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A HARSH VERDICT:

The UK cost of energy review

by David Wadham and Justyna Bremen

MENA investment protection: An augmentation of options

BY MATTHEW SAUNDERS AND DYFAN OWEN

Brexit: Impact on dispute resolution

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Australia's National Electricity Market: Recent developments and future challenges
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Waste-to-wealth initiatives: Waste-to-energy projects
BY MICHAEL HARRISON, RICHARD GUIT, ANTHONY JOHNSON AND NICK STALBOW

High yield bonds: A financing solution for energy projects
BY TAMER BAHGAT AND NATALIA SOKOLOVA

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We are delighted to introduce this nineteenth 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.

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A HARSH VERDICT:

The UK cost of energy review

by David Wadham and Justyna Bremen

In October 2017 Professor Dieter Helm published a report summarising the findings of his "cost of energy review", commissioned by the UK Government. In this article we consider the impetus for the review, the key findings and the possible implications for the UK's electricity industry.

Commissioning of the review

Ahead of the snap general election called by the UK's Prime Minister, Theresa May, in the earlier part of 2017, the Conservative party pledged in its election manifesto to commission "an independent review into the cost of energy". The background to this pledge is the fact that there has been growing political pressure on the UK Government to address the rising costs of energy in the UK, the blame for which, to a large extent, has been put on the various energy policies of successive Governments over the past decade and beyond. Part of the blame has also been directed at the structure of the retail gas and electricity supply market, and that aspect was considered by the Competition and Markets Authority (CMA) in a two-year energy market investigation carried out between June 2014 and June 2016. The CMA investigation has led to a large number of remedies being implemented, primarily aimed at the retail market.

As discussed in more detail below, key among the alleged "culprits" for high energy prices have been the various incentives introduced to drive investment in low carbon generation. While this is a point many involved in the electricity industry would challenge, what is inarguable is that the various policy instruments introduced into the market over time have led to a very complex electricity market structure (readers less familiar with the UK electricity market may wish to refer to the text box titled "A short history of the UK's complex electricity market"). What is also significant is that only a few years have passed since the implementation of the Electricity Market Reform (EMR) package of policies, which were intended to address the UK's energy needs, while keeping costs down. Against this background, and facing the Labour Party's election manifesto pledges to shake up the energy industry radically, including plans to nationalise the gas and electricity distribution and transmission networks, it is perhaps not surprising that the Conservative Government decided to commission an independent critique of the policies that have formed the current electricity market.

A short history of the UK's complex electricity market

The UK electricity industry was privatised in the 1990s. The aim was always to create a fully liberalised and competitive electricity industry, and with this in mind the Electricity Act 1998 provides for a regulatory structure founded on a licensing system of four core activities – generation, distribution, transmission and supply. Ofgem, the gas and electricity markets regulator, oversees and enforces the regulatory structure. A key principle is the separation of the monopoly activities – distribution and transmission – from generation and supply. Originally, at privatisation, an electricity pool was introduced as the mechanism for wholesale electricity trading in England and Wales. In 2001 the pool was replaced with the New Electricity Trading Arrangements, which involves bilateral trading generators, suppliers and traders. This was subsequently extended to Scotland, when Scotland joined the England and Wales electricity market in 2005, in the form of British Electricity Trading and Transmission Arrangements. However, in parallel to steps being taken to create a fully liberalised market, it was recognised that some government intervention may be required to encourage investment in a relatively new and expensive type of generation plant: renewables. Accordingly, in 1990 the Government introduced the Non-Fossil Fuel Obligation to support generators of renewable energy, which operated alongside the Fossil Fuel Levy, imposed on consumers to support nuclear power. In 2002, the Renewables Obligation (RO), a green certificate scheme, became the main mechanism for incentivising investment in renewable energy. This was later supplemented by the small-scale Feed-in Tariff scheme, aimed at supporting small-scale renewable generators (e.g. solar panels on buildings) and the Renewable Heat Incentive scheme.

In 2014, to address what was identified as an energy "trilemma" – how to ensure energy security, while reducing carbon emissions and keeping the cost down – the Government implemented Electricity Market Reform (EMR). EMR has introduced a completely new incentive framework which comprises four main elements: Contracts for Difference for low carbon generation (replacing the RO); a carbon price floor; an emissions performance standard for fossil fuel generating plant; and a capacity market aimed at incentivising generators to make capacity available as an insurance against potential future shortages.

A key point to understand about the UK electricity market is that the various incentives aimed at supporting investment in new generation are funded by levies imposed on suppliers, which are then passed down to electricity consumers through their electricity bills.

The review's remit and findings

There is a sense of déjà vu in the remit of the review. The terms of reference state that "carbon targets need to be met, whilst concurrently ensuring security of supplies of energy, in the most cost-effective way... The specific aim of this review is to report and make recommendations on how these objectives can be met in the power sector at minimum cost and without imposing further costs on the exchequer". This sounds remarkably like the energy trilemma that Electricity Market Reform (EMR) was intended to fix. However, Helm was tasked with looking at not just generation, but the whole electricity industry chain, including generation, supply, distribution and transmission, with a focus on the potential cost savings that could be achieved across the whole chain.

Having been set a wide remit, Helm has recommended quite significant changes to the structure of the electricity industry, and, in particular, the way new capacity is procured. The changes recommended in the review are aimed at addressing Helm's two key findings:

- that the cost of energy is significantly higher than it needs to be to meet the Government's policy objectives; and
- that the regulatory structure and market design is "not fit for the purposes of the emerging low-carbon market".

In this article we have summarised some of the key recommendations.

A "legacy bank" of renewables costs

Helm notes that there is a legacy of costs associated with support for renewables being passed down to consumers, which originates from a time when renewable energy technologies were more expensive and were supported by various incentives at a high cost to consumers. While these costs have already been incurred, and will continue to be incurred until the expiry of the support granted, Helm recommends that such costs be grouped into a separate "legacy bank". It is argued that while such costs will still need to be recovered from consumers/taxpayers, the advantage would be that the Government would have more flexibility in how such costs should be passed down. It is argued that another key advantage is that such an approach would take the costs out of the market, "leaving the future market to reflect the expected falling prices for renewables".

As discussed below, a key assumption behind the "legacy bank" approach is that support schemes for low carbon generation, such as the small-scale Feed-in Tariff (FIT) scheme and Contracts for Difference, will be replaced with a new, single mechanism that Helm argues would be more cost-effective.

Equivalent firm power capacity auction

Helm does not refrain from criticising the mechanisms that have been the bedrock of investment in renewables in the UK. Stating that the small-scale FIT scheme and CfDs "are badly designed simply because they do not reflect the underlying cost structure", he recommends a new approach. Helm considers that the way forward to reduce the costs of energy while meeting the UK's carbon budgets is to:

- develop a single carbon price (see below); and
- create a single unified capacity auction on an equivalent firm power (EFP) basis.

Helm acknowledges that having a single mechanism to procure all capacity, regardless of technology type, would be a "radical" change, particularly given that his proposed approach would require intermittent generators to bear their intermittency costs. It is proposed that the EFP capacity auction would be on an equivalent basis – i.e. that the de-rated contribution of intermittent capacity would be taken into account. Helm notes that EFP is not a new concept, because National Grid already deducts the EFP contribution of existing intermittent generation when calculating the capacity level required to be procured through the capacity market mechanism. Helm suggests that the proposed mechanism would give renewable generators a strong incentive to enter into arrangements with other parties who may offer back-up services, to develop storage options and to engage with customers on demand-side management, to increase their value in EFP auctions.

The report notes that if the price of carbon is set at the "right" level, then there will be no need to give low carbon generators any special treatment in the EFP auction mechanism. If, however, the Government is not prepared to set the price of carbon at the "right" level for political reasons, then an alternative might be to structure the EFP auction in a way that recognises the value of low carbon generation in reaching carbon budgets – e.g. by having a scored auction.

Helm acknowledges that the proposed mechanism would place new and emerging technologies at a disadvantage. However, his view is that technologies should be supported through research and development support mechanisms.

Reforming existing incentive mechanisms

The report recognises that the Government may not be willing to move to the EFP auction model, at least immediately, and that in any case there will need to be a transitional period. Helm, therefore, recommends a reform of the structure of the existing small-scale FIT and CfD mechanisms, to reflect the different financial pressures present at different phases of nuclear and renewable energy projects. Specifically, it is recommended that capital support and tax concessions should be made available during project development and construction phases, and then at completion a refinancing arrangement should be put in place. However, Helm considers that long-term, fixed-priced support mechanisms for the whole project life, or a substantial period of its life, should eventually be abolished. Moreover, it is recommended that a closure date for the small-scale FIT and CfD regimes should be set now. While currently the future of the CfD regime is uncertain, the Government indicated in the Autumn Budget, in November 2017, the the small-scale FIT scheme would close to new applicants on 1 April 2019.

Network company price control

Under Ofgem's current RIIO (Revenue = Incentives + Innovation + Outputs) price control model, each network company is subject to a price control mechanism to cover an eight-year period. Helm is of the view that this approach is no longer appropriate on the basis that "the future is fundamentally uncertain and challenged by fast technical progress; technical developments are undermining the distinction between networks on the one hand and generation, demand side and storage, and supply on the other; and there are lots of opportunities to let markets reveal costs through auctions, rather than Ofgem try to predict them". It is recommended that periodic price reviews should be abandoned, in favour of a more flexible approach. Helm, however, stops short of recommending what that new approach might entail. However, it is envisaged that this would be tied to the new NSO and RSO model proposed (see below), and,

given the monopoly nature of network assets, it is implicit that some form of price regulation is still required.

State-controlled system operators

Arguably, it is in the context of network regulation that the report's recommendations are at their most radical, seeking to unravel a structure that has been seen as the bedrock of a liberalised market. Helm proposes that new National System Operator (NSO) and Regional System Operator (RSO) roles should be created, and these new bodies would determine what operations, maintenance and enhancements to the networks are required. Importantly, Helm concludes that rather than being private companies, the NSO and RSOs should be public bodies, accountable to Government, and subject to the National Audit Office and public accounts committee scrutiny and, ultimately, to Parliament.

The proposed public body model is in contrast to the current System Operator model, where the SO role is undertaken by National Grid, a private company that also owns transmission assets. However, it is relevant to note in this context that National Grid itself is currently undertaking a review of its role,[1] and is considering structuring options to make the SO role more independent. In addition, it has to be observed that the Labour party, in its 2017 election manifesto, included a pledge to transfer the ownership of distribution networks to publicly owned local companies and over time nationalise all grid infrastructure. It needs to be emphasised that Helm's proposed model stops short of the actual transfer of assets to the public body NSO and RSOs.

In terms of the new role, it is proposed that the NSO would take on some of the functions and duties currently vested in transmission licensees, including the duty to ensure security of supply.

The report notes that an independent NSO could, for example, also play a role in ensuring that when new capacity is procured through a competitive auction process, an appropriate balance of different generators provides that capacity – that is, so that decisions are made not just on the basis of price, but also on the type of plant. The report cites the recent domination of the capacity market mechanism by small-scale diesel generators as the type of scenario that the NSO could prevent.

Helm observes that the NSO/RSO model would result in Ofgem's

1 "Industry transformation: The changing role of the electricity System Operator", National Grid, July 2017.

role being "substantially diminished", as the newly established public bodies would take on a number of regulatory functions currently performed by Ofgem. However, he acknowledges that there would be residual regulatory roles to fulfil, but these could be undertaken by a single network regulator (together with water, transport and communications networks).

Introduction of a "general licence"

Related to the report's recommendations for the NSO/RSO model is a proposal for an equally fundamental change: the replacement of separate licences for distribution, supply and decentralised generation with a "general" licence, on the basis that the distinctions between these activities are becoming blurred. Helm acknowledges that current market structures are constrained by the EU's internal energy market rules (specifically, the Gas and Electricity Directives), which may still be relevant post-Brexit implementation. However, he also notes that the breakdown of the distinctions between generation, supply and networks is widespread across Europe.

Helm does not discuss in detail what such a general licence might entail, but the proposal is likely to have the support of investors in decentralised energy, who currently have to grapple with the complexities of a licensing system not designed for smaller-scale projects which may involve generation, distribution and supply activities.

Default supply tariff

In the context of retail electricity prices, Helm explores the findings and recommendations of the recent CMA inquiry (referred to above) and recommends a new approach: the introduction of a more transparent default tariff. Retail tariffs for domestic customers have become in recent years a highly politically charged issue. In October 2017, the Government, bowing to political pressure to "do something" about rising energy prices, committed to press ahead with a temporary tariff cap notwithstanding that the CMA expressly considered and rejected the idea of a cap that would apply to all domestic customers.

Helm's proposed default tariff would include all costs of supplying energy (wholesale price, network costs, taxes and levies, etc.), plus the supplier's margin. Helm argues that this model, where competition is all about the margins offered by different suppliers, is reflective of the fact that the other elements of the retail energy price are a cost pass-through. Furthermore, it is proposed that the new default tariff model could be used to set the price cap being legislated for by the Government. The report suggests that in implementing the new legislation, Ofgem should focus its price cap proposals on a maximum margin within the default tariff recommended by Helm, leaving headroom for competitors to offer lower margins or other tariffs.

Harmonising carbon prices and taxes

Helm points to the "mind-numbing complexity" of several of the seven main energy and carbon taxes identified in his review[2]. Although he praises the effectiveness of the Carbon Price Floor (CPF) introduced in 2013 as part of EMR, his recommendation is that all current carbon and energy taxes be replaced with a single, harmonised carbon price. The report lists a number of advantages to this approach, including the fact that a single carbon price would provide common incentives across the economy (including sectors such as agriculture and transport), and allow the market to find the most cost-effective solutions to reducing carbon emissions. It is suggested that a harmonised carbon price could be introduced by extending the CPF beyond the power sector to include all the other sectors in the economy.

Conclusion

It is clear that, having been given a wide remit, Helm was determined to deliver a comprehensive review of the whole market structure, rather than tread softly to maintain the status quo. As he himself acknowledges, his "package of measures is a major shift from the original market design and regulation model at privatisation". While not everyone will agree with Helm's recommendations for change, there are many review findings that few industry insiders would challenge. A damning but difficult to refute statement is that "the sheer number of interventions in the UK energy market is so great that few if any participants... regulators... ministers or civil servants can have grasped them all". On the other hand, there may be little appetite, by either Government or industry, for a "back to the drawing board" approach, at a time when regulatory stability is a key priority for the UK.

In November 2017 the Government launched a call for evidence on Helm's report, seeking views from industry and other interested stakeholders. It will be interesting to see which, if any, of the recommendations are ultimately implemented.

2 The seven main taxes on energy and carbon identified by Helm are: fuel duty; value added tax (VAT), which is levied on supplies of fuel and power; the EU Emissions Trading System (EU ETS); the Carbon Price Floor, which is made up of the price of CO_2 from the EU ETS and the UK Carbon Price Support rate per tonne of CO_2; the CRC Energy Efficiency Scheme, designed to improve energy efficiency; the Climate Change Levy (CCL), which is a tax on energy delivered to non-domestic users in the UK; and Climate Change Agreements, which allow energy-intensive participants in 53 sectors to pay reduced main rates of CCL.

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MENA INVESTMENT PROTECTION:

An augmentation of options

by Matthew Saunders and Dyfan Owen

It is now commonplace for investors to take advantage of the legal protections available for their investments under bilateral and multilateral investment treaties (BITs and MITs). The availability of such protection is considered by investors from the outset of investment planning, relying on the approximately 3,000 BITs that have been entered into by governments across the globe. States in the Middle East and North Africa (MENA) region have featured significantly over the years as respondents in cases brought by unhappy investors before various types of tribunals, including before investment treaty arbitration tribunals. Recent, but largely unreported, developments mean that significantly more effective treaty protection may now be available for investors within the MENA region.

Impetus for treaty protection

Public international law treaty protection for investments matters because it is both free to obtain and effective. In many instances it can be a great deal more effective than private law alternatives such as litigation in domestic courts or contract-based international arbitration. The sectors for which investment protection under BITs and MITs is most relevant are those requiring close interaction with states and state agencies. It is no surprise, therefore, that the energy and resources sectors feature at the top of the list for claims under BITs and MITs. Claims for infringement of treaty obligations have been especially prevalent in areas such as taxation, licensing and environmental regulation, all of which represent clear "pressure points" for interaction with states.

Availability of treaty protection

Treaty protection is available subject to nationality tests being met (i.e. the requirement that the investor has the nationality of an investment treaty signatory and does not have the nationality of the host-state signatory). It is often enough that such test is met at just one of the stages in a chain of ownership and control – for example, the personal nationality of a shareholder or corporate nationality of a holding company. The widespread use of special project companies and tax-focused holding structures in the energy and resources sectors means there will often be significant scope for "treaty shopping" through the use of "brass plate" entities aimed at acquiring relevant nationality

in order to trigger the protection of one or more treaties. In this context it is important to note that attempts have been made by the drafters of some treaties to exclude such entities through "denial of benefits" clauses that require substantive economic activity by a corporate entity at its place of incorporation.

Investment treaties also require the relevant economic activity to qualify as an "investment". The very broad definitions of "investment" commonly contained in BITs and MITs, along with the expansive interpretation given by tribunals, mean that a very wide spread of economic activities commonly qualify (in certain cases even extending to cash held in a bank account).

The protections provided

The most significant areas of protection afforded by BITs and MITs are: protection from expropriation; a requirement to afford "full protection and security" to investments; and – crucially – the obligation to provide "fair and equitable treatment" (FET) to an investor.

These concepts are interpreted under public international law (i.e. the body of law that governs relationships between states), not private law, and have been applied broadly by tribunals. It is important to appreciate the full breadth of these concepts under public international law. For example, tribunals have found that outright seizure (such as Venezuela's expropriation of oil projects in the Orinoco Belt) is not necessary and that the test for expropriation is met where an investor is deprived of the economic value of the investment. The test may be met even where individual measures by the host state are not immediately expropriatory but, when considered as a whole, are "tantamount to expropriation" (such as a refusal to renew or withdrawal of a licence).

Similarly, the obligation of FET has been interpreted as requiring treatment that is consistent with representations given by the host state at the time the investment was made, and that engagement by state authorities with the investor is in a manner that is transparent and consistent. The FET standard, in effect, can therefore operate as a "minimum legal standard" for the treatment of investors by host states. In practice, the standard focuses upon "due process" requirements in a host state's legal and administrative structures, rather than whether a host state's actions are substantively legal or not.

A number of the investment treaty cases relating to FET have concerned the tax treatment of investments – for example, a series of recent cases relating to investment in renewable energy projects in Spain. This is timely as states in the MENA region are putting in place new regulations relating to the introduction of new forms of taxation. Foreign investors will be looking closely at whether the processes for introduction of such taxes provides them with treatment that meets the FET standard, especially in terms of non-discrimination, transparency and predictability.

Enforceability

These treaty protections for investment are effective because – uniquely in the world of public international law – they are directly

enforceable by investors through international arbitration, and the resulting arbitral awards are enforceable against states through either the Washington Convention of 1965 or the New York Convention of 1958. Because the arbitration process operates in the public international law sphere it is effectively immune from interference by state courts (or indeed other forms of state interference).

Intra-MENA investment protection

Countries in the MENA region have entered into numerous BITs but few have been intra-MENA, meaning that relatively little bilateral investment treaty-based protection has been available to investors from one state in the region who have made their investment into another state within the region.

However, in actual fact, there have for decades been MITs in place between states in the region that are capable of providing protection to investments under public international law. However, these have – until relatively recently - been ineffective procedurally or excessively narrow in their application. Recent developments have changed this position but appear to have gone largely unnoticed.

One established MIT in the region is the Unified Agreement for the Investment of Arab Capital in Arab States (the Arab Investment Agreement). It came into force in 1980 but its scope is limited to the protection of "an Arab citizen who owns Arab capital which he invests in the territory of a State Party of which he is not a national". The requirement that the citizen investing and the origin of the capital be Arab has the effect that much investment in the region will not be covered because it cannot be demonstrated to be "Arab capital". Given the global nature of so much international financing of investment activity, particularly within states in the MENA region, this restriction is very limiting.

The alternative MIT that covers the region suffers no such restriction as to the nature of the capital involved, but has until recently been largely ineffective for other reasons. The Agreement on Promotion, Protection and Guarantee of Investments of the Organisation of Islamic Cooperation (referred to here as the OIC and the OIC Agreement) has been ratified by 27 states, including Egypt, Indonesia, Iran, Jordan, Morocco, Pakistan, Saudi Arabia and the UAE and has been in force since 1986.

Because the OIC Agreement contains what is known as a "most favoured nation" clause, it is possible to import into it terms that exist in treaties that OIC signatory states have signed with

third party states (i.e. non-OIC signatory states). This means that protection such as the FET standard (not otherwise provided for in the OIC Agreement) may be imported in. Because of the "minimum legal standard" it effectively applies, it may be especially useful for investors in the region, if they are concerned that treatment by state entities lacks transparency or consistency, or that it may be negatively discriminatory.

Following a decision by the arbitration tribunal in *Hesham Al-Warraq -v- Indonesia*, the OIC Agreement was found to permit ad hoc arbitration (in this instance adopting the UNCITRAL rules) "until an Organ for the settlement of disputes arising under the Agreement is established". It therefore appeared as though the OIC Agreement might become an effective vehicle for investment protection, but hopes proved short-lived when respondent states adopted a practice of refusing to nominate an arbitrator and the OIC Secretary-General followed likewise in refusing to make a default appointment, thus ensuring that any arbitration process was frustrated at the outset. Three cases filed in 2014 against Egypt by a Saudi investor failed to proceed for this reason. The result of this practice, while convenient for host states, was to frustrate the effective enforcement of the investment protections in the OIC Agreement.

Recent developments and the potential for wider use of the OIC Agreement

Most recently, however, the Secretary-General of the Permanent Court of Arbitration (PCA) (an international body that offers administrative support to various types of arbitral processes, based in The Hague) appointed an arbitrator following Libya's and the OIC Secretary-General's failure to do so. It is reported that the appointment was made through a route involving the MFN clause importing a right to ad hoc arbitration under the UNCITRAL rules from a BIT between Libya and a third party state, the rules of which expressly stated that the PCA may play the default appointment role.

The OIC could move to establish a dispute resolution "organ", with the result that there would no longer be any entitlement to ad hoc arbitration. Such a dispute resolution "organ" could have characteristics or procedures that would make it, from an investor's perspective, a less attractive forum for resolving disputes. However, there are as yet no signs of it doing so.

A further aspect of the OIC Agreement's operation that may appeal to investors needing to seek a remedy from an OIC host state is the availability of conciliation processes. A common reason for investors being reluctant to commence full blown investment treaty arbitration claims against host states is the fear that the respondent state will see it as a highly hostile move, precluding the investor from future opportunities in the state (indeed the option of commencing such claims has been described as the "nuclear option"). Unusually for an investment treaty, the OIC Agreement contains formal conciliation procedures as an alternative to ad hoc arbitration. This may be a particularly attractive option where an investor is simply unable, through contract-based arbitration or domestic legal processes, to get the attention of the host state authorities but does not wish to "burn bridges" with the host state by commencing a formal arbitration process.

Final thoughts

The expansion of effective investment treaty protection to many investors within the MENA region (as presumably originally intended by the drafters of the OIC Agreement) is a potentially significant boost to legal protection for investors in the region. It is important that investors are aware of the protections now available and that their investment planning strategies take full account of them. Because of their unique vulnerabilities to state action, such protections are likely to be of particular importance in the energy and resources sectors.

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BREXIT: Impact on dispute resolution

by Matthew Saunders and Amy Billing

On 29 March 2017, UK Prime Minister Theresa May wrote to European Council President Donald Tusk to notify him of the UK's intention to leave the European Union. The following day, the UK Government published its White Paper on the Great Repeal Bill (now the European Union (Withdrawal) Bill (the Withdrawal Bill)), setting out its approach to converting existing EU law into domestic law post-Brexit. The Withdrawal Bill is now at the Committee Stage, which is due to end on 20 December 2017.

Despite significant progress on key points (with a measure of compromise shown, particularly on what had been "red lines" for "Brexiteers", such as any continuing role for the European Court of Justice (the CJEU)[1]), the UK and EU are yet to finalise a "divorce" deal.

One of the many issues under negotiation is the extent of judicial co-operation in civil and commercial matters post-Brexit, i.e. the impact Brexit will have on choice of law and jurisdiction. It may not be a headline issue in the daily newspapers but it is recognised as an important foundation for commerce – and is potentially significant in the bid to ensure the UK legal services market (a significant element of UK invisible exports) does not suffer post-Brexit. The EU Commission set out its position on judicial co-operation on 13 July 2017. On 22 August 2017, the UK Government published its response. Unlike the EU's paper, the UK's paper looks beyond transitional arrangements to a future relationship.

Here we look at the impact Brexit may have on dispute resolution in the UK, including the potential threat of foreign investors bringing claims against the UK in the event that Brexit has a damaging effect on the value of their UK-based investments.

Civil judicial co-operation: the current framework

There are various EU instruments that govern the interaction between the different EU legal systems in cross-border situations. These include Rome I, Rome II, the Brussels Regulations and the Lugano Convention.[2] These instruments provide certainty by avoiding litigation of an issue in the courts of more than one EU member state. They ensure that each EU member state applies the same rules to determine both governing law and which court has jurisdiction to hear the case, and to ensure ease of recognition and enforcement in one EU member state of a judgment obtained in another.

Once withdrawal from the EU is effective, these instruments will no longer apply to the UK. While the UK Government has stated that it will take steps to adopt UK agreements with the EU into domestic law, the reciprocal nature of some of these

1 In a joint report from the negotiators of the EU and the UK Government, dated 8 December 2017, it was confirmed that the EU and the UK are in agreement with respect to the role of the CJEU in the context of the rights for both UK citizens living in the EU and UK citizens living in the EU. However, formal agreement on the wider role of the CJEU remains to be seen.

2 The Rome I Regulation on the law applicable to contractual obligations ((EC) 593/2008) (Rome I); The Rome II Regulation on the law applicable to non-contractual obligations ((EC) 864/2007) (Rome II); Council Regulation (EC) No. 44/2001 on jurisdiction and the recognition and enforcement of judgments in civil and commercial matters (the 2001 Brussels Regulation); Regulation (EU) No. 1215/2012 of the European Parliament and of the Council of 12 December 2012 on jurisdiction and the recognition and enforcement of judgments in civil and commercial matters (recast) (the Recast Brussels Regulation); and the Convention on jurisdiction and the recognition and enforcement of judgments in civil and commercial matters (the Lugano Convention).

instruments means that wholesale adoption will not be possible. The long-term implications will only become apparent once it is known what any negotiated deal and the replacement instruments will look like.

Will the approach to choice of law clauses change?

The short answer is no. The courts of England and Wales currently apply Rome I in contractual disputes and Rome II in non-contractual disputes (such as claims in tort). These regulations do not require reciprocity, so the position should not change post-Brexit, as the UK Government has confirmed that both will be incorporated into domestic law as part of the Withdrawal Bill.

Likewise, the rest of the EU will continue to give effect to English governing law clauses because Rome I requires EU member states to give effect to the governing law chosen by the contracting parties, irrespective of whether it is the law of a member state, or whether the parties are from outside the EU.

In addition, the reasons for choosing English law – such as certainty and respect for party autonomy – will not change as a result of Brexit. It will remain just as good a choice of governing law, supporting contractual certainty, post-Brexit as it does now. Brexit should therefore not deter contracting parties from opting for English governing law clauses. (However, it is striking that certain EU financial institutions have already taken steps to adopt Paris-based arbitration mechanisms in place of London court jurisdiction, although the choice of English law remains – for now.)

Does the choice of English law remain a good one?

Yes. Currently, English law encompasses UK legislation, case law and EU law. What English law looks like post-Brexit will depend on the extent to which the UK Government decides to adopt existing EU legislation (and does not repeal it as part of any process of reviewing EU law incorporated into English law). The Withdrawal Bill confirms that, to the extent possible, all existing EU law will be enshrined in English law once the UK leaves the EU. So, wherever possible, the same rules and laws will apply on the day after the UK leaves the EU as before. This will achieve certainty in the short term, but the UK parliament will then be able to amend and repeal any unwanted aspects.

The major "sticking point" is the role of the CJEU post-Brexit. The Withdrawal Bill confirms that historical CJEU case law will have the same precedential status as decisions of the UK Supreme Court. As such, the courts of England and Wales will interpret EU-derived law by reference to CJEU case law as it stands on the day the UK leaves the EU. Going forward, however, the CJEU will no longer have direct jurisdiction in the UK. This means that there could arise a divergence in approach between the CJEU and the courts of England and Wales. However, the UK paper does acknowledge the role of the CJEU as "the ultimate arbiter of EU law within the EU"[3] and it is likely that the courts of England and Wales will have regard to decisions of the CJEU when applying EU law principles (although the judiciary has requested legislative certainty on this). Existing legal principles and the breadth of what may be considered "persuasive authority" by the courts of England and Wales give valuable flexibility here.

3 "Providing a cross-border civil judicial cooperation framework: a future partnership paper", 22 August 2017, paragraph 20.

Contracting parties will therefore need to consider what impact EU law has on their contracts, particularly those drafted to reflect, rely upon, or fall within, certain EU laws or "safe harbours", and whether future-proofing/Brexit clauses are required.

Is the choice of English court jurisdiction affected by Brexit?

Here the position is potentially more complicated. Currently, the Brussels Regulations determine the rules which are applied by EU member state courts when giving effect to jurisdiction clauses and the enforcement of judgments within the EU. These rules mean that:

1. EU member state courts will uphold jurisdiction clauses that confer jurisdiction on the courts of member states; and
2. enforcement of a judgment of one EU member state in another is straightforward.

Because of its reciprocal nature, the Brussels regime cannot simply be retained by importing it wholesale into English law. The UK Government has confirmed that it will seek to agree similar arrangements, but no specific proposals have been put forward, and the EU paper[4] does not address arrangements going forward. Much will therefore depend on the negotiations.

There is scope for optimism (assuming it is desirable that the UK continues to recognise EU member state court decisions). The EU and UK papers do appear to agree essentially on how judicial co-operation will work during the transition period. In particular, existing EU arrangements will continue to apply to legal proceedings commenced pre-Brexit and choices of court made pre-Brexit.

The UK has taken this further by proposing that existing arrangements should also apply to any judgments flowing from pre-Brexit choice of court agreements. If the EU agrees to this proposal, this at least puts an end to the current uncertainty surrounding enforceability of English court judgments for choice of court agreements entered into pre-Brexit.

4 "Position paper on Judicial Cooperation in Civil and Commercial matters", 13 July 2017.

The Government has also confirmed its intention to ratify the Hague Convention on Choice of Court Agreements (the Convention). The Convention operates to give effect to exclusive jurisdiction clauses and enforcement of any resulting judgment. It only came into force on 1 October 2015 and as such remains untested. However, the EU has ratified it (as have Mexico and Singapore), and so the Convention potentially provides a fallback position if there is no deal on judicial co-operation post-Brexit. Nonetheless, it is not ideal as it only applies to exclusive jurisdiction agreements and any resultant judgments (unless extended to apply to judgments flowing from a non-exclusive jurisdiction clause, but as yet no contracting states have exercised that option). The Explanatory Report to the Convention confirms that this does not cover asymmetric clauses (where one party is required to bring proceedings in one jurisdiction exclusively, while the other party has the option to bring proceedings in any competent jurisdiction).

There is also a potential issue in respect of timing as to application. The Convention only applies to jurisdiction agreements concluded after its entry into force in the state of the chosen court. The UK is currently a signatory via its membership of the EU. It can only ratify (unilaterally) in its own right once the EU treaties no longer apply. If there is a lengthy gap between Brexit and the UK's ratification of the Convention, that could be an issue. However, it is hoped the fact that the UK Government has recognised the potential problem will mean that any problematic gap will be avoided.

What if no deal is reached?

As mentioned above, there seems to be EU and UK consensus that existing EU arrangements will continue to apply with regard to legal proceedings commenced pre-Brexit and choice of court agreements made pre-Brexit. As such, any choice of court agreement reached pre-Brexit will be upheld and recognised by EU member state courts post-Brexit.

Looking further ahead, if no deal is reached, the general approach of the courts of England and Wales towards jurisdiction clauses is unlikely to change. Choice of jurisdiction will generally be upheld. It is also likely that courts of EU member states, applying the Recast Brussels Regulation, will continue to uphold English jurisdiction clauses where the courts of England and Wales are first seized, although the position is less certain where proceedings are commenced first in an EU member state court.

The greater potential impact is on the enforceability of judgments of the courts of England and Wales as – subject to whatever arrangements are negotiated – holders of those judgments will lose the automatic right to enforce judgments throughout the EU. Instead, the national law of each EU member state would determine the enforceability of a given judgment. As such, if enforceability within a particular EU state is an issue, contracting parties should give careful thought as to whether their dispute resolution clause is fit for purpose.

An opportunity for international arbitration?

Although it is too early to say what the long-term implications will be, the courts of England and Wales may lose business to EU member state courts on matters where EU law is concerned in so far as parties are averse to any degree of uncertainty. Certain EU regulations also provide that disputes should be heard by an EU member state court or in an EU member state-seated arbitration.

However, given London's position as a financial centre and the popularity of English law as the law governing international business relations, it is generally considered unlikely that Brexit will have such an impact. Indeed, some have argued that the courts of England and Wales will be a more attractive jurisdiction once the restrictions imposed by the Brussels regime fall away (for example the removal of the West Tankers limitations on anti-suit injunctions).

The more likely threat to the courts of England and Wales is international arbitration, which may become more attractive as a result of Brexit, in so far as parties may wish to retain the advantages of contractual certainty that flow from its use while avoiding any degree of uncertainty concerning enforcement. The international arbitration regime is based on the New York Convention, which provides for recognition by national courts of arbitration agreements, and broad international enforcement of arbitration awards. As such, international arbitration and the enforceability of awards is not affected by Brexit. Therefore, provided there are no other objections to arbitration, agreeing to English-seated arbitration offers the simplest solution if enforcement of English court judgments post-Brexit is a concern.

Investor protection in the UK

Subject to whatever trade deal is reached with the EU, investor protection under international law in the UK may improve post-Brexit. Since the Lisbon Treaty came into force in 2009, the EU has assumed exclusive competence with regard to any trade agreements entered into between EU states and non-EU states. The EU Commission has taken an interventionist approach with regard to any bilateral investment treaties (BITs) between EU member states (intra-EU BITs), intervening in intra-EU investment arbitrations: arguing, for example, that the tribunal lacked jurisdiction, and in one case finding that the resultant award amounted to state aid.[5] Post-Brexit, and pending a UK/EU deal, investors will be able to rely on the BITs the UK has in place with EU member states free of EU

5 In December 2013, the ICSID Tribunal in Ioan Micula, *Viorel Micula and others -v- Romania* (I) (ICSID Case No. ARB/05/20) ruled that Romania had breached the fair and equitable treatment standard in the Sweden-Romania BIT. However, the EU Commission later ordered Romania to recover the compensation it paid to the claimant investors pursuant to the award on the basis that the grant of such compensation constituted new state aid incompatible with EU Law.

"interference". The UK will also be free to maintain its many BITs with non-EU states and enter into new ones.

Brexit will also have implications for the trade deals currently being negotiated by the EU. These include free trade agreements with the USA (the Transatlantic Trade and Investment Partnership or TTIP), Canada, Japan and China. Whereas the deal with Canada (the Comprehensive Economic Trade Agreement) has entered into force provisionally, the other agreements are still being negotiated (although, the TTIP negotiations between the EU and USA were paused earlier this year). The UK will no longer take part in these negotiations and, post-Brexit, will have to negotiate new deals. That said, given the complexities created by the fact that the EU has to negotiate on behalf of all EU member states, it may well be that the UK will find it easier to negotiate its own deals by itself.

Separately, in September 2017, the Council for the European Union gave the go ahead to the European Commission to begin talks for the establishment of a multilateral investment court to settle investment disputes as an alternative to the investor-state dispute settlement system. The UK would not be obliged to adopt this alternative disputes process and it will instead be able to continue to use the tried and tested investment arbitration procedure.

Investment claims against the UK

There is a risk – albeit at this stage largely an academic one – that foreign investors will seek to bring claims against the UK as a result of Brexit.

It may be that foreign investors will bring investment treaty claims (the UK is currently a signatory to 95 in-force BITs as well as the Energy Charter Treaty) against the UK for breach of the "fair and equitable treatment standard" contained within such treaties, on the basis of the UK Government's failure to maintain a stable legal framework. It is widely accepted that the obligation of fair and equitable treatment, which is generally recognised in the UK's BITs and in the Energy Charter Treaty, includes the protection of foreign investors' legitimate expectations. At a high level, legitimate expectations may arise by way of contractual arrangements, informal agreements or the legal and regulatory framework of the host state. Wholesale regulatory change and uncertainty post-Brexit could infringe such commitments.

It is due to such significant regulatory change (specifically, wholesale changes to legal and regulatory measures in the Spanish renewable energy sector) that Spain has recently been the subject of numerous claims brought by foreign investors under the Energy Charter Treaty. The investors claim, among other things, that the changes made by the Spanish Government amount to a violation of the fair and equitable treatment standard. In June 2017, in the first of these cases to reach final award (*Eiser Infrastructure Ltd. -v- Spain* (ICSID Case No. ARB/13/36)), the tribunal found that, while the provisions of the Energy Charter Treaty did not give the investor immutable economic rights that could not be altered by changes in the regulatory regime, it did have the legitimate expectation that the changes would not destroy entirely the value of its investment. It is not too difficult to see a potential parallel with changes that could take place in heavily regulated UK sectors where regulations change post-Brexit (for example, the nuclear sector if the UK was to exit the Euratom Treaty on the basis of its CJEU jurisdiction provisions).

Other potential claims that have been mooted include claims arising out of breach of legitimate expectations arising from access to a single market and loss of passporting rights (which allow UK firms to access customers and financial markets in the EU and EEA).

It may also be relevant that such claims could be instituted for other than the purely "legal" reasons – it could be an effective route to "shine a spotlight" on elements of the UK Government's Brexit-related actions (for example, the giving of "commitments" to key players in the automotive industry, which has been the subject of significant press scrutiny).

Key takeaway points

1. English law will remain just as good a choice of governing law post-Brexit as it is now.
2. If a contract is one that falls within or relies upon certain EU laws or "safe harbours", future-proofing to ensure EU law still applies may be required.
3. Proceedings commenced pre-Brexit and any resultant judgments will continue to be recognised and enforced under existing EU arrangements.
4. Pre-Brexit choice of court clauses will continue to be recognised under existing EU arrangements.
5. Post-Brexit, exclusive choice of court agreements that fall within the Hague Convention should be recognised and enforceable within the EU provided the UK promptly ratifies the Convention so that there is no break in its application in the UK.
6. Post-Brexit, and subject to whatever arrangements are negotiated, UK judgment holders will lose the automatic right to enforce throughout the EU that they currently enjoy.
7. The enforceability of international arbitration awards is not affected by Brexit. The choice of English-seated arbitration as a forum for dispute resolution therefore remains a good choice.
8. Foreign investors in the UK whose investments are negatively impacted by Brexit should consider whether investment treaty commitments may have been infringed.

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AUSTRALIA'S NATIONAL ELECTRICITY MARKET:

Recent developments and future challenges

by Paul Newman, Michael Harrison and Tristan Shepherd

The Australian energy market is currently undergoing a period of profound change. This article serves as a brief introduction to Australia's east coast National Electricity Market (NEM) and the impact of recent events on it and its future, and the causes of higher electricity and gas prices. Its aim is to demystify the current political rhetoric surrounding energy policy in Australia.

Introduction

As in other advanced economies, in Australia the dominance of centralised thermal electricity generation (coal-fired (73 per cent of supply) and gas-fired (seven per cent of supply)) is being challenged by increased investment in renewable generation incentivised by emissions reduction policies. Unlike some other advanced economies, Australia has some of the best conditions for solar and wind power generation in the world, and should be able to achieve relatively efficient renewable power generation.

Nevertheless, there are a number of factors that have raised concerns about energy security and affordability, and the state of the NEM: the fact that the renewable energy industry is still developing; the loss and planned further withdrawals of significant levels of synchronous generation; and a black system event affecting the entire State of South Australia in September 2016 and load shedding in December 2016. These issues have also brought into focus the need for a clear energy policy.

The changes in the supply side of the electricity industry are occurring at the same time as Australia moves to being the world's largest exporter of LNG, with historic levels of LNG exports under long-term contracts. This, coupled with several state-based moratoriums on new onshore gas exploration, is perceived[1] as resulting in higher gas prices.

In this context, there has been no shortage of ideas as to how to overcome system security and wholesale electricity price pressure. However, there are a number of challenges that need to be overcome to implement them, including:

- the existence of current economic disincentives to investment in new gas peaking plant to smooth the transition between thermal and renewable generation;

1 We say perceived because the reporting of these issues tends to be incomplete. For example, the higher gas prices are an eastern seaboard dynamic, with the eastern seaboard LNG projects being coal seam methane projects in Queensland – projects that would not have been developed but for overseas buyers of LNG entering into long-term LNG SPAs, and that were developed without a domestic gas reservation requirement at a policy level. As such, the debate and reporting has been less nuanced than the facts require.

- the need to increase interest in innovative technologies such as utility-scale battery storage to ensure system security and stability; and
- frequent changes in energy policy and the inability to achieve a cohesive energy policy between the State and the Federal Governments.

What is the National Electricity Market?

Overview

The NEM is one of the world's longest interconnected electricity networks, spanning approximately 5,000 kilometres and six Australian jurisdictions: the Australian Capital Territory and the States of New South Wales, Queensland, South Australia, Tasmania and Victoria. It supplies approximately nine million customers per year and has a total generating capacity of approximately 52.5 GW (as of April 2017).

Spot market and hedging transactions

The NEM is a spot market in which fiscal arrangements between generators and customers are separated from physical supply arrangements.

Generators are dispatched in five-minute trading intervals by the Australian Energy Market Operator (AEMO) in merit order based on bids submitted in pricing bands and forecast electricity demand. Renewable generators such as solar and wind farms participate in central dispatch (in a limited manner) – their generation may vary but they are required to comply with turndown instructions from AEMO.

Wholesale electricity customers pay a spot price to AEMO for each megawatt hour of electricity consumed, which then pays the spot price to generators for each megawatt hour of electricity generated. The spot price is calculated on a half-hourly basis as the average of the price of the last megawatt hour to be dispatched by AEMO in each trading interval within that half-hourly period.

However, the National Electricity Rules (Rules) have recently been amended to reduce the 30-minute financial settlement period in the NEM to five minutes to match the five-minute dispatch interval. This amended rule is anticipated to improve NEM pricing signals for fast response generators such as battery storage projects attached to intermittent renewable generators. This change will commence on 1 July 2021, with some transitional arrangements commencing on 19 December 2017.

As the spot price can fluctuate significantly between settlement periods and regions (i.e. the various States) in the NEM, many generators and customers separately enter into OTC derivative transactions to manage spot price risk.[2] These transactions typically take the form of swaps and caps (and some swaptions) documented using the ISDA 2002 Master Agreement or a bespoke power purchase agreement (PPA).

2 The current mark cap price is A$14,100/MWh and market floor price is negative A$1000.

Although short-term hedges are relatively common, there has recently been an increased willingness for large electricity retailers to offer longer-term contracts to renewable generators to 31 December 2030. This is the date on which Australia's Renewable Energy Target (RET) scheme (and the renewable generator's right to create and trade large-scale generation certificates (LGCs) created under that scheme) closes.

Our insights

These longer-term contracts and the ability of renewable generators to create LGCs are highly significant for the bankability of new renewables projects. Although LGCs can be traded independently of the generator's electrical generation, retailers are often willing to offer a bundled price for "black" electricity and "green products" such as LGCs.

Given the number of policy proposals developed in response to recent developments in the NEM (discussed later in this article), there is a high probability of significant changes to the legal framework applying to generators, including the introduction of a generator reliability obligation (requiring intermittent renewable generators to pair with dispatchable energy sources such as battery storage or gas-fired generators) and new "green product" schemes.

The change in law clauses in PPAs must be sufficiently robust to properly allocate the risks and costs of these changes in law as between the generator and offtaker. PPAs should also deal with the likely ability of renewable generators to create new "green products" in the future, and in particular, whether the generator must sell those to the offtaker at zero cost (as part of a bundled price PPA).

Key regulators

As a market essentially created by subordinate legislation, the effective performance of the NEM relies on the interplay between a series of government bodies, including the following:

- Council of Australian Governments (COAG) Energy Council – comprising Commonwealth (i.e. federal), state and territory energy ministers, the COAG Energy Council provides a forum to initiate, develop and monitor the implementation of national energy policy reforms where co-operation is required between the Commonwealth and state and territory governments;
- Energy Security Board (ESB) – a body established by the COAG Energy Council to co-ordinate the implementation of the recommendations from the recently released Finkel Report (discussed later in this article) and to provide whole of system

oversight for energy security and reliability;

- Australian Electricity Market Operator (AEMO) – the body responsible for, among other things, electricity market functions (including the operation of the spot market and central dispatch process), NEM system operations and national transmission planning;
- Australian Energy Market Commission (AEMC) – the body responsible for making the Rules, which are the principal piece of subordinate legislation that governs the operation of the spot market and central dispatch processes, power system security, network expansions and planning and metering. The AEMC also advises the COAG Energy Council on energy reform;
- Australian Energy Regulator (AER) – which provides economic regulation of transmission and distribution network service providers and monitors compliance with the Rules; and
- other state and territory regulators (e.g. the Queensland Department of Energy and Water Supply) – which are responsible for administering other relevant electricity legislation which may contain other approval requirements (e.g. to obtain a generation authority under the Electricity Act 1994 (Qld)).

Our insights

The regulatory landscape of the Australian renewable energy market is complex, with regulators potentially adopting different solutions to complex problems or novel solutions presented by project proponents. Maintaining a good working relationship with each of the regulators interacting with generators on a day-to-day basis (AEMO, AER and State bodies) is critical to meeting project development time frames and when operating the project.

The Rules are a complex, technical and lengthy instrument which are often supported by guidelines developed by the AER and AEMO (e.g. the Network Service Provider Registration Exemption Guidelines). Regulators are generally willing to consider a project proponent's interpretation of the Rules in novel situations, but individual exemptions for a project proponent from any requirement of the Rules (as opposed to class exemptions set out in those Guidelines) in "grey areas" are often not forthcoming.

It is therefore important to understand the full regulatory (including exemption), technical and policy landscape to ensure that efficient, commercial and technically sound solutions are developed in new renewable energy projects.

Western Australia and Northern Territory markets

For completeness, we note the State of Western Australia and the Northern Territory operate separate electricity markets (e.g. Western Australia operates a capacity-based wholesale electricity market) to the NEM and are subject to significantly different regulatory frameworks and market structures. In addition, in contrast to the NEM, they have not been subject to impacts such as gas supply issues or reduced generation affecting wholesale prices.

Current state of the NEM

Generation composition

In 2015-16, the NEM was powered by the following fuels.[3]

Fuel source	Registered capacity	Output supply
Coal	52%	73%
Gas	19%	7%
Hydro	15%	10%
Wind	7.5%	6%
Solar	6.5%	4%

Recent pressure to move away from coal-fired power has been motivated by a goal to reduce Australia's carbon emissions, with the energy sector responsible for one-third of those emissions (mainly due to reliance on high emitting coal-fired generation). To achieve this, Australia has made an international commitment to reduce its total carbon emissions by 26-28 per cent below 2005 levels by 2030, and has also made national abatement commitments.

Australia's current national emissions reduction policy involves:

- the Commonwealth purchasing emissions reductions from businesses through an Emissions Reduction Fund; and
- requiring that the nation's largest emitters do not increase their emissions above business-as-usual levels and offset the reductions purchased.

3 AER State of the Energy Market Report 2017.

Significant interest in utility-scale solar PV facilities was recently kick-started by an A$86 million investment into the development of solar farms in the NEM by the Australian Renewable Energy Agency (ARENA) in its large-scale solar photovoltaics competitive funding round. ARENA was established to increase the competitiveness of renewable energy in Australia by funding projects that have met feasibility and commercialisation requirements, in exchange for knowledge sharing. ARENA has also recently committed to funding demand response pilot projects (with a total capacity of 200 MW).

Battery storage does not currently play a significant role in the NEM. However, the rapidly declining costs of battery technology and its ability to complement renewable generation has received significant interest in recent times. This is also coupled with the likely impact of reliability obligations that will be "paired with" variable renewable generation. For example, Tesla and Neoen (a French renewables company) recently completed construction of a 100 MW battery storage system to be paired with the Hornsdale Wind Farm in South Australia.

Our insights

We see battery storage playing an increased role in the NEM in the future, both when paired when renewable generators and when providing ancillary services to the system. However, there are significant regulatory and commercial challenges involved with retrofitting a battery storage system to an existing renewable generator.

Despite their goal of being technology-neutral, the Rules have not been written in a manner that facilitates the import and export of electricity to and from batteries in a "behind the meter" style arrangement. We expect further developments on this front and a number of Rule changes. Close attention will need to be paid by regulators and industry alike to ensure that battery storage is given the chance to fully participate in the NEM.

Challenges facing the market

As mentioned above, like other markets around the world, the NEM is facing a number of challenges, including:

- forecast flat demand over the next 20 years in most regions, in part due to increasingly efficient electrical appliances;
- the increased installation of distributed rooftop solar PV generation by both domestic and business/industrial customers and flow-on effects of this trend for network design and the legacy effect of State-based schemes that resulted in long-term high cost feed-in tariffs for the electricity exported from small-scale solar systems into the NEM – these schemes have been wound back but continue to impact on the market;
- an aging thermal baseload generation fleet that is increasingly being retired (e.g. Alinta closed the Northern Power Station in March 2016, Engie closed the 1,600 MW coal-fired Hazelwood Power Station in March 2017 and AGL has announced plans to close the 2,000 MW Liddell Power Station in 2022), without replacement by similar levels of baseload generation;
- the price of gas has risen significantly over the last two to three years, which reflects the shift in gas prices associated with the reduced availability of gas to the domestic market – this has not been assisted by several state-based moratoriums on new onshore gas exploration;

- the integration of utility-scale renewable generators (primarily wind and solar PV) and battery storage technology while maintaining sufficient levels of power system stability and security: the Australian regulatory system for transmission and distribution networks tends to encourage this to be considered on a connection by connection basis, rather than a system wide basis; and
- frequent changes to Federal government energy and climate change policies, coupled with State-based renewable energy targets that are significantly higher than those under the Federal government policies.

In particular, the rise of non-dispatchable variable generation renewable projects (which only generate while the wind is blowing or the sun is shining) has led to the NEM having a reduced capability to continue supplying electricity to consumers in the event of shocks to the network, such as the loss of transmission network assets during severe weather (as happened in the State of South Australia in September 2016, as discussed later in this article).

The challenges have also all led to a two to three year period of increasingly high wholesale power prices for residential and business consumers (after 10 years of relatively flat wholesale electricity prices). This has been particularly contentious and been the subject of extensive political commentary and action taken to encourage cost reductions in the wholesale market – including the Australian Competition and Consumer Commission (ACCC)

inquiry on retail electricity pricing,[4] and the action taken by the Queensland government to direct its state-owned generators to take action to reduce power prices.

We are now seeing large industrial consumers considering entering into corporate PPAs with generators to manage their exposure to high prices, while consumers are continuing to install rooftop solar PV to reduce the load they draw from the NEM (and consequently, their electricity bills).

Our insights

These challenges are not unique to Australia and are currently being experienced in a range of other advanced economies.

However, it is notable that these challenges are being experienced in a country with ample solar resources (Australia is a world leader in the adoption of rooftop solar PV), a booming LNG export market (but without concurrent increases in gas supplies, leading to a tightening gas market), and other high-quality natural resources (e.g. coal, gas and uranium) capable of fuelling a baseload generation fleet.

Unfortunately, there is no quick fix for these issues. State-based moratoriums on onshore gas exploration have meant the ability of gas-fired power stations to smooth the transition from a coal-fired nation to a renewable energy nation has been significantly diminished, at the expense of industry and consumers alike.

Renewable Energy Target as a driver for investment in renewable generation

A key driver for renewable energy investment in the NEM has also been the Commonwealth Government's RET. In 2015, this target was revised in a bipartisan agreement between the major political parties to be 33,000 GWh per annum of generation from renewable sources by 2020 (with lower targets ramping up to that figure in preceding years), being approximately 23.5 per cent of Australia's electricity generation. Until the bipartisan agreement on the RET, Australia had experienced a dearth of investment in renewable generation as ongoing policy debate created significant uncertainty for investors.

The RET is apportioned among retailers and wholesale energy purchasers in proportion to their total annual wholesale energy acquisitions. Liable entities meet their liability by acquiring LGCs that are created by accredited renewable energy generators for each MWh of electricity purchased, failing which they must pay a penalty of A$65/MWh (non-tax deductible) for each MWh that they fall short of.

Commentators have suggested that an additional 5,000 MW of renewable capacity (measured against 2015 installed capacity) will need to be installed in Australia by 2020 in order to meet this target.

4 The preliminary report was issued in September 2017 and final report to be issued in 2018.

In addition, State and territory renewable energy target schemes range from support for the Commonwealth RET (e.g. in New South Wales) to policy targets (e.g. 50 per cent by 2030 in Queensland) and legislated targets (e.g. 100 per cent by 2020 in the Australian Capital Territory). Both Victoria (650 MW) and Queensland (400 MW) are currently conducting reverse auctions for long-term offtake contracts to further develop new renewable generation.

Our insights

The RET scheme has undoubtedly been successful in increasing the levels of renewable energy generation in Australia since its introduction in 2001. However, we see liable entities offering flat or declining prices for LGCs after 2020, being the date on which the RET will be fixed at 33,000 GWh until 31 December 2030.

This means that a new mechanism will be required after 2020 if generators are to derive a secondary revenue stream from creating renewable energy. One such potential mechanism is the National Energy Guarantee, which may involve a trading scheme among retailers (as discussed later in this article).

However, with the increasing reduction in costs of developing renewable generators and sustained high wholesale electricity prices, we think that renewable generators could become cost-competitive with baseload generators for the first time (so as to not require the support of a certificate scheme in order to be economical and profitable to operate). As a result, notwithstanding proposed policy changes and the variable nature of the generation, we expect to see increased deployment of renewable generators over other technologies (including fossil fuel technology).

Our insights: Recent developments in the NEM

South Australian Black System Event

The State of South Australia has become increasingly reliant on renewable energy. In addition, the closure of a coal-fired power station at Port Augusta meant that limited dispatchable, gas-fired generation capacity was available in the State in September 2016.

On 28 September 2016 South Australia experienced a "black system" event – the first state-wide blackout since the creation of the NEM. The black system event arose as a consequence of extreme weather which caused significant damage to transmission network infrastructure, creating voltage instability.

That instability tripped a number of wind farms offline, and caused several others to reduce output, and the AC Heywood Interconnector between South Australia and Victoria (used to transfer electricity across state lines/NEM regions) to exceed its operating limits and also trip offline, leading to a black system event affecting the entire state (approximately 850,000 consumers).

The black system event sparked a national conversation concerning the security and reliability of the NEM and the place of renewable energy in the Australian generation mix. It culminated in the commissioning of an Independent Review into the Future Security of the NEM (Finkel Report) by the COAG Energy Council by an expert panel led by Australian Chief Scientist Dr Alan Finkel AO.

The Finkel Report

The Finkel Report was released in July 2017. It sets out a number of recommendations which seek to deliver four key outcomes: increased security, future reliability, rewarding consumers and lowering carbon emissions. Its recommendations include:

- the adoption of a clean energy target (CET) to drive investment in low emissions generators across Australia;
- the introduction of a package of energy security obligations, including inertia requirements in each region or sub-region of the NEM, generator fast frequency response capabilities, and a wholesale update to connection standards;
- a shift towards a market-based mechanism for procuring fast frequency response services where there is a demonstrated benefit in doing so;
- the implementation of a generator-reliability obligation to ensure that each region of the NEM retains adequate dispatchable capacity; and
- giving AEMO a "last resort" power to procure or enter into commercial arrangements to have gas-fired generators available to maintain reliable supply (but without a broader shift to a capacity market).

Our insights

The Finkel Report was widely seen as an opportunity to reset Australia's often fractious energy and emissions policy debate. Notably, it did not recommend any major reform to the operation of the wholesale electricity market. Nor did it contain significant detail on a number of items that we expected to feature significantly given the surrounding press coverage and political environment (e.g. in relation to the adoption of five-minute trading intervals, which was nevertheless separately progressed by the AEMC).

However, with a number of recommendations also requiring further analysis to be performed and work to be done by the AEMC and AEMO, the Finkel Report was very much a starting point and a blueprint for future reform, rather than a complete solution to the challenges facing the NEM.

The Clean Energy Target becomes the National Energy Guarantee

Chief among the Finkel Report's recommendations was the introduction of a CET by 2020. The CET was intended to assist Australia in reaching its Paris COP21 emissions reduction target of 28 per cent by 2030 based on 2005 levels. The CET was expected to operate in a similar manner to the existing RET scheme and was considered a pragmatic policy compromise given previous statements by the Australian Prime Minister ruling out the introduction of an emissions intensity scheme or an emissions trading scheme (reflecting the fractious energy policy debates experienced in Australia over the past decade).

However, on 17 October 2017, the Commonwealth Government announced that it would introduce a National Energy Guarantee (NEG) in place of the CET. The NEG would consist of an obligation on electricity retailers to meet the following guarantees:

- a reliability guarantee to deliver certain levels of dispatchable generation capacity, as determined by the AEMC and AEMO; and
- an emission guarantee to deliver emissions reductions, as determined by the Commonwealth Government and enforced by the AER.

In modelling prepared to support the NEG, the Energy Security Board found that adopting the NEG would lead to a fall in wholesale electricity prices by 23 per cent by 2023 (being 30 per cent lower than in a business-as-usual case) and the renewables share of total output by 2030 would be approximately 36 per cent, of which approximately 28 per cent would be intermittent generation.

At a meeting of the COAG Energy Council on 24 November 2017, the Commonwealth and a majority of the States/Territories voted to support further extensive work on the design of the NEG, including consultation in early 2018. The COAG Energy Council is due to next consider the design of the NEG in April 2018.

Our insights

The adoption of the NEG by the Commonwealth Government and the States would represent a significant breakthrough after a decade of significant debate on Australia's energy and emissions policy. However, the NEG is still subject to detailed design work, final agreement in COAG, and adoption in legislation. This process may yet prove to be challenging as the current governments of South Australia, Queensland and the Australian Capital Territory appear to favour an emissions intensity scheme or CET.

The mechanism that has been proposed for the implementation of the NEG contemplates the retailers relying on the energy contracts between the retailers and the generators. We have concerns about how this will operate given the extent of the derivative market in the NEM.

Previous emissions policy uncertainty, associated in particular with a price on carbon introduced by the Clean Energy Act 2011 (Cth) (now repealed) and the precise MWh target for renewable generation under the RET scheme, all led to a significant decline in investment in new renewable energy facilities. It will be important for industry to participate fully in the consultation to be undertaken by the ESB on the design of the NEG to ensure it provides the certainty required to underpin significant investment in new generation.

In summary

This article provides a brief overview of the NEM, the challenges it faces, and the impact of recent events on its future. Innovative technologies and new policies offer a path forward from the current state of play, which has been marked by high power prices, limited but growing investment in renewable generation and difficult policy debates. However, with increasing interest and levels of investment in utility-scale renewable facilities and battery storage in the last 12-18 months, these challenges are by no means insurmountable, and it is hoped that the awakening to the need for policy certainty will allow Australia to exploit its solar and wind resources.

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WASTE-TO-WEALTH INITIATIVES:

Waste-to-energy projects

by Michael Harrison, Richard Guit, Anthony Johnson and Nick Stalbow

Waste-to-energy (WtE) is a generic description for a process that takes waste, and combusts that waste to produce energy. The energy produced can take the form of electricity or steam (or both). WtE projects use a variety of types of waste and a range of combustion processes. They divert waste from landfill to generate low-emission electricity and are environmentally and economically sustainable.

This article considers the key revenue streams from WtE projects and the key risks which need to be addressed – either through government policy or contractual mechanisms – to make WtE projects economically viable.

In our first article, "Waste-to-Wealth Initiatives – Waste Projects",[1] we provided an overview of waste projects, including WtE. In response to the positive feedback which this article received, we have taken the decision to devote three further articles to WtE. In our next article, we will consider specific policy settings in Asia Pacific, Europe and the Americas for WtE projects and the final article of the series will consider waste processing and treatment using other methodologies, including mechanical and biological treatment, material recovery, and organics recovery and processing.

What do we mean by waste-to-energy?

Waste-to-energy is a broad term (with the same meaning as "Energy-from-Waste"). We use the term to mean any process or treatment that takes waste and converts it into energy (for the primary purpose of producing electricity – or electricity and heat – for sale) using a thermal or biological technology. A variety of "processes" are used, each of which is likely to have its own proprietary and intellectual property rights. Each of these processes tends to be referred to as a "technology".

Irrespective of the technology used, the same two outcomes result:

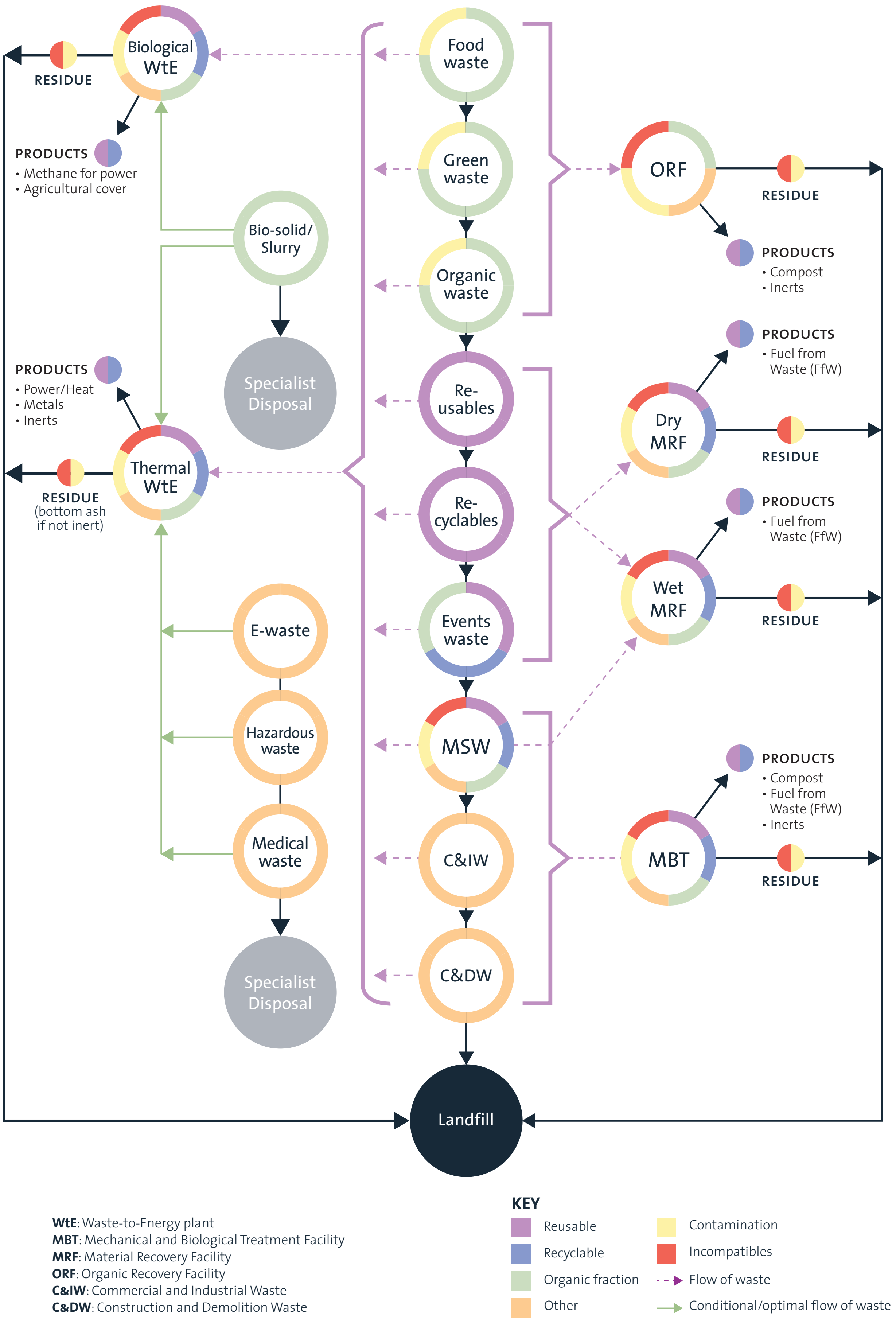
(a) reduction in the mass and volume of waste disposed of to landfill; and
(b) production of energy from the non-reusable and non-recyclable fractions of the waste stream.

Key waste streams

Waste is characterised in a variety of ways, with industry and regulators using common descriptions. These are: Municipal Solid Waste (MSW),[2] Commercial and Industrial Waste (C&IW),[3] onstruction and Demolition Waste (C&DW),[4] Events Waste,[5] Green Waste,[6] Organic Waste[7] (including bagasse[8] and biomass[9]), Food Waste,[10] Hazardous Waste,[11] E-Waste,[12] Medical Waste,[13] and Bio-solid and Slurry Waste.[14] Subcategories exist too: for example, MSW can be sorted in people's homes which enables recyclable waste to be separated out.

Figure 1 shows the various categories of waste types and which waste processes can be used for each type: Biological WtE and Thermal WtE, Organic Recovery and Treatment Facilities (ORF), Material Recovery Facilities (wet and dry MRFs) and Mechanical and Biological Treatment Facilities (MBT).

Figure 1: Waste types and how they may be treated



WtE: Waste-to-Energy plant
MBT: Mechanical and Biological Treatment Facility
MRF: Material Recovery Facility
ORF: Organic Recovery Facility
C&IW: Commercial and Industrial Waste
C&DW: Construction and Demolition Waste

WtE "technologies"

Thermal or Biological technologies

In broad terms, the technologies used to generate energy from waste take two forms:[15] biological[16] and thermal.[17] "Biological" technologies use anaerobic digestion (AD), which requires a consistent type of organic waste and a highly controlled environment in which to produce and combust methane. The waste streams suitable for AD are limited (as noted in Figure 1 above) to Food Waste and Bio-solid and Slurry Waste. The overall energy output from AD is low in comparison to thermal technologies. Therefore, large-scale WtE projects predominantly use "thermal" technologies. These include:

- combustion of waste;
- gasification of waste[18] (including close-coupled gasification, slagging and plasma); and
- pyrolysis of waste.[19]

Mass combustion

Combustion is the globally prevalent WtE technology. As a general statement, moving grate[20] and fluidised bed[21] technologies are the main combustion technologies used, with both having low emissions and high thermal efficiency.[22]

A WtE project using combustion technology, and taking large volumes of waste without any form of prior systemised sorting, separation or treatment is referred to as a "mass burn" or "mass combustion" WtE project. Some combustion WtE projects take waste after it has previously been sorted into different streams (perhaps with recyclable items removed) or shredded in some way: these are not mass burn projects. Mass burn does not: pre-sort to derive reusables or recyclables from the waste stream, blend or mix waste (other than by crane in the bunker), shred waste in preparation for processing and treatment, nor use RDF.[23]

Gasification

Gasification involves deriving synthesis gas (syngas) from waste in low oxygen, high temperature chambers, and then combusting the syngas.[24] The use of gasification as a WtE technology continues to be developed for large-scale WtE. In Japan, for example, there are examples of WtE projects using some form of gasification.

Pyrolysis

Pyrolysis involves deriving gas (and char or tar) from the sublimation of waste at high temperatures in the absence of oxygen, with the gas then being combusted. While pyrolysis WtE plants do exist, they are not as prevalent as mass combustion or gasification plants.

Sorting or treating waste before it is combusted

In jurisdictions with more developed waste collection systems, MSW is collected from homes and businesses using single or multiple bins, including using dedicated "recycling" and green bins (and perhaps food bins). The use of multiple bins is often referred to as "source separation" or "source segregation". Depending on the waste collection system, separated fractions of the waste stream can then be delivered to different waste projects; for example: recyclables to a dry MRF; organics to an ORF; and non-segregated MSW to an MBT facility or a WtE facility.

In addition to source separation, and again depending on the waste collection system being used, waste may be "pre-sorted" or "pre-treated" after collection.[25] An MBT facility or MRF can be co-located with, or close to, a WtE facility (including being connected to it) or may be geographically separate, with a transport solution in place to deliver the pre-sorted waste to the facility.

The Waste Management Hierarchy (see **Figure 2**) promotes source separation or pre-sorting as a preferred policy outcome. While adding an MRF or MBT requires additional capital expenditure (thereby increasing the cost of a WtE project), it provides an outcome consistent with the Waste Management Hierarchy. This is particularly the case if waste is not source-separated in an effective manner or, indeed, at all (typically, because there is no recycling bin or because the bin is not used), in which case there may be a desire for pre-sorting at the WtE facility.

Whether or not an MRF or MBT is used will be a function of the additional cost[26] and the revenue expectations from recovery of reusables and recyclables by pre-sorting. The revenue expected to be earned is a function of waste composition (critically, the proportion of the waste stream comprising reuseables and recyclables), and the market for them. Recycling markets around the world have fluctuated immensely over the past decade and (in some cases) market appetite has disappeared.[27] This can make revenue forecasting from the sale of recyclables difficult.

Procurement methodology

Variety of procurement methods

As noted in our "Waste-to-Wealth Initiatives – Waste Projects" article, WtE projects can be procured using a variety of different procurement methods. The simplest method is direct procurement under a D&C[28] or EPC[29] contract, with the procuring municipality (following operational completion of the WtE project) either operating the WtE project itself or contracting with the private sector to provide operation and maintenance services under an O&M[30] contract. This direct procurement model is the prevalent model in China.

For the purposes of this article, we are assuming that the municipality is not procuring the WtE project directly under a D&C/EPC contract and operating and maintaining the facility by itself or under an O&M contract, but is instead contracting with the private sector to procure the WtE project under a BOO,[31] BOOT,[32] DBFOM[33] (or DBOM), or PPP[34] model.

Affordability for municipalities

A WtE project provides a waste processing service to municipalities. The affordability of such services compared to other forms of waste projects (or landfill) will be an overarching consideration for such municipalities. Affordability is a function of competing calls on the municipal budget. Therefore, the ability of the municipality to charge its residents for services, or to obtain funding from other sources, is an important consideration.

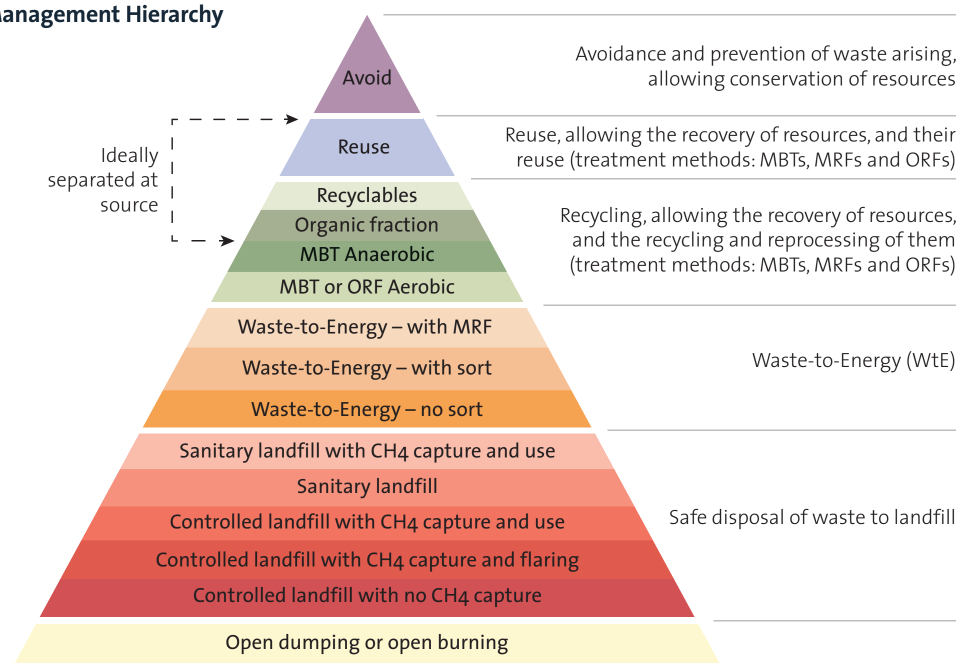
In some jurisdictions, municipal budgets have been insufficient to support waste projects, so other government entities have had to implement policies to allow WtE projects to be developed. Examples of such policies include the introduction of a feed-in-tariff (FiT) regime[35] or a mandatory renewable energy requirement under which participants in the electricity industry are mandated to pay a FiT for renewable energy (at a prescribed price) or to source a percentage of their electricity requirements from renewable energy sources.

Project sponsor economics

For the sponsor of a WtE project (as well as the equity investors and, if project financed, the debt providers), understanding the source and amount of both revenue and costs (and, as such, net revenue) and the risks associated with generating that revenue and incurring those costs is critical. As we consider in detail below, the revenue stream from a WtE project is a function of the unit charge (per tonne or per MWh) and the quantity of waste delivered and electricity generated (and, as such, net revenue is a function of revenue less operating costs (including insurance), the cost of servicing shareholder loans and, if project financed,[36] the cost of servicing loans from debt providers and the repayment of interest).

The greater the certainty of an assured revenue stream from a creditworthy municipality or private sector counterparty (as a supplier of waste or an off-taker of power, or both), then the larger the debt sizing can be, and the higher the gearing.

Figure 2: The Waste Management Hierarchy



Key revenue streams

General background

As a general statement, there are two primary sources of revenue for WtE projects:

Primary sources of revenue	Approximate breakdown (%)	Relevant factors
Fee for processing waste at WtE plant (**Gate Fee**) (usually expressed in a unit rate per tonne)	66.6	Gate Fee must be affordable to municipalities (or private sector supplier) and lower (on a like-for-like basis) than landfill fees payable for the same waste
Payment for sale of energy (electricity or steam, or both) (**Offtake Revenue**)	33.3	Power needs to be competitively priced or FiTs need to be certain (as to amount and term). Electricity can be sold into a "market" or to specific users

The above table is deliberately simplistic. In some jurisdictions, Offtake Revenue (typically through a FiT regime) is the only form of revenue, or it may generate a higher proportion of the revenue than the Gate Fee.

There may also be other revenue sources which fluctuate or which depend on the location and characteristics of the WtE plant. Debt financiers may discount, or even disregard, these other sources of revenue in the financial model for the purposes of sizing debt. Examples include:

Other revenue sources	Relevant factors
Metals recovered from the waste stream (both pre- and post-thermal processing)	Depends on composition of the waste delivered to the plant, the particular technology's ability to recover metals and the price for recovered metals in the local market
Use of ash from combustion (bottom ash) in road base, cement or ceramic production[37]	Usually the bottom ash starts as a cost liability (as it must be landfilled) unless and until it has been tested and proven as inert and safe[38]
Renewable or green benefits (e.g. FiTs for renewable projects, tradeable renewable certificates issued for being a renewable generator or "embedded benefits" from avoided transmission costs)	Local regulatory environment for producing low carbon energy, price adjustments under relevant green subsidy scheme (e.g. indexation, price degression, price increases for certain events) and proportion of energy eligible for support (e.g. based on biogenic vs. fossil fuel content of waste)

Contracted and Merchant WtE Projects for supply of waste

In broad terms, WtE projects are developed as either:

- **Contracted WtE Projects**: under which the project sponsor contracts directly with a municipality or a number of municipalities, and the municipality/each municipality agrees to deliver waste for a long-term period, to pay a Gate Fee for the supply of the waste to the facility (or possibly not if the WtE project will earn sufficient revenue from energy sales), and to deliver waste on a firm basis; or
- **Merchant WtE Projects**: under which the project sponsor contracts with multiple non-municipal parties for the supply of waste to the WtE project (typically with waste supply contracts being for varying periods of time), with each supplier of waste paying a Gate Fee.

Whatever the ratio of Gate Fees to Offtake Revenue, the project sponsors will always be keen to match the time frames of a long-term obligation to supply all (or a high proportion of) the energy capacity of the WtE project and a long-term waste supply contract (or contracts), possibly contracting with the same entity as both a supplier of waste and an off-taker of energy.

Whether a WtE project is a Contracted or a Merchant WtE Project, energy (in the form of electricity generated and heat produced) is likely to be sold under a PPA (or a PPA and Steam Supply Agreement if heat as well as electricity is produced) at a price specified in the PPA, or into a market for electricity[39] or to energy companies under, and at a price determined by, a FiT regime.

Location of WtE project

The geographical location of a WtE project will have an impact on its economics in two key respects. First, it will determine the sources, quantity and composition of waste supplied over time. Secondly, it will enable the stakeholders who are developing the project to consider and therefore determine (and possibly guard against) substitutability risk: i.e the risk that another waste project will substitute the service provided by the WtE project. This is a critical risk for Merchant WtE Projects as, irrespective of the basis on which energy is sold, waste is required in order to produce energy (and hence revenue for the project).

The substitutability risk of a Contracted WtE Project is a function of: (i) the catchment area of the municipality and the power (or statutory duty) of the municipality to collect waste from within that area and deliver it to the WtE project; and (ii) the terms on which the municipality is prepared to contract, including assurances that sufficient waste will be delivered to the WtE project. The substitutability risk on a Contracted WtE Project is likely to be best characterised as low or negligible if the relevant contract addresses volume risk effectively. Of course, the composition of waste arising in the catchment area and ensuring that municipalities are prevented from substituting that waste is a different matter altogether, and is a key "composition risk" issue, which we discuss further below.

The substitutability risk of a Merchant WtE Project is not a function of the catchment area of the municipality. Instead, the risk is whether the service being provided by the Merchant WtE Project (or a substitute for that service) can be provided by another provider of waste processing, treatment or disposal services at a lower price (or possibly at no cost in some jurisdictions). Whether a substitute entity is able to provide the service at a lower price will be a function of the cost of the service being provided by the Merchant WtE Project (compared to any substitute service, including landfill and transportation costs), the quantity and composition of waste available to be contracted (and in fact contracted) to the Merchant WtE Project, the contract term of the waste supply contracts, the Gate Fee (if any) and the Offtake Revenue.

Policy settings

Irrespective of whether a WtE plant is Contracted or Merchant, it is unlikely to be economically feasible or sustainable without the right policy settings.

In most jurisdictions where WtE projects are developed, policy settings inform and are vital to (and, in some cases, are the primary drivers for) the sustainability and certainty/ security of revenue streams: i.e. ensuring that the Gate Fee is lower than landfill costs, and (perhaps) ensuring electricity pricing can compete with non-renewable energy sources. The policy settings "close the gap" to allow WtE projects to compete on price on a like-for-like basis with landfill and other energy sources.

The form and substance of policy settings will differ between individual jurisdictions and may include:

Environmental levers		
Environmental prohibitions prohibiting ocean dumping, open dumping and landfilling certain waste streams	**Environmental standards for landfill** to address contamination, leeching into the water table and methane emissions	**Environmental standards on emissions** to limit emissions, contamination and residue disposal for waste projects
Co-ordinated approval and licensing processes to allow timely and effective development	**Licensing for expansion of projects over time** to take advantage of increased waste arising in specific areas	**Classification of waste** to regulate how and where waste may be disposed of and to license receipt of waste
Disposal of Hazardous Waste, Medical Waste and E-Waste to divert from specialist disposal to provide additional feedstock	**Specification of residual material** to regulate how and where residue is disposed of	**Enforcement of approvals and regulation** to settle the economics of the project, including whether the project will take waste arising risk
CONSISTENCY OF REGULATION AND ENFORCEMENT: Unless regulations are consistent, and enforced across a jurisdiction, market forces will find a way to dispose of waste at the least cost and greatest profit, even in jurisdictions with developed waste collection systems.		
Municipality powers and levers, and enforcement		
Duty or power to collect waste, which may be an existing legislative outcome or require legislation if waste policy is less developed	**Power to recover payment** for the cost of collecting waste generally and for specific waste streams	**Power to contract** with the private sector to develop waste projects, including power to contract for longer term projects
Levelling the playing field		
Waste and landfill levies to incentivise more environmentally beneficial waste projects on a consistent basis across jurisdictions	**Gap funding** including government grants and subsidies to achieve environmentally beneficial outcomes using WtE projects	**Revenue from MSW processing and treatment**, including Gate Fees because municipalities chose WtE over landfill
Revenue opportunities		
Revenue from renewable energy generation under power purchase agreements, into market, under contracts for differences or the feed-in-tariff regime[40]	**Sale of power and heat to co-located businesses** within development zones to promote smaller refining and paper businesses or to provide district heating	**Allowing broader revenue opportunities** including the development of land to enable sponsors to cross-subsidise WtE projects and other revenue streams
Revenue from particular waste generators such as C&IW and C&DW, and particular waste streams, such as from shopping centres or malls	**Revenue from landfills** to manage available landfill capacity over time, e.g. requiring WtE project to take landfilled waste at a higher Gate Fee	**Revenue from government-sourced waste** where municipalities are able and willing to pay, which may result in higher Gate Fees
Large power users pay more for WtE energy to close revenue gap, but preventing material increase in power prices for all users	**Government pays higher price for WtE energy** to close revenue gap, but preventing material increase in power prices for all users	**Revenue from reusable and recycled products** where there exists a sophisticated separation at source or pre-sort regime
Change in law		
The law is needed to "level the playing field" to allow the development of and to regulate WtE projects. Therefore, the risk of change in law is important to the private sector: it informs thinking as to how change in law risks need to be addressed contractually. Project sponsors and financiers will want economics that are sustainable on a long-term basis, assuming consistent regulation and enforcement and where underlying costs and revenue remain relatively predictable. Every contract will need to address changes in law affecting the relative costs and revenue of the WtE project.		

Key risks

All WtE projects are different, but key risks remain the same

As will be clear from the above, there is no universal blueprint for WtE projects. The "size and shape" of each WtE project will be influenced by a number of factors including:

- the identity of the municipality (or private sector supplier) procuring the services from the WtE project and, critically, the affordability of those services to the municipality;
- the terms (including the price) on which the counterparty for services wants to contract and its preparedness to provide security (e.g. parent company guarantees, letters of credit) if required by sponsors or financiers to support the counterparty's contractual obligations;
- current and projected waste arisings and the historic and projected composition of such waste;
- the location of the project (including sources of additional waste within a transportation net revenue accretive catchment area);
- the opportunities (if any) for "embedded" power offtake;
- the shareholder structure for the project and the proposed approach to financing; and
- the policy and legal settings directly or indirectly relevant to the project and its forecast costs and revenues.

While the context of each WtE project is unique, there are certain key risks that need to be assessed on all WtE projects. Depending on the contractual arrangements (and risk allocation between the contractual counterparties including municipalities and private sector waste suppliers), these risks may have an impact on gross and net revenue (including as a result of revenue shortfall, increased costs, and liability for not accepting waste or for not supplying electricity). Two key risks relate to the quantity and quality of the waste material being supplied to the WtE facility, which we will now consider in detail.

Quantity of waste: volume risk

Broadly speaking, waste supply contracts require the municipality (or private sector supplier) either to deliver a stated quantity of waste or to deliver all waste arising within its area (or from stated activities within a stated area). Under both a "stated quantity" and a "waste arising" contract, sufficient waste might not be delivered because the municipality (or private sector supplier) has the required quantity or sufficient waste arisings, but does not deliver in accordance with the contract (so-called "Non-delivery Risk"). Under a waste arising contract, volume risk also arises if the quantity of waste arising within the stated area is less than anticipated for reasons that are not attributed to the action/inaction of the relevant supplier (so-called "Waste Arising Risk").

Volume risk: risk allocation:

(a) Non-delivery Risk: Under both stated quantity contracts and waste arising contracts, municipalities (and private sector suppliers) will assume the obligation to deliver the stated quantity of waste (whether by reference to minimum quantity or all waste that arises), and agree to compensate the sponsors if this is not delivered.

(b) Volume risk on stated quantity contract: Under a stated quantity contract, the municipality (or private sector supplier) will take volume risk on the basis of being required to pay for the minimum quantity of waste it has agreed to deliver (whether or not it delivers that quantity), typically using a "deliver-or-pay" regime.

(c) Volume risk on waste arising contract: Under a waste arising contract, the municipality (or private sector supplier) will want the WtE project to take and to process all waste arising within the stated area (or from the stated activities) for the term of the contract, but is likely not to want to have to pay to reserve capacity in the WtE plant to allow for a growth in waste arisings. For the project sponsor, volume risk on a waste arising contract has two elements: (i) certainty of a minimum quantity of waste to be delivered (and compensation if that quantity is not delivered or the relevant supplier delivers the minimum quantity but directs excess quantities to other facilities/landfill); and (ii) if the municipality (or private sector supplier) is not paying to reserve capacity, certainty of a maximum quantity of waste that may be delivered. These risks are dealt with in different ways across and within jurisdictions.

How to address volume risk?

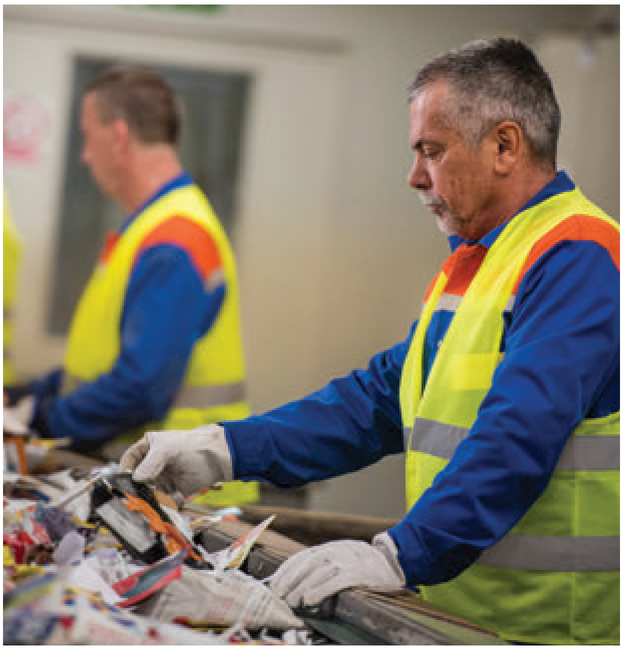
We describe (at a high level) in the table below how volume risk may be addressed.

Non-delivery Risk	Waste Arising Risk
A deliver-or-pay (or "put-or-pay") obligation is used: if the municipality does not deliver a stated quantity of waste (whether or not it has such waste), it must pay as if it had	**Increasing per tonne charge**: if the quantity of waste arising is less than anticipated the unit cost per tonne is adjusted and the Gate Fee revenue is thereby maintained
An exclusive and sole obligation to deliver: if the municipality does not deliver all waste arisings, it must pay the Gate Fee (plus, potentially, other compensation, in each case as pre-agreed damages) as if it had	**Assumed waste arisings**: if an assumed percentage (typically 90 per cent) of historical waste arisings or project usage capacity is not delivered (floor), the Gate Fee is payable by reference to the floor
An exclusive and sole obligation to deliver with right to claim general damages: if the municipality does not deliver all waste arisings, it is in breach of contract, not as pre-agreed damages	**WtE project to source waste from other sources**: project sponsor entitled (and possibly some level of obligation) to make up shortfall in waste arisings, with increased costs reimbursed

Offtake Revenue is affected by non-delivery of waste and waste arising shortfalls. While the project sponsor may seek to impose a liability on the municipality (or private sector supplier) for loss of

Offtake Revenue in different scenarios (e.g. non-delivery of a stated minimum quantity of waste), it is possible that the municipality (or private sector supplier) will resist such liability.

Depending on the proportion of gross revenue derived from Offtake Revenue, the impact on a project sponsor of loss of Offtake Revenue will differ, and therefore it is critical that, both contractually and through practical mitigation strategies, the project sponsor is able to source additional waste and to recover the cost of doing so from the relevant municipality/private sector supplier to the extent that such municipality/private sector supplier has failed to comply with its supply obligations. Developing these mitigation strategies is something that the project sponsor will be doing in any event because it will need to understand how rejection of incompatible waste[41] and the delivery of an insufficient volume of waste can be mitigated either by delivery of compatible waste from another source at the cost of the municipality (or the private sector supplier) or by itself sourcing compatible waste from another source at its own cost to ensure that sufficient waste is delivered to the WtE project.



Quality of waste: waste composition risk

(a) Incompatibility risk

The composition of waste needs to be understood and addressed in the contractual relationship between the municipality (or the private sector supplier) and the project sponsor. The project sponsor will want to be able to reject any waste that it is not licensed to take (so that it complies with the law) or that is not compatible with the technology used, i.e. so-called incompatible waste.

For these purposes, the contract between the municipality (or private sector supplier) and the project sponsor will need to clearly define compatible and incompatible waste or so-called "on-spec" and "off-spec" waste (Compatible Waste and Incompatible Waste). Incompatibility risk becomes a revenue risk if the WtE project is not provided with sufficient volumes of Compatible Waste from the municipality (or the private sector supplier), or if it is not able to source sufficient volumes of Compatible Waste from another source on a timely basis (Other Source Waste).

(b) CV risk

Even where waste is consistent with the WtE project's licence and is compatible with the technology used at the WtE project, the composition of the waste delivered will be variable and, critically, the net calorific value (NCV) of such waste will vary. As noted in the "Waste-to-Wealth Initiatives – Waste Projects" article, there can be a considerable range in the CV of MSW across, and within, jurisdictions. Each WtE project and its financial model is designed to reflect an assumed CV of waste delivered, processed and treated (CV bandwidth).

If the NCV of waste is above or below the CV bandwidth, the capacity of the WtE project to process and treat waste is affected, as is its thermal efficiency. CV risk is therefore a revenue risk to the extent that thermal capacity is reduced by the delivery of waste with an NCV outside the CV bandwidth, both in terms of the quantity of waste capable of being processed (affecting the number of tonnes in respect of which the WtE project receives the Gate Fee), and the number of MWh of electricity generated and the quantity of heat produced (which is the basis on which the WtE project is paid under the PPA, contract for differences or FiT). Furthermore, if NCV impacts thermal capacity of the WtE plant this may result in the project sponsor being liable under a PPA or contract for differences if the WtE project does not deliver the quantity of contracted energy to the off-taker.

Contractual options for addressing risk of change in CV

General CV fluctuation: if CV is outside the bandwidth, variable Gate Fee payable (if the relevant supplier accepts CV risk) or project sponsor required to source waste of required CV at its own cost to bring average within bandwidth	**CV change caused by municipality, e.g. by changing collection arrangements, including bin structure**: adjustment to Gate Fee to reflect reduction in thermal capacity	**CV change caused by change in law**: adjustment in Gate Fee, but municipality may seek to place this risk with project sponsor if not a change in law which is specific to the facility/type of facility/type of services
CV change caused by change in composition over time: WtE project likely to be expected to take this risk and therefore source waste of required CV at its own cost to bring average within bandwidth	**CV risk in Other Source Waste delivered by municipality**: WtE project likely to be expected to take risk, other than to source required quantity	**CV risk in Other Source Waste sourced by WtE project**: WtE project likely to be expected to take risk, unless such risk can be transferred to the supplier of the Other Source Waste

As with volume risk, there are a number of ways in which CV risk may be addressed contractually. The way in which a change in CV risk is addressed will tend to depend on the cause of the change in composition, the effect of that change on NCV and whether or not the municipality (or the private sector supplier) accepts CV risk.

Conclusion

WtE projects provide a compelling alternative to landfill: as Figure 1 illustrates, WtE projects are able to process the broadest range of waste types of any waste project. The economic viability of WtE projects is, however, dependent on policy settings that allow WtE projects to compete on a like-for-like basis with landfill, and effective contractual mechanisms that address key risks, critically those relating to waste volume and waste composition. Although each WtE project is unique, across the globe we have seen policy settings emerge, and applied as best suits each jurisdiction, and a range of contractual mechanisms develop to address key risks. The range of contractual mechanisms is responsive to each jurisdiction, and its policy settings, and specific features of each WtE project and the needs of its sponsors, financiers and waste suppliers.

In our next article, we will consider the policy settings in countries across Asia, Europe and the Americas. In so doing, we will outline how policies can be used effectively to underpin the sustainable viability of WtE projects.

Endnotes

1 See the March 2017 issue (Issue 9) of InfraRead and the April 2017 issue (Issue 18) of EnergySource.

2 Municipal Solid Waste is waste arising from human activities in urban environments (other than sewage and waste water).

3 Commercial and Industrial Waste is waste arising from commercial and industrial premises.

4 Construction and Demolition Waste is waste arising from construction and demolition work.

5 Events Waste is waste arising from entertainment and public events within municipalities, including music concerts and festivals, parades and sports events.

6 Green Waste is organic material from domestic "green" bins and the activities of municipalities (typically, parks and gardens, and lopping and topping of trees).

7 Organic Waste is a generic term for any waste that arises from the human management of flora, including agricultural, forestry and husbandry.

8 Bagasse is organic material arising from sugar cane or sorghum production.

9 Biomass is organic material arising from agricultural, forestry and husbandry activities.

10 Food Waste is organic material arising from commercial or domestic food preparation, which is increasingly being separated at source by households and commercial food outlets.

11 Hazardous Waste is waste that is potentially harmful to human health, animals, plants or the environment. Characteristics may include that the waste is explosive, flammable, poisonous, toxic, exotoxic or infectious, including hydrocarbon/water mixtures and wastes containing certain compounds such as zinc, lead and asbestos.

12 E-Waste is electronic waste including mobile phones, computers and other electronic appliances. Given the high rate of technological advancement and consumption of electronic goods, E-Waste is an ever-growing fraction of the waste stream.

13 Medical Waste is a generic term for waste arising from medical and pharmaceutical activities.

14 Bio-solid and Slurry Waste is human and animal waste matter derived from waste water processing or agricultural collection. This may be used in Biological WtE projects or in Thermal WtE projects to balance Net Calorific Value (NCV) and to maintain thermal capacity.

15 Arguably there is a third form of WtE Thermal technology, namely methane collection from existing landfill, and its subsequent combustion of methane to derive energy. Our view is that methane collection and combustion is better considered as part of a landfill strategy, rather than as a WtE project.

16 Biological processing and treatment involves anaerobic digestion (AD) and requires waste streams that are wet and of reasonably consistent composition (for example, Food Waste; Bio-solid and Slurry Waste). AD is not suitable for the processing and treatment of MSW, C&IW, C&DW or Events Waste.

17 Combustion, gasification and pyrolysis are technologies which process and treat waste at high temperatures. The temperatures and oxygen levels differ for each technology.
18 Gasification of MSW occurs within a temperature range of 300 to 760 degrees Celsius.
19 Pyrolysis involves subjecting MSW to a temperature range of between 2,700 and 11,000 degrees Celsius to sublimate organic matter in the absence of oxygen. Pyrolysis differs from gasification in that gasification (including plasma) reduces the oxygen content of the feedstock while pyrolysis sublimates organic matter in the absence of oxygen.
20 There are four main types of moving grate technology: forward reciprocating, reverse reciprocating, roller and horizontal. A detailed consideration of each type is beyond the scope of this article.
21 There are three main types of fluidised bed reactor technologies: bubbling, circulating, and revolving. Again, a detailed consideration of each type is beyond the scope of this article.
22 Leading companies using combustion technology include Hitachi Zosen Inova, Martin GmbH, Keppel Seghers, Wheelabrator Technologies, China Everbright International, Babcock and Wilcox/B&W Vølund, and CNIM.
23 As noted in the "Waste-to-Wealth Initiatives – Waste Projects" article, RDF is refuse-derived fuel, sometimes referred to as process-engineered fuel (PEF) or solid or specified recovered fuel (SRF). Each of these fuels has limited/negligible organic content and is sometimes used to fire industrial facilities, including cement kilns.
24 Leading companies using gasification technology include Covanta, Hyundai, Viridor, Fortum, Mitsubishi Heavy Industries Environmental and Chemical Engineering Co. Ltd., Sembcorp, Suez Environment (SITA) and CISC.
25 Pre-sorting/pre-treatment can include use of a wet MRF to allow recovery of reusables and recyclables (and possibly the food/organic fraction) before processing the balance of the waste stream in an MBT, or use of a wet MRF or MBT facility before treatment of the residual fraction in a WtE facility.
26 The inclusion of pre-sorting at a WtE project will increase the capital and operating cost of the WtE project (possibly by up to a third) and as such may affect the affordability of the WtE project.
27 For example, the market for brown plastics in China has ceased, leaving some waste projects "short" of projected revenue from recycling of plastics.
28 Design and Construction (D&C).
29 Engineering, Procurement and Construction (EPC).
30 Operation and Maintenance (O&M).
31 Build Own Operate (BOO) means that the project sponsor builds, owns and operates the WtE project, and the municipality (or government agency, authority or corporation) contracts with the WtE project for the provision of services using the WtE project (i.e. the provision of waste acceptance, treatment and processing and, if the municipality is the off-taker of electricity, for the supply of electricity).
32 Build Own Operate Transfer (BOOT) means that the project sponsor builds, owns and operates the WtE project for the term of the BOOT contract, providing services to the municipality (or government agency, authority or corporation) and then transfers the WtE to the municipality (or government agency, authority or corporation) at the end of the term of the BOOT contract, usually at the option of the municipality, and typically for a nominal purchase price on the basis that the municipality has effectively paid for the WtE project through the payment of service charges.
33 Design Build Finance Operate Maintain (DBFOM) means that the project sponsor designs, finances, builds, operates and maintains the WtE project, and "hands over" the project at the end of the DBFOM term. Again, under the DBFOM contract, the municipality (or government agency, authority or corporation) may be the off-taker of the electricity produced, but this model may also be used to allow for delivery of waste to the WtE project (at no charge to the municipality) to enable the WtE project to generate electricity which it then supplies under a Power Purchase Agreement (PPA) or under the FiT regime.
34 Public Private Partnership (PPP, or P3) means that the private sector contracts with the municipality (or government agency, authority or corporation) to provide services to the municipality, or to the public as users of the infrastructure developed by the project sponsor, with the project sponsor responsible for all associated DBFOM activities. In the context of WtE projects, the municipality (or government agency, authority or corporation) will have services provided to it in the form of waste acceptance, processing and treatment.
35 In our next article, we will consider which jurisdictions have FiT regimes, and their terms.
36 If a WtE project is project financed, for the project financiers the WtE project must be able to earn sufficient revenue to service debt and repay interest. It is important to note, however, that not all WtE projects are project financed.
37 To be distinguished from fly ash captured through the "air pollution control system" (a by-product of controlling emissions) which is hazardous and which must be disposed of to an appropriately licensed hazardous waste facility/landfill.
38 In many jurisdictions, the assumption for the purpose of the financial model will be that bottom ash is a residual material that needs to be disposed of to landfill. If the ash does not have to be disposed of to landfill, this will remove the disposal cost and improve the net revenue position of the WtE project.
39 If electricity is sold into an electricity market, the price paid for electricity will be determined by the price at which supply matches demand (for uncontracted capacity) or by a contract for differences (for contracted capacity).
40 Other revenue opportunities include bottom ash use, APCR use, char use (from pyrolysis) and sale of ferrous/non-ferrous metals and possible CO_2 use in the context of greenhouse agriculture.
41 Incompatible waste is waste that the WtE project is not able to process or treat because it is not designed to process or treat that waste, or because it is not licensed to do so, and as such cannot do so lawfully.

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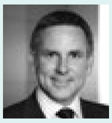

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HIGH YIELD BONDS:

A financing solution for energy projects

by Tamer Bahgat and Natalia Sokolova

Traditionally, energy project developers have obtained the majority of financing through their balance sheet or traditional bank debt. However, in response to heightened political and economic instability, energy companies, including traditional sectors such as upstream oil and gas as well as less established renewable energy technologies, have had to consider diversifying their sources of funding. The global financial crisis has resulted in stricter regulations on banks and higher capital requirements, leading to pressure on banks to reduce their loan books, particularly in relation to longer-term liabilities. This has meant, among other things, that energy projects can no longer rely on traditional debt alone for financing, leading to a gradual shift from bank-led financing to non-bank and capital markets-based funding. As a result, more innovative ways of funding, such as high yield bonds, are being considered and implemented.

What are high yield bonds?

As the name suggests, a high yield bond is a type of corporate bond that offers a higher rate of return because of its higher risk profile. High yield bonds offer an opportunity for institutional investors to participate in energy-related projects through listed, tradable securities that can offer superior risk-adjusted returns due to their access to a deep and liquid market.

High yield bonds are securities that can be issued in public markets or placed privately. Publicly listed bonds tap into a very large investor pool, require regular financial reporting and offer the benefits of daily liquidity, pricing and higher levels of transparency. A private placement is the method of placing debt with a small number of selected, sophisticated investors, which debt may be listed or unlisted. Often, though not exclusively, such investors are non-bank institutions. Most bonds are issued in the public bond market, although the private placement market also provides an important liquidity source. The attraction of private placement derives from the limited amount of disclosure, flexibility on maturity and greater certainty around execution.

A material distinction between high yield bonds and other forms of traditional energy project financings is that high yield bonds have incurrence (instead of maintenance) covenants. Such "incurrence covenants" control the issuer's ability to incur a non-ordinary course liability, based on a financial ratio, and are only tested when the issuer chooses to incur debt or take other relevant actions. Whereas the more pertinent maintenance covenants used in reserve-based lending (RBL) and other traditional funding require the borrower to maintain certain financial ratios on an ongoing basis. Therefore, energy projects exposed to political or economic volatility would benefit more from high yield incurrence covenants.

When issuing in the international bond markets, companies can choose between the Regulation S disclosure standard, which limits them to investors outside the United States, and the Rule 144A standard, which gives them access to US institutional investors. Complying with the Rule 144A standard is more demanding because of the broad anti-fraud provisions of US securities laws.

New investors

Energy project finance has proved to be an attractive new asset class for alternative investors, such as insurance companies and pension funds, which are facing pressures (for example, under Solvency II and other regulatory regimes) to diversify and ensure the profitability of their portfolios and to match investments to their long-term liabilities, while often subject to a relatively conservative risk appetite. Within the past five years, non-bank investors have significantly increased their commitments and exposure to energy financing, given the long-term nature of the liabilities for many types of institutional investors and their corresponding need for suitable long-term assets, coupled with significant policy support for clean energy. This is particularly true for established renewable energy technologies, where the risks are relatively well understood and government subsidies are encouraging investment. As a result, there have been increases over the last few years – particularly across Europe – in investment from non-bank lenders, in both the public bond markets and private placements, and most large energy businesses are now funded at least in part through corporate bonds (high yield or investment grade, depending on the rating of the issuer).

Historically, high yield bonds have been widely used in the construction, refinancing or expansion financing of large LNG, pipeline and petrochemical projects. However, there is also a growing potential for the high yield capital market to provide further support to the independent oil and gas sector as well as to renewable energy projects.

Independent oil and gas companies are the largest users of RBL facilities. These players typically use RBL structures for development financing and general corporate purposes. However, the cheaper price of public bonds and the covenant-light nature of alternative funding sources is shifting companies towards non-traditional sources of finance and away from the bank markets. Bond markets are increasingly being accessed to finance new development opportunities within the mid-cap exploration and production sector. For example, Hellenic Petroleum, DEA Finance and Seven Energy took out their RBL facilities with senior high yield bonds, while each of Aker, Ithaca and Tullow Oil placed high yield bonds alongside their existing RBL facilities.

More recently, high yield bonds have also been successfully used to finance alternative energy projects. Among examples of the alternative energy projects financed with high yield bonds are multiple iterations of the Abengoa and Areva transactions, which tend to issue high yield bonds typically on an annual basis, as well as the more recent UK examples of Melton (MEIF) and Drax (both of which issued bonds to finance biomass fuel projects).

Financing at various stages of the project

In general, large energy projects can be divided into three phases: the planning phase, the construction phase and the operational phase. The most commonly used types of financings for each of the phases are listed in figure 1.

Figure 1: Principal sources of energy project funding through the different stages of development

Planning (pre-development, including exploration in the upstream oil and gas context)	Development/construction	Fully operational project
Project balance sheet	Reserve-based lending	High yield bonds (public or private placement)
Private equity	High yield bonds (public or private placement)	Bank loans
IPO	Retail bonds	Cash flow from operations
Bank loans	Project finance	Infrastructure funds
Project finance	Multilateral development banks	Proceeds from divestments
	Mezzanine finance	

INCREASED PREDICTABILITY OF CASH FLOWS AND BUSINESS MATURITY

Due to the lack of cash flows to service debt, resulting in negative carry, and high risk of non-completion during the **planning stage**, high yield bond issuance is not one of the common sources of energy project funding during this stage. It is often observed that the capital markets are unlikely to be available to support development projects with no track record. Instead, bonds have focused on the refinancing of existing indebtedness once a project is operational (and thus generating sufficient revenues), rather than financing prior to project completion. Recently, institutional investors have been seen to take construction risks on properly structured greenfield projects where what is key is (i) meeting the rating agency requirements and (ii) providing appropriate credit enhancement in the structure through, for example, shareholder or parent guarantees, equity backstop or government support. Note for example Abengoa Greenfield Euro- and USD-denominated bonds due 2019. Additionally, ContourGlobal, KCA Deutag, International Power and Puma each had a number of greenfield projects in their portfolios and were contemplating launching several more at the time they issued their senior notes (though each of them already did have a number of revenue-generating assets - either operational or development phase projects - in their portfolios at the time).

Bond financing is making even greater inroads in the **construction phase**, where there is more certainty around the project completion timeline and predictability of future cash flows. An increasing number of energy projects are refinanced with high yield bonds during the construction stage, and this is where the new frontier lies for energy-related bonds – see for example the Greenko bond transaction highlighted in figure 2.

Figure 2: Spotlight – green bonds

Corporates in western countries and in developing countries alike are looking at green bonds. These offerings add to the supply of bonds available to project developers who previously had to focus on financings from development banks and equity. UN Environment estimates that the number of policy measures to "green" the financial system has more than doubled to over 200 measures across 60 countries. These policies translate into the rapid growth of green finance in the marketplace. Financial centers including London, Hong Kong, Paris and Casablanca have set out plans to seize the green finance opportunity. Climate Bonds Initiative, an international organisation working on mobilising the bond market for climate change solutions, reported that there was a record-breaking issuance of US$81 billion of climate-aligned bonds in 2016, with the largest number of new issuers and the largest single month of issuance to date. The issuance of the RMB 30 billion (US$4.3 billion) green bond by Bank of Communications in China in November 2016 is recognized as the largest single green bond issued to date.

GREEN BOND CASE STUDY

A leading hydro, wind and thermal power Indian green bond offering – late brownfield phase and beyond

Greenko Group is one of the largest clean energy independent power producers in India, with more than 1 GW of projects across hydro, wind and thermal energy. The Group's portfolio includes operational run-of-river hydropower projects and wind projects, as well as two run-of-river hydropower projects that at the time of the initial bond issuance were under construction and near operational. Greenko Investment Company's issuance of US$500 million of senior notes due 2023 at 4.875 per cent enabled the company to access the international capital markets for a competitive source of financing to address the ongoing need for green energy for India. The high yield notes are guaranteed on a senior basis by Greenko Energy Holdings and represent an innovative structure that addressed the company's financing needs during the construction/early stages of operations of its portfolio assets (which have subsequently been refinanced with an upsized high yield bond issuance)

Ashurst advised the joint bookrunners and lead managers as well as the lead green structuring agent in this transaction, which was India's first high yield green bond issuance (and Asia's largest dollar green bond offering). This transaction won High Yield Deal of the Year by Asian Mena Counsel 2016 and was shortlisted for High Yield Deal of the Year by IFLR Asia Awards 2017. For coverage of our recent work on Greenko bond refinancing, please go to: https://www.ashurst.com/en/news-and-insights/news-deals-and-awards/ashurst-advises-underwriters-in-asias-largest-dollar-corporate-green-bond-offering/

Historically, however, high yield bonds were most often used during the **operational phase** of an asset, which is the time period after construction risk has ended and the asset begins to generate positive cash flow and the initial bank loans are being refinanced. With stable underlying cash flows in the operational phase, energy projects are akin to fixed income securities and therefore bond financing is a natural and economically appropriate financing instrument.

Nonetheless, the above dichotomy is somewhat artificial, and capital structures of varying degrees of complexity may make sense to energy companies at different stages of development, based on a number of factors such as the number, types and geographies of projects under development within the portfolio and the interested investor pools. Some of the energy-related financing structures incorporating high yield bonds include the following:

- smaller sized, bond-only deals to fund national power (both conventional and renewable), and other utility and energy infrastructure projects in developing countries;
- a bond tranche inserted or pre-packed into a multisource bank/bond financing structure for major petrochemical projects; and
- bond financings for established sub-investment grade energy corporates to fund expenditures on major assets under development.

Key features of high yield bonds in the context of energy project finance

A side-by-side comparison of the most salient features of a typical high yield bond and the typical terms of project finance is set out in figure 3.

Figure 3: Principal sources of energy project funding through the different stages of development

	Public high yield bonds*	Project finance
Depth of market	Very deep and liquid. Investors are mutual funds, hedge funds, insurance companies, pension funds, private wealth and sovereign wealth management accounts.	Bank markets continue to provide majority of capital. Infrastructure funds, pension funds and other institutional investors increasingly looking to invest in long-dated infrastructure.
Interest rate	Typically, fixed rate funds (though floating rate notes are also available).	Floating rate (with interest rate hedging).
Documentation	Documentation process longer and more costly – requires OM disclosure and road show.**	No disclosure requirements.
Size	Borrowing capacity linked to credit strength. Minimum size US$150m.	Variable dependent on size of project, structuring and risk profile.
Drawdowns	Single drawdown at closing – cost-of-carry considerations.	Multiple drawdowns when required by the project's timetable.
Recourse	Gives rise to a claim against the corporate balance sheet.	None or limited recourse finance projects – limited to the project balance sheet and are more highly structured for credit enhancement.
Maturity	Long-dated capital available (typically matures in 5-10 years).	Maturity of 7 years (mini perm) or 15 years with debt sizing and amortization period linked to asset life. Capital often structured to incentivize refinancing post-construction of projects.
Hedging	Bonds are typically issued in local currencies to minimise potential currency mismatches – no swap required.	Interest rate hedging.
Mandatory prepayments	No mandatory prepayments. No amortization payments. Bullet repayment at maturity.	Traditional loans have amortization payments (with a balloon payment for mini perm structures).
Optional prepayments	Early redemption costs (non-call periods of up to fh of the tenor of the bonds and thereafter repayable at decreasing premium (e.g. fh coupon and stepping down to fb and par depending on tenor)).	Limited or no prepayment penalties.
Covenants	Lighter covenants: generally a more flexible incurrence covenant package than traditional project finance debt (resulting in less intrusive oversight of project-level decision making).	Maintenance covenants: debt service coverage ratio and loan life coverage ratio testing apply for debt sizing, distribution tests and events of default. Covenants include timelines and milestones.
Amendments	Expensive to amend - requires consent solicitation and payment of consent fee.	Amendments relatively common and straightforward.
Reporting	Public reporting (quarterly + annually).***	Private reporting (monthly or quarterly + annually).
Ratings	Rating required (typically Moody's/S&P).***	External ratings not required.

* Except as otherwise footnoted, the features described in this column apply to privately placed bonds as well.
** This process is less involved in the context of private placements.
*** Not applicable to private placements.

Several of these features merit a more detailed discussion, as outlined overleaf.

Economics

High yield bonds are long-term non-amortising instruments typically issued in the form of fixed rate funds (though floating rate notes are also available), which makes financial modelling for the project easier. Longer-tenor bonds ensure financing costs that are fixed for the life of the project, thereby avoiding refinancing risk. The longer interest payment profile and bullet principal payment at maturity have the effect of extending the debt service payments over a longer term, which reduces the size of each payment, making the project more affordable for the issuer in the project finance scenario where predictability of cash flows increases as the business matures.

Recourse to the corporate balance sheet

Instead of bearing the risks of an individual project, high yield corporate bonds bear the risk of the issuing corporate entity. Thus creditworthiness is determined by an issuer's general ability to service the debt, making them less risky than project bonds. Market prices for such issuances are readily available and credit quality of issuances is independently observable by many market participants. High yield bonds may be issued either by the project company or by a separate (usually sister) company (FinanceCo) incorporated to issue the bonds and on-lend the proceeds to the project company.

Public disclosure and reporting

The one feature of high yield bond financing that is typically cited as its disadvantage is the time-consuming and costly regulatory requirements of listing, public disclosure (offering memorandum or prospectus preparation, which means exposure to potential liability for misleading disclosure), ratings, planning and implementation of a road show marketing process and preparation of final transaction documentation and placement. As part of the public disclosure, the provision of two to three years of audited financial statements is usually expected by market participants. However, these features are strongly mitigated in the private placement context, where the parties can bilaterally agree on the amount of disclosure being provided. Moreover, even in the public bond context, often the issuers do not mind the burden of the additional documentation drafting, disclosure and regular public reporting, especially if the company is considering a subsequent equity raise, an IPO or another debt or equity capital markets transaction as the next step of its growth and capitalization. All that work on public bonds will have laid a strong foundation for such a capital markets transaction, as it will have prepared the framework for future disclosure documentation and will have sensitized the company's management to periodic public reporting.

Cash drawdown

High yield bonds are structured to have one closing upon which the whole amount is drawn down, with no subsequent drawdowns (versus committed funding and drawdowns when required in project finance or a bank revolving credit facility). Without staged drawdown to match capital investment needs, surplus funds received under the bond financing at financial close will need to be held in a bank account or otherwise invested until required. Given the current low interest rate environment, the yield on the bank account will almost certainly be well below the interest rate of the financing, leading to what is known as "negative carry". In contrast, traditional bank loans can be disbursed to the project company according to a predetermined schedule, although banks do charge commitment fees (a percentage of the margin) on available, but undrawn, facilities. The counterbalancing factor is that the bond financing is generally cheaper (due to the depth of the bond market). An "all in funding cost" should be calculated (which will take into consideration the cost of carry on bond proceeds) when determining the most appropriate type of financing. Another factor in the cost calculation is the normally longer maturity of bond financing relative to bank financing, which may increase the equity returns and decrease the risks and costs of refinancing. Note also that there has been some discussion among practitioners of structuring a staged drawdown bond, though we are not aware of any such instruments currently in the market – this is a space to watch.

Redemption

High yield bonds ordinarily carry early redemption costs (non-call periods of up to half of the tenor of the bonds, which means during this period voluntary redemption of the bonds may not be permitted or permitted only with the payment of a "make-whole" amount, which is rather expensive). The make-whole amount is calculated so as to guarantee a certain rate of long-term minimum returns to the investor on the basis of the amount which the prepaid investor would need to invest at a risk-free or low-risk rate (such as the Bund rate or the UK Gilt rate plus a premium) to achieve the same return as the bond, over what would have been the life of the bond. In contrast, project financing carries limited or no prepayment penalties. However, in the context of construction/early stages of operation of an energy project, it is highly unlikely that the project will start generating excess cash and thus drive an early prepayment during the first few years after the financing is put in place. It is worth noting that high yield bonds contain a change of control set at 101 per cent of the principal amount so that, if the project changes ownership, the bonds may be redeemed in whole or in part (which may or may not make economic sense to the investors depending on the price at which the bonds are trading at such time).

Conclusion

While energy projects have traditionally been financed through banks, the implementation of Basel III regulations, requiring stricter monitoring and disclosure, ultimately leading to higher costs and higher capital requirements, has opened the door to high yield bonds as an alternative source of finance. By accessing the institutional bond market, companies are able to reduce their project funding cost. As a result, high yield bond financing is now being used during the construction and operational stages of energy projects, and occasionally even during the planning stage, and we believe this trend will continue.

APPENDIX

Oil and gas high yield bonds – features and terms unique to the industry

The oil and gas industry presents an array of perhaps the most geographically diverse issuers, with probably the highest percentage of emerging markets issuers (typically from the Middle East, North Africa, Nigeria and the CIS). Because of the variety of jurisdictions involved, the terms of the bonds tend to vary quite a bit as well, and certain very bespoke terms can be found in this market. Nevertheless, some trends emerge. As a general matter, the issuers tend to have higher EBITDA(X) and Total Assets than issuers in other industries, and tend to be less levered (the long-term oil price dip notwithstanding). Despite that, the covenants in the oil and gas deals are generally more conservative than average, probably due to the oil price volatility and geopolitical risks faced by some of the issuers.

Some recent representative oil and gas high yield deals include Corral Petroleum Holdings AB (Preem AB) €570 million 11.75 per cent/13.250 per cent senior PIK toggle notes and SEK 500 million 12.255 per cent/13.750 per cent senior PIK toggle notes (Sweden); DEA Finance SA €400 million 7.5 per cent senior notes (Germany); KCA Deutag UK Finance plc US$535 million 9.875 per cent senior secured notes (Scotland) and Motor Oil (Hellas) €350 million 3.250 per cent senior notes (Greece).

A few peculiarities of the oil and gas high yield deals to highlight:

- The use of EBITDAX as a metric of performance: Earnings Before Interest, Taxes, Depreciation, Amortizations and Exploration Expenses – this is a variant of EBITDA commonly used in the oil and gas industry to measure performance.
- Grower baskets: These tend to be based on a percentage of Total Assets. While grower baskets based on a percentage of EBITDA are generally considered more issuer-friendly, for this industry baskets based on a percentage of Total Assets make more sense because these issuers tend to be asset-heavy and the value of the assets tends to be rather stable, while their EBITDA depends heavily on the oil prices, which may be volatile.
- Maturity, non-call periods: The oil and gas issuers tend to be fairly disciplined in this respect, with the average tenor for the bonds hovering around five years, and the non-call period at around half of the tenor.
- Portability: While this concept made a comeback in 2017 in the European high yield space, it is yet to make much headway in this industry. Leverage-based portability is unheard of, though several of the larger public issues do have the ratings decline trigger in the definition of "Change of Control".
- Ratio debt test: The standard test for incurrence of ratio debt in the high yield bonds is 2x FCCR. In this area, the oil and gas issuers tend to be subject to a more conservative 2.25x FCCR test (and an additional senior secured leverage ratio test, if such ratio debt is to be secured).
- Contribution debt: There is still no contribution debt basket in the majority of oil and gas deals (though it is making an appearance in the most recent deals), while this basket has become almost the norm in some other sectors.
- Sponsor management fees: There is no addback and no restricted payment carve-out for sponsor management fees (primarily a reflection of a small number of private equity sponsor-backed deals in this sector).
- Sector-specific permitted investments: Often uncapped business investments (JVs) in oil and gas businesses are permitted, as well as investments in community development projects and economic development activities.

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Stop press

Legal rankings: a tier one firm

Ashurst's energy and infrastructure team is proud to announce that we have maintained our Tier One ranking in the leading legal directories for international work in these sectors. These guides are published annually and provide unbiased commentary and insight into the marketplace. Ashurst is ranked as a Tier One firm for our advice in the following areas:

Chambers
- Energy and Natural Resources, UK
- Energy and Natural Resources, Australia
- Infrastructure and Project Finance, Australia

Legal 500 2017
- Oil and gas, UK
- Infrastructure, UK
- Project Finance, Australia
- Project Development, Australia
- Natural Resources (Transactions and Regulatory), Australia
- Energy (Transactions and Regulatory), Australia

New partner hires strengthen global energy team

Tamer Bahgat, Partner, London

Tamer joins from Allen & Overy, where he was part of the high yield bond group. His experience includes international capital market transactions in connection with leveraged buyouts, acquisition finance and corporate finance, with particular emphasis on high yield debt offerings.

While at Allen & Overy, Tamer spent time on secondment in the Leveraged Finance Execution Team of Goldman Sachs International where he was primarily responsible for working on leveraged buyouts, refinancings and dividend recapitalisations transactions. Prior to joining Allen & Overy, Tamer worked at Cravath, Swaine & Moore in New York and London.

Sarah Rackoff, Partner, New York

Sarah is a partner in our energy and infrastructure group in Washington, D.C.

She has significant experience structuring complex public finance transactions in the petrochemicals, public power, transportation, housing and healthcare sectors.

Sarah focuses her practice on high yield municipal bonds, general obligation bonds, infrastructure finance, revenue bonds, private activity bonds, public private partnerships and distressed bonds.

She regularly represents sponsors, borrowers, issuers and underwriters for issuances of publicly offered and privately placed tax-exempt and taxable fixed and variable rate bonds.

Chris Redden, Partner, Sydney

Chris joins Ashurst's project finance practice from Norton Rose Fulbright, where he was head of financial institutions. He has recognised expertise in project and infrastructure finance, having advised on numerous high-profile international and cross-border financings across sectors including oil and gas, infrastructure, mining and energy. Chris is qualified to practise in Australia, Hong Kong and the UK and has extensive experience in each of these jurisdictions. The hire bolsters the firm's strategy to maintain and build upon its leading project finance practice in the Asia Pacific region.

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