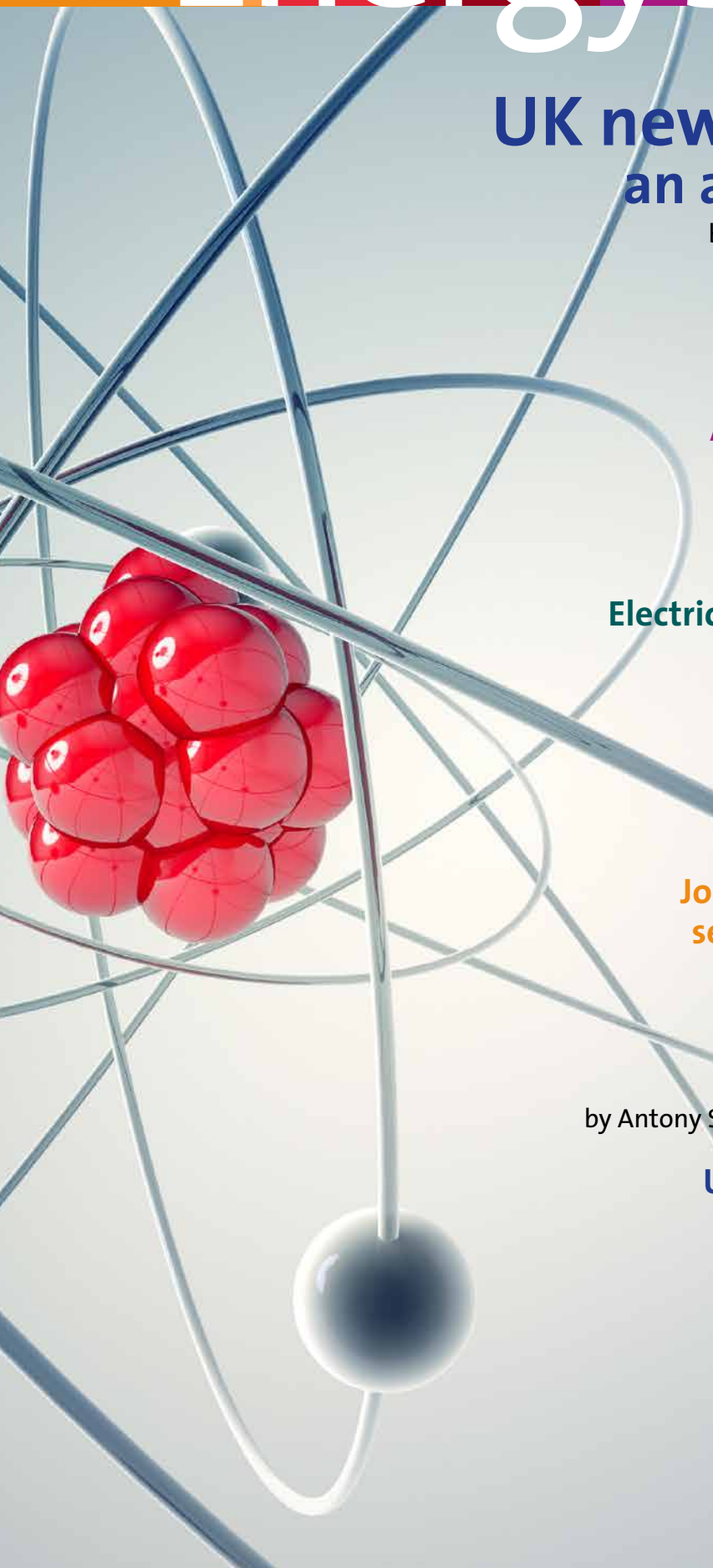
ISSUE 14: JANUARY 2015

EnergySource



ashurst

AN OVERVIEW OF THIS ISSUE

We are delighted to introduce this fourteenth issue of Energy**Source**, our biannual publication in which we cover a range of legal and transactional issues relevant to the energy sector from our offices across the globe. In this issue, we will be looking at:

UK NEW-BUILD NUCLEAR (p3) Nearly seven years have passed since the previous Government published its nuclear power white paper, confirming that nuclear power needs to be part of the UK's energy mix to address the country's energy "trilemma": energy security, carbon emission reductions, and rising prices. David Wadham and Anthony Johnson discuss the UK nuclear new-build project pipeline and the main legal issues for these projects.

LIQUEFIED NATURAL GAS (p9) It is 50 years since the first liquefied natural gas (LNG) cargo was shipped; today, LNG is the fastest-growing source of gas. Philip Thomson and Julia Derrick summarise some of the recent developments in the global LNG market and consider what impact they are having on LNG sale and purchase agreements.

ARBITRATION IN THE MIDDLE EAST (p12) International arbitration is the dispute resolution mechanism of choice within the energy sector. Dyfan Owen investigates recent cases which suggest a welcome trend in support of arbitration and enforcement of arbitral awards in Middle Eastern states.

THE WESTERN AUSTRALIAN ELECTRICITY MARKET (p15) In response to high wholesale electricity costs and a corresponding high level of government subsidy of retail tariffs, the Western Australian Government announced an Electricity Market Review on 6 March 2014. James Bruining and Caroline Lindsey consider the potentially wide-ranging changes to the WA electricity market that may flow from the review.

SPECIAL REPORT: UK ELECTRICITY MARKET (p18) By comparison, while Western Australia is considering abolishing its capacity market, the UK has just introduced one. In "A tale of two capacity markets: the contrasting UK experience", Antony Skinner and Justyna Bremen provide a snapshot of the UK's new capacity market regime.

MYANMAR ELECTRICITY SECTOR (p20) Myanmar is currently at a pivotal moment in its development: ongoing reforms and the easing of sanctions have opened up exciting possibilities. Against this backdrop, John McClenahan and Shan Koh report on the challenges and opportunities presented by the country's electricity industry.

JORDAN'S SOLAR LANDSCAPE (p23) Energy diversification is a key priority for Jordan, given its heavy dependency on foreign energy imports. The country's solution is, in part, to generate ten per cent of its primary energy from renewables, a target it is looking to hit by 2020. Mhairi Main Garcia discusses how Jordan is utilising its abundance of solar energy to its advantage.

TIDAL POWER (p27) Is it time for tidal power to take the front seat? In this article, Antony Skinner, Cameron Smith and Alex Bartho examine the main tidal technologies that are undergoing commercial development, the UK's position at the forefront of the industry, and its ability to capitalise on future growth in marine power.

UK SHALE GAS (p32) The UK's conventional oil and gas industry continues to be an important contributor to the country's overall economy and energy security. But as conventional reserves decline, the UK Government is anxious to foster the development of a shale gas industry. Martin Kudnig and Denva Poyntz discuss the regulatory regime for shale gas in the UK, and the steps taken by the Government to ensure that the regime does not pose an impediment to the industry.

We hope that you find Energy**Source** useful and enjoy reading this issue. Please let us know if you have any feedback or if there are any topics that you would like us to cover in future editions

Geoffrey Picton-Turbervill
Partner – Energy, Resources and Infrastructure
T: +44 (0)20 7859 1209
E: geoffrey.picton-turbervill@ashurst.com

Philip Thomson
Partner – Energy, Resources and Infrastructure
T: +44 (0)20 7859 1243
E: philip.thomson@ashurst.com

UK NEW-BUILD NUCLEAR:

An atom's width away

by David Wadham and Anthony Johnson

Nearly seven years have passed since the previous Government published its Nuclear White Paper,[1] confirming that nuclear power needs to be part of the UK's energy mix to address the country's energy "trilemma" – energy security, carbon emission reductions and rising prices. Following the European Commission's state aid approval of the support package being offered to EDF's Hinkley Point C project, announced on 8 October 2014, new-build nuclear power is one step closer to becoming a reality in the UK.

In this article, we consider the main legal issues which will still be faced by nuclear projects in the UK, despite the policy and legal framework that the previous and current Governments have put in place to support nuclear power to implement the recommendations of the Nuclear White Paper.

The nuclear state of play

The UK currently has 8.3 gigawatts (GW) of existing nuclear generation capacity, details of which are set out in figure 3. However, all but one of Britain's existing nuclear energy stations are scheduled to close by 2023 if their operational lives are not extended.

With regard to new-build nuclear, the UK Government currently contemplates that approximately 16 GW of new capacity could be constructed at five sites by 2030 (pushed back from 2025). The contemplated 16 GW of nuclear capacity refers to the following projects:

- the **Hinkley Point C project**, being developed by EDF Energy (through its subsidiary, NNB Generation Company Limited (NNBG)), and involving the construction of two Areva European pressured reactors (EPRs) (with a total capacity of 3.2 GW) at Hinkley Point on the Somerset coast. EDF is currently in discussions with potential investors in the project, including China General Nuclear (CGN), China National Nuclear Corporation (CNNC) and certain financial investors, as well as possibly Saudi Electricity Company;
- EDF Energy's second UK EPR project, the 3.2 GW **Sizewell C project** in Suffolk;
- NuGen's **Moorside project**, near Sellafield, for up to 3.6 GW of capacity using Westinghouse's AP 1000 technology. NuGen is a consortium of GDF SUEZ and Toshiba; and
- Horizon Nuclear Power (a wholly owned subsidiary of Hitachi Ltd), which is looking to develop around 5.4 GW of capacity at **Wylfa** and **Oldbury** using Hitachi's advanced boiling water reactor (ABWR) technology.

All the projects are at sites adjacent to existing reactors. The Hinkley Point C project is the most advanced of all the projects in

1 Department for Business, Enterprise & Regulatory Reform: *Meeting the Energy Challenge – A White Paper on Nuclear Power,* January 2008.

the pipeline. Westinghouse's AP 1000 and Hitachi's ABWR technology are currently undergoing the Generic Design Assessment (GDA) process undertaken by the UK regulator, the Office for Nuclear Regulation (ONR).

Nuclear safety and security

The regulator

Recognising that safety and security are critical issues in the context of nuclear power generation, the ONR, as an independent regulator, is tasked with their regulatory oversight. The ONR took over the functions previously undertaken by the Nuclear Directorate within the Health and Safety Executive (which is responsible for health and safety regulation for most industries) as part of the various steps being undertaken by the Government for "nuclear new-build preparedness". Indeed, the Government's decision to create a new regulator proved provident, as it was while the arrangements for a transition to the new regulator were being made that the Fukushima disaster propelled nuclear safety into the spotlight. Following the Fukushima disaster, the Government commissioned a review of the nuclear safety regime in the UK and the final report (the Weightman Report[2]) found no fundamental weaknesses in the regime, and noted, among other things, that the creation of the ONR would further enhance the regulatory framework.

The ONR became a fully independent regulator in April 2014, with the coming into force of Part 3 of the Energy Act 2013, which establishes the ONR as an independent body and bestows upon it the necessary enforcement powers for the regulation of nuclear safety and security in the UK.

The Generic Design Assessment process

The approval of new-build projects by the ONR involves a two-step process – a generic approval of the technology to be used (i.e. the GDA process), followed by an assessment of site-specific issues for an individual project (the NSL, the requirements of which are discussed below).

The first step is the GDA process developed in 2006 and used by the ONR, together with the Environment Agency (EA), to assess new nuclear power station designs. The GDA allows the regulators to assess the safety, security and environmental implications of new reactor designs, separately from applications to build them at specific sites. The process is extremely complex, involving a number of steps, including public consultation, and takes a number of years to complete.

The first round of GDA commenced in July 2007 to assess four reactor designs. Out of the initial four, two designs were withdrawn part-way through assessment, and the AP 1000 assessment was paused at Westinghouse's request. Only the UK EPR design was issued with a Design Acceptance Confirmation (DAC) from the ONR and a Statement of Design Acceptability (SoDA) from the EA in December 2012.

In January 2013, the Energy Minister asked the ONR and the EA to undertake GDA of the UK ABWR reactor technology, following Hitachi's purchase of Horizon Nuclear Power, who has plans to build nuclear power stations at the Wylfa and Oldbury sites. The ONR has estimated that the GDA process for UK ABWR could be completed by the end of 2017. In addition, in September 2014, Westinghouse formally recommenced the GDA of the AP 1000 reactor technology.

The complexity and cost of the GDA process place a constraint on how many reactors can be assessed. The ONR has estimated that the GDA for UK EPR cost around £33m (funded by EDF/NNBG), and involved the submission of over 7,000 documents, 150 technical support contracts, and more than a thousand meetings to discuss technical issues. It is expected that the next "slot" for other reactor designs to be assessed will not open until 2016.

Strictly speaking, the GDA process is not mandatory and the ONR's guidance states that potential developers are free to submit NSL applications for designs that have not been subject to GDA. However, in practice it seems unlikely that an NSL would be issued for a project using reactor technology that has not been approved under the GDA process.

Site licensing

At the heart of the regulatory framework is the requirement for all nuclear plant operators to hold an NSL, issued pursuant to the Nuclear Installations Act 1965 (NIA 1965). The NSL and conditions contained in it apply at all times throughout the life of the nuclear plant and therefore cover the design, construction, commissioning, operation, maintenance and decommissioning phases.

The regime established under the NIA 1965 is supplemented by various legislative instruments dealing with environmental, health and safety matters, including:

- the Health and Safety at Work, etc. Act 1974;
- the Nuclear Reactors (Environmental Impact Assessment for Decommissioning) Regulations 1999;
- the Ionising Radiations Regulations 1999;
- the Radiation (Emergency Preparedness and Public Information) Regulations 2001;
- the Radioactive Substances Act 1993;
- the Environmental Permitting Regulations 2010;
- the Control of Major Accident Hazards Regulations 1999; and
- the Nuclear Industries Security Regulations 2003.

While the grant of an NSL is a key requirement and a major milestone for a project, it does not give permission for the start of nuclear-related construction. That will require permission from the ONR in accordance with the NSL conditions, and will be dependent on the ONR's satisfaction with the pre-construction safety case. Other

Figure 1: The Hinkley Point C project

EDF Energy is developing a 3.2 GW nuclear power plant using EPR (Areva) technology, adjacent to the site of Hinkley Point A and Hinkley Point B on the Somerset coast. Hinkley Point A is a twin reactor which stopped generating in 2000 after 35 years of operation and is currently being decommissioned. Hinkley Point B, also a twin reactor, is still generating electricity. It commenced generation in 1976 and was originally scheduled to be shut down in 2016, but has now had its operational life extended to 2023, to coincide with the planned commissioning of the new Hinkley Point C plant.

The Hinkley Point C plant, a two-reactor plant, will have an estimated operational life of 60 years. Construction will take around ten years, with commercial operation estimated to commence from 2023/2025. A 20-year decommissioning period is due to start in the 2080s.

Hinkley Point C's reactors will be the first EPRs built in the UK. The delayed Olkiluto 3 (Finland) and Flamanville 3 (France) plants also utilise this technology, as do the Taishan 1 and 2 reactors being developed in China by a joint venture of EDF Energy and CGN. EPR technology successfully passed the GDA in December 2011, and in November 2012 NNBG was issued a nuclear site licence (NSL) by the Office for Nuclear Regulation.

2 *Japanese earthquake and tsunami: Implications for the UK nuclear industry.* Final Report, HM Chief Inspector of Nuclear Installations, September 2011.

permits are required to allow construction to proceed, including permits under the legislation outlined above.

Given that an NSL governs all activities from the design phase onwards, it needs to be obtained at a relatively early stage for a new-build nuclear project. For the Hinkley Point C project, an NSL was granted by the ONR to NNBG in November 2012.

The planning regime for nuclear

The Planning Act 2008

The Planning Act 2008 sets out the planning and other related consenting regime for Nationally Significant Infrastructure Projects (NSIPs) in England and Wales, including large-scale power generation projects (for onshore projects, this means projects generating greater than 50 MW of energy) such as nuclear.

For NSIPs, the Major Infrastructure Planning Unit within the Planning Inspectorate administers and reviews planning applications, and then provides advice and recommendations to the relevant Minister, who makes the final decision. For nuclear projects, the final decision is made by the Secretary of State for Energy and Climate Change.

National Policy Statements

Under the Planning Act 2008, any decisions made in relation to NSIPs must be made in accordance with the relevant National Policy Statements (NPSs). This is subject to some limited exceptions, such as where making the decision in accordance with the NPS would lead to the UK being in breach of its international obligations. The NPSs were finalised following two public consultations held between 2009 and 2011. For nuclear projects, there is an overarching Energy NPS,[3] as well as a Nuclear NPS.[4]

The Nuclear NPS sets out the policy imperative for nuclear power, with the intention that this issue should not be reopened at the development consent stage, leaving the decision makers to consider site-specific issues. Importantly, the Nuclear NPS lists the sites that have been identified as potentially suitable for the deployment of new nuclear power stations by the end of 2025. The sites were identified following a Strategic Siting Assessment process.

There are eight sites identified in the Nuclear NPS as potentially suitable and they are all situated next to existing nuclear sites, as listed in figure 4. It is possible for an application for development consent to be submitted in relation to a site not identified in the NPS, but in practice it would seem very unlikely that such an application would be successful. Such a site would be subject to greater consideration of the suitability of the particular location. In the absence of policy support of specific sites in the NPS there is a higher risk that local impacts could result in refusal of any application for development consent. The Nuclear NPS itself states that the Government does not believe that there are any alternatives to the listed sites that are potentially suitable for the deployment of new nuclear power stations in England and Wales before the end of 2025.

3 *Overarching National Policy Statement for Energy* (EN-1), Department of Energy and Climate Change, July 2011.

4 *National Policy Statement for Nuclear Power Generation* (EN-6), Department of Energy and Climate Change, July 2011.

The Development Consent Order process

As would be expected, obtaining development consent for a nuclear project is a lengthy process. The Hinkley Point C project received development consent in March 2013, nearly 18 months after submitting its formal application in October 2011. However, this seemingly short period belies the fact that the formal application was preceded by extensive public consultations, initiated in November 2009, and the submission of an Environmental Impact Assessment scoping report (running to thousands of pages) in January 2010.

The development consent takes the form of a Development Consent Order (DCO), which for Hinkley Point C is set out pursuant to the Hinkley Point C (Nuclear Generating Station) 2013 (the Order). Importantly, as well as granting planning permission, the Order gives the project company, NNBG, compulsory purchase powers. The powers allow the project company to acquire land or land rights (e.g. easements) for the purposes of the project by compulsory acquisition pursuant to the Compulsory Purchase Act 1965 and associated legislation where agreement cannot be reached with the landowners. The DCO can also include a wide range of other powers and authorisation otherwise required under other statutory regimes.

Nuclear new build remains controversial in the UK as it is in Europe generally. The Hinkley Point C project attracted objection from the Governments of Ireland and Austria, as well as the Implementation Committee of the UN Convention on Environmental Impact Assessment in a Transboundary Context. Two legal challenges were made following grant of the DCO, both in the form of judicial review; one made by Greenpeace and the other by An Taisce, the National Trust's counterpart in Ireland. Greenpeace subsequently abandoned the judicial review application, while the An Taisce application was rejected by the Court of Appeal in August 2014.[5] It is noted that the DCO spent longer under the shadow of litigation than was needed for the formal assessment of the application. No legal challenge to the grant of a DCO has yet been successful, but they are time-consuming.

Decommissioning

The Energy Act 2008 introduced a new regime intended to ensure that operators of new nuclear plant will have secure financing arrangements in place to meet the full costs of decommissioning and their share of waste management and disposal costs. This regime replaces the previous regime under which the UK's Nuclear Decommissioning Authority (NDA) – a non-departmental public body of the United Kingdom formed by the Energy Act 2004 – is responsible for funding and managing nuclear decommissioning and radioactive waste management. Under that regime, the NDA is currently overseeing the clean-up and decommissioning of 17 nuclear sites in the UK, which date back as far as the 1940s.

A key requirement under the new regime is that before construction begins, an operator of a new nuclear plant must submit a Funded Decommissioning Programme (FDP) for approval by the Secretary of State. The operator must also enter into a contract (a waste transfer contract) with the Government regarding the terms on which the Government will take title to and liability for the operator's radioactive waste. The contract will set out the payment(s) that the operator must make to the Government following the transfer of such radioactive waste.

Under the FDP (once approved by the Secretary of State), the operator is responsible for making payments and issuing investment orders to an insolvency-remote "FundCo" (an entity that holds and administers the fund) during the operational life of the facility. Such payments and investment orders are structured to ensure that FundCo has sufficient and secure funding to meet the full costs of decommissioning and waste management/disposal by the start of decommissioning.

The operator takes risk on the investment strategy, including risks associated with:

- a failure of the investment strategy to deliver the anticipated growth;
- significant increases in decommissioning and/or waste management/disposal costs above forecast levels; and
- project revenue being insufficient to meet the operator's decommissioning and waste management/disposal obligations.

Incentive regime

Contracts for Difference regime

It has been recognised that, like renewables, new-build nuclear power is not currently commercially viable without a revenue support mechanism. Nuclear projects are therefore eligible for support under the new Contracts for Difference (CfD) regime.

The CfD regime was introduced under the Energy Act 2013, and will ultimately replace the Renewables Obligation (which is currently being phased out) as the main form of revenue support for low-carbon electricity generators. Importantly, CfDs are not just available to traditional "renewables" projects, but are also available to nuclear and carbon capture and storage projects which the Government has determined fall under the "low carbon" banner.

CfDs involve a payment to low-carbon electricity generators of a top-up above the wholesale price for electricity (the "market reference price"), up to a set "strike price". The strike price is intended to be an amount equal to that needed to make low-carbon power projects a viable investment proposition in the UK. A key feature of CfDs is a two-way payment mechanism, so to the extent the market reference price is higher than the strike price, the generator will be required to make a payment back to the CfD counterparty.

Figure 2: The Contract for Difference in brief

The CfD is a private law, bilateral contract between the CfD counterparty and a low-carbon generator. The Government has established a Government-owned limited liability company, the Low Carbon Contracts Company (LCCC), to act as the counterparty to the CfDs entered into with low-carbon generators. The LCCC is responsible for collecting from licensed electricity suppliers a levy that will be used to fund the CfD payments to eligible generators who are allocated and then enter into a CfD, and also for administering payments under CfDs. The cost of the levy will be passed down to end-users of electricity.

Allocation of CfDs

For most renewable energy projects, CfDs will be allocated through a CfD allocation round process, to be held once a year. The first allocation round commenced on 16 October 2014. A different allocation procedure applies to nuclear projects and other bespoke, low carbon electricity projects. It is envisaged that eventually, in the long term, CfDs for nuclear projects may be allocated through a competitive allocation process, but it is recognised that this is not currently feasible. Therefore, for the time being at least, CfDs for nuclear projects are being allocated through a bilateral negotiation process between the project developer and the Secretary of

5 *R (An Taisce (The National Trust for Ireland)) -v- Secretary of State for Energy and Climate Change, and Anor* [2014] EWCA Civ 1111.

State for Energy and Climate Change. The legislative basis for this process is laid down under section 10 of the Energy Act 2013 and Part 10 of the Contracts for Difference (Allocation Regulations 2014), which give the Secretary of State the power to direct the LCCC (see figure 2) to enter into a CfD with an eligible generator.

The Government has not published detailed guidance on the process to be followed for the allocation of CfDs outside of allocation rounds, but has indicated that the following principles apply:

- the direction may be given following a bilateral negotiation or a competitive process;
- before making a direction, the Secretary of State will have to take into account relevant factors such as the impact on the Levy Control Framework budget and any state aid considerations;
- contract terms that can be offered in a bespoke contract are based on, but will not be restricted to, the standard terms that are applicable to CfDs offered through the generic CfD allocation process; and
- direction-making power could therefore be used in relation to large or unusual projects for which the standard terms and generic allocation process are not suitable.

The Hinkley Point C CfD

When negotiations commenced between EDF Energy and the Government in respect of a CfD for the Hinkley Point C project, the new CfD regime was not yet in force. Instead, provision was made by the Energy Act 2013 for the Government to grant to certain projects so-called "investment contracts", or early form CfDs, to accommodate projects which may have otherwise been delayed pending full implementation of the CfD regime.

Therefore, EDF negotiated a bespoke investment contract heads of terms with the Department of Energy and Climate Change (DECC), with agreement being reached in October 2013 on the following key terms:

- a strike price of £92.50/MWh over a 35-year period. If the Sizewell C project goes ahead, the Hinkley Point C strike price will drop to £89.50/MWh and there will be a payment from Sizewell C to Hinkley Point C equivalent to £3/MWh, reflecting the fact that the first-of-a-kind costs of EPR reactors will be shared across the two projects; and
- the strike price will be fully indexed to the Consumer Price Index from the date of signature of the CfD. Based on current assumptions, this would translate into a nominal strike price of £279/MWh in 2058.

The net present value of the difference payments to be made by the CfD counterparty (LCCC) have been estimated at between £3.5bn and £9.obn, depending on the market price for power (and hence the value of the "top-up" to the strike price).

Hinkley Point C financing

Financing of nuclear plants is not straightforward; the capital costs are very high and the operating period very long. The amount of debt to be raised and the necessary debt tenor make these projects difficult for commercial banks who would typically finance conventional IPPs. To support the financing of Hinkley Point, the Government has confirmed that it will be offering a government guarantee to the Hinkley Point C project, pursuant to the UK guarantee scheme (UKGS), to make it easier for the project to secure finance. It has been agreed that the guarantee will support 65 per cent of the total budgeted costs prior to operation (with the remaining 35 per cent being funded by the shareholders).

Essentially, the idea behind the UKGS is that Infrastructure UK (IUK) (part of HM Treasury) provides a guarantee in respect of amounts due to funders from a particular project. For Hinkley Point C, project bonds will be issued by a financing company (a company related to NNBG), and IUK will guarantee the repayment of these bonds to funders who have purchased the bonds. Therefore, this has the effect of substituting project risk for UK Government risk in return for a guarantee fee, thereby facilitating the financing of a major infrastructure project. The guarantee fee will be paid at commercial rates.

In December 2013, the Government announced that it would also be offering a guarantee to Hitachi and Horizon to support the financing of the proposed new-build nuclear project at Wylfa, subject to final due diligence and ministerial approval.

This has been followed by a Government announcement in December 2014 that HM Treasury has reached a co-operation agreement with Toshiba, GDF SUEZ and NuGen with the aim of issuing a statement of intent to provide a guarantee to assist the financing of the proposed Moorside plant, subject to due diligence and ministerial approval. Even with the benefit of IUK support, financing of nuclear plants remains challenging and it is to be anticipated that funders will require strong sponsor support to mitigate the risks associated with schedule delays and cost overruns.

State aid approval

In line with the European Commission's state aid rules, the Government was required to obtain approval from the European Commission for the Hinkley Point C incentive package. As mentioned above, that approval was finally granted on 8 October 2014, following a lengthy investigation, and was only granted on the basis of some modifications to the support structure.

In particular, the Commission has required the following key changes:

- **Guarantee fee:** in relation to the UK Guarantee, the Commission found that the initial guarantee fee which NNBG would have paid to the UK Treasury was too low. The fee has therefore been significantly raised. The Commission has said that the increase will reduce the subsidy by more than £1bn and procure the UK Treasury an equivalent gain.
- **Gainshare:** at the time the application for approval was made, EDF Energy and DECC had been discussing various possible gain share and cost reopener mechanisms, to ensure that the Hinkley Point C project would offer value for money for consumers. This was a key consideration in, and indeed a condition of, the Commission's decision.

However, the Commission decided to approve the CfD support being given to the project on the condition that a greater proportion of future profits would be shared with the Government (and therefore the taxpayers). The profit-sharing mechanism will therefore be triggered once the project's overall profits exceed an internal rate of return of around 11.4 per cent.

Further, while it was originally contemplated by EDF Energy and the Government that the gainshare mechanism would be in place only for the duration of the CfD (i.e. 35 years), the Commission has required that it be in place for the entire lifetime of the project, namely 60 years.

At the time of writing the European Commission had not yet published the full text of its decision. While the basic outcome is clear, the details and reasoning will be of great interest, given the difference between the Commission's position in its interim decision and its final decision.

Additional protection for the Hinkley Point C project

In addition to the CfD, NNBG and its investors will also enter into an agreement (Secretary of State Agreement) with the Secretary of State for Energy and Climate Change to manage the risk that the plant is shut down in the future as a result of a political decision, and not a decision related to health, safety, security, environmental, transport or safeguards concerns, or other specified circumstances.

If such political shutdown were to occur, the counterparties to the Secretary of State Agreement will have the following options:

- the Secretary of State will have a "call" option requiring the shares in NNB HoldCo (who will own 100 per cent of shares in NNBG) to be transferred to it (or its nominee); and
- EDF Energy and other investors will have a "put" option requiring the shares in NNB HoldCo to be transferred to the Secretary of State (or its nominee).

Following the exercise of either option, compensation will be payable by the LCCC (or the Secretary of State as a fallback) to NNBG's investors.

What next?

Despite the fact that significant progress has been made recently for the development of nuclear projects in the UK – facilitated by the UK Government's policy support for new-build nuclear – getting new-build projects off the ground is clearly not a straightforward process. Due to the:

- limited number of suitable sites and the time, cost and complexity of the DCO process; and
- combined with the rigorous ONR approval process and the limits on the number of designs that can be accepted for the GDA,

initial barriers to entry are high.

Developers who overcome these initial obstacles, and who are armed with a consented site and GDA-approved technology, face further challenges, including:

- uncertainty in respect of whether a CfD will be offered to the relevant project and, if it is, uncertainty as to the strike price and terms of the CfD;
- sourcing and structuring a cost-effective funding package;
- challenges associated with developing a robust construction strategy and allocating risk between the project company and its construction sub-contractors; and
- the final, significant hurdle of obtaining state aid clearance from the European Commission and the conditions attached to any such clearance, including conditions which limit investors' returns or which dictate the cost of finance (as with the Hinkley Point C project).

Despite all these challenges, UK new-build nuclear continues to generate significant interest from developers. A successful closing of the Hinkley Point C project would lend some real momentum to the sector and give the Government a fighting chance of achieving its target for new-build nuclear capacity, significantly rebalancing the UK's future generation mix and going some way towards solving the UK's energy "trilemma".

Figure 3: Nuclear power plant currently operating in the UK (Source: ONR)

Power Station	Owner	Operator	Output (MW)	Year commenced generation
Wylfa	National Decommissioning Authority	Magnox Ltd	475	1971
Dungeness B (two reactors)	EDF Energy	EDF Energy Nuclear Generation Ltd (NGL)	520	1983
Hartlepool (two reactors)	EDF Energy	NGL	595	1983
Heysham 1 (two reactors)	EDF Energy	NGL	585	1983
Heysham 1 (two reactors)	EDF Energy	NGL	615	1988
Hunterston B (two reactors)	EDF Energy	NGL	430	1976
Hinkley B (two reactors)	EDF Energy	NGL	430	1976
Torness (two reactors)	EDF Energy	MGL	600	1988
Sizewell B (single reactor)	EDF Energy	NGL	1188	1995

Figure 4: Sites for new-build nuclear

The following sites are those that the Government has determined are potentially suitable for the deployment of new nuclear power stations in England and Wales before the end of 2025, as set out in the National Policy Statement for Nuclear Power Generation:

- Bradwell
- Hartlepool
- Heysham
- Hinkley Point
- Oldbury
- Sizewell
- Sellafield
- Wylfa


David Wadham
London
T: +44 (0)20 7859 1064
E: david.wadham@ashurst.com


Anthony Johnson
London
T: +44 (0)20 7859 1780
E: anthony.johnson@ashurst.com

LIQUEFIED NATURAL GAS:

A snapshot of global trends

by Philip Thomson and Julia Derrick

It is fifty years since the first LNG cargo was shipped. This article summarises some of the recent developments in the global LNG market and considers what impact these developments are having on the terms of LNG sale and purchase agreements.

Introduction

As at the end of 2013, there was 290.7 million tonnes per annum (MTPA) of liquefaction capacity located in 17 different countries.[1] Nominal liquefaction capacity will increase further still, with the ramp-up of Australian volumes anticipated from 2015, the start-up of some of the US projects and the further development of LNG liquefaction capacity in emerging regions such as Canada, Mozambique, Tanzania and potentially the Eastern Mediterranean.

In terms of regasification capacity, at the end of 2013 there was 688 MTPA of capacity located in 29 different countries.[2] Significantly, there is more than twice as much regasification capacity as there is liquefaction capacity. Much of the under-utilised regasification capacity is located in Europe. The global LNG fleet comprised 357 LNG vessels as at the end of 2013.[3]

In 2013, 236.8 million tonnes of LNG was traded globally, representing ten per cent of global demand for gas. Reaching this milestone followed a long period of rapid growth in the trade of LNG volumes. Since 2000, volumes have grown at an annual average rate of 7.5 per cent, which makes LNG the fastest growing source of gas supply.[4] Demand is expected to continue to grow in Asia, driven in particular by China; and industry analysis indicates a risk of significant shortfall in supply in the first half of the next decade.

Current LNG market trends

Global LNG trade is currently characterised by a number of key trends, including the following:

Marked LNG price differences globally

In recent years, the price benchmarks by which LNG is priced in different regions (e.g. the Henry Hub gas index in the US, the UK National Balancing Point, Brent in Europe, and the Japanese Crude Cocktail or Japan Korea Marker in Asia) have diverged significantly. In Asia, the LNG price has increased in response to increased demand, especially following the Fukushima nuclear incident; whereas in the US, LNG is coming to market at relatively low prices because the US gas market has been flooded by shale gas. European prices have been between Asian and US prices. To give an idea of the scale of this divergence, when Henry Hub reached its low point at US$1.9/MMBtu in April 2012, it was trading at a discount of approximately US$8-10/MMBtu to European prices and at a discount of up to US$14 to Asian prices. While this gap in prices has reduced since April 2012, it is expected to remain significant.[5]

1 Source: International Gas Union World LNG Report – 2014 Edition.
2 Source: International Gas Union World LNG Report – 2014 Edition.
3 Source: International Gas Union World LNG Report – 2014 Edition.
4 Source: International Gas Union World LNG Report – 2014 Edition.
5 Source: International Gas Union World LNG Report – 2014 Edition.

Recently, with high prices for LNG in Asia, many Asian buyers (in particular from Japanese, Korean and Indian companies) have focused on the opportunity to source "cheap" LNG from the US, based on Henry Hub pricing or linked to other US gas indices. This represents a move away from the more traditional oil-linked contracts into Asia. The extent to which this opportunity will remain available depends on the relative movements of US gas prices and global oil prices. However, oil indexation is still expected to continue to be the dominant pricing mechanism outside of the US.

Growth of spot market

The spot and short-term markets for LNG have continued to grow. From being insignificant in 2000, volumes sold under contracts with a term of five years or less accounted for 33 per cent of global trade in 2013. The largest supplier of short-term cargoes has been Brunei, which renewed long-term contracts at a reduced volume, thus leaving volume available to be sold on the spot and short-term market. China, Malaysia, Argentina and Brazil have been major importers of spot and short-term cargoes. However, despite the development of the spot and short-term market, the traditional single-source of supply take-or-pay contract, albeit with some relatively minor modifications, still remains the model for the development of greenfield liquefaction projects because it insulates investors in the liquefaction project from the risk of lack of demand for LNG.

Growth of the re-export markets

Re-exported volumes have grown over the past four years, and reached 4.6 MTPA in 2013. Most volumes have been re-exported from Europe (in most cases Spain and Belgium, although further regasification terminals in Europe are seeking to develop or have developed re-export capacity in recent years) to meet demand in Asia. The significant difference in prices has incentivised LNG buyers to import LNG into Europe and re-export it to Asia. The success of this model has also depended on there being excess capacity in the European regasification sector. Re-export may not oblige the buyers to share the resultant upside with sellers, as they would traditionally have been obliged to do if they diverted a cargo before delivery under a long-term LNG sale and purchase agreement.

Innovation on both the supply and demand sides affects the prospects of further market growth

Examples of innovation include:

- the development of LNG as a marine and vehicular transportation fuel, which should stimulate further demand for LNG;
- the development and increased use of floating liquefaction technology, which offers the ability to monetise reserves that are too small or too remote to be developed by using conventional land-based liquefaction solutions; and
- the development of break bulk facilities (e.g. at the Gate LNG receiving terminal in the Netherlands), which will allow LNG from distant supply sources to penetrate small markets which may have previously been beyond their reach.

New market participants and changes in commercial objectives

The market has seen the introduction of new market participants with new commercial objectives and constraints (e.g. most obviously, LNG sellers willing to sell LNG sourced from the US at prices linked to Henry Hub or other gas indices). This has been coupled with changes in the commercial objectives and capabilities of market participants (e.g. portfolio sellers and traders, both of whom have shown themselves willing to take risks relying on mitigation strategies that are based on the increased liquidity in the market).

Common themes in LNG contracting

The LNG market has changed dramatically since 1964 when the British Gas Council started importing LNG into the United Kingdom from Algeria under a 15-year, 1 MTPA LNG sale and purchase agreement. For many years, LNG was traditionally sold under long-term (15-20 years) contracts, on a take-or-pay basis. The early LNG sale and purchase agreements were generally based on point-to-point supply of fixed volumes, between creditworthy, often state-owned sellers and buyers, with short contracts.

However, as the LNG market has developed, LNG sale and purchase agreements have become increasingly more flexible in terms of volumes, destinations, supply sources and price mechanisms, and increasingly more detailed and complex in their drafting and dealing with issues such as risk allocation between the parties. The trend towards flexibility has increased in recent years.

In light of the current LNG market trends described above, current issues and themes which commonly arise in LNG sale and purchase agreement negotiations include the following:

Supply source flexibility

Linked to the growth in the spot and short-term market for LNG is the increase in the number of portfolio-supply arrangements under which the seller retains the flexibility to source cargoes from a portfolio of supply sources (which may be defined more or less explicitly in the agreement between the parties). Buyers may seek to limit the seller's supply source flexibility by including carve-outs in the LNG sale and purchase agreement – for example, prohibitions on the seller supplying from specific named sources which may be viewed as "unreliable" or which have historically been prone to force majeure. In order to maximise the value of any supply source flexibility, sellers will also typically want some flexibility to use bigger or smaller ships than those originally scheduled. A buyer will need to consider the extent to which it can accept this flexibility given its storage capacity and its demand profile.

Destination flexibility

The difference in the prices that can be achieved for LNG in different markets is one of the factors that has led to increased destination flexibility in LNG supply agreements. North-West Europe in particular is dominated by long-term, but flexible, LNG sale and purchase agreements. This enables producers and sellers to use that market as a flexible outlet for LNG, diverting cargoes to higher paying markets in Asia whenever possible, and using North-West Europe as a market of last resort. At the same time, Brazil and Argentina have emerged as new markets and have been able to absorb many diversion cargoes. Buyers are also increasingly wanting very flexible contracts which enable them to sell the cargo into different markets.

Force majeure

For buyers, one of the potential attractions of a portfolio supplier is that the risk of a force majeure event interrupting supply can be spread across the portfolio of supply sources. In this case, a force majeure event affecting a particular production facility will not cause the delivery of the full contractual volume to be suspended. As regards LNG sourced from the US, given the very liquid nature of the US gas market and the robust gas transportation network

within the country, buyers may argue that sellers supplying LNG from the US do not need force majeure protection for assets upstream of the LNG plant (and any pipeline dedicated to supply to the plant) because US sellers have adequate mitigation options in the event of upstream or grid force majeure.

Buyer's shortfall

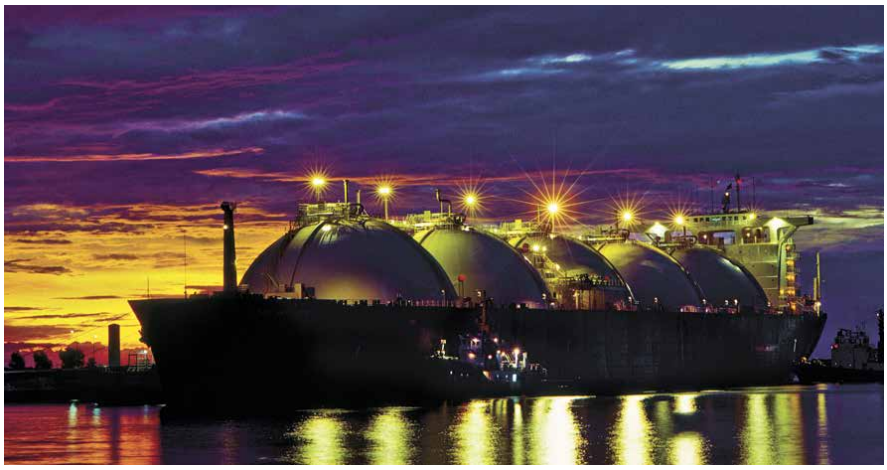
The traditional formulation for dealing with buyer's failure to take LNG in long-term LNG sale and purchase agreements is that the buyer is required to pay for the LNG not taken, and may become entitled to receive make-up LNG at a later date of an equivalent quantity that the buyer has paid for, but not taken. This formulation is increasingly being seen as cumbersome and difficult to manage. As alternatives, we are seeing concepts borrowed from the spot/short-term market being employed in long-term LNG sale and purchase agreements – for example, adopting a cargo-by-cargo liability approach, where, instead of make-up, the seller is able to sell the cargo not taken by the buyer to a third party and reimburse to the buyer the net proceeds from the mitigation sale up to the amount paid by the buyer under the take-or-pay clause. An alternative approach to take-or-pay (sometimes favoured by a portfolio seller) is for the buyer to pay a percentage of the contract price for the missed cargo to the seller as liquidated damages for the failure to take.

Caps on liability

Parties are increasingly looking to cap their liability in all circumstances and on an aggregate basis. The focus on caps on liability often reflects that, in a more flexible and less predictable market, it can be challenging to assess the level of loss that a breach might cause the counterparty and for which the counterparty would look to be indemnified.

Title transfer

Under a typical DES/DAT LNG sale and purchase agreement, where the seller is responsible for transporting the LNG from the loading port to the unloading port, title to, risk of loss and custody of LNG transfers from the seller to the buyer at the unloading port. Hybrids of and variations to this regime have been in use for many years. For example, it is not uncommon to see LNG sale and purchase agreements which provide that, while custody will remain with the seller until the unloading port, title to and risk of loss of LNG will



transfer to the buyer in international waters immediately prior to the LNG vessel entering the territorial waters of the importing country. However, traditionally sellers only opted for a DES/DAT hybrid including offshore title transfer provisions if deliveries were being made into a country where title transfer at the unloading port was known to have adverse tax implications for the seller. As the parties move towards increasing destination flexibility, LNG sale and purchase agreements are increasingly providing for one or other party to be able to elect for an offshore title transfer mechanism.

Off-specification LNG

The likelihood that LNG sold on a DES/DAT basis will come from a variety of sources (and that FOB LNG will be sold into different markets) has increased the consideration that parties may give to the risk of LNG not meeting the required quality specifications prescribed in the contract. As a result, the traditionally brief clause dealing with this risk has increased in length as the parties develop detailed drafting to deal with the actions of the parties and remedies available following the discovery of off-specification LNG at different stages. This approach started in spot and short-term contracts (where the parties might not necessarily have a long-term relationship) but is increasingly being seen in long-term LNG sale and purchase agreements.

Credit support

The creditworthiness of buyers under LNG sale and purchase agreements has been a key point for discussion for many years. However, historically the provision of credit support tended to be more firmly insisted upon where the buyer was a special purpose vehicle or a company with a weaker balance sheet. Since the global financial crisis in particular, as in other sectors and contracts, parties to LNG sale and purchase agreements have become more alert to the need for robust credit support (or at least the need to include contractual provisions which require the buyer to provide credit support if during the term it ceases to meet certain minimum credit criteria), even if the buyer appears at the date of signing to be creditworthy. In addition, while traditionally it was only buyers who would be asked to provide credit support for their obligations under LNG sale and purchase agreements, increasingly sellers are also now asked to provide credit support (e.g. to cover any seller's shortfall liability or termination payments).

Conclusions

As the LNG industry looks ahead to the next 50 years, the global market for LNG is continuing to develop in terms of overall volume, the number of market participants and the types of business models underpinning those market participants.

These developments are having knock-on effects on the contractual models and terms used for the sale and purchase of LNG. This evolution is likely to continue for the foreseeable future.

It should be noted, however, that at the time of writing, the figures for the global LNG trade for 2014 were not available, and the oil and gas industry is yet to face the full implications of the falling oil price. There is, therefore, a degree of uncertainty about what 2015 will hold for the LNG industry.

Philip Thomson
London
T: +44 (0)20 7859 1243
E: philip.thomson@ashurst.com

Julia Derrick
London
T: +44 (0)20 7859 1117
E: julia.derrick@ashurst.com

ARBITRATION IN THE MIDDLE EAST:

Towards greater acceptance

by Dyfan Owen

In the energy sector, international arbitration is the preferred dispute resolution mechanism.[1] The main reasons for this are the neutrality, flexibility, confidentiality, ease of enforcement and expertise of the decision maker that arbitration offers. Recent cases suggest a welcome trend in support of arbitration and enforcement of arbitral awards in Middle Eastern states.

Background: enforcement is key

The enforcement advantage that arbitration offers is dependent on the attitude adopted by the courts of the state in which enforcement is required. While many jurisdictions have shown themselves to be arbitration-friendly and pro-enforcement, others have not.

In the Middle East, it remains the case that enforcing arbitration awards in a number of states can be problematic. Some jurisdictions, such as Yemen and Iraq, are not signatories to the New York Convention.[2] Even where the New York Convention has been adopted, enforcement can still be problematic. Parties often use public policy arguments to allow the local court to reconsider the merits of the dispute or refuse enforcement because, for example, the award fails to comply with Sharia law (the courts of Saudi Arabia have refused to enforce several arbitration awards for this reason).

There is, however, an increasing trend in favour of arbitration and the enforcement of awards in some states, in particular the UAE. Recent cases that support this trend include decisions of the Dubai International Finance Centre (DIFC) Court of First Instance[3], the DIFC Court of Appeal[4] and a judgment given by Qatar's Court of Cassation.

The cases before the DIFC Court

The case of *Banyan Tree -v- Meydan Group LLC* involved Banyan, a company incorporated in Singapore, and Meydan, a company incorporated in the UAE. The dispute concerned the validity of Meydan's termination of an agreement under which Banyan would take over the management of a luxury hotel that Meydan was building. The agreement provided for Dubai International Arbitration Centre (DIAC) arbitration. DIAC is widely viewed as the busiest and best-known arbitration centre in the UAE and the Gulf Co-operation Council (GCC) region.

The sole arbitrator issued an award in favour of Banyan, declaring that the

THE DIFC

The DIFC is a financial-free zone within Dubai and has its own autonomous and independent judicial system. The DIFC Courts are an independent, English language, common law judicial system – in contrast to the UAE's civil law system – and they have a judicial panel of renowned commercial and civil law judges, including a Court of Appeal.

The DIFC has its own arbitration law based on the UNCITRAL Model Law (the DIFC Arbitration Law). The grounds for refusing to enforce an arbitration award under the DIFC Arbitration Law are narrower than under Dubai law.

The Judicial Authority Law, which sets out the authority of the DIFC Courts, provides that the Dubai courts do not have discretion or jurisdiction to review the merits of a DIFC Court judgment or arbitral award. In contrast, the UAE Civil Code requires an award rendered in onshore UAE to be ratified by the Dubai courts before it can be enforced. This can be a protracted process and can, in practice (although it should not), involve a review of the merits of the underlying dispute.

1 In a 2013 survey conducted by PwC and Queen Mary University of London, 56 per cent of those surveyed in the energy sector said that arbitration was the preferred method of dispute resolution, with 22 per cent saying litigation, 17 per cent saying adjudication/expert determination, and 5 per cent saying mediation.

2 Convention on the Recognition and Enforcement of Foreign Arbitral Awards (New York, 1958).

3 *Banyan Tree -v- Meydan Group LLC* (Case No. ARB 003-2013) and *X1 and X2 -v- Y1 and Y2* (Case No. ARB 002-2013).

4 *Banyan Tree -v - Meydan Group LLC* (Case No. CA-0052-14).

agreement had been wrongfully terminated and awarding damages of approximately US$20m. No payment was made by Meydan, and Banyan sought to recognise and enforce the award in the DIFC Courts.

In *X1 and X2 -v- Y1 and Y2*, the parties were companies incorporated outside Dubai. The claimants wanted to enforce a foreign arbitral award obtained in their favour against award debtors incorporated outside the DIFC, in Dubai. The judgment does not provide details of the seat of the arbitration or whether it was institutional or ad hoc.

The decisions

In both cases, the DIFC Court was asked to consider whether it had jurisdiction to hear an application for an order seeking recognition and enforcement of an arbitral award. The only issue considered by the DIFC Court was whether it had jurisdiction. It did not consider the merits of the argument in favour of recognition or enforcement of the award.

The defendants challenged the claims on jurisdictional grounds, alleging that the Dubai courts, and not the DIFC Courts, were the proper forum to deal with such a claim. They argued as follows:

- the DIFC Court does not have jurisdiction to recognise and enforce awards in circumstances where the awards in question have no connection to the DIFC;
- the decision to file a claim in the DIFC Court was an attempt to circumvent the ratification procedure for domestic awards set out in the UAE Civil Procedure Code. The Judicial Authority Law provides that the Dubai courts do not have discretion or jurisdiction to review the merits of a DIFC Court judgment or arbitral award. The claim should therefore be rejected as it was: (i) an abuse of process; (ii) contrary to the public policy of the UAE; and (iii) against the doctrine of *forum non conveniens*.

In support of their arguments, the defendants pointed to the fact that they had no assets within the DIFC.

In rejecting these arguments, Sir John Chadwick (in *X -v- Y*) and H.E. Justice Omar Al Muhairi (in *Banyan*) held that:

- The DIFC Court has jurisdiction under Article 5(A)(1)(e) of the Judicial Authority Law, and Articles 42, 43 and 44 of the DIFC Arbitration Law, to hear the claims relating to the recognition of the awards.
- Article 5(A)(1)(e) of the DIFC's Judicial Authority Law provides that the DIFC Court *"shall have exclusive jurisdiction to hear and determine … any claim or action over which the Courts have jurisdiction in accordance with DIFC Laws and DIFC Regulations"*. The DIFC Court should therefore determine jurisdiction over a claim by reference to its own laws, not the federal law of the UAE.
- Article 42(1) of the DIFC Arbitration Law provides that: *"An arbitral award,* ***irrespective of the State or jurisdiction in which it was made, shall be recognised as binding*** *within the DIFC and, upon application in writing to the DIFC Court, shall be enforced subject to the provisions of this Article and of Articles 43 and 44…"* [emphasis added]. This gives the DIFC Court jurisdiction to recognise and enforce arbitral awards "*irrespective of the State or jurisdiction*". The DIFC Court has jurisdiction in relation to enforcement of arbitral awards not seated in the DIFC whether domestic (i.e. from Dubai, as in *Banyan*) or from outside the UAE (as in *X -v- Y*).
- Article 42 provides that arbitral awards shall be recognised as binding within the DIFC only. Enforcement of awards within Dubai (but outside the DIFC) is a matter for the Dubai courts. However, it is clear from Articles 7(2) and 7(3) of the Judicial Authority Law that both the DIFC Court and the Dubai courts may recognise and/or enforce the same arbitral award.
- A connection with the DIFC is not required as no such requirement is to be found in Article 5(A)(1)(e) of the Judicial Authority Law. The DIFC can therefore hear an application for recognition of an award without such a connection.
- Although the absence of assets within the jurisdiction against which to enforce the award may be fatal to an application for an order for execution, that was not a reason to refuse to hear the claim on the grounds of lack of jurisdiction.
- In *Banyan*, the Court held that the doctrine of *forum non conveniens* only applies in the DIFC where the alternative court is a foreign (as opposed to UAE) court. This reflects previous DIFC Court judgments.
- In *X -v- Y*, the DIFC Court held that there was no support in public policy for the proposition that Articles 42 and 43 of the DIFC Arbitration Law should be construed restrictively so as to be limited to circumstances where enforcement is to take place in the DIFC.
- In circumstances where the DIFC's own laws permit the DIFC Court to accept jurisdiction over a claim for recognition and enforcement of the DIAC award, a decision to file such a claim in the DIFC Court could not be regarded as an abuse of process.
- The New York Convention does not apply to enforcement or recognition of UAE awards in the DIFC, as they are considered domestic awards.

Appeal

The decision of the DIFC Court of First Instance in *Banyan* was affirmed by the DIFC Court of Appeal on 3 November 2014. No appeal was submitted in *X -v- Y*.

In supporting the DIFC Court of First Instance's decision, the DIFC Court of Appeal held in *Banyan* that it was plain from the provisions of Article 7 of the Judicial Authority Law that the legislator did contemplate that there could be circumstances in which recognition of a foreign arbitral award by the DIFC Court could trigger enforcement proceedings, through the Dubai courts, against assets in Dubai (outside the DIFC) without the need for separate recognition of the award by the Dubai courts.

Comment

It is important to remember that these decisions are in respect of jurisdiction only – the DIFC Court did not address the merits of the argument in favour of recognition or enforcement of the award.

While we must wait to see the true impact of these decisions, they are important and potentially groundbreaking. They confirm that the DIFC Court has jurisdiction to recognise and enforce in the DIFC awards rendered: (i) in Dubai or elsewhere in the UAE (but outside the DIFC) (domestic awards); and (ii) anywhere outside the UAE (foreign awards). This came as a surprise to many who had assumed that the DIFC Court's jurisdiction to recognise and enforce awards was limited to cases where the parties or the dispute had some connection with the DIFC.

They also have potentially more wide-ranging consequences for arbitration practice and procedure in Dubai. The UAE Civil Code requires an award rendered in onshore UAE to be ratified by the UAE courts before it can be enforced. This can be a protracted process and involve a review of the merits of the underlying dispute. The Dubai courts do not, however, have discretion or jurisdiction to review the

merits of a DIFC Court judgment or arbitral award.

The decisions could potentially permit parties to circumvent the UAE's ratification process by having their awards recognised first by the DIFC Courts. It will be interesting to see how the Dubai courts or other Middle Eastern courts respond to any attempt to use the DIFC Court as a portal to enforcement in the UAE or further afield.

These cases may therefore have a further part to play: (i) in respect of the interaction between the civil law and common law systems of the offshore DIFC and onshore Dubai; and (ii) in developing arbitration practice and procedure in the UAE.

Qatar's Court of Cassation recognises applicability of the New York Convention

In 2013, the Qatar Court of First Instance accepted a motion to annul an arbitral award on the basis that the award violated public policy due to the fact that it was not rendered in the name of H.H. the Emir of Qatar. This was based on the text of Article 69 of the 1990 Code of Civil and Commercial Procedural Law, which provides that judgments are to be issued and executed in the name of H.H. the Emir.

The annulment was granted despite the fact that the ICC arbitration was seated in France and the parties had, in the arbitration agreement, agreed that French law would govern the procedure of the arbitration. The Qatar Court of Appeal then upheld the decision.

This decision was subsequently appealed to the Qatar Court of Cassation, the court of final appeal in Qatar. The Court of Cassation published a judgment clarifying which laws should apply in Qatar to international, rather than domestic, arbitration. The Court of Cassation found that the first instance judge had incorrectly applied Qatar's civil code to an arbitration award rendered outside Qatar.

The Court of Cassation held that the New York Convention was part of Qatari law and, since the Convention does not impose particular rules as to the format or details of an arbitral award, it follows that Qatari law should not impose rules on the format or details of an award made and published by a tribunal seated overseas. The Court of Cassation held that a Qatari court should not annul a foreign-seated award on the grounds that it had not been issued in the name of H.H. the Emir.

The Court of Cassation therefore confirmed that jurisprudence relating to the New York Convention is to be applied to arbitral awards governed by procedural laws outside of Qatar. The decision by the Court of Cassation not to rely on local procedural requirements in the context of international arbitration is a positive step towards the enforcement of foreign arbitral awards in Qatar. This development will be welcomed by arbitration practitioners and those conducting business with companies whose assets are located within Qatar.

The New York Convention

Enforcement of arbitral awards is facilitated by the United Nations Convention on the Recognition and Enforcement of Foreign Arbitral Awards, New York, 1958 (the New York Convention). The New York Convention is the bedrock of international arbitration. A contracting state is obliged to recognise arbitration awards as binding and to enforce them in accordance with its procedural rules. Over 150 countries have ratified the New York Convention, including most of the world's leading trading nations (including all GCC states). For a full list of countries, see the UNCITRAL website.[5] While arbitral awards are usually complied with voluntarily, where enforcement proceedings are necessary, the New York Convention greatly assists award creditors, although it should be noted that not all states have a good track record of compliance with their obligations under the New York Convention.

5 http://www.uncitral.org/uncitral/en/uncitral_texts/arbitration/NYConvention.html.

Conclusion

There is, as supported by these cases, an increasing trend towards recognition of arbitration and arbitral awards in a number of Middle Eastern states, particularly the UAE. This, as a result, has meant that foreign counterparties in the energy sector can have greater confidence in arbitration as a means of resolving their disputes (and Middle Eastern seats of arbitration) when contracting with Middle Eastern counterparties.

However, the enforcement of arbitration awards in a number of Middle Eastern states remains problematic. Further, in some states, enforcement is largely untested – there is limited reported precedent of enforcement of arbitral awards to determine the extent to which parties seek to avoid enforcement and of the approach of local courts to such attempts. It is therefore important, when negotiating dispute resolution clauses, to consider in which jurisdiction enforcement of any award will be required, and to seek legal advice so that the dispute resolution clause can be tailored accordingly.

Dyfan Owen
London
T: +44 (0)20 7859 1176
E: dyfan.owen@ashurst.com

THE WESTERN AUSTRALIAN ELECTRICITY MARKET:

Can new solutions be found to an old problem?

by James Bruining and Caroline Lindsey

The Western Australian wholesale electricity market (WEM) is currently the subject of a comprehensive review, which may result in wide-ranging changes, including a structural separation of the government-owned power company, Synergy; the abolition of the capacity market; and the introduction of full retail contestability.

Background

The WEM presents some distinct challenges to policy makers. It is geographically isolated from the rest of Australia with no interconnection capacity; is a relatively small market; and, traditionally, has a high peaking demand. In contrast to other states in Australia, the majority of its electricity generation assets continue to be owned by a state-owned entity, which is also the largest retail electricity supplier. In addition (and in part as a result of its geographical isolation), the WEM has been a capacity and energy market since 2006.

In response to (among other factors) high wholesale electricity costs when compared to the rest of the country and a corresponding high level of government subsidy of retail tariffs, the Western Australian Government announced an Electricity Market Review (the Review) on 6 March 2014.

The Review is being undertaken in two phases. In phase one, the Electricity Market Review Steering Committee (the Steering Committee) will assess and examine the strengths and weaknesses of the current industry structure, market institutions and regulatory arrangements, and the options for reforms to better achieve the three objectives set out in the Terms of Reference for phase one (summarised below). In phase two, the detailed design of selected reforms and the implementation arrangements will be considered.

As part of phase one, the Steering Committee published a discussion paper (the Discussion Paper) on 13 August 2014, which sets out wide-ranging options for the reform of the WEM.

The Terms of Reference for phase one state that the Review will be undertaken with three objectives (the Review Objectives) in mind:

(1) reducing costs of production and supply of electricity and electricity-related services, without compromising safe and reliable supply;
(2) reducing government exposure to energy market risks, with a particular focus on having future generation built by the private sector without government investment, underwriting or other financial support; and
(3) attracting to the electricity market private-sector participants that are of a scale and capitalisation sufficient to facilitate long-term stability and investment.

These objectives revisit themes that have been a feature of discussions on Western Australian energy policy for decades.

This article examines some of the legal issues which arise from the options for reform contained in the Discussion Paper.

Summary of options for reform

The Discussion Paper groups the options for reform of the WEM into two general categories:

(1) **changes to industry structure and regulation**, including structural separation of Synergy (the government-owned generator and supplier), the introduction of full retail contestability into the electricity retail and gas markets (FRC), and associated changes to existing government subsidies to retail tariffs; and

(2) **changes to market mechanisms** by either:

- refining the current market, including changing the way capacity is procured under the RCM and encouraging fungibility of energy contracts; or
- fundamentally changing the structure and operation of the WEM by joining the National Electricity Market (NEM) as a non-connected region.

The Steering Committee characterises the changes to industry and regulation as common reforms, which may be appropriate regardless of which changes to the market mechanisms are pursued.

Legal issues for consideration

Future of the RCM remains uncertain

The Discussion Paper poses the question of whether the RCM is delivering the right capacity at a reasonable cost.

The view of the Steering Committee appears to be that it is not. This is supported by evidence identifying the substantial cost to taxpayers of procuring excess capacity to date (far above what is needed to ensure security of supply in the WEM). This echoes concerns previously raised by the Economic Regulation Authority (WA) and some market participants. It is also consistent with the Minister for Energy's directive in April 2014 that the 2014 Reserve Capacity Cycle (affecting the 2016–17 Capacity Year) be deferred for a year.

The Steering Committee's options for reform of the RCM range from making changes to the existing mechanism (for example, moving to an auction mechanism to determine the price for Capacity Credits) to removing the RCM and introducing an energy-only market (discussed below).

While the Steering Committee does not express an opinion as to the future of the RCM (and the Government has made clear that the Discussion Paper does not represent government policy), the Steering Committee's questions as to the efficacy of that mechanism, coupled with the Minister for Energy's directive, suggest that the RCM's future in its current form remains in serious doubt.

This raises important issues for market participants who have entered into contracts for the sale and purchase of Capacity Credits (whether bundled with electricity supply or not); the owners of generating plant (and their funders) that is financially underpinned by the RCM remaining in place in its current form; and prospective electricity generation projects which might rely (at least to some extent) on an income stream from the RCM. More generally, any significant change to the structure of the WEM, such as the repeal

A brief overview of the WEM

The WEM operates in the south-west region of Western Australia (referred to as the South West Interconnected System or SWIS) under the WEM Market Rules administered by the Independent Market Operator (IMO). The SWIS services an estimated 1.1m customers and has approximately 6,000 MW of installed generation and demand side management capacity. The remainder of Western Australia is supplied by the North West Interconnected System or by islanded networks. Horizon Power, a government-owned entity, generally operates those networks. The WEM currently comprises:

- an energy market, including balancing and short-term energy markets and bilateral contracts between market participants; and
- a capacity market (referred to as the Reserve Capacity Mechanism, RCM).

The key features of the capacity market are:

- a Reserve Capacity Requirement is set annually by the IMO (on a rolling four-year cycle);
- electricity generators and demand side management facilities can apply (on an annual basis) for the capacity of their facility to be certified to meet that requirement. The IMO can also (but to date has not needed to) run an auction to procure capacity;
- each MW of Certified Reserve Capacity that a facility contributes to the SWIS receives a Capacity Credit;
- electricity retailers (and other market participants) must procure sufficient Capacity Credits to meet their proportion of the Reserve Capacity Requirement and can do so either by bilateral trades with other market participants or by acquiring Capacity Credits from the IMO;
- each uncontracted Capacity Credit entitles the holder to receive a AU$/MW price determined by the IMO based on the cost to install a 160 MW open-cycle gas turbine generation facility in the WEM. The Reserve Capacity Price for the current capacity year (2014–15) is AU$122,427.87 per MW; and
- the cost of the RCM is ultimately borne by end consumers.

of the RCM, is likely to have an effect on all market participants.

It would also be prudent for market participants to consider how these changes might be addressed when drafting new contracts for electricity and/or Capacity Credits until the position is clearer.

Fungibility of electricity contracts

A number of the options raised in the Discussion Paper would involve a change to the terms on which market participants typically contract in the WEM.

One option raised by the Steering Committee is the possibility of "sponsoring" standardised bilateral contract forms and encouraging trade in those contracts through mandatory requirements on large participants to "make markets".

Comparative examples

There is evidence from other jurisdictions that standard form contracts for the bilateral trading of electricity in wholesale electricity markets are attractive to market participants (although they do not necessarily address liquidity concerns). For example, in Great Britain, transactions in the wholesale electricity market are often concluded on the basis of the Grid Trade Master Agreement (GTMA) developed by the Futures and Options Association (now FIA Europe). Internationally (including in the NEM), the ISDA Master Agreement, developed by the International Swaps and Derivatives Association (ISDA), is used to trade physically and financially settled electricity products.

The basic structure of those contracts is the same as the form of bilateral trade agreement commonly used in the WEM; the general terms on which transactions will be entered into and performed are agreed by the parties upfront and set out in a master agreement, while the specific terms of each transaction (including volume and price) are agreed on a transaction-by-transaction basis and documented in a legally binding confirmation. If the parties wish to make any amendments to the general terms set out in the master agreement, then these are set out in a schedule to the agreement (terms which are typically amended include credit and events of default).

Application to the WEM

The use of standard contracts can reduce the cost of electricity transactions by reducing the time spent drafting and negotiating contracts and in obtaining internal approvals. They also offer an industry-standard approach to key areas of risk, which can then be easily "back-to-backed" with related transactions.

However, to be attractive to market participants, the development of standard form contracts needs to be supported – and ideally, driven – by the entities who intend to use them. Common approaches to key risks (such as force majeure, credit, termination and change in law) need to be debated and agreed.

Consequently, the dominant players in the WEM will need to support and contribute to the development of a standard form contract for it to be a success.

Interestingly, in Great Britain, the Office of Gas and Electricity Markets (the economic regulator of Britain's gas and power markets) recently introduced a licence obligation on large electricity generators to offer a form of GTMA to eligible small electricity suppliers, primarily to improve liquidity in the wholesale electricity market. The merits of introducing a similar obligation on large electricity generators in the WEM would need to be considered in view of (among other things) the relatively small number of generators in the WEM, the level of uncontracted capacity available, the cost to those generators of complying with that obligation, and the impact of introducing such an obligation on investor appetite for the WEM (one of the Review Objectives).

The success of Synergy's wholesale standard product offering, which it is required to offer by the Electricity (Standard Products) Wholesale Arrangements 2014 (WA), should provide some guidance as to

whether a broader offering from Synergy and other large market participants on the basis of standard terms is likely to have a positive impact on the level of liquidity in the WEM.

Some legal issues posed by a move to the NEM

The possibility of Western Australia moving to become a non-connected region of the NEM would constitute a fundamental change in the structure, operation and regulation of the WEM. This possibility has previously been rejected on the basis of, among other things, Western Australia's geographical isolation from the NEM, the significant cost, and other practical and legal issues likely to arise from the transition from a bilateral contract market for energy and capacity to a gross pool in which all generating capacity must be offered.

Putting aside questions such as whether a cost-benefit analysis is likely to support this change and whether the NEM model is appropriate for Western Australia, the prospect of moving to the NEM raises significant legal issues for both existing and potential investors and market participants such as:

- How will existing bilateral contracts with electricity generators be affected by the move to a mandatory gross pool? If Western Australia joins the NEM will those contracts be able to continue in some form until they expire? Or will the contracting parties seek to terminate the contract under change in law or change in market rules provisions (if they can)?
- How will the terms of project finance for existing power projects be affected?
- What effect will the transition to new regulatory institutions have on approvals given and decisions made by the former WEM institutions (for example, as to the accreditation of market participants)?
- Will moving towards a market in which derivative transactions are commonplace trigger an obligation on market participants to obtain an Australian Financial Services Licence under chapter 7 of the Corporations Act 2001 (Cth)? Currently, under section 18A of the Electricity Industry (Wholesale Electricity Market) Regulations 2004 (WA), arrangements that are engaged in for the purpose of short-term trading, balancing and reserve capacity in the WEM are declared to be excluded matters for the purposes of chapter 7.

Our comments above in relation to the cessation of the RCM also apply equally here.

Conclusions and next steps

The Discussion Paper provides a framework for discussion, rather than the detailed and considered cost-benefit analysis of the available options that is required before a decision is made about the future of the WEM. It does not assess the extent to which any of the options proposed will meet the Review Objectives. Nor does it necessarily reflect government policy. In this respect, a key consideration is likely to be whether the recommended course of action can be implemented – and the intended benefits realised – within the term of the current Government.

Fifty stakeholders, including utilities, industry associations and investors, made written submissions to the Steering Committee in response to the Discussion Paper.

The majority of submissions support some form of structural change to Synergy, the introduction of FRC and changes to government retail subsidies. There is less support for a move to the NEM and/or the removal of the RCM in its entirety. A number of submissions noted the significant transitional issues associated with either of those options, and questioned the suitability of the NEM model for WA.

At the time this article was written, the industry was awaiting the publication by the Steering Committee of an Options Paper outlining its recommendations for the reforms to be considered in phase two of the Review.

Given the broad level of support in the public submissions and the views expressed in the Discussion Paper, it would be unsurprising if the Options Paper recommends some form of structural change to Synergy and a transition to FRC, coupled with changes to government retail subsidies. Public statements by the Minister for Energy indicate that those options are also being considered by the Government.

James Bruining
Perth
T: +61 8 9366 8117
E: james.bruining@ashurst.com

Caroline Lindsey
Perth
T: +61 8 9366 8109
E: caroline.lindsey@ashurst.com

A TALE OF TWO CAPACITY MARKETS: The contrasting UK experience

by Antony Skinner and Justyna Bremen

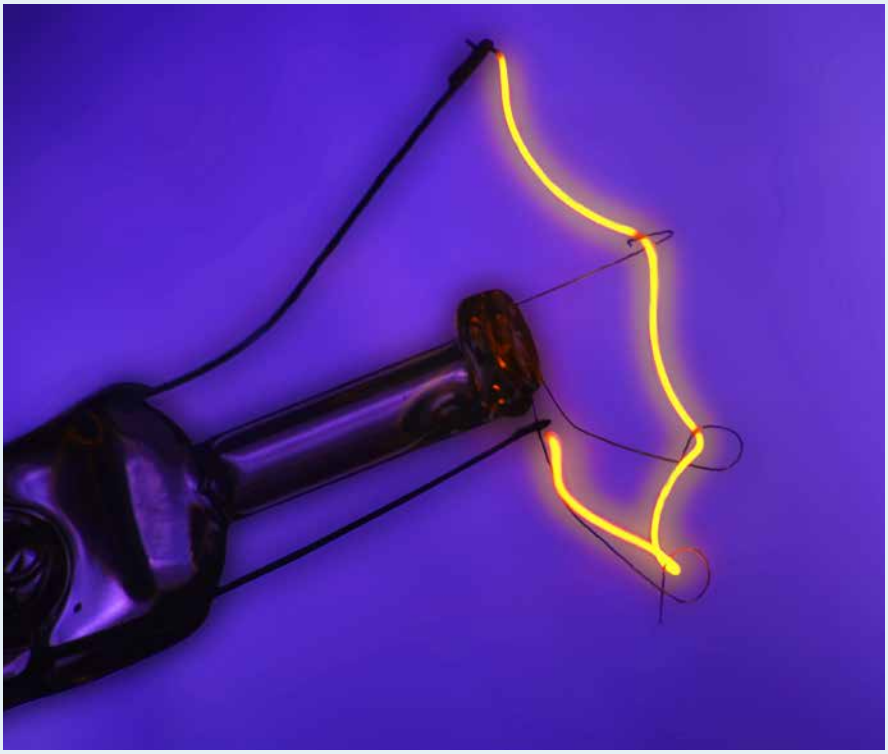
While Western Australia is coming to grips with the consequences of a capacity market that has resulted in excess capacity and high costs, the UK is currently at the start of its capacity market journey.

Simply put, the UK is potentially facing what has been described by some as an energy crisis. The root cause is a lack of investment in new plant, coupled with the imminent closure of a large volume of capacity, either due to the plant reaching the end of their life (as is the case for a large number of nuclear plant and some ageing gas-fired plant) or as a result of planned closures of coal-fired plant to comply with the EU Large Combustion Plant Directive. Recognising that current market conditions, together with the existing incentive regime for renewables, are insufficient to attract the scale of investment required to bridge the capacity gap, the UK Government embarked on its Electricity Market Reform (EMR), which was fully implemented this year. The two main elements of EMR are:

- the Contracts for Difference (CfD) regime, involving a payment to low-carbon generators of a top-up above the wholesale price (the reference price), up to a set "strike price" (which will be different for each technology), for the term of the CfD allocated to the generator. Renewable generation, nuclear and carbon capture and storage-equipped fossil fuel power plant will be eligible for CfD; and
- the Capacity Market regime, involving capacity payments to providers of capacity, including both generation and non-generation forms of capacity such as demand side response (DSR) and storage, for the term of the capacity agreement granted to the provider.

Main features of the Capacity Market

To determine how much capacity needs to be procured through the Capacity Market, the Government will estimate on an annual basis the total volume of capacity required 4.5 years ahead of the delivery year (running from 1 October to 30 September). The system operator (National Grid) will then contract for the required volume of capacity from providers through a central auction process.



The main auction for physically backed capacity will be held every year, for delivery four years later. A further year-ahead auction will be held in the year immediately prior to the delivery year of the main auction. The first capacity auction (the T-4 auction) is being held in December 2014, for the 2018–19 delivery year. It will be open to all types of eligible capacity.

Auctions will be run on a "pay as clear" basis, which means all successful auction participants (including existing plant) will be paid the same price per unit of capacity, and the price will be set by the most expensive successful bidder. Each auction will be run in multiple rounds on the basis of a "descending clock" format, which means that providers will confirm they will offer capacity at a particular price, and then further rounds will be held at a lower price, until the auction discovers the minimum price at which there is sufficient capacity.

To mitigate the risk of existing plant seeking to force up the capacity price, at the pre-qualification stage all participants will be required to register whether they wish to participate in the auction as "price makers" (i.e. price setters) or "price takers". Existing generators will default to being price takers, unless they are a plant that will undergo refurbishment. Price takers will only be able to bid up to a relatively low threshold, which will be set to allow the majority of existing plant to participate in the auction as price takers.

Successful providers of capacity will enter into capacity agreements, committing to provide electricity or reduce demand, as the case may be, in return for capacity payments. Existing plants and DSR or storage providers will be awarded capacity agreements for a term of one year, while plants requiring major refurbishment will have access to a longer term. New-build plants will receive a 15-year term. For generators, the principal obligation under the capacity agreement will be to deliver a specified quantity of electricity in "system stress periods", upon being given four hours' notice by the system operator. Penalties will be imposed if a capacity provider fails to meet its commitment.

Under the terms of the capacity agreements, no provision is made for the offtake of the electricity generated. It is envisaged that the capacity provider may sell its electricity under a power purchase agreement or, alternatively, may simply receive the "system sell price" for the electricity generated.

Competitive process is key

In formulating the design of EMR, the Government has been mindful of the need to control cost. Another important influence on the final design has been the requirement for the Government to obtain state aid approval from the European Commission. As a member of the European Union, the UK is bound by the starting position that aid granted by a Member State or through state resources does not distort competition and trade within the EU by favouring certain companies or the production of certain goods. Where state aid is given, it must comply with the relevant EU rules and be cleared by the Commission. The use of an auction to procure capacity was one of the key factors considered by the Commission in granting state aid approval to the UK capacity market, with the Commission homing in on the fact that the design "*embraces the principles of technology neutrality and competitive bidding to ensure generation adequacy at the lowest possible cost for consumers, in line with EU state aid rules*".

High expectations – but will it deliver?

In the short to medium term, gas-fired generation is expected to provide a significant proportion of the much-needed new capacity in the UK. As set out in the UK Government's Gas Generation Strategy of December 2012, up to 26 GW of new gas capacity could be required by 2030. In recent years, a low clean spark spread (in effect the price for power minus the cost of gas and carbon required to generate that power) in the UK has deterred investment in new gas generation. Therefore, the Capacity Market is key to attracting the scale of investment in gas-fired generation contemplated by the Government.

The stakes are high. At the end of October 2014, in its Winter Outlook 2014–15, National Grid warned that capacity in the UK this winter will be at a seven-year low due to generator closures and breakdowns. The "Average Cold Spell" peak demand margin has been calculated at 4.1 per cent, compared to 5 per cent last winter and 17 per cent three years ago. The House of Lords' Science and Technology Select Committee is currently conducting an inquiry into the resilience of electricity infrastructure and, as part of that inquiry, has heard evidence from the industry and expert commentators expressing some misgivings about the ability of EMR to deliver the right mix of capacity at the right price. It is hoped that the design of the UK Capacity Market avoids the pitfalls that have befallen the Western Australian model for capacity procurement, but time will tell.

Antony Skinner
London
T: +44 (0)20 7859 1360
E: antony.skinner@ashurst.com

Justyna Bremen
London
T: +44 (0)20 7859 1848
E: justyna.bremen@ashurst.com

NEW LIGHTS OF MYANMAR:

Powering ahead

by John McClenahan and Shan Koh

Earlier this year, for the first time since its accession in 1997, Myanmar assumed the chair of the Association of Southeast Asian Nations – another milestone in the country's re-emergence from isolation. This article looks at what this means for the country's electricity industry.

Myanmar is currently at a pivotal moment in its development: ongoing reforms and the easing of sanctions have opened up exciting possibilities, both for the country as it seeks to catch up with its neighbours, and for foreign investors looking for a new frontier market – but these opportunities are not without their attendant risks. One of these risks is Myanmar's inadequate electricity infrastructure, which could pose a serious constraint on growth in the years to come.

In this article, we look briefly at:

- Myanmar's current and projected power needs;
- the structure of Myanmar's electricity supply industry; and
- some of the ways in which Myanmar might be able to plug its emerging electricity deficit.

Powering ahead?

Electrification rates in Myanmar are currently some of the lowest in the world, reflective in part of a predominantly rural population, low industrial development and a limited grid infrastructure. There is, in theory, sufficient capacity in the system to meet peak demand. A significant proportion of Myanmar's installed capacity, however, is in the form of hydroelectric power stations – not the most reliable source of power during the annual dry season that stretches over several months. Couple that with inefficient plant and significant transmission losses and the result is frequent load-shedding and rolling blackouts in the few electrified areas of the country: a problem that is likely to be exacerbated by the increase in demand for electricity if economic growth takes off over the coming years.

Organisation of the electricity sector

The electricity sector in Myanmar remains largely state-controlled and fragmented. Overall responsibility for energy policy lies with the Ministry of Energy, with oversight of the electricity sector resting with the Ministry of Electric Power (MOEP). Within MOEP are three key departments responsible for the four state-owned enterprises operating in the sector (as set out in figure 1 on page 21).

Somewhat confusingly, thermal power plants (other than gas-fired plants) fall within the remit of the Departments of Hydropower Planning and Hydropower Implementation, while gas-fired plants and wind generation are administered by the Department of Electric Power. A National Energy Management Committee, comprising representatives from both the Ministry of Energy and MOEP (among others), has been established to improve co-ordination in developing the electricity sector, but it is unclear if this has helped to streamline policy making and enhance efficiencies in the management and oversight of the industry.

Single-buyer model

The linchpin of the Myanmar electricity sector in any event is not MOEP or its departments, but the Myanmar Electric Power Enterprise (MEPE). In a sector organised around a single-buyer model, MEPE (as bulk buyer of power) sits at the centre of a contractual web of power purchase agreements with third-party generators. The electrical power it purchases is sold to the Yangon Electricity Supply Board (YESB) and the Electricity

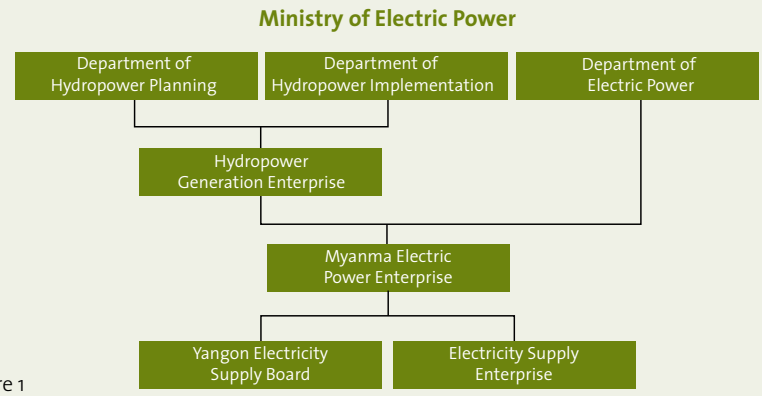


Figure 1

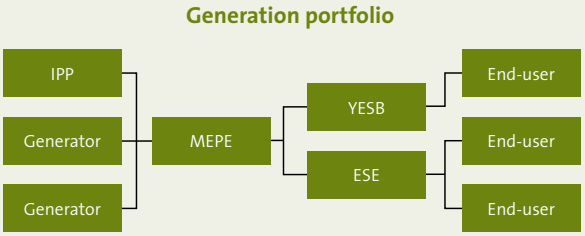


Figure 2

Supply Enterprise (ESE) for distribution and onward sale to end-users (see figure 2 above). In addition to its role as single buyer, MEPE is also responsible for dispatch and for transmission along the grid.

MEPE, in its current guise, was established pursuant to the Myanmar State-Owned Economic Enterprises Law 1989. Its powers and authority, however, are not set out in that law and (unsurprisingly in a country still in the process of opening up) its corporate constitution is not publicly available. What appears clear is that MEPE is a separate legal entity to MOEP, which means that the obligations it assumes under its power purchase agreements are not binding on the Myanmar Government, and its financial standing is separate to that of the Myanmar Government. This has given rise to concerns about MEPE's creditworthiness, particularly given that the subsidised tariffs for end-users are below the cost of supply, but it is believed that MEPE benefits from a degree of Myanmar Government funding and support – for the time being, at least.

Transmission and distribution infrastructure

The grid network in Myanmar comprises 66 kV lines, as well as high-voltage 132 kV and 230 kV overhead lines, and primarily covers the populous Irrawaddy delta area and the corridor linking the key cities of Yangon, Naypyidaw and Mandalay (see figure 3 for a simplified schematic of the grid). There are proposals to extend the grid by constructing a 500 kV line to link the north of the country (with its rich hydroelectric potential) to the demand centres in the south.

The distribution network comprises low-voltage 33 kV, 11 kV and 0.4 kV lines, operated by YESB in the Yangon region and by ESE in the remainder of the country.

As previously noted, electrification rates in Myanmar are low: the geographical extent of the transmission and distribution systems is limited, and there is a particular need for rural electrification (whether on- or off-grid). What is more, transmission and distribution losses are high, so improving system reliability and efficiency is vital.

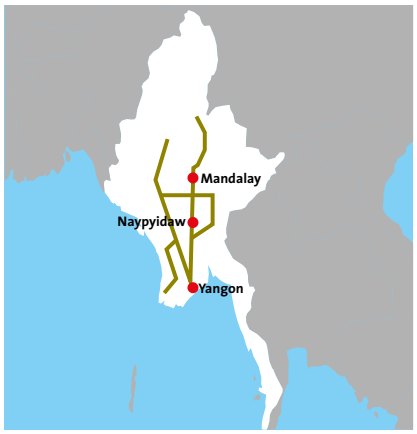


Figure 3

Legislative framework

The key sector laws in Myanmar are the Electricity Act 1948, the Electricity Law 1984 and the Electricity Rules 1985. These are dated, and acknowledged to be inadequate for a sector in need of investment, modernisation and expansion. The current legislative framework was never intended to create a regulatory regime for independent power projects, so MOEP has been working with the Asian Development Bank to develop a new electricity law better suited to the country's current needs. At the same time, the National Energy Management Committee is understood to be working with the relevant ministries to prepare a new legislative framework for the entire energy sector. Drafts of the new electricity law have been circulated and, based on an unofficial English translation that we have seen, the new law is likely to provide for (among other things):

- the establishment of an Electricity Regulatory Commission to oversee the sector;
- a licensing regime for participation in electricity sector activities; and
- the promulgation of industry norms and specifications.

Until the law is finalised and passed, however, there is little that can be said for certain about the new structure of the electricity supply industry. Although it has been hotly anticipated for some time now, we understand that the new law had still not been passed at the time this article went to press.

Myanmar IPPs

For all the flaws of the current legal framework, there has been some legislative progress: a new foreign investment law was enacted in 2012, and investment regulations promulgated under it the following year (more details on the foreign investment regulations can be found in our Myanmar briefing of April 2013[1]). Also, despite the absence of any specific basis for public-private partnerships and independent power projects (IPPs), a number of IPPs have been implemented.

The IPP process, however, lacks transparency and structure: at the present time, power projects tend to be initiated by way of a submission of proposals to MOEP, instead of through a formal MOEP-led bid process. An open tender was announced late last year in relation to an IPP at Shwe Taung, but it remains to be seen if this marks a systematic change in MOEP's approach to IPP procurement. In the meantime, many key project details are left to bilateral negotiations between MOEP and project sponsors, as no model form power purchase agreement has been developed or adopted. For those familiar with Myanmar's upstream oil and gas sector, where exploration acreage is awarded in organised bid rounds based on model production sharing contracts, the contrast is stark.

1 *Myanmar: Regulations implementing the Foreign Investment Law shed further light on rules for foreign investment*, Ashurst, April 2013.

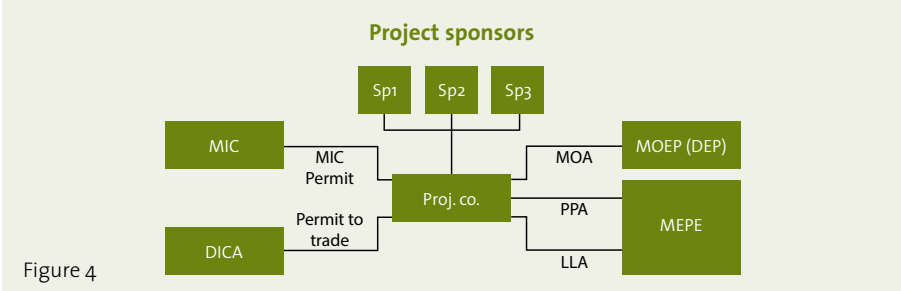


Figure 4

That said, as a matter of practice, there are two main steps in the IPP process for a gas-fired plant:

(i) a preliminary phase, during which a relatively short, non-binding memorandum of understanding is entered into for the conduct by the project sponsors of a feasibility study, and environmental and social impact assessments in relation to the proposed power project; and

(ii) a project development phase, marked by the award of:

- a binding memorandum of agreement (MOA) with the Department of Electric Power; and
- a binding power purchase agreement (PPA) with MEPE;
- following successful completion of the feasibility study and the environmental and social impact assessments. (There are, however, no published criteria or guidelines for the award of an MOA or a PPA.)

IPP project documents

The MOA and PPA together form the contractual basis for the construction and operation of the power project. Typically, the MOA provides a framework for the implementation of the project (documenting key principles such as the concession rights granted, the specifications of the plant, the tariff, site and land lease issues, and tax concessions), while the PPA addresses the construction schedule for the plant, the sale and purchase of power generated, technical matters (such as plant dispatch and metering), payments and liabilities. A separate land lease agreement (LLA) will also be entered into in relation to the site of the power plant. In practice, the focus of the parties will shift from the MOA to the PPA and LLA once these have been signed.

It will also be important for foreign sponsors to obtain a permit from the Myanmar Investment Commission (MIC) in relation to their investment in Myanmar, and a permit to trade from the Directorate of Investment and Companies Administration (DICA). (See figure 4 for a diagrammatic overview of the project structure.)

Gas supply issues

Feedstock gas for gas-fired IPPs has typically been provided by MEPE, sometimes at no cost to the IPP. This structure is similar to a tolling arrangement, placing fuel supply risk primarily with the Myanmar Government. In return, the Government often takes a proportion of power generated as "free power" and/or a proportion of project equity as a "free share". Gas consumption in excess of specified thresholds, however, may be charged to the IPP by way of a pass-through of the cost to MEPE of such additional gas.

While Myanmar has considerable gas reserves, these are only gradually being developed. With a significant proportion of current domestic gas production having been committed to China and Thailand, the availability of feedstock gas for gas-fired IPPs could be limited – at least until new gas fields are brought onstream.

Coal is a viable alternative fuel for thermal plants (Myanmar has major coal deposits) and, as previously noted, the country is also rich in hydroelectric potential.

Tariffs and payments

As noted above, end-user tariffs in Myanmar are heavily subsidised. The Myanmar Government took a bold step in raising rates earlier this year – an unpopular move that had sparked protests previously – but the revised tariffs are still not cost-reflective. In the absence of market-driven tariff pricing, sponsors considering IPP projects in Myanmar will to look to continuing Government support for MEPE as part of their analysis of project economics.

PPAs we have seen have included hard currency "guaranteed payments" to the IPP. These "guaranteed payments", which are akin to a take-or-pay commitment, help to provide a stable revenue stream to the project, while provision for them to be made in hard currency (typically in US dollars, despite end-user tariffs being set in kyat) helps to mitigate currency risks.

PPA protections

In addition to the protections afforded to foreign investors under the foreign investment law, the PPAs we have seen have also offered contractual safeguards such as:

(i) change in law protections, which provide for payments under the PPA to be adjusted to take account of material increases in project capex or opex, or material decreases in project revenues; and

(ii) compensation on termination, *if* MEPE elects to purchase the power plant on termination of the PPA.

There are, however, limitations to the comfort these give: there is no indication, for example, as to *how* payments will be adjusted in the event of an adverse change in law, or *how* the plant is to be valued for the purposes of any sale and transfer to MEPE, and the contractual compensation on termination regime does not apply if MEPE chooses *not* to purchase the plant. The application of these provisions also remains untested under Myanmar law – but their inclusion in PPAs is nevertheless helpful.

Financing

It is early days for project financing in Myanmar. Long-term economic sanctions have only recently been eased, so the capacity of the domestic banking and financial services sector is underdeveloped and limited. Much of the funding available for projects in Myanmar at the present time is in the form of export credit and development finance. While commercial banks in the region and beyond are interested in lending to projects in Myanmar, conventional project financing is realistically some way off. This is in part due to a host of legal uncertainties around the structure and regulation of the electricity sector, as we have seen, but also in relation to the taking of enforceable security under Myanmar law and the robustness of legal rights and remedies in general.

For those with an appetite for risk, however, the Myanmar electricity sector is a potential bright spot: will the next one to arrive please turn up the lights!


John McClenahan
Tokyo
T: +81 3 5405 6201
E: john.mcclenahan@ashurst.com


Shan Koh
Tokyo
T: +81 3 5405 6229
E: shan.koh@ashurst.com

JORDAN'S SOLAR LANDSCAPE:

Energy security through diversification

by Mhairi Main Garcia

Jordan is seeking to diversify its energy sources away from conventional energy in order to "decrease the Kingdom's dependency on international fuel prices, to enhance security of supply and to shift patterns of energy supply and demand into a more sustainable direction".[1] Solar energy is key to achieving that ambition.

Background

Energy diversification is a fundamental priority for Jordan given its heavy dependency on foreign energy imports – 97 per cent of the oil and natural gas consumed in Jordan is imported. In 2013, crude oil and oil products and natural gas accounted for 93 per cent of Jordan's total primary energy demand, with domestic sources of oil and natural gas only satisfying three per cent of that demand.[2] Jordan's energy dependency is coupled with rising energy prices, increased demand and issues regarding security of supply, as a result of its location and the ongoing tumultuous political and security concerns that surround Jordan.

As part of its diversification drive, Jordan is aiming to generate ten per cent of its primary energy from renewables by 2020, representing approximately 1,800 MW. This will be split mainly between wind and solar projects, with approximately 1,200 MW coming from wind energy and 600 MW from solar power. Jordan is also investing in exploring its shale oil deposits and developing nuclear power.

Legislative basis

The political will to achieve Jordan's renewable energy goals has resulted in a number of legislative instruments and initiatives, including the Renewable Energy and Efficiency Law (Law No. 13 of 2012) (the Renewables Law), the launch of the Renewable Energy and Energy Efficiency Fund and the development of feed-in tariffs. The Renewables Law:

- established a direct proposal regime for private companies seeking to develop renewable energy projects to negotiate directly with the Ministry of Energy and Mineral Resources (MEMR);
- gives priority to renewable energy projects on the national grid and requires the National Electric Power Company (NEPCO) and regional distribution companies to purchase electricity generated by renewable energy projects and to pay for the grid connection; and
- exempts systems and equipment for renewable energy projects from customs duty and sales tax.

The Renewable Energy and Energy Efficiency Fund was established in 2013 by MEMR. The fund provides renewable energy subsidies to privately owned and operated facilities, interest rate subsidies on commercial loans, a public equity fund to support the deployment of private investment in the sector, a renewable energy guarantee facility and research and technical co-operation grants for targeted programmes and feasibility studies.

Under the Renewables Law, Jordan can set capped feed-in tariffs for electricity

1 MEMR (May 2011), Investment Opportunities in Renewable Energy Projects "Direct Proposals Submissions" Request for Expression of Interest, Government Policy Statement on Developing Renewable Energy Projects through Direct Proposals Submission.

2 Source: Ministry of Energy and Mineral Resources, Energy 2014 – Facts & Figures, available at http://www.memr.gov.jo/

generated by wind facilities, solar photovoltaic (PV) facilities, non-PV solar facilities, biomass facilities and biogas facilities through the Reference Pricelist Record (RPR), further details of which are set out below.

The direct proposals scheme

Jordan plans to phase in renewable energy power capacity increases through a combination of tenders (independent power projects (IPPs)) and direct proposals, subject to technical grid capacity, financial constraints, and other constraints such as land ownership and transaction readiness of data (namely, sufficient solar irradiation data or a completed wind atlas, as applicable, for a specific site). As part of the process, MEMR identifies locations that demonstrate the potential for exploiting renewable energy resources and creates a priority list for their development.

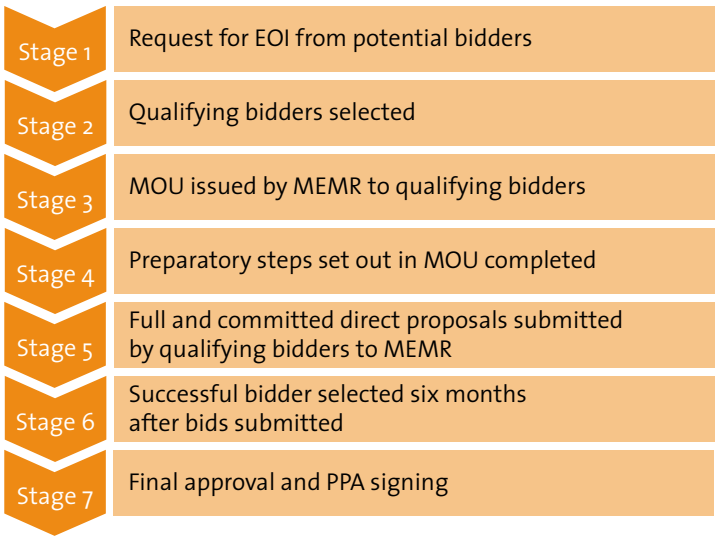
Under the direct proposal scheme, developers may submit proposals for renewable energy projects to be implemented on a build-own-operate basis. Projects are assessed on their technical and financial feasibility and the need to obtain the best possible price. Applicants must submit an expression of interest (EOI). In addition to setting out details of the project (including a general description, the capacity and estimated annual generation, the technology and details of the location), the EOI must also include evidence of the applicant's technical and financial capability and experience as well as the applicant's ability to raise debt and equity. Applicants that qualify to bid are then required to enter into a memorandum of understanding (MOU) with MEMR. The MOU permits applicants to proceed with measurement studies, feasibility studies and other preparatory and due diligence work in order to develop their proposals. Once the requirements set out in the MOU are completed, the applicant is required to submit a full and committed direct proposal. The MOU provides for the completion of the project within a specified timeline and for a power purchase agreement (PPA) to be entered into upon the submission of a successful proposal.

A summary of the procedure for submission of a direct proposal through to the final approval of the proposed project is set out at the bottom of this page.

Jordan has now launched three rounds of direct proposals for renewable energy projects. Jordan is also in the process of negotiating the 90 MW Fujeij wind power project on an IPP basis. This is against a backdrop of having closed and financed conventional IPPs (Amman East, Al Qatrana, IPP3 and IPP4). There are a number of key differences between the IPP process and a direct proposal. In a direct proposal, the developer:

- proposes the type of technology;
- proposes the energy output and estimated annual generation for the project; and
- selects the site for the project.

The contractual risk allocation also differs in some respects, particularly in relation to site risk, as to which see further details below. In an IPP, the procurer stipulates the type of technology (namely, whether it is wind, solar PV, solar non-PV, and so on), designates the minimum required energy output of the project and selects and leases (directly or through another government or quasi-government entity) the site. In an IPP, financing is usually commenced concurrently with negotiating the PPA, so lenders are involved ahead of signing the PPA (although financial close typically occurs after the PPA is signed). In the direct proposals to date, the PPAs have been signed ahead of bringing in lenders for the projects.



The Reference Pricelist Record

The RPR for the Calculation of Electrical Energy Purchase Prices from Renewable Energy Sources sets out the pricing mechanism for the purchase of electrical power from renewable energy sources in Jordan. It is issued by the Electricity Regulatory Commission (ERC) and sets an electricity tariff cap for electricity generated by renewables. The current tariff caps are set out below:

Technology type	Reference price/ kWh	
	JD (fils)	US$ (approx.)
Wind power	85	0.12
Solar power	135	0.19
Solar power (PV)	120	0.17
Biomass (waste)	90	0.13
Biogas	60	0.08

The RPR includes a local content incentive: if a winning bidder installs a renewable energy facility that is of "fully Jordanian origin", the proposed tariff will be increased by 15 per cent. The ERC's Council of Commissioners has the power to terminate the local content incentive once 500 MW of renewable energy facilities are connected to the grid. The Council of Commissioners reviews the RPR annually and whenever deemed necessary; however, it has not been updated since 2012.

Direct proposals[3] – a focus on solar

Jordan has an abundance of solar energy. As one of the "Sun Belt Countries", it has some of the highest solar irradiance in the world. Solar power generation, therefore, seems a natural choice when considering what key sectors to include in Jordan's energy mix. With the signing of the PPAs for the Round 1 direct proposals, Jordan is the first country in the Middle East to successfully procure a solar energy programme.

Round 1

MEMR launched Round 1 of the direct proposals in May 2011, permitting proposals for solar, wind, waste and geothermal projects. For solar projects, it provided

3 Information on the status of each round is based on publicly available information at the date of writing.

that the projects could be up to 50 MW for concentrated solar power (CSP) and 20 MW for PV, with priority being afforded to CSP projects ranging from 25-50 MW and PV projects ranging between 5-10 MW, the aim being to meet the interests of as large a number of investors as possible. Larger projects were nonetheless permitted, subject to demonstrating "superiority in terms of technical and financial aspects" as well as compliance with the Renewables Law. Geographically, Round 1 focuses on the southern region of Ma'an and in particular the Ma'an Development Area, an administrative area which has advantageous regulatory and fiscal regimes.

MEMR received 64 EOIs for Round 1 and issued a shortlist of 34 companies and consortia. Subsequently, 30 MOUs were agreed. Ultimately, 12 PV schemes were approved and the PPAs for all 12 projects were signed by the end of March 2014, representing a total capacity of 200 MW and expected investment of US$560m. The projects are now in the process of closing financing, with international banks and export credit agencies/development banks backing a number of the projects.

Round 2

Round 2 was launched by MEMR in October 2013. The launch of Round 2 while Round 1 was still ongoing was unexpected but is in line with Jordan's aim to reduce its dependence on imported energy. Round 2 is more limited in scope than Round 1. While Round 1 applies to various types of renewable energy sources, Round 2 is restricted to wind and solar PV. Another departure from Round 1 is the fact that applicants are not permitted to bid for different renewable types and technologies (therefore, a developer could not bid for both a solar and a wind project).

Moreover, while Round 1 focuses on the Ma'an region in the south of Jordan, Round 2 focuses on the northern and eastern parts of Jordan: submissions for projects in those parts of the country are prioritised. The reason for the shift in geographic focus is reportedly to ease the pressure on the grid in the south of Jordan; the grid in the northern and eastern regions is less saturated. The geographic shift in Round 2 potentially presents additional challenges as compared with Round 1. The northern and eastern regions of Jordan are more industrialised than the Ma'an region. This could bring added challenges in terms of available land and permitting. Proximity to the border with Syria creates security concerns too. Some of the potential areas for development are close to the growing number of refugee camps inside Jordan and are close to the Syrian border. What's more, the location presents challenges in relation to the PPA counterparty: if the project requires a high voltage connection, the counterparty will be NEPCO; otherwise, the counterparty will be one of Jordan's three distribution companies: Jordanian Electric Power Company, Electricity Distribution Company or Irbid District Electricity Company, none of which have the same experience as NEPCO in negotiating offtake agreements with private developers.

The size of the projects for Round 2 is limited as follows: solar PV projects, 50 MW; and wind power projects, 50-100 MW. MEMR has pre-qualified 23 companies and consortia and conditionally pre-qualified a further 24. Bidders have until 31 December 2014 to submit their bids for the solar PV projects. In terms of wind, MEMR has pre-qualified four companies and consortia and

conditionally pre-qualified a further two. Bids were due for submission for the wind projects by 30 September 2014.

Round 3

MEMR launched Round 3 in February 2014 but has since cancelled the round. Although no reason was given for the cancellation, commentators have suggested that a lack of capacity in Jordan's electricity grid may have been a factor. The launch of Round 3 while Round 2 was still ongoing may also have reportedly overstretched MEMR's administrative capacity. In a similar scenario in 2013, South Africa was forced to slow the progress of its renewable energy programme after the first round of deals reached financial close, due to limited local resources to administer the projects.

Round 3 was set to become the largest round, with MEMR having increased the capacity of proposed solar PV projects to 100 MW, from the maximum of 50 MW for PV facilities in Round 2. However, Round 3 did not expressly prioritise projects in certain parts of the country, as was the case in previous rounds.

Contractual structure

In addition to the PPA, the other key documents which form part of the direct proposal process are:

- a transmission connection agreement (regulating connection of the project to the grid);
- a land lease agreement;
- a government guarantee (guaranteeing the offtaker's payment obligations); and
- direct agreements with lenders.

The solar PV PPA[4] contains commercial and legal terms and conditions covering, among other items:

- the project company's obligations and responsibilities in matters relating to development, design, engineering, procurement, manufacture, construction, completion, permitting, testing, commissioning, insurance, ownership, operation and maintenance and power production; and
- the offtaker's payment obligations.

As a renewable energy PPA, the PPA is based on a take-and-pay structure, where the offtaker is required to receive and pay for all of the energy output. No capacity payments are payable. Under the PPA, if the project company is unable to commission the project or deliver energy output for specified reasons outside of its control, the project company may be paid as if it had commissioned the project/delivered such energy output. The project will also benefit from time and cost protection in relation to natural force majeure events ("Other Force Majeure") and specified political force majeure events ("Government Force Majeure"). The Government Force Majeure events include:

- nationalisation or expropriation;
- acts of war, armed conflict or blockade, in each case involving, occurring within Jordan;
- riot, civil commotion, terrorism or sabotage of a political nature, nationwide strikes, industrial disturbances, lockouts, or any prolonged civil action that blocks access to the Government;
- any boycott or sanction imposed directly on Jordan by the Government of a key equipment supplier for the project (prior to the commercial operation date of the project);
- Government acts resulting in any Government authorisation ceasing to remain in force or not being issued in a timely manner;
- grid failure, if caused as a result of Government Force Majeure; and
- a change in law.

Termination of the PPA in certain circumstances may give rise to a termination payment. Examples include:

- If the PPA is terminated by the offtaker as a result of a project company event of default, the offtaker may elect (but is not required) to purchase the project for the "Total Debt Outstanding" (outstanding principal and unpaid interest and finance breakage costs, to the extent that such outstanding principal and interest does not result from a default of the project company).
- If the PPA is terminated by the project company as a result of an offtaker event of default or by the offtaker as a result of prolonged events of Government Force Majeure, the offtaker must accept and pay for the project for a termination payment (based on the actual price paid by the project company but not more than ten per cent more than the price determined by the relevant land registry department on the PPA signature date).

In relation to the land lease, a significant difference in the direct proposal process as compared with Jordan's conventional IPPs relates to the land ownership: land for the projects is not owned by a government entity. Land for the projects is instead procured by the developer. Consequently, there is only limited protection available in relation to ground risk. This means that developers and their lenders have to assess more carefully typical ground risk issues according to the location (for example, accessibility, pre-existing contamination and the presence of archaeological remains) and in relation to solar projects (for example, adequacy of the site and the level of solar irradiation).

Direct agreements in respect of the key contracts are entered into with the lenders, in addition to the financing agreements and related security documentation. Lenders can expect to take security in respect of real property (but only where owned by the borrower), moveable assets, shares, contracts and bank accounts.

Closing remarks

Jordan's dependency on energy imports and the related security of supply and cost issues make energy diversification critical. To this end, Jordan has been successful in establishing a legislative basis for developing a domestic renewable energy industry, demonstrating a strong political will towards renewable energy. This contrasts with some of Jordan's hydrocarbon-rich neighbours, where notwithstanding gas shortages and the opportunity cost of using domestic production to meet power generation needs, there is a lack of renewables-specific legislation and a fluctuating commitment towards renewable energy.

Despite a number of difficulties and delays, Jordan has now closed several solar projects, with many more in the pipeline. It is attracting both local and international developers and financiers to develop these projects. While there remain a lot of challenges ahead for Jordan, not least the ongoing political and security issues, the financial close of the Round 1 solar power projects will represent a milestone and should pave the way for further solar projects to be developed in Jordan.

Mhairi Main Garcia
Dubai
T: +971 (0)4 365 2012
E: mhairi.maingarcia@ashurst.com

4 Based on the standard form PPA provided by MEMR. The terms and conditions of the PPA may be subject to negotiation between the offtaker and the project company.

SEAS OF CHANGE:

Tidal power surges forward

by Antony Skinner, Cameron Smith and Alex Bartho

In this article, we examine the main technologies that are undergoing commercial development, and the UK's position at the forefront of the industry and its ability to capitalise on future growth in marine power.

Introduction

The last decade has seen an enormous boom in solar, wind and hydro power. Ever-increasing demand for energy and the need to address the environmental challenges posed by fossil fuels mean further growth in renewable energy. By contrast, tidal power – harnessing the twice-daily rise and fall of sea levels caused by the combined effects of the gravitational forces exerted by the sun, the moon and the rotation of the earth – has historically lagged behind other forms of renewable power generation.

Yet tidal power offers several unique advantages that complement increasing the use of intermittent solar and wind generation, most notably through having regular, predictable generation output. This output can (to a certain extent) replace base-load generation, currently primarily generated from nuclear, gas and carbon-intensive coal. Significant engineering advances in the last decade and an improving supply chain, largely shared with that of the more mature offshore wind industry, mean sponsors and governments alike are beginning to recognise the opportunities offered by tidal power.

With unique tidal geography and a reasonably enthusiastic government, the UK is currently the undisputed global leader in marine energy, having more wave and tidal stream devices installed than the rest of the world combined. Against the background of a global market for tidal power forecast to reach £50bn in value by 2050, maturing technologies and falling levelised costs, generous government support for tidal power is likely to see significant investment in the UK tidal industry over the next few years. Excellent marine resource and expertise in oil and gas exploration and offshore wind power mean the UK is in a unique position to benefit from any surge in tidal energy development.

The UK environment

Several complementary factors lead to the UK being arguably the most attractive jurisdiction for tidal power investment in the world. The UK has unique tidal geography, giving it many sites with among the greatest tidal range and tidal stream velocities in the world. The UK also benefits from its extensive offshore wind and North Sea oil and gas engineering and construction supply chains, which offer many synergies, and therefore cost reductions, for tidal power projects. The UK Government has shown consistent commitment to renewable energy generation, including generous treatment for tidal power generation under both the existing Renewables Obligation scheme and new Contracts for Difference regime (both of which are discussed further below). Finally, the UK has national grid infrastructure and regulations that enable renewable energy generators to plug into the existing network and sell power in almost any location.

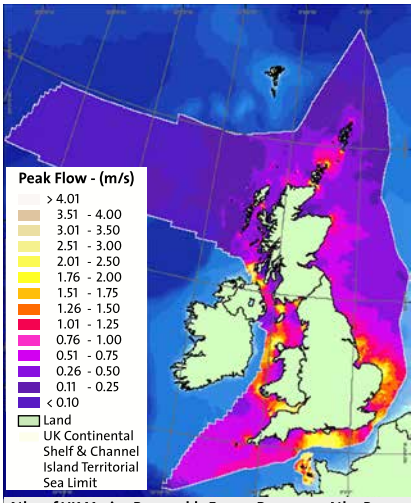
The past few years have seen a focus on demonstrating the viability of the technology and reducing costs through the operation of demonstration devices. While the current installed capacity is fairly

modest at around ten megawatts (MW), the industry is on track to deliver over 120 MW by 2020 and rapidly accelerate thereafter, making a meaningful contribution to the UK's energy mix.

Geography

Tidal power relies upon a high tidal range (the vertical difference between high and low tide) to force water through a turbine. While the mid-ocean tidal range is typically less than a metre, local geography has a significant impact on the effect at the shoreline. Basin geography, in particular narrow passages between land masses, can accentuate tidal ranges up to 12–15 metres, producing large local tidal stream velocities. Tidal patterns follow simple predictable cycles, making these local velocities easy to track and quantify, presenting a large opportunity for energy extraction by marine current devices.

The UK has many sites with exceptionally high tidal ranges in excess of ten metres, the most significant tidal resource in Europe, including eight of the 20 most promising sites identified by the industry worldwide. The Pentland Firth, the narrow strip of water between the north-east tip of Scotland and the Orkneys, is arguably the single best tidal power site in the world due to its unique geography. Commercially viable tidal power capacity in the UK is estimated to be sufficient to meet between 20 and 34 per cent of the UK's electrical demand.



Atlas of UK Marine Renewable Energy Resources: Atlas Pages A Strategic Environmental Assessment Report September 2004

Political environment and supply chain

Tidal power is a renewable source of energy, but unlike the unpredictable intermittent generation from solar or wind power, its output follows a repeating and steady cycle which can be forecast with precision. Environmental concerns over global warming and a public and political consensus on the necessity of a significant decarbonisation of the economy over the coming decades, together with this generation profile of tidal power, make it extremely attractive to the UK Government as a supplement to wind, solar and conventional hydro technologies to help the UK meet its carbon-reduction targets. Tidal power deployed on sufficient scale at a range of different sites can, due to its predictability, directly replace base-load generating capacity previously provided by coal and gas. Certain forms of tidal technology may even operate as a form of pumped storage, the only large-scale form of peaking generation capacity currently realisable from renewable sources, enabling improvements in efficient grid management.

Artist's impression of vessel installing a tidal stream turbine – source: Atlantis Resources Limited

The UK has led the world in marine energy technology development over the last decade. The world's first test facility, the European Marine Energy Centre established in Orkney in 2003, offers grid-connected facilities for companies to test prototype technologies in real sea conditions. Tidal energy developers who have benefitted from the site include Alstom, Scotrenewables Tidal Power, ANDRITZ HYDRO Hammerfest, OpenHydro and Voith. Alstom announced in early November 2014 that its two test devices had generated over 1 GWh to the grid. The centre has led to the deployment of more marine power devices than any other single site in the world and has cemented the UK's position as the world leader for marine power.

Finally, the long-established North Sea oil and gas industry and maturing offshore wind industry has led to a concentration of marine and energy engineering expertise in the UK that is second to none. Many specialist sub-contractors who have developed their business in the demanding environment of the UK offshore wind and oil and gas industries will be well-placed to adapt to the requirements and opportunities offered by tidal power. In the longer term, institutional investors currently investing in the wind power industry may be a source of financing for later phases of tidal power expansion.

Tidal technologies

Modern tidal power projects can be split into four broad categories, each suitable for locations with distinct geographical and tidal features. Three of these – tidal barrages, lagoons and stream generators – are all relatively well-understood and conceptually proven technologies, while a fourth subset – dynamic tidal power generation – is largely untried and at a conceptual stage.

Tidal barrage

A tidal barrage involves a barrier spanning a tidal estuary that generates electricity as water passes through turbines embedded within it as the tides advance and recede. Tidal barrages are suitable for estuaries with a high tidal range, using the strategic placement of a damming span to retain large volumes of water at high tide with significant potential energy and subsequently to drain it through turbines to create mechanical energy as the tide recedes.

Tidal barrages are the most venerable of the tidal generation technologies, building on well-understood dam engineering principles and hydropower turbines adapted for salt-water operation. Around the world, the handful of existing tidal barrages include a 240 MW station at La Rance, France, which has been operating since 1966, and more recently a 245 MW station at Sihwa Lake in Korea.

As well as the difficulty of identifying a suitable site, the main drawbacks of barrage systems are very high civil infrastructure costs and the potential impact on the estuarine ecosystem, which has deterred more wide-scale adoption. The advantages include large-scale, predictable (in some more complex designs, near-continuous) and carbon-free electricity output.

The placement of a barrage into an estuary has a considerable effect on the characteristics of the estuary (including salinity, sediment and hydrology), as the flow of salt water is considerably impacted. In estuaries with significant wildlife habitats, the change in conditions may cause a negative environmental impact and this is typically one of the main objections raised to such schemes. On the other hand, after the initial impact during and following construction, the new conditions created by the barrage may provide a suitable habitat to other species, a claim borne out by studies on the La Rance barrage.

Studies have estimated the UK's maximum possible tidal barrage generation capacity at between 25 and 30 GW – enough to supply more than ten per cent of current UK electricity demand. The Severn Estuary provides the majority of this capacity (between 8 and 12 GW), with the estuaries and bays of north-west England and western Scotland representing a similar amount, and the east coast the remainder.

A two-year cross-government feasibility study into a barrage proposal in the Severn (the most suitable, but also largest, of the UK barrage sites) by Hafren Power could not see a strategic case for public investment in a Severn tidal scheme in the immediate term, though private sector groups are continuing to investigate the potential. The vast capital investment required for the Severn project (estimated at anywhere between £10bn and £30bn, which would make it one of the largest engineering feats in the world) will likely mean that a number of smaller-scale projects will need to demonstrate the effectiveness of the technology in the UK before the Government, investors and funders are willing to risk progressing the proposal. Other potential projects assessed by developers at sites around the UK include the Mersey, the Humber, the Deem, the Solway Firth and Ramsey Sound on the North Wales coast.

Swansea Bay Tidal Lagoon – Tidal Lagoon Power Limited

Artist's impression of Swansea Bay Tidal Lagoon – source: Tidal Lagoon Swansea Bay

The Swansea Bay Tidal Lagoon project proposal consists of an up to 11 kilometre long lagoon wall protruding from the existing Swansea harbour with planned installed capacity of up to 320 MW of renewable energy with 14 hours of reliable energy production a day. The project could have the potential to power over 150,000 homes and would save 230,000 tonnes of carbon emissions a year compared to the equivalent generation from coal. An 8.5m average spring tidal range makes the location particularly well-suited.

The Planning Inspectorate announced in March 2014 that it has accepted an application in respect of the project for consideration, and, if such application is successful, work is likely to begin in 2015, targeting first generation in 2018. The project is reliant on receiving financial support under a Contract for Difference. In a further positive development for the project, the Government announced in December 2014 that it will start closer discussions with the project company to establish whether the project is "affordable and value for money for consumers".

Tidal Lagoon Power Limited, the project company, is largely owned by a group of entrepreneurs and private investors.

In October 2014, the Prudential agreed to invest up to £100m in the project as a cornerstone equity investor, though total investment needed is estimated at £850m–£1bn+, so further equity raisings and potentially some form of debt financing will need to follow.

If successful, a network of a further five larger coastal lagoons have been mooted, with a combined capacity sufficient to meet eight per cent of the UK's electricity needs.

Tidal lagoons

Tidal lagoons, a more recent technological development, share many features with tidal barrages but do not require an estuary span, or indeed any connection to land at all, and thus may not face such significant local or environmental challenges. Tidal lagoon technology involves the use of large, artificially constructed lagoons to trap water at high tide, releasing it through turbines to generate electricity as the tide recedes. In some designs, water also passes through turbines as the tide comes in, generating more electricity. Developers tout the sea berms and artificial lakes as suitable for sightseeing and leisure activities such as boating, creating a tourist attraction. As tidal lagoons do not require damming an estuary, the ecological impacts are significantly lessened and the civil infrastructure costs scale with lagoon size.

Locations suitable for tidal lagoons have a high tidal range, but the lagoon bounding wall need not intersect the shore provided the depth of water is sufficiently shallow to allow construction. The size of the lagoon may be adjusted to ensure that any impact on shipping and wildlife is minimised, and projects requiring somewhat smaller capital outlay than a typical barrage may be economically feasible, leading to a significant amount of interest.

An exciting additional feature of tidal lagoons is that they may be designed to incorporate elements of pumped storage, allowing excess generation capacity elsewhere in the grid (for example, due to particularly windy conditions during the night) to be used to top up the lagoon, which can then be drained to generate electricity when demand is higher, operating as a form of energy storage. The UK currently has a few hundred MW of pumped storage capacity, a few per cent of its total output at most, and as the installed capacity of wind generation increases this will become increasingly important for effective grid management.

Tidal Lagoon Power Limited has proposed to build the first project in the world of this type in Swansea Bay and has begun attracting significant equity investment (see box on page 29).

Tidal stream turbines

Tidal stream generation relies on the high tidal velocities that occur in narrow channels between land masses to turn propeller-like turbines. Industry body Renewables UK estimates between 200 and 300 MW of generation capacity may be able to be deployed around the UK by 2020.

The Pentland Firth, off the north-east tip of Scotland, offers a uniquely favourable environment for development of tidal stream power, with tidal velocities in excess of 4m/s. Recent research by Oxford University estimates that tidal turbines in the Firth could generate up to 1.9 GW of commercially feasible capacity. A number of other strong sites around Scotland include Islay and Orkney.

Smaller scale projects include Tidal Energy Limited's deployment of an initial 400 KW turbine in Ramsey Sound, off the coast of Pembrokeshire, as the first phase of an up to nine turbine array capable of producing up to 10 MW. Tidal Energy Limited recently announced signing a PPA with EDF, indicating significant interest in the industry.

Pentland Firth Tidal Stream Array – MeyGen Limited

MeyGen Limited is in the early construction phase of an up to 398 MW tidal stream turbine project in the Inner Sound of the Pentland Firth.

MeyGen Limited is majority owned by tidal turbine manufacturer Atlantis Resources Limited and in mid-2014 secured additional equity investment from Scottish Enterprise, grant funding from the Highland and Islands Enterprise and the Department of Energy and Climate Change, an investment from the Crown Estate, and project finance debt facilities from Scottish Enterprise, totalling over £50m of committed funding.

In the project's initial phase, MeyGen will install four to six 1.5 MW turbines by 2016, 86 MW by 2020, and scaling up in subsequent phases to up to 398 MW of total capacity across the whole array, the largest tidal power project of its kind in the world.

Ashurst acted for MeyGen Limited in respect of the debt and grant funding and Atlantis Resources Limited in respect of the equity funding of the project.

Government support and legal framework

The government support mechanism for tidal projects in the UK is changing, with the introduction of a new incentive regime for all renewables as part of the UK's Electricity Market Reform. As discussed in more detail below, the type of support available, and the means of getting it, depend on the size, technology type and the timing of the project.

The Renewables Obligation

Until very recently, the Renewables Obligation (RO) regime and the associated tradable Renewables Obligation Certificates (ROCs), together with the small-scale Feed-in Tariff (FIT) scheme, has been the main form of support for renewable energy in the UK. Under the RO regime, accredited renewable generators receive a certain number of ROCs for each MWh of electricity they generate, over a 20-year period. The RO regime is fairly complex, but in essence, generators earn an income by selling ROCs to electricity suppliers or traders, who in turn are required to surrender ROCs as evidence that they have discharged their obligation, imposed by the RO, to supply a set proportion of electricity from renewable energy sources.

Artist's impression of tidal stream turbine farm – source: Atlantis Resources Limited

Tidal stream technologies under the RO are eligible to receive support at 5 ROCs/MWh up to 30 MW. Support for any installed capacity exceeding the 30 MW limit receives 2 ROCs/MWh. On the other hand, tidal lagoon and tidal barrage projects (up to 1 GW DNC) are eligible to receive 2 ROCs/MWh, falling to 1.9 ROCs if accredited after 31 March 2015 and 1.8 ROCs if accredited after 31 March 2016.

The RO is being replaced with a new Contacts for Difference (CfD) regime, discussed in more detail below. Subject to some limited grace periods for projects which may experience delay in commissioning, the RO will close to new accreditations on 31 March 2017. The RO will continue to provide support for tidal projects already accredited, but new projects will need to apply for a CfD. Between now and 31 March 2017, eligible projects can choose to either seek accreditation for the RO or apply for a CfD.

Contracts for Difference

Under the new CfD regime, established under the Energy Act 2013, tidal projects will need to apply for a CfD, which takes the form of a private law bilateral contract, for a term of 15 years (subject to some exceptions) between the generator and the CfD counterparty (the Low Carbon Contracts Company). The CfD provides for a payment to the generator of a top-up above the wholesale "reference price", up to a set "strike price". Importantly, if the wholesale price is higher than the strike price, the generator will be required to make a payment back to the CfD counterparty.

For most renewable energy technologies, a strike price was determined through an administrative process, the results of which were published in a delivery plan in December 2013. Those technologies are required to apply for a CfD using the so-called generic allocation process taking place once a year, with the first allocation round having commenced in October 2014. For tidal stream generation, the strike price has been set at £305/MWh (in contrast to £155/MWh for offshore wind). However, there is no guarantee that a tidal stream project applying for a CfD through the generic allocation process will receive that strike price, or indeed a CfD at all, as in theory it will be competing with other projects, including other "less established technologies" such as wave and offshore wind, for a share of a pre-determined pot of money.

There are a few technologies, including tidal lagoon and tidal barrage generation, for which a strike price has not been set. Such projects are required to apply to the Secretary of State for a CfD outside of the generic allocation process and negotiate a strike price on a project-by-project basis. In March 2014, energy and engineering consultancy Pöyry concluded that the Swansea Bay lagoon project would require a strike price of at least £168/MWh over a 35-year term (a length of CfD only previously contemplated for the Hinkley Point C nuclear power project). Political appetite for these less conventional projects will therefore have a significant impact on their commercial viability.

Conclusion

Geographical advantages, a government committed to renewable generation, a developed supply chain and a history of technological innovation together mean the UK is now set to lead the world into the next phase of tidal energy generation, gearing up to enter commercial-scale operations with several different tidal technologies.

While the sector is in its infancy and technical risk and high capital requirements remain the main concerns for investors, there is a significant upside in the form of a competitive ROC allocation and/or CfD strike price available for successfully completed and operational projects. Once technologies have proven themselves commercially, significant and rapid expansion of the sector should be a given provided government support continues.

2014 has been an exciting year for tidal power, financial close having been achieved on the £50m mixed grant and project financing of the initial phase of the MeyGen Limited's Pentland Firth tidal stream project, as well as Tidal Lagoon Power Limited securing significant equity funding and applying for planning permission for the Swansea Bay tidal lagoon project. These milestones demonstrate a significant belief by financiers, sponsors and other industry players in the commercial viability of tidal power. As these projects progress through construction into operation, and other projects follow, 2015 and 2016 may well see an opening of the floodgates and the UK tidal project pipeline taking off in earnest.

Antony Skinner
London
T: +44 (0)20 7859 1360
E: antony.skinner@ashurst.com

Cameron Smith
London
T: +44 (0)20 7859 1125
E: cameron.smith@ashurst.com

Alex Bartho
London
T: +44 (0)20 7859 3366
E: alex.bartho@ashurst.com

UK SHALE GAS:

The scene is set – but will there be any action?

by Martin Kudnig and Denva Poyntz

The UK's conventional oil and gas industry continues to be an important contributor to the country's overall economy and energy security. But as conventional reserves decline, the UK Government is anxious to foster the development of a shale gas industry. It is not clear at this stage to what extent the success of the industry in the US can be replicated, even to a lesser degree, on UK soil. However, as discussed in this article, whether the industry succeeds or fails will not be for want of action by the Government which, over the last two years, has continued to introduce successive policies designed to smooth the path for investors, with planning and environmental issues being at the forefront of policy discussion and reform.

The UK's shale gas reserves

There is considerable uncertainty and much debate about the reserves of technically recoverable shale gas resources in the UK. To date, three studies have been undertaken by the British Geological Society (BGS) of the UK's main shale gas formation, with mixed results:

- the Bowland–Hodder study of June 2013 concluded that the current central estimate of shale gas in place in the Bowland–Hodder shale formation in northern England alone is 1,329 trillion cubic feet (tcf) (the low estimate is 822 tcf and the high estimate 2,281 tcf). Assuming a similar recovery rate to that experienced in the US (eight to 20 per cent), the BGS concluded in this study that the UK is estimated to have potentially recoverable shale resources of between 63.5 and 458.9 tcf;
- the Weald Basin study of May 2014 found no significant gas resources in the Weald Basin formation, but instead found shale oil in place, which is estimated to be between 2.20 and 8.57 billion barrels (bbl), with a central estimate of 4.4 bbl; and
- the Midland Valley of Scotland study of June 2014 estimated the range of shale gas in place to be between 49.4 and 134.6 tcf, with the central estimate for the resource being 80.3 tcf. The range of shale oil in place is estimated to be between 3.2 and 11.2 bbl, with the central estimate for the resource being 6.0 bbl. The study noted that the relatively complex geology and limited amount of good quality constraining

data (seismic reflection and borehole) result in a higher degree of uncertainty about the estimates than the previous Bowland–Hodder and Weald Basin studies.

Regardless of the exact figures, it is generally accepted that shale gas could, potentially, play a material role in contributing to the UK's economy and energy security.

The regulatory approach

Generally speaking, shale gas projects undertaken in the UK are currently governed by the same regulatory regime that applies to conventional onshore oil and gas exploration and development. However, as discussed below, some additional regulatory issues arise within the existing framework.

Since the decision was taken in December 2012 to end the moratorium on shale gas exploration, the Government has taken action to, on the one hand, alleviate community concerns about shale gas development, and, on the other hand, address any regulatory barriers faced by the industry.

Licensing – new licence terms

A company wishing to undertake any onshore oil and gas exploration and production is required to obtain a Petroleum Exploration and Development Licence (PEDL) under the Petroleum Act 1998. The licence conditions, referred to as model clauses, are published in statutory instruments made under the Petroleum Act 1998.

A PEDL grants the licensee the exclusive right to undertake various activities within defined phases, which are: exploration (six years); appraisal, during which the licensee must draw up and submit a field development plan (five years); and production of oil and natural gas (20 years, with a possibility of extension). The licence will expire at the end of each phase unless the licensee has made sufficient progress to move to the next phase. Significantly, licensees are required to relinquish 50 per cent of the acreage at the end of the exploration phase.

The existing relinquishment obligations are designed to ensure that licensees do not hold on to acreage which they are not exploiting. However, shale gas reserves, unlike conventional gas reserves, are likely to be dispersed over a much larger area. An obligation to relinquish acreage could, therefore, undermine the economic viability of a shale gas development. Following consultation with existing licensees and the industry body United Kingdom Onshore Oil and Gas (UKOOG), the Government decided to prescribe new model clauses which address this issue. The new model clauses are set out in the Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014, which came into force on 17 July 2014.

Most significantly, under the new model clauses, the usual obligation to relinquish at least half of the initial licensed area is now subject to a new power for the Secretary of State to agree with the licensee to the creation of Retention Areas and Development Areas. A licensee must apply to the Secretary of State for any part of the Licensed Area to become a Retention Area, and the application must be accompanied by, among other things, a Retention Area Plan describing the exploration and appraisal activities that the licensee intends to carry out in the Retention Area. Similarly, an application for a Development Area must be accompanied by a Development Area Plan. Where an application is approved by the Secretary of State, the licensee may retain the Retention Areas and Development Areas into the second term. The Secretary of State may remove acreage that is not comprised in either a Retention Area or a Development Area, if, for example, the licensee does not carry out the work in the relevant plan.

In addition, the new model clauses recognise that in some cases the licensed area that is surrendered or retained can be identified in three dimensions, rather than just two dimensions.

The Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014 also introduce model clauses to allow an onshore Exploration Licence to be granted for a term of three years.

Environmental Awareness Statement

Prospective licensees were able to bid for a PEDL in the 14th onshore licensing round, which was open to applications between July and October 2014. The licensing round was preceded by a Strategic Environmental Assessment (SEA) of the areas proposed to be offered to applicants, in accordance with the EU SEA Directive (Directive 2001/42/EC). Among other things, the SEA identified a range of measures which could be implemented to avoid or minimise any potential negative environmental effects – the so-called "SEA Mitigation Measures".

In accordance with the recommendations of the SEA process, the Department of Energy and Climate Change (DECC) introduced a requirement for applicants participating in the 14th onshore licensing round to submit with their application an Environmental Awareness Statement (EAS). An EAS is intended to set out the applicant's:

- understanding of the UK's onshore environmental and planning regime relevant to the exploration, development, production and decommissioning stages of a project;
- understanding of the environmental sensitivities of the area they are applying for and their options for addressing these sensitivities, and their approach to establishing the eventual plan for operations; and
- options for addressing the SEA Mitigation Measures and the applicant's approach to establishing the eventual plan for operations in the light of these.

Overview of regulatory consents

DECC, together with other regulators, such as the Health and Safety Executive (HSE) and the Environment Agency (EA), has been developing its approach to how the existing regulatory regime for conventional oil and gas applies to shale gas. As well as introducing some reforms and guidance in areas such as planning consent, the Government is anxious to ensure that the mere prospect of navigating the regulatory "maze" does not deter potential developers. To address this, DECC published in December 2013 a "regulatory roadmap" intended to steer developers through the consenting process step by step.

The various consents required by licensees before commencing full exploration activities, and which are detailed in the roadmap, include:

- environmental consents;
- DECC consent to drill a well and undertake fracturing;
- planning permission; and
- land access consents from landowners.

It is important to note that currently the focus of the regulators has been on the consent process for shale gas exploration activities as opposed to production, and this is the scope of the regulatory roadmap. This is a reflection of the fact that currently no shale gas production is taking place in the UK. Licensees who wish to progress from exploration to production, and who have already obtained some of the regulatory consents discussed below, will

need to proceed through a second round of regulatory consents, and the regulators are still developing their approach to this.

It is clear that while regulators and the industry navigate the unchartered waters of the consent process for shale gas operations, delays are a significant risk and will need to be factored in by operators. Last year, it was reported that Cuadrilla withdrew its planning application to conduct operations at its site near Blackpool in order to resubmit a new application supported by a more detailed environmental impact assessment, thereby delaying its plans to restart test drilling. As Cuadrilla's experience shows, patience and perseverance may be vital during these early days of the industry.

Environmental consents

The EA (and its equivalent counterparts in Scotland and Wales) is responsible for issuing various environmental consents for shale gas exploration. In particular, under the Environmental Permitting (England and Wales) Regulations 2010 and the Water Resources Act 1991, shale gas operators are required to obtain a number of permits, including:

- mining waste permits;
- water abstraction licence;
- groundwater activity permits;
- radioactive substances activity permits; and
- assessment and approval of chemicals used for hydraulic fracturing.

An environmental impact assessment (EIA) may also be required. For the production phase, an EIA is mandatory where the volume of natural gas to be produced exceeds 500,000 cubic metres per day.

DECC consent to drill and fracture

Under the terms of the PEDL, licensees are required to obtain various consents and approvals from DECC before undertaking work. In particular, in order to undertake drilling activities, shale gas operators are required to obtain a consent to drill from DECC. Before granting that consent, DECC will liaise with the HSE and the EA to ensure that there are no outstanding environmental and safety issues arising. Additional requirements apply if fracturing activities are to be carried out. Following earth tremors in Lancashire in 2011, which were alleged to have been triggered by the UK's first shale production test, in order to obtain a consent to drill where fracturing is intended to be undertaken, shale gas operators will be required to:

- assess the seismic hazards posed by undertaking hydraulic fracturing in each well site area;
- monitor the seismic activity of each well site area; and
- develop and implement a mitigation plan to reduce the possibility that hydraulic fracturing will cause future earthquakes.

In addition, DECC will require shale gas operators to install a real-time trigger that will cut off injection into the well where there is a significant risk of an earthquake.

Planning approvals

At present, planning permission for onshore shale gas projects in England and Wales is subject to the requirements of the Town and Country Planning Act 1990, which is administered by minerals planning authorities (MPAs). MPAs are local authorities with responsibility for planning control of work undertaken in connection with mineral developments.

In considering a planning application, the MPA will consult with statutory referral agencies, such as the EA, and relevant stakeholders, including any affected landowners.

An MPA is required to determine a planning application within 13 weeks, in accordance with its local minerals planning policies, unless material considerations require otherwise. Such considerations include, but are not limited to, air quality, traffic, risk of contamination to land, wildlife and land stability. Notably, most of the material considerations have been said to apply to shale gas developments. The Government's Planning Practice Guidance for MPAs was recently updated to incorporate further details on the Government's approach to development for unconventional hydrocarbons in National Parks and Areas of Outstanding Natural Beauty. The guidance states that where an application for planning permission for hydrocarbons development represents major development, then planning permission should be refused in National Parks and Areas of Outstanding Natural Beauty except in exceptional circumstances and where it can be demonstrated that the development is in the public interest.

Permission must also be obtained from the Coal Authority if a proposed well may encroach on one or more coal seams.

In January 2014, the Government moved forward with some reforms to the planning regime as it applies to onshore gas exploration. The most significant proposed reform relates to the removal of the requirement to notify landowners of planning applications where solely underground operations take place under their land. This significantly reduces the administrative burden on shale gas operators and streamlines the planning procedure.

Land access

A company wishing to undertake a shale gas project is required to negotiate a land access agreement with relevant landowners. Under these land access agreements, compensation will usually be payable by the shale gas operator to the landowners. If a shale gas operator and a landowner are unable to agree on such an agreement, the shale gas operator may seek to acquire so-called "ancillary" rights pursuant to the provisions of the Petroleum Act 1998 and the Mines (Working Facilities and Support) Act 1966.

Currently, in addition to needing land rights for access and the location of the drilling pad itself, shale gas operators need permission from all the landowners beneath whose land they drill, otherwise they may be found to be trespassing on their land. This has been identified as a significant barrier to the shale gas industry. The Government has therefore decided to introduce a new statutory regime to give shale gas operators an automatic right of access to allow them to undertake horizontal drilling which takes place at least 300 metres below the surface of land. The provisions are set out in the Infrastructure Bill currently before Parliament, which is expected to come into force in 2015.

The shale gas industry has made voluntary commitments to make a one-off payment of £20,000 for each unique lateral (horizontal) well that extends by more than 200 metres. If the Secretary of State is not satisfied with this scheme, then he may introduce regulations to set up a statutory payment mechanism. The final element of the new regime is to be a public notification system, under which the company would give notice to the affected community of matters such as the relevant area of underground land, and details on the payment that will be made in return for the access.

The changes do not impact on the surface rights that operators need to obtain to commence drilling.

Unlike in the US, the Petroleum Act 1998 vests ownership of all mineral rights (including hydrocarbons) in the Crown.

Therefore, while landowners will be entitled to compensation for granting access rights to a shale gas operator in respect of their land, they do not own and are therefore not entitled to sell shale gas reserves located under their land.

Community benefits

The UKOOG has a community engagement charter under which each UKOOG operator promises, among other things, to engage with individuals and organisations from an early stage. In 2013, the charter proposed that local communities receive £100,000 per well site where hydraulic fracturing takes place, as well as one per cent of revenues generated during the production stage, allocated approximately two-thirds to the local community and one-third at county level. This could be worth £5–10m for a typical producing site over its lifetime.

The UK Government also announced in January 2014 that councils can keep 100 per cent of the business rates they collect from shale gas sites – double the current 50 per cent figure. This commitment could be worth up to £1.7m a year for a typical site. This is a clear indication that in seeking to facilitate the shale gas industry, the Government is recognising the importance of local buy-in.

Most recently, in a further effort to gain public support for the shale gas industry, the Government announced in December 2014 that it will provide £5m of funding to deliver independent evidence directly to the public about the robustness of the existing regulatory regime. At the same time, the Government also confirmed that it will set up an investment fund from tax revenues from the shale gas industry.

EU developments

On 22 January 2014, the European Commission adopted a Recommendation on safeguarding principles that should be implemented by Member States to regulate shale gas operations. Originally, the Commission had contemplated introducing a Directive specifically dealing with shale gas – so this is a relatively light touch approach as, unlike a Directive, a Recommendation is not legally binding. The UK was heavily involved in lobbying the Commission to not proceed with the Directive at this stage. The Recommendation's flexibility will permit Member States to tailor their regulatory programmes to their own circumstances.

The principles set out in the Recommendation include, among other things, the following minimum requirements:

- a requirement for operators to carry out a risk assessment and a baseline environmental study before commencing fracturing operations;
- a requirement for operators to provide a financial guarantee or equivalent covering their obligations under permits and potential liabilities for environmental damage; and
- a requirement for a survey to be carried out after each installation's closure to compare the environmental status of the site with its status prior to the start of operations as defined in the baseline study.

Member States were "invited" to give effect to the principles by 28 July 2014 and, from December 2014 onwards, inform the Commission each year about measures that they have put in place. The Commission will monitor the application of the Recommendation with a publicly available scoreboard that will compare the situation in different Member States. It will review the effectiveness of this approach in 18 months.

Where do we go from here?

It remains to be seen whether shale gas operators will be able to overcome the barriers to the development of the UK's shale gas resources. However, at a time when security of supply remains a critical issue on the policy agenda, the potential benefits of developing the UK's shale gas resources and their contribution to the supply mix cannot be overlooked.

Martin Kudnig
London
T: +44 (0)20 7859 1679
E: martin.kudnig@ashurst.com

Denva Poyntz
London
T: +44 (0)20 7859 1832
E: denva.poyntz@ashurst.com

STOP PRESS:

Top tier rankings in Australia and the UK

Since the last edition of Energy**Source**, Ashurst's Energy and Natural Resources teams have been recognised as premier advisors in the regional leading legal directories, Legal 500 and Chambers and Partners. Published annually, these guides provide unbiased commentary and insight into regional legal marketplaces.

Here is a brief overview of our recent rankings:

CHAMBERS UK 2015
Energy & Natural Resources: Oil & Gas - UK-wide

TIER 1	ALLEN & OVERY LLP **ASHURST** BAKER BOTTS UK LLP CLIFFORD CHANCE LLP CMS HERBERT SMITH FREEHILLS LINKLATERS VINSON & ELKINS RLLP
TIER 2	DENTONS HOGAN LOVELLS NORTON ROSE FULBRIGHT
TIER 3	AKIN GUMP STRAUSS HAUER & FELD LLP BAKER & MCKENZIE BERWIN LEIGHTON PAISNER LLP BOND DICKINSON FRESHFIELDS BRUCKHAUS DERINGER LLP KING & SPALDING INTERNATIONAL LLP LATHAM & WATKINS MILBANK, TWEED, HADLEY & MCCLOY LLP PINSENT MASONS SHEARMAN & STERLING LLP SKADDEN, ARPS, SLATE, MEAGHER & FLOM (UK) LLP SLAUGHTER AND MAY WHITE & CASE LLP
TIER 4	CLYDE & CO LLP DLA PIPER LLP EVERSHEDS LLP SIMMONS & SIMMONS LLP SULLIVAN & CROMWELL LLP

LEGAL 500 UK 2014
Oil and Gas

TIER 1	ALLEN & OVERY LLP **ASHURST** CMS CLIFFORD CHANCE DENTONS HERBERT SMITH FREEHILLS LLP LINKLATERS LLP NORTON ROSE FULBRIGHT WHITE & CASE LLP
TIER 2	AKIN GUMP STRAUSS HAUER & FELD BAKER BOTTS (UK) LLP BERWIN LEIGHTON PAISNER LLP CLYDE & CO LLP FRESHFIELDS BRUCKHAUS DERINGER LLP HOGAN LOVELLS INTERNATIONAL LLP KING & SPALDING INTERNATIONAL LLP LATHAM & WATKINS MILBANK, TWEED, HADLEY & MCCLOY LLP PINSENT MASONS LLP SHEARMAN & STERLING LLP VINSON & ELKINS RLLP
TIER 3	BAKER & MCKENZIE LLP HOLMAN FENWICK WILLAN JONES DAY INCE & CO SIMMONS & SIMMONS SKADDEN, ARPS, SLATE, MEAGHER & FLOM (UK) LLP SLAUGHTER AND MAY SULLIVAN & CROMWELL LLP
TIER 4	BRACEWELL & GIULIANI (UK) LLP DLA PIPER FASKEN MARTINEAU LLP K&L GATES LLP STEPHENSON HARWOOD WATSON, FARLEY & WILLIAMS LLP
TIER 5	ADDLESHAW GODDARD LLP BOND DICKINSON LLP CURTIS DAVIS GARRARD LLP EVERSHEDS LLP

LEGAL 500 ASIA PACIFIC 2015
Energy and Resources

TIER 1	ALLENS **ASHURST** HERBERT SMITH FREEHILLS
TIER 2	CLAYTON UTZ CORRS CHAMBERS WESTGARTH JOHNSON WINTER & SLATTERY KING & WOOD MALLESONS MCCULLOUGH ROBERTSON MINTER ELLISON
TIER 3	ALLEN & OVERY BAKER & MCKENZIE GILBERT + TOBIN NORTON ROSE FULBRIGHT
TIER 4	CLIFFORD CHANCE AUSTRALIA DLA PIPER HWL EBSWORTH

Oil and Gas: A Practical Handbook (Second Edition)

Ashurst LLP has contributed to a number of sector-focused books published by Globe Law and Business. *Oil and Gas: A Practical Handbook*, edited by Geoffrey Picton-Turbervill, was one of the earlier titles and has now been fully updated and rereleased in a second edition. The book, with contributions from Ashurst and other leading practitioners and industry members, outlines in a single volume the essential principles involved in documenting oil and gas transactions, from the upstream exploration phase, to transportation by pipeline and liquefied natural gas, to sales and marketing. The book can be purchased from the Globe Law and Business website at www.globelawandbusiness.com/OG14.

ashurst