNECTORS	ELES has a cross border connection with neighbouring countries: Austria (Austria-APG) Italy (TERNA) Croatia (HEP) The interconnection between Slovenia and Hungary is anticipated for 2016 In 2011, a market coupling project on the Slovenian – Italian border was launched

SLOVENIA (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	99% of all gas in Slovenia is imported Importer Country: Russia (58%) Austria (35%) Italy (6%) Importer: the main importer is Geoplin d.o.o. (82% of all natural gas)
	TRANSPORTATION SYSTEM OPERATOR(S)	Plinovodi d.o.o.
	GAS DISTRIBUTOR(S)	The distribution of natural gas in Slovenia is organised as an optional local commercial public service and performed by gas distribution system operators in each individual local community. Gas distributors are either public companies or private companies which have acquired a concession
	PRINCIPAL GAS SUPPLIER(S)	Geoplin d.o.o.
	INTER-CONNECTORS	Three cross-border interconnectors with Slovenian transmission system exist: Ceršak on Austrian border Rogatec on Croatian border Šempeter on Italian border

SPAIN

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	National Markets and Competition Commission (*Comisión Nacional de los Mercados y de la Competencia* or "CNMC") Ministry of Industry, Tourism and Trade (*Ministerio de Industria, Turismo y Comercio* – "MINETUR")
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Independent Transmission Operator ("ITO") model

ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Endesa Iberdrola Unión Fenosa Hidrocantábrico E.ON
	TRANSMISSION SYSTEM OPERATOR(S)	REE (Red Eléctrica de España) OMEL (Operador del Mercado Eléctrico)
	ELECTRICITY DISTRIBUTOR(S)	Endesa Iberdrola Unión Fenosa Hidrocantabrico E.ON
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Iberdrola, S.A. Iberdrola Generación, S.A.U. Endesa Energía, S.A. Unión Fenosa Gas Natural Comercializadora, S.A.U.
	INTER-CONNECTORS	France Portugal Morocco Andorra

SPAIN (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer Main origin: Algeria Others: Nigeria, Qatar, Trinidad and Tobago, Norway and Peru Shale gas is in exploration phase in certain Autonomous Regions (investigation permits have been granted)
	TRANSPORTATION SYSTEM OPERATOR(S)	ENAGAS (Technical Manager Of The Natural Gas System)
	GAS DISTRIBUTOR(S)	Gas Natural Fenosa
	PRINCIPAL GAS SUPPLIER(S)	Gas Natural Fenosa Union Fenosa Gas Endesa Gas Iberdrola
	INTER-CONNECTORS	France (Larrau And Irun) Portugal (Badajoz And Tuy) Morocco Algeria

SWEDEN

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Swedish Energy Markets Inspectorate Swedish Energy Agency Swedish Radiation Safety Authority Swedish Competition Authority
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Full Ownership Unbundling
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Vattenfall Ab E.On Sverige Ab Fortum Power And Heat Ab Statkraft Sverige Ab
	TRANSMISSION SYSTEM OPERATOR(S)	Affärsverket Svenska Kraftnät
	ELECTRICITY DISTRIBUTOR(S)	E.On Elnät Sverige Ab Vattenfall Eldistribution Ab Fortum Distribution Ab
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Vattenfall Ab Eon Försäljning Sverige Ab Fortum Markets Ab Blixia Ab Scandem Ab
	INTER-CONNECTORS	Norway Denmark Finland Poland

SWEDEN (CONTINUED)

GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer. Mainly From Denmark
	TRANSPORTATION SYSTEM OPERATOR(S)	Swedegas Ab
	GAS DISTRIBUTOR(S)	Göteborg Energi Gasnät Ab E.ON Gas Sverige Ab
	PRINCIPAL GAS SUPPLIER(S)	Apportgas E.ON Försäljning Sverige Ab Göteborg Energi Kraftringen Energi Ab (Publ) Varberg Energi Öresundskraft
	INTER-CONNECTORS	Denmark

SWITZERLAND

GENERAL	NATIONAL REGULATORY AUTHORITY (-IES)	Electricity Commission ("ElCom")
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	Full Ownership Unbundling as of January 1, 2013
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Alpiq Group (ex Atel and EOS) Axpo Group (incl. NOK, EGL and CKW) BKW FMB Energie Group Elektrizitätswerke der Stadt Zürich ("EWZ") Repower AG Romande Energie Services Industriels de Genève (SIG)
	TRANSMISSION SYSTEM OPERATOR(S)	Swissgrid AG
	ELECTRICITY DISTRIBUTOR(S)	In Switzerland, there exist more than 800 electricity companies, differing in size and other respects, including municipalities and other regional distributors.
	PRINCIPAL ELECTRICITY SUPPLIER(S)	Alpiq Group Axpo Group BKW FMB Energie Group EWZ Repower AG Romande Energie Services Industriels de Genève (SIG)
	INTER-CONNECTORS	Austria (APG) France (RTE) Germany (EnBW TNG, Amprion, Tennt 50Hertz) Italy (Terna)

SWITZERLAND (CONTINUED)

IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Importer from (in decreasing order of volume): Netherlands Russia Norway Germany Algeria Around 95% of the gas used in Switzerland is imported. In 2013, Switzerland imported 39.8 Mrd. kWh gas It is assumed that Switzerland also disposes of shale gas reserves. Fracking is usually the method used to extract such gas reserves, however, it is highly controversial and heavily disputed. Some cantons in Switzerland prohibit fracking by law (Vaud and Fribourg) while others do not prohibit it but seek to regulate it with very strict rules (Zurich, St. Gallen, Thurgau, Schaffhausen, Appenzell, Glarus Zug and Schwyz). The Federal Office of Energy stated that it will not support fracking projects
TRANSPORTATION SYSTEM OPERATOR(S)	Transitgas AG
GAS DISTRIBUTOR(S)	More than 100 regional companies, eg: Swissgas AG Erdgas Ostschweiz AG ("EGO") Erdgas Zentralschweiz AG ("EGZ") Gasverbund Mittelland AG ("GVM") Gaznat SA
PRINCIPAL GAS SUPPLIER(S)	Swissgas AG Erdgas Ostschweiz AG ("EGO") Erdgas Zentralschweiz AG ("EGZ") Gasverbund Mittelland AG (GVM") Gaznat SA
INTER-CONNECTORS	Transitgas Pipeline: Wallbach to Germany Rodersdorf to France Griesspass (VS) to Italy

TURKEY

GENERAL	NATIONAL REGULATORY AUTHORITY(-IES)	For electricity and downstream oil & gas: Energy Market Regulatory Authority (EMRA) For upstream oil & gas: General Directorate of Petroleum Affairs (GDPA)
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	ISO and ITO models present Transmission Operators: Electricity: Türkiye Elektrik İletim Anonim Şirketi (TEİAŞ) Natural Gas: Boru Hatları İle Petrol Taşıma Anonim Şirketi (BOTAŞ) Both companies are fully state-owned
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	As of 1 November 2014, there are 1,717 electricity generation licences in force State-owned Eletkrik Üretim Anonim Şirketi (EÜAŞ) is the principal electricity generation company
	TRANSMISSION SYSTEM OPERATOR(S)	Türkiye Elektrik İletim Anonim Şirketi (TEİAŞ)
	ELECTRICITY DISTRIBUTOR(S)	The distribution network is divided into 21 regions, with one distribution company in each. All of these companies have been privatized
	PRINCIPAL ELECTRICITY SUPPLIER(S)	As of 1 November 2014, there are 198 supply licenses in force
	INTER-CONNECTORS	Interconnection lines with pre-determined capacities to: Bulgaria Azerbaijan (Nakhcivan) Iran Georgia Armenia Syria Iraq Greece
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Turkey imports natural gas from Russia, Turkmenistan, Azerbaijan and Iran in addition to LNG imports from Nigeria and Algeria There are shale gas reserves in the Thrace region and the Diyarbakır province. However, they are not utilised as yet
	TRANSPORTATION SYSTEM OPERATOR(S)	Boru Hatları İle Petrol Taşıma Anonim Şirketi (BOTAŞ)
	GAS DISTRIBUTOR(S)	As of 1 November 2014, there are 69 distribution licenses in force
	PRINCIPAL GAS SUPPLIER(S)	As of 1 November 2014, there are 48 wholesale licenses and 57 import licenses in force State-owned BOTAŞ is the principal natural gas supplier company
	INTER-CONNECTORS	Gas Interconnection Points (exit/entry points) There are eight gas entry points. These are in Malkoçlar (Russia Westline); Marmara Ereğlisi (LNG); Durusu (Blue Stream); Bazargan (Iran); Türkgözü (Shah Deniz I); Aliağa (LNG); Silivri (gas storage facility); and Akçakoca (gas processing facility). There is also an exit point at Kipi, for export of gas to Greece (Interconnector Turkey-Greece)

UKRAINE

GENERAL	NATIONAL REGULATORY AUTHORITY(-IES)	The Ministry Of The Energy And Coal Industry The National Electricity Regulation Commission The State Service Of Geology And Subsoil Use The Ministry Of Ecology And Natural Resources Antimonopoly Committee Of Ukraine
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	N/A
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	Thermal Power Generation ◦ Llc "Vostokenergo" (*Private*) ◦ Public Jsc "Dtek Dniproenergo" (*Private*) ◦ Public Jsc "Dtek Zakhidenergo" (*Private*) ◦ Public Jsc "Donbasenergo" (*Private*) ◦ Public Jsc "Centrenergo" (*State*) Hydroelectric Power Generation ◦ Public Jsc "Ukrhidroenergo" (*State*) Nuclear Power Generation ◦ State Enterprise "Energoatom" (*State*)
	TRANSMISSION SYSTEM OPERATOR(S)	State Enterprise National Power Company "Ukrenergo"
	ELECTRICITY DISTRIBUTOR(S)	State Enterprise "Energorynok"
	PRINCIPAL ELECTRICITY SUPPLIER(S)	27 Suppliers, which provide end users with electricity in a particular region (Oblenergos)
	INTER-CONNECTORS	State Enterprise National Power Company "Ukrenergo" Interconnectors With: Belarus Poland Romania Russia Slovakia
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER)	Importer (Russia, Hungary, Poland, Slovakia)
	TRANSPORTATION SYSTEM OPERATOR(S)	Public Jsc "Ukrtransgaz" – Subsidiary Of Pjsc "Naftogaz"
	GAS DISTRIBUTOR(S)	Public Jsc "Ukrtransgaz" – Subsidiary Of Pjsc "Naftogaz"
	PRINCIPAL GAS SUPPLIER(S)	Public Jsc "Ukrtransgaz" – Subsidiary Of Pjsc "Naftogaz"
	INTER-CONNECTORS	Public Jsc "Ukrtransgaz" – Subsidiary Of Pjsc "Naftogaz" Belarus Hungary Poland Romania Slovakia

UNITED KINGDOM

GENERAL	NATIONAL REGULATORY AUTHORITY(-IES)	The Gas and Electricity Markets Authority, acting through Ofgem
	UNBUNDLING REGIME (FULL OWNERSHIP UNBUNDLING ("FOU"), INDEPENDENT SYSTEM OPERATOR ("ISO"), INDEPENDENT TRANSMISSION OPERATOR ("ITO") MODEL)	FOU, ISO and the "unbundling derogation providing greater independence than the ITO model" pursuant to Article 9(9) of the New Electricity and Gas Directives are available in both the electricity and gas markets ITO model is only available for gas interconnectors
ELECTRICITY	PRINCIPAL ELECTRICITY GENERATOR(S)	RWE, EDF, E.ON, Scottish and Southern Energy, Scottish Power, Centrica, Drax Power, GDF SUEZ, Energy UK and Intergen
	TRANSMISSION SYSTEM OPERATOR(S)	National Grid Electricity Transmission Plc
	ELECTRICITY DISTRIBUTOR(S)	SSE, UK Power Networks, Northern Power Grid, Electricity Northwest, Scottish Power and Western Power Distribution
	PRINCIPAL ELECTRICITY SUPPLIER(S)	EDF, E.ON, RWE (nPower), Centrica, Scottish Power, Scottish and Southern Power
	INTER-CONNECTORS	4 GW of Capacity: Interconnexion France Angleterre, Britned, Moyle, Republic of Ireland (East West)
GAS	IMPORTER OR EXPORTER COUNTRY? (NAME ORIGIN OF GAS IF IMPORTER) ANY SHALE GAS IN THE JURISDICTION?	Net Importer. Gas is imported from Belgium, the Netherlands and Norway via Pipelines and as LNG via ship from several countries including Qatar, Algeria, Australia, Egypt and Nigeria
	TRANSPORTATION SYSTEM OPERATOR(S)	National Grid Gas Plc
	GAS DISTRIBUTOR(S)	National Grid Gas Plc, Scotia Gas Networks, Northern Gas Networks and Wales and West Utilities
	PRINCIPAL GAS SUPPLIER(S)	Centrica, E.ON,EDF Energy, RWE (nPower), SSE and Scottish Power
	INTER-CONNECTORS	Interconnector UK, Balgzand and Bacton Line ("BBL"), an Interconnector (Consisting of two Pipelines) between Moffat in Scotland and Republic of Ireland; the Langeled Pipeline, and the Scotland to Northern Ireland Pipeline

OVERVIEW OF THE RES REGIME IN EUROPEAN JURISDICTIONS

ALBANIA

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	100% of energy generation from renewable resources: exclusively hydropower plants. Approximately 85% of the energy is generated from HPP managed by Kesh and approximately 15% from private owned HPP.
	KEY GENERATORS OF RENEWABLE ENERGY	Hydropower plant (main HPP is "Kaskada e drinit" managed by Kesh)
FINANCIAL INCENTIVES	FEED-IN TARIFFS	There are currently two feed-in tariffs: (1) for existing HPPS up to 10MW which is 7.77 all/kWh and for (2) new HPPS up to 15 mw which is 9.37 all/kWh.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	Issued by ERE (regulatory body of electric system)
	TAXATION	–
	OTHER	–

AUSTRIA

PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	Compared to 2012, the domestic power consumption in 2013 increased by nearly 2% to 1,117 Petajoule (PJ). In 2012, the hydro coefficient of large run-of-river hydropower plants was 1.11 and increased by 26% compared to 2011. Hydropower is the leading source for domestic energy production. In 2013, hydropower plants generated 45,698GWh, which is a slight decrease compared to 2012 (47,618GWh). Storage power plants generated 15,149GWh in 2013, which is 964GWh less than in 2012. In 2013, wind, photovoltaic and geothermal plants generated 3,446GWh, which represented an increase of 33.3% compared to the previous year. In total, renewable energy contributed 68 Terawatt hours (TWh) to the domestic production. In 2013, fossil fuels declined by 19.4% compared to 2012, whereas biogenic fuels decreased by 0.6% (source: Market Report – National Report to the European Commission, E-Control Austria). In 2010, the share of renewable energy was 31%. According to the EU Renewables Directive 2009/28/EC, the Austrian target is 34% of renewables by the year 2020.
KEY GENERATORS OF RENEWABLE ENERGY	Verbund Hydropower AG Verbund Renewable Power Tiroler Wasserkraft AG Vorarlberger Illwerke AG Kelag Steweag EVN BEWAG Salzburg AG AWP ImWind Ökoenergie

AUSTRIA (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	The feed-in tariffs paid by the green power clearing and settlement agent OeMAG are set in the "Green Power Feed-in Tariff Ordinance" (*Ökostrom-Einspeisetarifeverordnung*) which was published in September 2012 and amended in 2013. It sets the tariffs for the years 2014 and 2015. According to this ordinance, geothermal, biomass or biogas plants specified are granted feed-in tariffs, if an overall energy efficiency of at least 60% is achieved. Wind farm tariffs remained unchanged with 9.45 Eurocents per/kWh. Feed-in tariffs for small hydropower plants vary in seven stages from 4.97 Eurocent per kWh (exceeding 7.5 million kWh) to 10.55 Eurocent per kWh (for the first 500,000kWh). Feed-in tariffs for solid biomass range between 10.94 to 19.9 Eurocents per kWh, for biogas between 12.93 and 19.5 Eurocent per kWh and for photovoltaic between 16.59 and 18.12 Eurocent per kWh.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	Austria has formally used a Tradable Green Certificate (TGC) scheme for only a short period of time (2000-2002), linked to its obligation to small-scale hydro production. Under this TGC-scheme, small hydro generators were obliged to issue so-called "Small Hydro Certificates" in denominations of 100kWh, with all distributors having to purchase certificates representing 8% of their total power sales. However, the system was never fully operational and faced certain difficulties (in particular, lacking homogeneity due to different support schemes in each federal state, meager market fluidity, opposition against the allocation of the equalisation fund, and doubts concerning compliance with Community law). Thus, the TGC-scheme was replaced in 2003 by a new feed-in tariff scheme introducing uniform support for renewables across the federal territory ("Green Electricity Act"). Feed-in tariffs are support schemes for promoting the use of renewable energy. They provide a fixed price incentive wherein a fixed tariff is granted for each kilowatt hour of renewable energy that is fed into the grid. Nevertheless, Austria was the first EU country to introduce the Guarantees of Origin (GoO) – as required by the RES Directive – and to allow foreign certificates meeting the GoO requirements to be imported. In December 2012, the Austrian electricity exchange, Energy Exchange Austria (EXAA) launched trading power, exclusively from renewable water and wind energy resources, as an additional market. EXAA offers the opportunity for exchange trading of green power. This segment offers a trading platform which is independent of the feed-in tariffs (as defined by the German "EEG" or the Austrian Renewable Energy Law "*Ökostromgesetz*").
	TAXATION	In 2014 an exemption from taxation for energy produced from RES for own use (up to 25,000 kWh) was introduced. No further exemptions exist. The tax amounts to €0.015 per kWh and is to be paid by the electricity supplier. There is a tax exemption from mineral oil tax if biofuels are used purely. Generally there is no VAT reduction.
	OTHER	In July 2011, the Green Electricity Act 2012 (*Ökostromgesetz*) was passed. Among other modifications, the promotion volume for renewable energy sources has been increased from €21 million to €50 million each year from 2015. This will, among other things, increase investments in national RES projects and thus raise the share of RES in Austria.

BELARUS

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	2010: 5.2% of the electricity generated in Belarus (information for the following years is not available). The latest breakdown is for 2009 only, according to which the structure of electricity generated from RES is as follows: biofuel – 142gwh (76% of renewable electricity), hydro – 44gwh (13.5%), solar, wind and other – 1gwh (0.5%). Information about 2020 target for energy generated from RES is not available.
	KEY GENERATORS OF RENEWABLE ENERGY	State industrial group GPO "Belenergo" (hydro power); "Bellesbumprom" concern (biofuels, mostly biomass)

BELARUS (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	Article 20 of the Act on renewable energy sources establishes prices for RES energy which equal energy tariffs for manufacturing enterprises (approximately 10.69 eurocents per kW), increased by a multiplier. The multiplier is 2.7 for renewable energy plants which use solar energy and 1.1 for hydro-electric power plants (for the first ten years after start up) and 0.85 for the following period. For other renewable energy plants the multipliers are 1.3 and 0.85 accordingly.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	Green certificates are issued by the ministry of natural resources and environmental protection of the republic of Belarus and prove the renewable nature of the energy. Certificates are required for conclusion of contracts with GPO "Belenergo" for the sale of generated energy and for the purposes of application of feed-in tariffs.
	TAXATION	Equipment which is used for the generation, receipt, transformation, accumulation or transmission of energy produced from RES is subject to zero customs duties and zero vat when supplying Belarus. Land plots occupied by renewable energy plants are exempted from land tax, including for the period of construction. Decreasing coefficient of rates of ecological tax for wastewater discharge for power plants with a straight-through arrangement for cooling of turbine condensers is 0.2 if they use renewables for generating energy and 0.5 if they use non-renewables.
	OTHER	In order to stimulate generation of energy from RES, Belarus provides the following privileges for RES plants: ◦ guaranteed connection to state energy networks; ◦ guaranteed purchase of generated energy by tariffs being indexed according to BYR/USD exchange rate fluctuations. Thus, there are no (Belarusian-rouble) devaluation risks for renewable energy plants.

BELGIUM

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2012:** 5.8% of the Belgian demand for energy was produced from renewable energy sources (14% of total electricity generation or 11,340GWh) Wind: 24.4% Solar: 15.6% Hydro: 3.4% Biomass: 56.6% **2020 target:** 13% The Federal Government of Belgium is considering working towards a fixed objective of 100% renewable energy sources by 2050.
	KEY GENERATORS OF RENEWABLE ENERGY	Aspiravi, Belpower, Belwind, EDF Luminus, Electrabel, Electrawinds

BELGIUM (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	N/A (on the contrary injection tariffs are due by decentralised electricity producers).
	GREEN CERTIFICATES (NAME OF THE SCHEME)	Federal level: federal GPC for offshore wind parks and hydro installations, awarded in accordance with the green electricity generated. Flanders: GPC (*groenestroomcertificaten*) and CHP (*warmtekrachtcertificaten*), awarded in accordance with the green electricity generated and corrected by a banding factor. The certificates can also be traded and renewable energy generation technologies are eligible for a quota system. Brussels Capital Region: GPC (*groenestroomcertificaten/certificats verts*), awarded in accordance with the CO$_2$-savings. Wallonia: GPC (*certificats verts*), awarded in accordance with the CO$_2$-savings. Each licensed supplier has the obligation to purchase a certain number of green certificates from the producers of renewable energy.
	TAXATION	Contribution to the financing of the connection costs of offshore projects (art. 7,§2 Federal Electricity Act and Royal Decree of 8 June 2007). Surcharge on the federal GPC to compensate the net costs between the purchase price and the market sale price (art. 7, §1 Federal Electricity Act and Royal Decree of 16 July 2002).
	OTHER	Regional energy premium schemes including the following: Brussels ◦ Energy subsidies pursuant to the *primes énergie 2014 programme* are provided for residential and industrial for renewable energy use in the Brussels region. ◦ Investment assistance is offered by the Brussels Capital government for companies who develop environmental projects including investments in renewable energy plants pursuant to the *Subsidy Aide à l'investissement*. Flanders ◦ Contribution to the financing of the connection cost of renewable energy projects in Flanders. Wallonia ◦ Photovoltaic installations of less than or equal to 10 kW are eligible for the Qualiwatt subsidy, which is allocated by the distribution system operators based on the amount of power produced. ◦ Energy subsidies are provided by the Walloon Region for the generation of electricity through biogas and biomass CHP plants. ◦ In the Walloon region, small producers of green electricity are entitled to benefit from a compensation mechanism for the difference between the amount of electricity taken from the grid and the amount of electricity fed into the grid (net-metering).

BOSNIA AND HERZEGOVINA ("BH")

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2013 for RS:** share of energy from renewable sources, of overall gross consumption of energy was 62.9%. Information on the breakdown is not available. **2013 for FBH:** share of energy from renewable sources, of overall gross consumption of energy was 37% and 39% in overall final consumption. Information on the breakdown is not available. **2020 target for BH (Energy Community):** 40% share of renewable energy's of the overall final consumption of energy.
	KEY GENERATORS OF RENEWABLE ENERGY	The main source of energy from renewables in BH is hydropower. Key generators are enterprises directly or indirectly owned by the state. RS: Mixed Holding Electric Power Company of the Republic of Srpska ("EPC") through its subsidiaries. FBH: Electric Power Company of BH ("EPBH"); and Electric Power Company of Croatian Community of Herceg Bosnia ("EPHB").

BOSNIA AND HERZEGOVINA ("BH") (CONTINUED)

FINANCIAL INCENTIVES

FEED-IN TARIFFS	In both RS and FBH, there is a feed-tariff system that anticipates the possibility of mandatory takeover of the RES produced energy under the guaranteed purchase price. In RS, the following facilities may be entitled to feed in tariff benefits: ◦ Hydro power plants installed capacity of up to and including 10MW; ◦ Power plants using biomass installed capacity of up to and including 10MW; ◦ Geothermal power plant installed capacity of up to and including 10MW; ◦ Biogas power plant installed capacity of up to and including 1MW: ◦ Wind power plants, installed capacity of up to and including 10MW; ◦ Solar power plants, with photo-voltage cells installed capacity of up to and including 1MW; and ◦ Efficient cogeneration facility installed capacity of up to and including 10MWe. In FBH, following facilities may be entitled to feed-in tariff benefits: ◦ Hydro power plants installed capacity of up to 10MW; ◦ Power plants using biomass installed capacity of up of up to and including 10MW; ◦ Geothermal power plant installed capacity of up to and including 10MW; ◦ Biogas power plant installed capacity of up to and including 1MW: ◦ Wind power plants, installed capacity of up to and including 10MW; ◦ Solar power plants, with photo-voltage cells installed capacity of up to and including 1MW; ◦ Power plant using waste, installed capacity of up to and including 5MW; and ◦ Efficient cogeneration facility installed capacity of up to and including 5MWh.
GREEN CERTIFICATES (NAME OF THE SCHEME)	In both RS and FBH, the generators of electricity energy may obtain the certificates of origin from (i) Regulatory Commission for Energy of Republic of Srpska in case of a generator from RS, and (ii) Operator for Renewables and Efficient Cogeneration in case of FBH. The validity of certificates of origin is up to 1 year, for energy of 1MWh.
TAXATION	No tax incentives.
OTHER	N/A

BULGARIA

OVERVIEW

PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	The energy generation from renewable sources in Bulgaria reached 16.4% by the end of 2012 according to the estimation of the Ministry of Economy, Energy and Tourism presented in the second national report on the progress of Bulgaria in promoting of the use of energy from renewable sources released in December 2013. The 2020 target for renewable energy for Bulgaria is 16%. It has been achieved ahead of schedule for two main reasons – the decrease of energy consumption, particularly among business clients and the commissioning of large new solar and wind capacities. Due to the achievement of the 2020 target, the legal incentives for renewable energy projects in Bulgaria – the main incentives being the feed-in tariff and the long-term power purchase agreements, provided in the Energy from Renewable Sources Act cease to apply effective from the end of 2013 for new projects (eg projects without effective and valid grid connection agreements).
KEY GENERATORS OF RENEWABLE ENERGY	The National Electricity Company (*Национална електрическа компания*) with hydropower plants with an installed capacity of 2,713MW. AES wind power plant St. Nikola, with an installed capacity of 156MW. EOLICA Bulgaria, a part of ENHOL group, with a solar plant Suvorovo with an installed capacity of 60MW. ASTROENERGY, a part of CHINT group with a solar plant with an installed capacity of 50MW. HELIOS PROJECTS, owned by LUKOIL, with a solar plant Pobeda with an installed capacity of 50MW. SUN EDISON with a solar plant Karadzhalovo with an installed capacity of 50MW.

BULGARIA (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	The feed-in tariff applicable to each project depends on the date of its commissioning. The current feed-in tariff applicable to renewable energy plants commissioned after 1 July 2014 is the one announced by the State Energy and Water Regulatory Commission in its decisions No. Ц-13 and No. Ц-14 of 1 July 2014. The feed-in tariff rates are determined by type of renewable energy source and are subject to (i) an annual update by 30 June and (ii) an ad hoc update when there is a fluctuation of more than 10% of a pricing component of the respective renewable energy source rate after the regular annual update. The applicable feed-in tariff set out upon the commissioning of the plant remains fixed for the entire term of the long-term power purchase agreement (except in case of biomass power plants, where there is an annual indexation pursuant to a decision of the State Energy and Water Regulatory Commission). The public provider and end suppliers are required to purchase all electricity, certified with a guarantee of origin as such from renewable sources for the statutory term of the power purchase agreement (the term varies for the different types of renewable energy sources and is set in the law). However, since 1 January 2014, only the amount of electricity produced within the average annual period of operation of the respective renewable energy plant – according to the instructions of the national energy regulator, is to be purchased at the preferential price under the feed-in tariff. Any excess electricity produced is to be purchased at much lower prices by the public supplier and the end providers.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	N/A
	TAXATION	N/A
	OTHER	N/A

CROATIA

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2014 target:** 16.4% in gross final energy consumption. By September 2014 the total operational capacities of RES projects in Croatia reached 365.547MW, out of which wind farms with 297.25MW, solar power plants with 30.191MW, biomass power plants with 7.690MW, biogas power plants with 11.135MW, cogeneration facilities with 13.293MW, hydro power plants with 1.452MW, sewage gas power plants with 2.500MW and landfill gas power plants with 2.036MW. **2015 target:** 17.5% in gross final energy consumption. **2020 target:** 20.1% in gross final energy consumption. According to the National Action Plan for RES, it is envisaged to achieve the following share from RES in total electricity production by 2020: 79.6% from large and small hydro power plants, 10.5% from wind farms, 8.3% from biomass plants, 0.9% from geothermal plants and 0.7% from solar power plants.
	KEY GENERATORS OF RENEWABLE ENERGY	Wind farm Trtar-Krtolin (*Vjetroelektrana Trtar - Krtolin d.o.o.*) Wind farm ZD2 (*EKO d.o.o.*) Wind farm ZD3 (*EKO d.o.o.*) Wind farm Orlice (*Vjetroelektrana Orlice d.o.o.*) Wind farm Crno Brdo (*Vjetroelektrana Crno Brdo d.o.o.*) Wind farm ZD6 (*Velika Popina d.o.o.*) Wind farm Ravna 1 (*Adria Wind Power d.o.o.*) Wind farm Pometeno brdo (*Končar-Obnovljivi Izvori d.o.o.*) Wind farm Vrataruša (*Selan d.o.o.*) Wind farm Ponikve (*Vjetroelektrana Ponikve d.o.o.*)

CROATIA (CONTINUED)

FINANCIAL INCENTIVES

FEED-IN TARIFFS	**Summary:** Croatia has introduced a system based on a mandatory purchase with a feed-in tariff. The Croatian Energy Market Operator (HROTE) is obligated to purchase RES-electricity generated by eligible generators for an incentive price. **Mechanism:** The applicable incentive price for each RES or cogeneration plant is calculated by HROTE on the basis of number of pricing components set out in the tariff system applicable by the date of its commissioning. The feed-in tariff rate depends on the type of the RES or cogeneration plant and sources used for electricity production and the installed capacity of the plant. The right to an incentive price is granted for a period of 14 years. As of 6 June 2012 the incentive price is regulated by the Tariff system for the electricity production from RES and cogeneration (*Tarifni sustav za proizvodnju električne energije iz OIEiK*, Official Gazette of the RoC 'Narodne Novine' Nos. 63/12, 121/12 and 144/12). As of 1 January 2014 the incentive price is regulated by the Tariff system for the electricity production from RES and cogeneration (*Tarifni sustav za proizvodnju električne energije iz OIEiK*, Official Gazette of the RoC 'Narodne Novine' Nos. 133/13, 151/13, 20/14 and 107/14).
GREEN CERTIFICATES (NAME OF THE SCHEME)	**Note:** No Green Certificate schemes have been introduced in Croatia yet.
TAXATION	N/A
OTHER	N/A

CZECH REPUBLIC

OVERVIEW

PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2013:** Total is 10,197.7GWh (14.53% of the electricity generated). **2020 target:** 13% pursuant to the Renewable Energy Directive.
KEY GENERATORS OF RENEWABLE ENERGY	CEZ

CZECH REPUBLIC (CONTINUED)

FINANCIAL INCENTIVES

FEED-IN TARIFFS	A feed-in tariff can be granted only to operators of RES plants with an installed capacity up to 100kW (30kW in the case of photovoltaic (PV) or 10MW in the case of hydro power). PV and biogas plants are eligible only if put into operation before 31 December 2013. Wind, hydro or biomass plants are eligible only if the building permit was issued before 2 October 2013. The producer is obliged to register the chosen form of electricity production and its change through the purchaser or compulsory purchaser or directly in the market operator's system. Electricity promotion in the form of feed-in-tariffs cannot be combined within a single electricity production plant with electricity promotion in the form of 'green bonuses' for electricity. The terms and procedure for selection of the form of promotion of electricity from renewables and changes to the procedure during the market operator's registration into the system is stipulated by the implementing legal regulation.
GREEN CERTIFICATES (NAME OF THE SCHEME)	Green Bonus: All producers of electricity from RES are entitled to select the premium tariff option. Operators of renewable energy plants receive the green bonus in an annual or hourly mode on top of the regular market price of electricity. The annual green bonuses are set by the Energy Regulatory Office (ERU) for the following calendar year. The amount of the hourly green bonuses will be derived from the market price of electricity on the day-ahead market; their amount will therefore change at every hour. Operators generating renewable electricity to cover their own requirements only are also entitled to a green bonus. PV and biogas plants are only eligible if put into operation before 31 December 2013. Wind, hydro or biomass plants are eligible only if the building permit was issued before 2 October 2013.
TAXATION	Feed-in tariff: The feed-in tariff for PV installations put into operation between 1 January 2010 and 31 December 2010 is subject to a tax of 10%. The tax applies to all electricity generated from 1 January 2014. Exception: Roof-top and facade-integrated installations with a capacity of up to 30kW. Green Bonus: The green bonus for PV installations put into operation between 1 Jan 2010 and 31 Dec 2010 is subject to a tax of 11% (except for building-integrated installations with a capacity of up to 30kW). The tax applies for all electricity generated from 1 January 2014.
OTHER	NA

CYPRUS

OVERVIEW

PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	The European Union RES target (2020) for Cyprus is 13%.
KEY GENERATORS OF RENEWABLE ENERGY	Solar Energy.

FINANCIAL INCENTIVES

FEED-IN TARIFFS	N/A
GREEN CERTIFICATES (NAME OF THE SCHEME)	There are no green certificates currently in place.
TAXATION	N/A
OTHER	N/A

DENMARK

OVERVIEW

PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY

Total: 15,652GWh (49.5% of the electricity generated).

Wind: 71.1%

Wood: 13.5%

Biodegradable Waste: 5.0%

Straw: 4.5%

Solar: 3.3%

Biogas: 2.6%

Water: 0.1%

KEY GENERATORS OF RENEWABLE ENERGY

DONG Energy A/S

Vattenfall A/S

FINANCIAL INCENTIVES

FEED-IN TARIFFS

Production from renewable energy sources is subsidised through PSO funds, which all electricity consumers pay for through their electricity bill. The subsidy depends on which technology is used to produce the electricity. Eg for wind turbines, the subsidy varies depending on whether it is offshore or onshore, the size of the wind turbine generator, size of the blades and the date of the connection to the grid etc.

However, in June 2014, the European Commission declared the PSO levy illegal, and the Danish Government is now negotiating with the Commission to change the subsidy system.

GREEN CERTIFICATES (NAME OF THE SCHEME)

None, but the TSO (Energinet.dk) will issue Guarantees of Origin in accordance with the rules provided in the Electricity Supply Act and the Danish Promotion of Renewable Energy Act.

TAXATION

Electricity is included under the Danish rules of excise duties. The duties are increasing and are as follows:

Øre/kWh	2011	2012	2013	2014	2015
Electricity tax	62.4	63.5	64.7	83.3*	84.7
Electricity saving payment	0.6	0.6	0.6	N/A	N/A
Electricity distribution tax	4.0	4.0	4.0	N/A	N/A
Surtax	6.0	6.1	6.2	N/A	N/A
Energy saving payment	6.3	6.4	6.5	N/A	N/A

(*Effective 2014 the various types of electricity tax has been replaced with one aggregate tax rate)

From 2016, the electricity tax (with the exception of a base line of 4.6 øre/kWh) will follow the development of the Net Price Index.

OTHER

ESTONIA

OVERVIEW

PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY

The EU target for Estonia's consumption of energy from renewable resources is 25%. Estonia achieved the referred target in 2011.

Waste and biomass account for 52%, wind energy for 46% and hydro energy for 2%.

KEY GENERATORS OF RENEWABLE ENERGY

Fortum

Nelja Energia

Eesti Energia

Utilitas

ESTONIA (CONTINUED)

FINANCIAL INCENTIVES

FEED-IN TARIFFS	A fixed price for each kWh generated (i) from a renewable source with a generating installation the capacity of which does not exceed 100MW (at the rate of 0.0537 €/kWh), (ii) from biomass in an efficient co-generation plant (at the rate of 0.0537 €/kWh), (iii) from waste, peat or retort gas in an efficient co-generation plant (at the rate of 0.032 €/kWh), or (iv) with a generating installation the capacity of which does not exceed 10MWe (at the rate of 0.032 €/kWh) is payable by the TSO in addition to the price received upon sale of the electricity on the market. The relevant cost is passed on in the network charges and thus the support is financed by all consumers in proportion to their volume of consumption of network services. The support is payable for 12 years following commencement of production. Certain restrictions also apply. For example, wind energy producers may use the subsidy for up to a maximum of 600GWh of electricity produced in a calendar year, plants using biomass will qualify for the subsidy only if they are also qualifying co-generation plants. It is expected that the support payable for electricity generated from renewable resources will be reduced, however, to what extent and as of when remains unclear as the relevant draft act is still being discussed at the parliament.
GREEN CERTIFICATES (NAME OF THE SCHEME)	There exists no national scheme of green certificates. However, consumers are offered green electricity packages by electricity suppliers.
TAXATION	Taxation of electricity in general is based on excise levied on the consumption of electricity (at the rate of 0.00447 €/kWh). There are no separate tax incentives for electricity generated from renewable resources. However, generation of electricity from renewable resources is not subject to environmental charges which are applied to non-renewable electricity generation (e.g. charges for use of resources, emissions).
OTHER	N/A

FINLAND

OVERVIEW

PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	According to the most recent annual statistics from Statistics Finland the percentage of total renewable energy of the total energy consumption in 2013 was 31%. Available figures according to Statistics Finland include following figures in relation to particular percentages of certain renewable sources of the total energy consumption in 2013: Hydro power 3%, wind power 0.21%, wood based fuels 24%. The 2020 renewable energy target for Finland is 38%.
KEY GENERATORS OF RENEWABLE ENERGY	Pulp and paper industry, hydro power companies, wind power companies and other energy companies. The major players include Fortum Oyj, Kemijoki Oy, Pohjolan Voima Oy, EPV Energy Oy and the forest industry.

FINLAND (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	Through the Act on Production Subsidy for Electricity Produced from Renewable Energy Resources ("PSRESA"), Finland has established a state funded subsidy scheme consisting of a feed-in tariff for electricity production based on wind power, wood-based fuel and biogas. Electricity generators accepted in the scheme may receive a subsidy for a period of up to 12 years. According to the PSRESA, the feed-in tariff is the target price (€83.50) reduced by the three month average market price of electricity in the area where the plant is located. However, if the three month average price is less than €30, the feed-in tariff is the target price reduced by €30 per MWh. According to the Finnish NREAP, the energy production from wind power should increase to 6TWh by 2020. Due to the fact that there is hardly any wind power production in Finland – in 2012 the electricity production from wind power was only 492GWh – the rapid deployment of wind power generation has been incentivised in the PSRESA by a wind power premium. The above mentioned target price is €105.30 per MWh for wind power during the first three years of a wind power plant's operations or until the end of the year 2015, whichever occurs earlier. On top of the above target price, small CHP plants using wood fuel and CHP biogas power plants will receive a heat premium for heat that is produced together with electricity. Small CHP plants using wood fuel receive a €20 per MWh and biogas power plants receive a €50 per MWh additional heat premium on top of the feed-in tariff for efficient heat production. The feed-in tariff for electricity produced with wood chips is different from the above as it fluctuates on the basis of a calculation methodology involving the market price of an EU emissions trading system emission allowance, the price of peat and the level of national taxation on peat.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	There is no national scheme on green certificates in Finland. However, consumers are offered green electricity options by electricity companies.
	TAXATION	Taxation of electricity is based on excise taxes levied on the consumption of electricity. Fuels consumed in energy generation are tax exempt. The taxes for consumption of fossil fuels and peat were increased in order to make CO_2 neutral energy sources more competitive. Further, the energy content of and the greenhouse gas emissions from fuels were better taken into account in fuel taxation.
	OTHER	Investment subsidies: the Ministry of Employment and the Economy grants energy subsidies for eg investments made in: ◦ renewable energy; ◦ improvements in energy efficiency or in the efficiency of energy generation; and/or ◦ reduction of the environmental impact in energy production. The Ministry of Agriculture and Forestry grants subsidies for the harvesting and chipping of energy wood.

FRANCE

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2013:** 16.9% of total electricity generation (97.3TWh), which corresponds to 14.2% of gross final electricity consumption. **2020 target:** 23% of electricity consumption. The draft law on the energy transition sets out the new 2032 target for 32% of electricity consumption.
	KEY GENERATORS OF RENEWABLE ENERGY	For wind power, 3 main operators: GDF Suez (circa 1 000MW notably managed by: GDF Suez Futures Energies, La Compagnie du Vent, Maïa Eolis and la Compagnie Nationale du Rhône); EDF Energies Nouvelles (circa 650MW); and EoleRES (circa 380MW). For solar power, 4 main operators: EDF Energies Nouvelles (circa 430MW) Solairedirect (circa 375MW) GDF Suez (la compagnie du vent, la compagnie nationale du Rhône, CN'Air or Inéo (149MW) Akuo Energie (circa 115MW) Other operators (Casino-GreenYellow, Langa Solar, Urbasolar, E.ON)

FRANCE (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	There are two main systems for promoting the development of renewable energy: (i) power purchase obligations for EDF and certain other power distributors to purchase electricity at feed-in tariffs set out by ministerial orders specific to each source of energy; and (ii) call for tenders (launched from time to time by the minister in charge of energy). However, the draft law on the energy transition provides for a new alternative mechanism through market premiums (iii). This mechanism is subject to eventual modifications in the draft law. (i) Power purchase obligation mechanism: the electricity generators shall obtain a power purchase obligation certificate from the local State's representative confirming the production site complies with the requirements set out by the regulatory framework in order to be entitled to the feed-in tariffs. Then a power purchase agreement ("PPA") shall be entered into either with EDF or a local distributor of its choice on the basis of the statutory feed-in tariffs which are different form one energy source to another. Ministerial orders set out the feed-in tariff for the different RES. The duration of the guaranteed price depends on the energy source (12 years for combined heat and power, 15 years for onshore wind or biogas or 20 years for solar of offshore wind). (ii) Call for tenders mechanism: the winner of a call for tender is awarded the right to enter into a long term PPA with EDF or another local distributor at a guaranteed price set in accordance with the bid it submitted (ie, the purchase price will be the bid price of the selected bidder) and EDF has the obligation to enter into such PPA. (iii) Market premium: the electricity generators may claim a market premium for electricity they sell (based on a PPA entered into at market conditions). In general, they are free to choose between the regular feed-in tariffs and the market premium for direct selling. The draft law provides that the new mechanism will apply only to new generation plants. The purchasers of electricity from RES and calls for tender benefit from a mechanism of compensation of the extra cost generated by the execution of this purchase obligation. This compensation is financed by the ultimate power consumers, whatever their suppliers are, by the means of the contribution to the electricity public service, which is due by all electricity consumers (individuals, either professionals or not, and companies), in proportion to their consumed power.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	In France, the green certificate market is private and unregulated. The association Observ'ER in which the major actors of the electricity sector are present, issues the green certificates.
	TAXATION	Tax reduction or exemption from land tax in respect of energy-saving investments for purchasing equipment using renewable energy.
	OTHER	Special fund amounting to 1.2 billion euros for period 2009 to 2013 and €218 million for 2014 dedicated to generation of heat through renewable sources. 0% interest loans for purchasing equipment using renewable energy.

GERMANY

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2014: total renewable energy produced: 155.7TWh (Share in total energy produced: 25.8%)** ◦ Wind: 51.4TWh (9.7%) ◦ Solar: 32.8TWh (6.2%) ◦ Biomass: 53TWh (10.0%) ◦ Hydro: 18.5TWh (3.5%) **TARGETS:** Renewable national electricity—40 to 45% by 2025, 55 to 60% by 2035, and 80% by 2050 Renewable national energy—18% by 2020, 30% by 2030, and 60% by 2050 Energy efficiency: Energy consumption—reduction of 20% from 2008 level by 2020, and 50% less by 2050 Electricity consumption—reduction of 10% from 2008 level by 2020, and 25% less by 2050
	KEY GENERATORS OF RENEWABLE ENERGY	Various - no key generators

GERMANY (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	Statutory feed-in-tariffs paid per KWh for a period of 15 to 20 years plus a year of commissioning of facility; subject to an annual reduction depending on year of commissioning of facility, energy source and overall installed capacity. Facility operator is paid a feed-in-tariff by the distribution network operator; the latter is compensated by transmission system operator; inter transmission system operator compensation scheme, depending on total feed-in remuneration paid by each transmission system operator; purchase obligation for energy supply undertakings; levy on end consumer. As an alternative, plant operators may claim a market premium for electricity they sell directly, to be calculated each month. In general, plant operators are free to choose between the regular feed-in tariff and the market premium for direct selling. Operators of biogas plants who sell their electricity directly may claim a flexibility premium on top of the market premium. A plant operator wishing to be eligible for the flexibility premium needs to provide additional installed capacity that may only be used on demand rather than on a regular basis. From 2017, direct sales of renewable electricity will become mandatory for larger generators.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	N/A
	TAXATION	Electricity is subject to electricity tax (€0.0205/kWh) and the general VAT (19%), both to be paid by the end-consumer. Exemptions from the electricity levy are available for RES generated electricity subject to certain conditions.
	OTHER	Off-shore wind park connection: obligation of Transmission System Operators to connect off-shore wind parks at their expense. Loan programme by state owned KfW bank and investment supplement programme by BAFA Plants for the generation of electricity from renewable sources shall be given priority connection to the grid. Furthermore, grid operators are obliged to give priority to electricity from renewable sources when purchasing and transmitting electricity. Moreover, those interested in feeding in electricity may demand that the grid operator expands its grid. Owners of new buildings are required to satisfy a certain proportion of their energy use via renewable sources (subject to certain exceptions). New buildings are required to have an "energy-ID", old buildings have been obliged to have such an energy-ID since 2009 when sold or newly let.

GREECE

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	RES production accounts for approximately 15% of the total energy generated. The breakdown per RES technology of this 15% is as follows: Wind: 50% PV: 41% Hydro: 7.5% Biofuels: 1.5% The 2020 target for RES is 18%.
	KEY GENERATORS OF RENEWABLE ENERGY	EDF ELTECH WIND ENEL EUNICE PPC QUEST ROKAS TERNA

GREECE (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	Greece uses a feed-in tariff (FIT) scheme to compensate RES producers with a guaranteed selling price for the electricity which they produce, along with a guaranteed buyer for their product. The selling price depends on the type of RES technology used and whether the production takes place on a Greek island (non-interconnect system) or the mainland (interconnected system)
	GREEN CERTIFICATES (NAME OF THE SCHEME)	N/A
	TAXATION	The National Development Law (Law 3908/2011) covers all private investments (excluding PVs) in Greece and provides for tax breaks of up to 100% of the maximum allowable amount of aid. The relevant tax relief is comprised of exemption from the payment of income tax on pre-tax profits which result from any and all of the enterprise's activities.
	OTHER	According to the National Development Law (Law 3908/2011), other financial instruments for the promotion of RES in Greece (excluding PVs) are: Subsidies Leasing subsidies Soft loans by ETEAN (National Fund for Entrepreneurship and Development)

HUNGARY

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2012:** 8.9% **Breakdown of RES capacities in 2012: biomass:** 41%; wind: 42%; water: 7%, biogas: 6%, solar: 2%, waste: 2%. **2020 target:** 14.65%
	KEY GENERATORS OF RENEWABLE ENERGY	Pannonia Bioethanol Zrt. Alerion Hungária Energetikai Kft. Kaptár Szélerőmű Kft. Vento Energetika Kft. Pannonpower Holding Zrt. BHD Hőerőmű Zrt.
FINANCIAL INCENTIVES	FEED-IN TARIFFS	A feed-in-tariff system (mandatory off-take regime) allows participating generators to sell electricity at a price regulated by legislation, for a term and in an amount determined by the Hungarian Energy and Public Utility Regulatory Authority. Electricity traders, including universal service providers, power generators and electricity importers, must purchase a fixed percentage of their total electricity consumption or turnover from RES.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	N/A
	TAXATION	N/A
	OTHER	N/A

ICELAND

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2013:** 99.9% (Hydro at 71%, geothermal at 29%)
	KEY GENERATORS OF RENEWABLE ENERGY	Landsvirkjun Reykjavík Energy (Orkuveita Reykjavíkur) HS Energy (HS Orka) Fallorka RARIK

ICELAND (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	N/A
	GREEN CERTIFICATES (NAME OF THE SCHEME)	EECS Scheme certificates issued by Landsnet in accordance with the Renewable Energy Directive.
	TAXATION	N/A
	OTHER	N/A

IRELAND

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	In 2013, renewable generation comprised 30.2% of Ireland's fuel mix, including wind (26.29%), hydro (2.65%), landfill gas (0.59%), biomass (0.61%) and biogases, solar and ocean energy (together, <1%). **2020 Target:** 16% pursuant to the Renewable Energy Directive. It is projected that in order to meet the renewable electricity targets, the amount of wind generation across the island of Ireland will need to reach an installed capacity level of between 4,800MW and 5,300MW by 2020.
	KEY GENERATORS OF RENEWABLE ENERGY	ESB Brookfield Renewable Energy Viridian Airtricity

FINANCIAL INCENTIVES	FEED-IN TARIFFS	Renewable Energy Feed in Tariff Support Scheme: operates similar to a traditional feed-in tariff but with electricity purchased by suppliers who may recover costs from public service obligations. The REFIT 1 Scheme is fully contracted. The current schemes open to new projects are REFIT 2 and REFIT 3. Successful generators accepted into the REFIT 2 or 3 Schemes receive a letter of offer and must contract with a supplier licensed by the CER. Aid is granted to suppliers in the form of: (i) payments for every kWh contracted under a REFIT Power Purchase Agreement; and (ii) market price equalisation compensation below a floor price (not indexed).
	GREEN CERTIFICATES (NAME OF THE SCHEME)	N/A
	TAXATION	Section 486B of the Taxes Consolidation Act 1997, as amended, provides for a deduction from a company's profits for its direct investment in new ordinary shares in a qualifying renewable energy company which must be in the solar, wind, hydro or biomass technology categories and approved by the Minister. Relief from stamp duty on transfers of greenhouse gas emissions allowances. Employment and Investment Incentive Scheme allows individual investors to obtain income tax relief on investment made into EII-certified qualifying companies, which include renewable energy companies. Carbon Tax on the supply of Fossil Fuels with a partial relief available to holders of a greenhouse gas permit. Solid Fuel Carbon Tax is an excise duty which was introduced in May 2013, and which applies to solid fuel (coal and peat) supplied in Ireland. The rate of tax is €10 per tonne of carbon emitted, rising to €20 per tonne in May 2014. The securitisation regime under Section 110 of the Taxes Consolidation Act 1997, as amended, includes greenhouse gas emissions allowances. The regime was extended in 2011 to include carbon credits and in 2012 further extended to include forest carbon offsets.
	OTHER	Research and development grants to support innovative domestic and commercial schemes using biofuels, combined heat and power, large-scale wood heating systems and domestic renewable heat technologies. Funding programmes offered through the Sustainable Energy Authority of Ireland. Currently, there is a fund to stimulate the development and deployment of Ocean Energy devices and systems.

ITALY

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	Total is 110.2TWh (38% of the total gross final production, which is 287TW) Electricity production from renewable sources breakdown (AEEG on 2013 data on total gross production): Wind: 15,000TWh Biomass: 14,000GWh Hydroelectric: 53,240GWh Solar: 22,400GWh Geothermic: 5,650GWh 2020 RES target for the electricity sector: 26.4% of the total consumption 2013 GSE data: 27.4% of the total consumption (ie 2020 target with regard to RES has been achieved).
	KEY GENERATORS OF RENEWABLE ENERGY	ENEL A2A C.V.A. Edison Edipower E.ON
FINANCIAL INCENTIVES	FEED-IN TARIFFS	RES (different from Photovoltaic): The feed-in (tariff or premium) scheme provided under MED Decree 6 July 2012 applicable to renewable plants (other than photovoltaic) plants entered into operation on or after 1 January 2013. The new support scheme also introduces yearly supportable-capacity quotas for each year from 2013 to 2015. Plants up to 1MW: upon request, the GSE pays an all-inclusive feed-in tariff (To) on the net electricity generated and injected into the grid. The amounts of the tariff set out in Annex 1 of MED Decree 6 July 2012. Plants up to 5MW (hydro 10MW – geothermal 20MW): Incentive (I) depending on the type of sources, type of plant and capacity class and subject to enrolment into the GSE Registries. Plants over 5MW (hydro 10MW – geothermal 20MW): Incentive (I) determined on the basis of Dutch auctions held by the GSE as defined in MED Decree 6 July 2012. The electricity generated by plants benefiting from the incentive (I) remains the property of the producer. Indicative cumulative cost of all types of incentives awarded to RES-E plants (other than photovoltaic ones) shall not exceed an overall value of €5.8 billion per year. Photovoltaic (PV): the 5th feed-in scheme provided under MED Decree 5 July 2012 grants an all inclusive feed-in tariff on the net electricity injected into the grid and a premium tariff to the share of net electricity consumed on site. ◦ For the share of net generation injected into the grid: - by plants with a nominal capacity of up to 1MW, an all-inclusive tariff based on the capacity and type of plant; this tariff is granted to PV plants, building-integrated PV (BIPV) plants with innovative features and concentrated solar power (CSP) plants; - by plants with a nominal capacity higher than 1MW, the difference (if positive) between the all-inclusive tariff and the hourly zonal price; if the hourly zonal price is negative, this difference will not exceed the amount of the all-inclusive tariff applicable to the plant, depending on its capacity and type, as well as on the reference half-year. The electricity generated by plants with a nominal capacity of above 1MW will remain available to the producer. The monthly hourly zonal prices are posted on the website of GME. ◦ For the share of net generation consumed on site, a premium tariff.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	The Green Certificate Scheme has been progressively phased out and is no longer applicable to plants entered into operation after 31 of December 2012. A transitional regime is contemplated until 2015. Starting from 2016, renewable plants for which the GCs-based incentive period is still ongoing will switch to the new feed-in tariff scheme for the remainder of the relevant incentive period, and will not be subject to the auction mechanism.

ITALY (CONTINUED)

FINANCIAL INCENTIVES	TAXATION	The production and sale of electricity produced from renewable sources are, in principle, transactions which are taxable on the basis of the Italian taxation rules. From a tax perspective, the all-inclusive Feed-in Tariff for RES plants and the all-inclusive Tariff for PV plants, being linked to the input of energy into the grid, both qualify as a remuneration paid to the energy producers (irrespective of the incentive component). Therefore, they are deemed as taxable income for direct taxation purposes (IRES/IRAP) in the hands of the recipients. From an indirect taxation perspective, those payments are subject to VAT (on the assumption that the producer qualifies as a business entity), being deemed as an agreed price for the input of energy into the grid. The Premium Tariff for PV plants, being consumed on site by the energy producer and not injected into the grid qualifies as a grant for tax purposes and cannot be deemed as an agreed price for a transaction. Therefore, it is not relevant for VAT purposes (not falling within the scope of VAT) while it is relevant for income tax purposes (IRES/IRAP) being taxable according to the provisions of business income tax and subject to an advance provisional withholding tax at 4% rate, due to its nature of subsidy granted from a public entity. The positive difference between the all-inclusive tariff and the hourly zonal price qualifies as an additional remuneration granted to the producers, therefore its tax treatment is the same outlined above for the all-inclusive feed-in tariff. The Green Certificates: were granted by GSE to the producer of electricity from renewable source (over 1MW). For VAT purposes the sale of such certificates is considered as a supply of services subject to VAT at the ordinary rate of 22%. For direct tax purposes, the profits arising from the sale of green certificates is considered business income, taxable as capital gains. General provisions: notwithstanding the above, with regard to the production and sale of electricity from renewable sources it should be also underlined that specific legislation (the so called "Robin Hood Tax") provides that the general 27% corporate income tax ("IRES") rate is increased by 6.5% from the fiscal year 2014 (raising the IRES tax rate to an overall 34%). The Robin Hood Tax regime applies only to companies whose annual turnover exceeds €3 million and whose corporate tax basis exceeds €300,000. Furthermore, please note that an ad hoc favourable tax regime is provided for the producers of electricity that fall within the meaning of "agricultural entrepreneurs". The sale of electricity could be also subject to the application of the excise duty (accisa), in so far as certain conditions would be met.
	OTHER	

KAZAKHSTAN

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	Approximately 12.3% of power in Kazakhstan is produced from hydro resources. Alternative sources generate less than 0.2%. Given such a low rate of use of alternative sources, the government intends to increase the production of electricity by alternative energy sources up to 30% by 2030 and up to 50% by 2050. According to the Plan Of Development Of Alternate And Renewable Energetics in Kazakhstan for 2013-2020 generation of electricity from renewable energy sources in 2020 will be 3% of the total consumption.
	KEY GENERATORS OF RENEWABLE ENERGY	Bukhtarminsk hydro power plant Shulbinsk hydro power plant Kapchagai hydro power plant Ust-Kamenogorsk hydro power plant Moinak hydro power plant

KAZAKHSTAN (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	According to the Program On Development Of Electric Power Industry up to 2030 a series of measures should be put into legislation to promote green energy. These measures may include the exemption of companies involved in the installation of green energy sources from customs duties for the supply of equipment; release of companies owning these energy sources from VAT on electricity as the price of clean air.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	Green procurements stimulating processing enterprises' activities are expected to be introduced with a view to a move toward a greener economy in Kazakhstan. One of the innovations of the document is the concept of green procurements, which will stimulate the processing enterprises. According to the Solid Waste Management Modernization Programme for 2014-2050 the issue of "green" certificates will continue to encourage enterprises.
	TAXATION	Tax legislation of the Republic of Kazakhstan does not provide any special tax regime or additional benefits for activity on the use of renewable energy sources.
	OTHER	N/A

LATVIA

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	In 2012 approx. 37.4% (wind – 0.2%; hydro – 7%; biofuels – 0.5%; waste to energy – 1.2%; biogas – 1.1%; wood fuel – 27.4%). Target 2020 – 40%
	KEY GENERATORS OF RENEWABLE ENERGY	AS Latvenergo (hydropower); AS Rīgas siltums (biomass); SIA Getliņi eko (waste to energy); SIA Fortum Jelgava (wood fuel)
FINANCIAL INCENTIVES	FEED-IN TARIFFS	Feed-in tariffs calculated pursuant to special formula and depending on installed capacity of each respective power station. No new licences granting the right to receive feed-in tariff will be issued until 1 January 2016.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	N/A
	TAXATION	Subsidised electricity tax has been introduced in 2014. The tax is applied to taxable income from electricity sold within the feed-in tariff scheme or from payments for installed capacity. Tax rates depend on the energy source, installed capacity and type of generation.
	OTHER	N/A

LITHUANIA

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2012:** total 21.72% of gross final energy consumption. **2020 target:** 23% (pursuant to the Renewable Energy Directive)
	KEY GENERATORS OF RENEWABLE ENERGY	Vėjų spektras UAB Renerga UAB Vilniaus energija UAB Lietuvos energijos gamyba AB (includes Lietuvos Elektrinė Power Plant, Kruonis Hydro Pumped Storage Power Plant and Kaunas Hydro Power Plant) Vydmantai wind park UAB Naujoji energija UAB

LITHUANIA (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	Feed-in tariff for "small scale" generation of up to 10kW. Mechanism: public suppliers are required to purchase electricity produced from RES in small scale power stations at a fixed feed-in tariff defined by the Energy Commission. The obligatory purchase is applied for 12 years. Feed-in tariff for "large scale" generation of more than 10kW. Mechanism: electricity produced from RES in large scale power stations is traded on the basis of bilateral agreements (electricity can be sold to any supplier or the particular company appointed by the Ministry of Energy) or at the Nordpool power exchange, at unregulated prices. The producer is entitled to receive the premium equal to the difference between fixed feed-in tariff defined in the auction and the actual selling price of electricity to the consumers, which shall be no less than the average market price defined by the Energy Commission. The premium is applied for 12 years. NB: Currently only the auctions for allocation of quotas for hydro power plants can be organised. Auctions for allocation of quotas for biomass, solar and wind energy power plants cannot be held due to the fact that targets for total installed capacity of these plants prescribed by the Government are already achieved.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	N/A
	TAXATION	Law on the Environmental Pollution Tax provides for exemption from the obligation to pay the pollution tax which is applied to the natural and legal persons using biofuel who have proper documentation to substantiate the use. Pursuant to Law on the Excise Duty energy products produced using biomass are subject to a partial or full exemption (as applicable) from the excise duty in accordance with the specific conditions established in the legal provision. The electricity produced by using RES is exempted from the excise duty.
	OTHER	The Law on Renewable Energy stipulates that specific support schemes for promotion of the production and use of biofuel, biofuels for transport and bio-oils shall be established. Production of biofuel, biofuels for transport and bio-oils from the raw material originating in Lithuania shall be promoted through monetary compensation for producers purchasing raw materials needed for production of biofuel. The support scheme is financed from the state budget. Power stations producing energy from RES are connected to the existing networks with a discount of 80% or 60% depending on the installed capacity. The power-station which uses RES is excluded from the duty to pay the fee of power reservation. Lithuanian Environmental Investment Fund (LEIF) supports investment projects in the form of interest subsidies and loans on soft terms. The amount of the subsidy to one beneficiary may not exceed LTL 690,000 over three years or 80% of the total amount of the environmental investment project.

LUXEMBOURG

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2011:** 2.9% **2020:** target 11%
	KEY GENERATORS OF RENEWABLE ENERGY	SEO (directly and through subsidiaries) Enovos (directly and through subsidiaries)
FINANCIAL INCENTIVES	FEED-IN TARIFFS	**Feed-in tariffs:** these vary according to the technology, the capacity of the plant and the year of commissioning. **Mechanism:** model contract approved by the regulator between the operator of a plant and the grid operator.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	Luxembourg has joined the AIB EECS standard.
	TAXATION	**Compensation mechanism:** contribution levied on consumers to fund public service obligations and renewable energies. Income from certain photovoltaic systems is exempt from income tax based on administrative guidelines.
	OTHER	Investment grants.

FORMER YUGOSLAV REPUBLIC OF MACEDONIA ("FYROM")

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2013** According to the latest Energy Balance published by the State Statistical Office in October of 2014, the percentage of energy generation from renewable sources for 2013 was 22.1%. Out of that, 11.5% falls to biomass; 10% to hydro energy; 0.6% to geothermal and 0.05% to solar. **2020 Target** In accordance with both the "Strategy for Utilisation of Renewable Sources of Energy in the FYROM until 2020" and the "Strategy for Energy Development in the Republic of Macedonia until 2030" the target for energy from renewable sources is 21% by 2020. However, in a meeting of the Energy Community member states in October 2012, the FYROM has committed to a 28% share of renewable energy as part of the overall energy consumption in 2020 (which has recently been revised to 29%). No agreement on the conflicting 2020 RES targets (21% in national legislation and 29% within the Energy Community) has been reached thus far.
	KEY GENERATORS OF RENEWABLE ENERGY	The main source of energy produced from renewables in the FYROM is hydropower. Hydropower potential in the FYROM is utilised primarily through seven large hydropower plants and a number of smaller facilities. The hydropower plants Vrben, Raven and Vrutok form the Mavrovo hydropower complex. The hydropower plants Globocica and Shpilje along with the Ohrid Lake as an accumulation make up the hydro energy instalment complex of the river Black Drin. The third significant hydropower complex is situated on the river Treska with the hydropower plant Kozjak, Sv. Petka and Matka. Most of the major hydropower plants in the FYROM are operated by the 100% state-owned company Macedonian Power Plants (ELEM). Apart from hydropower, the FYROM also uses a lot of biomass (wood) for heating purposes.
FINANCIAL INCENTIVES	FEED-IN TARIFFS	There are several feed-in or preferential tariffs applicable in the FYROM. Energy generated from photovoltaic systems has a preferential tariff of 16.00 Eurocents/kWh (for plants with installed capacity of up to 50kW) and 12.00 eurocents/kWh (for plants with installed capacity from 51kW up to 1000kW). On the other hand electricity generated from small hydropower plants (ie hydropower plants with installed capacity of up to 10MW) is subjected to feed-in tariffs ranging from 450 to 12.00 eurocents/kWh depending on the installed capacity of the plant. Energy generated from windmills has a fixed preferential tariff of 8.9 Eurocents/kWh. Energy generated from electricity plants that use biogas or biomass has a preferential tariff that is dependent on the (i) type of fuel and (ii) percentage share of fossil fuels used in the generation process (ranging from approximately 12.7 to 18 Eurocents/kWh) Note, however, that these tariffs are applicable only to the installations which were granted authorisation/approval for construction after the entry into force of the decisions with which these tariffs were established. Different tariffs apply to the facilities that were gained authorisation/approval for construction before the entry into force of the decisions with which these tariffs were established.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	The Rules on Renewable Energy Sources, Macedonia set up a guarantee of origin system for energy generated from renewable sources. Namely, guarantees of origin can be obtained by producers of electricity that produce electricity from renewable energy sources. However, such guarantees of origin can be obtained only by the producers which have not obtained a status of preferential producer and consequently which do not sell the generated electricity at preferential tariffs. The guarantee of origin is issued for electricity of 1MWh and as a general rule such guarantees are valid for 12 months. Guarantees of origin can be transferred from the holder of the guarantee to another license holder for trade or supply of electricity in the FYROM. It should be noted that companies that deal with trade and supply of electricity are not legally required to supply a certain percentage of their electricity from RES, nor are consumers obliged to purchase a certain percentage of their electricity from RES.
	TAXATION	The only form of taxation incentives in regard to renewable energy sources is the application of a preferential tax rate for value added tax (5% rather than the regular 18%) for the trade and import of thermal solar systems and components. Other than this, energy from renewable sources is treated in the same manner (taxation wise) as regular energy.
	OTHER	N/A

MALTA

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2013:** in 2013 Malta reached 3.3% (pending audit) of its final energy consumption within the transport sector, however no data is available on Malta's renewable energy as a percentage of gross final energy consumption; furthermore in 2013 1.6% of electricity generation in Malta was derived from renewable sources (mostly due to solar, PVs & biofuels). **2020:** Malta's mandatory renewable energy target for 2020 amounts to 10% of final energy consumption. 10% of energy consumption within the transport sector must emanate from renewable sources.
	KEY GENERATORS OF RENEWABLE ENERGY	Windfarm sites: WasteServ plants and facilities in Hal Far, and Luqa. Two further onshore plants which are currently being assessed are Hal-Far and Wied Rini. Photovoltaic Plants: WasteServ plants and facilities in Hal Far, Luqa, Maghtab and Mriehel. Biomass through landfill gasses: Ta' Barkat Sewage Treatment Plant, Maghtab Environment Complex having two engineered landfills known as Ta' Zwejra & Ghallis, Thermal Treatment Facility in Marsa, Gozo Waste Treatement and Transfer Facility known as Tal-Kus, and St. Antnin MBT.
FINANCIAL INCENTIVES	FEED-IN TARIFFS	**2014:** Rates payable by Enemalta to operators for electricity generated from solar photovoltaic installations: (a) Applications for Feed-in Tariff submitted to, and approved by, MRA during the period 01 May 2014 and 31 October 2014 for any type of premises in Malta and Gozo: (i) Roof mounted installation having installation capacity of less than 40kWp €0.16,5/kWh for 20 years; (ii) Roof mounted installation having installation capacity of more than 40Kwp €0.16/kWh for 20 years; All the above having a maximum annual threshold of 1,600,000kWp and provided that the total maximum units of electricity allocated for payment of the feed in tariff shall not exceed 6,400,000kWh p.a. (b) Applications for Feed-in Tariff submitted to, and approved by, MRA during the period 01 November 2014 and 30 April 2015 for any type of premises in Malta and Gozo: i Roof mounted installation having installation capacity of less than 40kWp €0.15,5/kWh for 20 years; ii Roof mounted installation having installation capacity of more than 40Kwp €0.15/kWh for 20 years; (c) Feed-in Tariff Schemes for the period 01 January 2013 and 30 September 2014 where installation operator benefits from grant of not more than 50% of the initial capital investment: in the case of residential /domestic premises €0.22/ kWh for 6 years up to annual threshold of 1,600,000kWp. (d) Feed-in Tariff Scheme submitted to, and approved by, MRA during the period 01 July 2013 – 30 September 2014 for electricity generated on non-residential premises in Malta and Gozo: (i) If awarded a grant of not more than 50% of the initial capital investment before 01 July 2013 €0.15/kWh for 7 years; (ii) If awarded a grant of not more than 50% of the initial capital investment after 30 June 2013 €0.11/KWh for 7 years. All the above having a maximum annual threshold of 1,600,000kWp.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	"Green Certificates" were introduced by the Biofuels (Sustainability Criteria) Regulations 2010, as amended. Where installation operators opt to generate electricity from solar PV subject to a paid feed-in tariff or for which the net metering arrangement with a spill-off tariff is established then the installation operator will not be entitled to any tradeable green certificates for the electricity generated. So far no such certificates have been issued and the relevant schemes still need to be announced.
	TAXATION	Under the Deduction (Electric Vehicles) Rules, 2011, a company that carries on a trade or business is entitled to a deduction equivalent to 125% of expenditure of a capital nature incurred on the acquisition of electrical vehicles or a maximum of €25,000 in respect of each vehicle against the tax charged for the year of assessment.

MALTA (CONTINUED)

FINANCIAL INCENTIVES	OTHER	**2014:** Solar water Heaters: 40% rebate of expenditure capped at €400. Roof Thermal/Double Glazing: 15.25% of eligible costs up to a maximum of €1,000 Plug-In Vehicles: 25% rebate of the purchase price of new electric powers vehicles for personal use capped at €4,000. Well restoration: a rebate up to a maximum of €1000 of total expenditure C works (including certification costs capped at €100). Autogas: grant up to €200 for the conversion of an M1 motor vehicle used for private purposes into autogas. This grant is capped at 1,000 eligible claims on a first come first served basis.

MONTENEGRO

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2012:** 27% of energy generation was from RES (mostly hydropower and small percentage biomass). No electricity from other renewable sources to date. **2020 target:** 33%
	KEY GENERATORS OF RENEWABLE ENERGY	EPCG
FINANCIAL INCENTIVES	FEED-IN TARIFFS	Decree on the Tariff System for the Establishment of Preferential Prices of Electricity from Renewable Sources of Energy and Efficient Co-generations; The Electricity Market Operator (EMO) is required to agree terms for the payment of the feed-in tariff with eligible generators. For small hydro power plants tariffs have been set between 5.04 and 10.44 Eurocents/kWh, for biomass power plants – between 12.31 and 13.71 Eurocents /kWh, for biogas power plants – 15 Eurocents /kWh, for waste fired power plants –8 Eurocents /kWh and for landfill and sewage gas power plants 9 Eurocents /kWh, for solar power plants constructed at the roofs of the buildings 15 Eurocents /kWh, and for wind power plants 9.6 Eurocents /kWh
	GREEN CERTIFICATES (NAME OF THE SCHEME)	The Guarantees of Origin ("GO") are issued by the Regulatory Agency for Energy and are valid for a period of 12 months.
	TAXATION	N/A
	OTHER	N/A

NETHERLANDS

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2013 (most recent data available):** 4.52% (ie approximately 99 PJ) of gross final energy consumption. Total renewable energy consumption can be broken down as follows: Wind: 19.3% - Solar: 1.8% - Hydrothermal: 0.4% - Geothermal: 7.1% - Biomass (excluding transport): 56.4% **2020 target:** 14% (2023: 16%)
	KEY GENERATORS OF RENEWABLE ENERGY	Essent (RWE), Eneco, Delta, Nuon (Vattenfal), Windunie

NETHERLANDS (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	Feed-in premium (Incentive Scheme for Sustainable Energy Production) operating subsidy scheme for the production of renewable electricity, (bio)gas, heat and CHP. SDE+ subsidises the difference between the production costs of 'green' energy and 'grey' energy, resulting in a subsidy per produced kilowatt-hour. Under the SDE+ there is one budget for all production technologies. Applicants may apply in phases for an increasing amount of subsidy.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	The Guarantee of Origin Scheme (*Garantie van Oorsprong*) creates a system of green certificates. A supplier needs these certificates to (i) be eligible for SDE+ subsidy and (ii) guarantee off-takers that the energy supplied is in fact 'green'. Note: Certiq B.V. (in respect of sustainable electricity) and Vertogas (in respect of renewable gas) are in charge of administrating the Guarantees of Origin Scheme. Certiq and Vertogas are both fully owned subsidiaries of TenneT and Gasunie, respectively.
	TAXATION	Energy (electricity and gas) is taxed via a graded tax system. The tax payable depends on the number of kWh/m3 of electricity/gas used. Sustainable energy which is generated locally or regionally may be fed back into the grid, if it is not used by the local/regional generator itself, in which case the (value of the) energy fed back into the grid may be set off against the energy bill of this generator (without limitation in the number of kWh), which effectively results in a tax deduction. Since 2005 renewable energy is no longer exempted from the regular energy taxes. The SDE+ compensates the competitive disadvantage for renewable energy producers. Since 2013, SDE+ is financed by means of a surcharge (*Opslag Duurzame Energie*) on energy bills. The surcharge is also a graded system. The highest surcharge for sustainable electricity is 0.0023 Eurocents/kWh and for gas 0.0007 Eurocents/m3 (for the first 10,000 kWh - 170,000 m3). The effect of this surcharge on the energy bills of large users is negligible.
	OTHER	There are many subsidy schemes in the Netherlands which aim to stimulate the use of renewable energy. One of the larger and more important ones is the energy investment allowance (*Energie investeringsaftrek*), which allows companies to deduct 41.5% of investments in renewable energy and energy-efficient technology from their taxable profit. On average, this energy investment allowance results in a (net) tax advantage of 10%. In addition, the government tries to stimulate the use and generation of renewable energy and the development and use of energy-efficient technologies via various 'green deals'. With these green deals, the government agrees with corporation, local governments or organisation to take away any obstacles in the execution of sustainable projects developed by such corporations, local governments or social organisations. For example, the government may agree to change current legislation, assist in the funding of projects (for which specific funds have been set up) and assist the development of activities abroad.

NORWAY

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2012:** Energy generation from renewable energy sources in general approximately 65%, (more specifically, the percentage of electricity production from renewable energy sources approximately 96%) **2020 target:** 67.5%
	KEY GENERATORS OF RENEWABLE ENERGY	Statskraft Energi AS, E-CO Energi AS, Norsk Hydro AS, Agder Energiproduksjon AS, BKK produksjon AS, Lyse energi AS, NTE Energi AS, Eidsiva Vannkraft AS, Statoil and Hafslund produksjon.

NORWAY (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	N/A
	GREEN CERTIFICATES (NAME OF THE SCHEME)	A joint Norwegian-Swedish electricity certificate market for investments in electricity production from renewable energy sources was introduced in 2012. The certificate scheme provides incentives for eligible investments in electricity production from RES (as defined in the Renewable Energy Directive) in both Sweden and Norway.
	TAXATION	N/A. However, lower depreciation rights for wind power facilities are proposed for next year's budget.
	OTHER	The state-owned enterprise Enova has as a goal to strengthen the work in converting energy consumption and generation into becoming more sustainable, while simultaneously improving security of supply, and is financed via funds allocated from the Energy Fund. The Energy Fund is financed through a small additional charge to the electricity bill and supports the introduction of new technology, energy efficiency measures etc. The Energy Fund has been allocated the proceeds from the Green Fund, whose capital this year is NOK35 billion.

POLAND

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2013:** Total is 12,389GWh (approximately 7.75% of electricity generated) (amount of renewable energy confirmed with green certificates) **2020 target:** 15% pursuant to the Renewable Energy Directive
	KEY GENERATORS OF RENEWABLE ENERGY	N/A
FINANCIAL INCENTIVES	FEED-IN TARIFFS	Obligated parties (sellers of last resort) pursuant to article 9a (section 6) of the Polish Energy Law are obliged to buy the energy from producers of renewable energy at the average annual price of the previous calendar year. Energy generated in so called "micro-installations" (with a capacity up to 40kW, connected to grid with a voltage of a nominal rated voltage of below 110kV or a renewable source of heat which has a total capacity of up to 120kW) and sold by natural persons must be purchased by the seller of last resort at a price which equals 80% of the average sales price of electricity on the competitive market in the prior calendar year.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	Producers of renewable energy sources, traders which sell electricity to final customers or commodity brokers are obliged to obtain either "certificates of origin" issued by the Polish Energy Authority and submit them for redemption or else pay a "substitution fee".
	TAXATION	N/A
	OTHER	Connection of micro-sources to the distribution system grid is exempted from connection fees.

PORTUGAL

OVERVIEW

PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	2013: 53% 2020: 60%
KEY GENERATORS OF RENEWABLE ENERGY	Eneop 2 Iberwind EDP Renováveis Generg EEVM Lusovento Grupo Portucel Soporcel Acciona Energia Portugal EDF EN Portugal EDP – GPE

PORTUGAL (CONTINUED)

FINANCIAL INCENTIVES

FEED-IN TARIFFS	Feed-in tariffs are pending reduction or even abolition. There is uncertainty as to the remuneration for electricity from non-hydro plants because the period for application of the guaranteed tariffs provided for in Decree-Law no. 33-A/2005, of 16 February ("Decree-Law 33-A/2005") has passed. The remuneration rules for non-hydro Electricity Generators from Renewable Sources ("EGRS") were approved by Decree-Law no. 35/2013, of 28thFebruary ("Decree-Law 35/2013"). These rules provide that the non-hydro EGRS will see the guaranteed tariff (values still to be defined) maintained for an additional period of five years after the end of the initial 15 year period provided for such a feed-in tariff. As an alternative, Decree-Law 35/2013 gives the option to any wind energy EGRS already in operation prior to 17 February 2005 or after this date to choose, at the end of the corresponding period of 15 years from the respective start of operations, a guaranteed tariff for a further five years (receiving a tariff corresponding to the market value of between €74/MWh and €98/MWh or a tariff corresponding to the market price paid at a minimum of €60/MWh) against payment to the National Electricity Sector (*Sector Eléctrico Nacional*) for a period of eight years of €5000/MW of installed power. Alternatively, if it opts to pay €5800/MW of installed power during these eight years, it will receive a guaranteed tariff for seven years under the same conditions as those defined for the period of 5 years, all subject to annual updating. Note that if the option for a specific remuneration regime had not been exercised or accepted by 31 March 2013, following the 15 initial years, the energy generated by such wind energy EGRS will benefit from a guaranteed tariff - not yet fixed - for an additional period of five years. Specifications: Wind generation plants with the right to inject power into the network originating from public tenders may choose between extending the period of application of the guaranteed tariff rules in reduced terms or, as an alternative, joining another remuneration scheme after the respective period of guaranteed remuneration. Small Hydro Plants ("SHP") benefit from a period of 25 years from the date of issue of the respective operation licence (which may be extended up to the maximum of 10 years or up to the end of the validity of the respective water use licence) to maintain the earlier remuneration conditions. At the end of this period, the electricity generated will be sold under market conditions.
GREEN CERTIFICATES (NAME OF THE SCHEME)	No specific scheme has been approved. Tradable certificates will be implemented only after expiry of the period of feed-in tariffs still in force.
TAXATION	The government has decided to launch a review of environmental and energy taxation, as well as promote a new tax and related framework by developing mechanisms that allow the internalisation of environmental externalities. So by Dispatch no.1962/2014, of 7 February ("Dispatch 1962/2014") the Commission for the Reform of Green Taxation – 2014 ("CRGT") was selected to undertake an assessment of environmental and energy taxation, from then to revise the fundamental legal basis of the taxation system in this two areas. CRGT has until 15 September 2014 to submit to the Government that Reform Project.
OTHER	**Guarantees of origin:** attributable to electricity generators and to the generators of heating and cooling energy from renewable energy sources with installed power greater than 5MW who confirm to end consumers that 1MWh of the energy was generated from renewable sources.

ROMANIA

OVERVIEW

PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2013:** 54.44TWh of electricity generated, out of which: 27.36% hydro; 8.94% wind; 0.85% solar; 0.42% biomass. **2020 target:** 24% (same as pursuant to the Renewable Energy Directive)
KEY GENERATORS OF RENEWABLE ENERGY	Hidroelectrica (hydro) CEZ Romania (wind) EdP Romania (wind and solar) Enel Green Power Romania (wind and solar)

ROMANIA (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	**Feed-in tariff for "small scale" generation of up to 1MW or 2MW for high efficiency cogeneration from biomass:** suppliers in the area of the producer are required to acquire electricity generated at regulated tariffs, determined for each technology type. Producers receiving this feed-in-tariff will no longer benefit from green certificates. Applicable upon state aid approval by European Commission.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	**Trading of green certificates combined with the mandatory quota system:** producers of renewable electricity receive green certificates for the electricity produced and fed into the system and have the right to sell such green certificates independently from the electricity generated and electricity suppliers (as well as certain producers) are obliged to acquire a definite – mandatory – quota of green certificates, proportional to the amount of the traded electricity; green certificates are further invoiced by electricity suppliers to end consumers. **Support scheme for high efficiency cogeneration from RES:** a tariff granted for each MW of electricity produced from high efficiency cogeneration and fed into the system or at the producer's discretion, an extra green certificate in addition to those granted for the electricity generated from that specific RES.
	TAXATION	N/A
	OTHER	N/A

RUSSIA

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2010:** approximately 1% of the electricity generated (excluding major hydro power plants with a capacity of more than 25MW). **2020 target:** 2.5% of the electricity generated (excluding major hydro power plants).
	KEY GENERATORS OF RENEWABLE ENERGY	OJSC "Rushydro"

FINANCIAL INCENTIVES	FEED-IN TARIFFS	List of measures to support renewable energy sources generators includes (i) tenders for sale of capacity which allow successful bidders to receive capacity payments guaranteeing return of their investments within 15 years; (ii) subsidies from the federal budget for the compensation of grid connection costs; (ii) fixed regulated price premiums for produced electricity; and (iv) obligations on transmission and distribution companies to compensate losses in their grids by purchasing electricity produced primarily by certified renewable energy sources generators. However, some of the above measures don't have full effect due to a lack of legislation.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	The procedures and criteria for qualifying as a renewable energy sources generator include the requirements that such a generator shall: (i) generate power solely from renewable energy sources or combine generation of such power with traditional power; (ii) be commissioned (not be subject to repair works or decommissioned); (iii) be connected to electricity grids; (iv) be equipped with relevant metering devices; (v) be equipped with relevant metering devices that allow to measure amount of each type of fuel used in relation to generators that combine generation of power from renewable energy sources with traditional power; and (iv) be included in the scheme and prospective development program of electric power industry and approved by the relevant regional authority. Having qualified as a renewable energy sources generator, the generator shall be put in a special register and becomes able to obtain a "green" certificate which confirms that the generator produces a certain volume of power from renewable energy sources.
	TAXATION	The price of electrical capacity shall be increased for the renewable energy generators to cover certain proportion of the property tax and the allowable capital and operation (current) expenses.
	OTHER	N/A

SERBIA

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2014:** approximately 22% of energy consumption is from RES (mostly hydropower and small percentage biomass and solar PV). No electricity from other renewable sources to date. **2020 target:** 27% target pursuant to the Renewable Energy Directive.
	KEY GENERATORS OF RENEWABLE ENERGY	EPS
FINANCIAL INCENTIVES	FEED-IN TARIFFS	**Summary: Feed-in tariffs** determined by the Government of Serbia. **Mechanism:** Execution of a long term power purchase agreement with the public supplier (Serbian national electric utility – EPS). For hydro power plants, tariffs have been set between 5.9 and 12.40 Eurocents/kWh, for biomass power plants between 8.22 and 13.26 Eurocents/kWh, for biogas power plants between 12.31 and 15.66 Eurocents/kWh, for natural gas and fossil fuel fired CHP plants 8.89 and 8.04 Eurocents/kWh, for solar power plants between 16.25 and 20.66 Eurocents/kWh, for geothermal power plants between 6.92 and 9.67 Eurocents/kWh (depending on their installed capacity) and for waste fired power plants, landfill and sewage gas power plants and wind power plants, 8.57, 6.91, and 9.20 Eurocents/kWh respectively (regardless of their installed capacity). Feed-in tariffs will be adjusted pursuant to the inflation in the Euro zone in the previous year. Please note that certain limitations have been placed on the applicability of feed-in tariffs with respect to renewable energy sources.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	**Summary:** The Guarantees of Origin ("GO") are instruments issued by the TSO upon a request from the RES electricity producer.
	TAXATION	**Summary:** Although the Serbian Energy Act envisages the possibility of introducing tax incentives for electricity produced from RES, currently there are no tax incentives for generation of electricity from RES.
	OTHER	N/A

SLOVAK REPUBLIC

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2013:** energy generation from renewable energy sources was 11% of total consumption of energy. **2020 target:** 14%
	KEY GENERATORS OF RENEWABLE ENERGY	Slovenské elektrárne, a.s.
FINANCIAL INCENTIVES	FEED-IN TARIFFS	**Summary:** The feed-in tariff scheme applies to electricity generation from renewable energy sources and high-efficiency cogeneration depending on the source and installed capacity. **Mechanism:** The scheme is based on an additional payment included in the feed-in tariff set for a certain type of renewable energy, eg for solar energy. The additional payment is equal to the difference between the set feed-in tariff and the price set for the electricity to cover losses in the distribution grid.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	**Summary:** A green certificate (pursuant to Slovak law – a guarantee of origin of electricity from renewable sources of energy) is issued in electronic form for each 1MW of electricity generated from renewable energy sources or by cogeneration upon request of the electricity producer. A certificate is issued for 12 months and is tradable in other EU Member States. There are no mandatory quotas for the use of a guarantee of origin of electricity from renewable sources of energy.
	TAXATION	**Summary:** Electricity generated from renewable energy sources is generally exempted from the consumption tax generally levied on electricity.
	OTHER	N/A

SLOVENIA

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2011:** The share of energy in the gross final consumption of energy in 2011 was approximately 19%. **2020 target:** 25% pursuant to the Slovenian Action Plan for Renewable Energy as well as the Renewable Energy Directive.
	KEY GENERATORS OF RENEWABLE ENERGY	Elektro Ljubljana OVE d.o.o. GEN energija d.o.o. Biomasa d.o.o. Etc.
FINANCIAL INCENTIVES	FEED-IN TARIFFS	Feed-in tariffs are managed by the Centre for Support within Borzen d.o.o. The centre promotes supporting schemes for electricity production from renewable energy sources (RES) and high efficiency cogeneration. There are two basic forms of feed-in tariffs, namely the operation support (financial aid business) and guaranteed purchase. Under the guaranteed purchase price scheme, a generator (with a production capacity of a maximum of 1MW) is entitled to sell all of the electricity produced to Borzen. Under the financial support scheme, the generator receives a contribution covering the difference between production costs and the expected market price.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	If a certain amount of electricity is generated from renewable sources the Energy Agency (*Agencija Republike Slovenije za energijo*) issues guarantees of the origin of electricity and RECS green certificates (one for every 1MWh of energy).
	TAXATION	The amendment of the Excise Duty Act, taking effect as of 1 May 2014, abolished the tax benefits previously granted to fuel distributers for (mandatory) marketing of biofuels (blending biofuels with fossil fuels in the prescribed minimum quotas). The Motor Vehicle Tax Act (*Zakon o davku na motorna vozila*) provides an incentive to purchase motor vehicle with a lower CO_2 emission.
	OTHER	The Energy Efficiency and Renewable Energy Sources Division (*Sektor za učinkovito rabo in obnovljive vire energije*) of the Ministry of the Economy promotes the use of renewable energy sources by providing funds for investment projects in a public tender procedure. Moreover, Eco Fund (*Eko sklad*) encourages the development of environmental protection by providing loans or guarantees for environmental investments.

SPAIN

PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	In 2013 the total energy generation from renewable sources represented the 17.39% of the total primary energy production (110,949GWh), according to MINETUR and IDAE sources. Although public sources do not expressly identify this information, the MINETUR report states that the total energy generation from renewable sources has increased a 28% with respect to the previous year (15.6%), that is, 1.79%. As a result, we have estimated the total energy generation from renewable sources by adding 15.6% and 1.79% which gives rise to 17.39%. The forecast of energy generation from renewable sources for 2020 is expected to be 22.7% of the total energy production). We include below the breakdown for the different renewable sources according to MINETUR, IDAE and CNMC sources. The details included below reflect the actual capacity for year 2012, the estimated capacity for year 2013 and the estimated capacity for year 2020: ◦ Hydroelectric: - 2012: 17,761MW - 2013: 19,650MW - 2020: 22,672MW ◦ Onshore wind energy: - 2012: 22,618MW - 2013: 22,949MW - 2020: 35,000MW ◦ Offshore wind energy - 2012: 0MW - 2013: 0MW - 2020: 750MW ◦ Solar thermoelectric - 2012: 1,950MW - 2013: 2,300MW - 2020: 4,800MW ◦ Solar photovoltaic - 2012: 4,541MW - 2013: 4,711MW - 2020: 7,250MW ◦ Biomass - 2012: 838MW - 2013: 846MW - 2020: 1,950MW ◦ Geothermal - 2012: 0MW - 2013: 0MW - 2020: 50MW
KEY GENERATORS OF RENEWABLE ENERGY	Abengoa, S.A. Acciona Energía, S.A. Endesa Cogeneración y Renovables, S.A. – ECYR Iberdrola, S.A.

SPAIN (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	On 12 July 2013 the Spanish Council of Ministers approved a reform of the Spanish energy sector pursuant to the Royal Decree-Law 9/2013, of 13 July ("RDL 9/2013"), which implements a series of urgent measures to guarantee the financial stability of the energy system, that entered into force on 14 July 2013. In this regard, in order to implement the new remunerative regime applicable to power plants generating electricity from renewable energy sources, the following legal provisions have been approved: Electricity Sector Act 24/2013, of 26 December (the "New ESA"), which introduces, among other things, a new legal and economic framework for the generation of electricity using renewable energy sources cogeneration and waste; Royal Decree 413/2014, of 6 June, which regulates the production of electricity from renewable energy sources, cogeneration and waste (the "RD 413/2014"), which entered into force on 11 June 2014; and Order IET/1045/2014, of 16 June, which approves the remuneration parameters for standard plants that will apply to certain renewable energy, cogeneration and waste-to-energy generation plants ("Order IET/1045/2014"), which entered into force on 21 June 2014. RD 413/2014 implements a new system of specific remuneration (*retribución específica*) – on top of the remuneration received for the sale of energy valued at market rates – and establishes the calculation formulas and remunerative parameters for each category of "standard plant" in accordance with the classifications made in the Royal Decree, while also establishing a reasonable rate of return for each project. The specific remuneration has two different components: (1) income from the sale of electricity generated valued at market prices; and (2) income composed of: an installed power component that covers the investment costs of a standard installation that cannot be recovered through energy sales, if any, and an operation component covering the shortfall between operating costs and income obtained by the standard installation from the market, if any. In order to calculate the specific remuneration, each plant will be allocated to a standard reference plant on the basis of its characteristics which is set out in Order IET/1045/2014.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	N/A
	TAXATION	Act 15/2012, of 27 December, of tax measures for energy sustainability, establishes the following measures: Electricity production tax over the total income received from the power produced by each of the tax payer's installations at a tax rate of 7%. Tax on the radioactive waste produced as a result of the generation of nuclear power and on the storage of nuclear waste in centralised plants. Creation of the so called "green cents" on natural gas, fuel-oil, coal and diesel. Duty on hydroelectric water.
	OTHER	

SWEDEN

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2012:** 51% of the energy consumed comes from renewable sources. **2020 target:** 50% of the total energy consumption.
	KEY GENERATORS OF RENEWABLE ENERGY	Vattenfall AB E.ON Sverige AB Fortum Power and Heat AB Statkraft Sverige AB

SWEDEN (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	N/A
	GREEN CERTIFICATES (NAME OF THE SCHEME)	The Electricity Certificate system: Green certificates issued to generators of electricity produced from renewable energy.
	TAXATION	The main legal framework for energy taxation is laid down in the Swedish Act on Excise Duties on Energy (SFS 1994:1776), which contains provisions on energy tax, carbon dioxide tax, sulphur tax on fuels and energy tax on electricity. The framework works as a means for Sweden to reach its energy policy goals. If the requirements in the Act Concerning Sustainability Criteria for Biofuels and Bioliquids (SFS 2010:598) are met, a tax exemption is awarded.
	OTHER	NA

SWITZERLAND

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2013:** 60% of energy generation out of which: hydro 56.6%, waste 1.7%, wind 0.14%, solar 0.82%,biomass 0.54%, sewage gas 0.20% **Target 2020:** 20% increase of energy generation from RES in relation to the total energy consumption. Any increase in electricity consumption shall be covered by RES whenever possible.
	KEY GENERATORS OF RENEWABLE ENERGY	Alpiq Group (ex Atel and EOS) Axpo Group (NOK, EGL and CKW)BKW FMB Energie AG GroupRepower AG Swiss Federal Railways (SBB) Elektrizitätswerke der Stadt Zürich ("EWZ") EnAlpin Groupe E Industrielle Werke Basel (IWB) Energie Wasser Bern (EWB) Energie Wasser Luzern (EWL)

SWITZERLAND (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	Mechanism: Cost-covering remuneration for the input into the network of electricity produced from RES is financed through a surcharge on electricity transmission price paid by all consumers. This form of remuneration has been made available since 2008 to hydropower (up to 10MW), photovoltaics, wind energy, geothermal energy, biomass and waste material from biomass. The tariffs for remuneration for electricity from renewable energy sources have been specified and updated on the basis of reference facilities for each technology and output category. Remuneration will be applicable for a period of between 20 and 25 years, depending on the technology. Owner of new facilities have to apply to the national grid company (Swissgrid), at the moment, however, there is a waiting list. The feed-in tariff at the moment is around CHF 0.15 per kWh on the average
	GREEN CERTIFICATES (NAME OF THE SCHEME)	Certified green electricity is sold by power companies to consumers whom are willing to receive green power. Producers of RES have to choose between this model and the cost-covering remuneration. However, the electricity company of the canton Basel (IWB) already and of the canton Zurich (EWZ) will from 2015, provide its customers with renewable energy only. Up until now, in contrast, electricity generated by nuclear power was the norm. The green-certificates model is not compulsory for electricity generators in Switzerland. However, the Climate Cent Foundation (*Stiftung Klimarappen*) (founded by principal members of the petroleum industry) has committed itself to reduce CO_2 emissions by the purchase of green certificates.
	TAXATION	A CO_2 fee was introduced in 2008. From 1 January, 2014, it amounted to CHF 60 per 1 ton of exhausted CO_2.
	OTHER	NA

TURKEY

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	According to provisional data in EÜAŞ's electricity sector report, as of 2013: ◦ Natural gas: 44% of overall electricity generation ◦ Hydro-power: 24.8% of overall electricity generation ◦ Wind-power: 3.1% of overall electricity generation ◦ Coal: 25.4% of overall electricity generation ◦ Liquid fuel and asphaltite: 1.6% of overall electricity generation ◦ Waste and geothermal: 0.9% of overall electricity generation ◦ Other resources: 0.1% of overall electricity generation 2023 targets: ◦ increasing the share of renewable energy sources to 30% ◦ maximising the use of hydro-power ◦ increasing wind power installed capacity to 20,000MW ◦ establishment of new power plants with 600MW of geothermal energy ◦ installing new power plants with 3,000MW of solar energy
	KEY GENERATORS OF RENEWABLE ENERGY	Elektrik Üretim Anonim Şirketi (EÜAŞ) (mostly hydro) EnerjiSa Enerji Üretim Anonim Şirketi Zorlu Grup Polat Enerji ve Sanayi Ticaret Anonim Şirketi Borusan Enerji Yatırımları ve Üretim Anonim Şirketi

TURKEY (CONTINUED)

FINANCIAL INCENTIVES

FEED-IN TARIFFS	The Law on Utilisation of Renewable Energy Resources for the Purpose of Generating Electrical Energy (the "RER Law") sets forth different feed-in tariffs according to the renewable energy resource, which are as follows:

Schedule I

TYPE OF GENERATION FACILITY BASED ON RENEWABLE ENERGY RESOURCES	PRICES APPLICABLE (USD CENT/KWH)
Hydroelectric generation facility	7.3
Wind power based generation facility	7.3
Geothermal power based generation facility	10.5
Biomass based generation facility (including landfill gas)	13.3
Solar power based generation facility	13.3

Please see "Other" column for additional incentives.

GREEN CERTIFICATES (NAME OF THE SCHEME)	The RER Support Mechanism includes price, terms, procedures and principles regarding payments, from which companies generating energy from renewable energy resources within the scope of the RER Law can benefit. The prices in Schedule I will apply for 10 years for generation licences subject to the RER Support Mechanism that are commissioned until 31 December 2020. However, in line with other developments, the foremost being security of supply, amount, price and payment terms and resources applicable to this law will be determined by a decree of the Council of Ministers.
TAXATION	Renewable energy facilities can benefit from certain tax incentives upon a decree of the Council of Ministers.
OTHER	**Other incentives** If the mechanical and/or electro-mechanical equipment used in the renewable energy generation facilities commissioned before 31 December 2020 are manufactured in Turkey, the prices in Schedule I will be added to the prices given in Schedule II (provided in the RER Law) for five years.

UKRAINE

OVERVIEW

PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-, SOLAR-, HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2014:** Total is 1358.1MWh (1% of the electricity generated). **2020:** 1.6% (target pursuant to the Energy Strategy of Ukraine)].
KEY GENERATORS OF RENEWABLE ENERGY	Neptun Solar Wind Parks of Ukraine, LLC Wind Power LLC Bolgrad Solar Franko Sola Priozerne 1 Priozerne 2 Rengy Development Ekotechnik Czeck

UKRAINE (CONTINUED)

FINANCIAL INCENTIVES	FEED-IN TARIFFS	The "green" tariff for generated electricity depends on the source of renewable energy. It is effective until 1 January 2030. For the power generating facilities, construction of which started after 1 January 2012, the "green" tariff is granted under condition of including a fixed percentage of a "Ukrainian component" (ie amount of materials and services of Ukrainian origin) in total cost of construction of power generating facilities. Currently the percentage of "Ukrainian component" amounts to 30% for the wind, solar and biomass power generating facilities, construction of which started after 1 January 2012 and which were commissioned after 1 July 2013, and for those to be commissioned after 1 July 2014 the percentage of the "Ukrainian component" is set to increase to 50%. For the facilities generating power from biogas, construction of which started after 1 January 2012 and were commissioned after 1 January 2014, the "green" tariff is granted under condition of 30% of a "Ukrainian component", however for those commissioned after 1 January 2015 the percentage of "Ukrainian component" is set to increase to 50%. The NERC establishes "green" tariffs for each producer monthly by multiplying coefficient, which value depends on the source of energy, to the January 2009 general retail tariff for low-voltage electricity consumers (in EUR). Product is converted to UAH in accordance with effective exchange rate.
	GREEN CERTIFICATES (NAME OF THE SCHEME)	N/A
	TAXATION	Income received from business activities of energy companies producing electricity from renewable sources, is released from income tax during 10 years starting from 1 January 2011. Up to 1 January 2020 the CPT is also cancelled for producers of biofuels in relation to income derived from sales of biofuels. Promoting taxation scheme is applied only if the exempted costs are used for upgrade of equipment or repay of loans within 3 years from the end of tax period in which such exemption took place.
	OTHER	All electricity produced from RES, which was not sold to consumers, is bought by the state enterprise "Energorynok" for monetary funds.

UNITED KINGDOM

OVERVIEW	PERCENTAGE OF ENERGY GENERATION FROM RENEWABLE SOURCES WITH BREAKDOWN (WIND-,SOLAR-,HYDRO-, GEOTHERMAL POWER, BIOFUELS, WASTE TO ENERGY ETC.) AND 2020 TARGET FOR RENEWABLE ENERGY	**2013:** Total is 53.67TWh (14.9% of total UK electricity generation) Renewable energy fuel use (2013): ◦ Bioenegy: 70.5% ◦ Wind: 21.8% ◦ Hydro and shoreline wave/tidal: 3.6% ◦ Other: 4.1% (Source: Digest of UK Energy Statistics) **2020 target:** 20%
	KEY GENERATORS OF RENEWABLE ENERGY	◦ SSE ◦ Infinis ◦ EDF Renewable Energy ◦ RWE AG ◦ Drax ◦ E.ON

UNITED KINGDOM (CONTINUED)

FINANCIAL INCENTIVES

FEED-IN TARIFFS	Summary: feed-in tariff for "small scale" generation of up to 5MW with effect from 1 April 2010 by means of amendments to the licence conditions of electricity suppliers in Great Britain, raised to 10MW for ground mounted solar under the Energy Act 2013 Mechanism: under terms of the licence, larger suppliers are required to agree terms for the payment of the feed-in tariff with eligible generators, including households. The tariff comprises a payment for each unit generated and an additional payment for export, calculated by reference to tariff tables set out in each supplier's licence. Generators can elect to sell their export independently. Feed-in tariff based on CfD: the UK Government has enacted powers to introduce feed-in tariffs for "large scale" renewable and other low carbon generation which will take the form of long-term contracts for difference, entered into with a central government counterparty – the Low Carbon Contracts Company (the "LCCC"). The LCCC became operational on 1 August 2014.
GREEN CERTIFICATES (NAME OF THE SCHEME)	Summary: The Renewables Obligation ("RO") is an obligation placed on licensed suppliers to supply a certain amount of the electricity they supply from renewable sources in each year. The RO scheme will close on 31 March 2017, with the exception of new solar PV generating stations above 5MW, for which the scheme will close from 1 April 2015. Note: the Non-Fossil Fuel Obligation (the "NFFO") is no longer open to new generators but will continue to operate alongside the RO until all fixed-price contracts entered into under that scheme (the NFFO) expire (2019); there is an equivalent regime applicable in Scotland.
TAXATION	Summary: The Climate Change Levy ("CCL") is a tax chargeable on non-domestic supplies of various commodities including electricity. By removing certain exemptions on the levy for fossil fuels used for power generation, a floor price for carbon was introduced on 1 April 2013. Mechanism: Renewables Levy Exemption Certificates ("LECs") issued by Ofgem can be used by energy suppliers to claim exemption from the CCL as evidence that a generator has produced "renewable source electricity" from an eligible generating station.
OTHER	N/A

NOTES

NOTES

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