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Update on US Federal Tax Reform Proposals and Their Effect on the Renewable Energy Industry

By Gerald M. Feige

While tax reform has been a stated focus of the Trump administration and Congress, details remain elusive. The administration has recently reaffirmed its desire to enact comprehensive corporate and individual tax reform, but so far has provided few concrete details of its plan, instead reaffirming several "core principles" that will drive its negotiations with Congress. Due to the lack of detail in the most recent reform proposals and the uncertain prospects for passage in Congress, the precise impact of tax reform on the renewable energy industry is not yet known.

Summary of Tax Reform Proposals

While the Trump administration has not provided significant details on its tax reform plan, the broad contours of the plan have developed over the past several months (the "Trump Plan") and are summarized below.

The Trump Plan proposes a 15 percent rate on the net income of corporations, small businesses and partnerships. The Trump Plan, at least as it was proposed during the campaign, would permit companies engaged in manufacturing in the United States to elect to immediately expense capital investments. However, the administration's most recent announcement was silent as to whether it would include full expensing of capital investments.

The Trump Plan also would lower individual income taxes by reducing the number of tax brackets from seven to three (with a maximum individual income tax rate of 35 percent), doubling the standard deduction and increasing certain child care tax benefits. The plan would partially offset the decrease in revenue from these proposals by eliminating most itemized deductions, including the deduction for state and local taxes. The home mortgage interest expense and charitable contribution deductions would be preserved. The Trump Plan also would eliminate the alternative minimum tax and the 3.8 percent net investment income tax.

The House Republicans' business tax plan, as set forth in their "Blueprint" released last summer, would reduce tax rates on the net income of corporations to 20 percent and on partnerships to 25 percent. The Blueprint would provide immediate and automatic full expensing of all business investments other than land. The Blueprint also would disallow deductions for net interest expense in order to equalize the tax treatment of debt and equity financing. In addition, the Blueprint would introduce border adjustments to the taxation of products, services and intangibles that are imported into or exported from the United States. Border adjustments would mean that income from goods exported from the United States would not be subject to tax while the cost of goods imported into the United States would not be deductible from income. The border adjustment tax is not included in the Trump Plan, and the administration has indicated that it does not support it in its current form.

As to individuals, the Blueprint is similar to the Trump Plan in that it reduces the number of income tax brackets to three (but with a maximum individual income tax rate of 33 percent) and increases the standard deduction, but it goes further in reducing taxes on investment income (i.e., capital gains, dividends and interest) through a 50 percent exclusion of such income.

Both the Trump Plan and the Blueprint have as a stated goal the elimination of so-called special interest tax breaks, but few details have been provided as to which specific provisions would be eliminated.

Prospects for Comprehensive Tax Reform

The Trump Plan faces significant obstacles. While both the Trump administration and the House Republicans are generally in favor of lower corporate and individual tax rates, accelerated expensing and the elimination of certain special tax incentives, the prospects for passage of these proposals, particularly in the Senate, is not clear. Democrats have promised opposition to any tax plan that, in their view, provides tax breaks to the highest income earners. Furthermore, many so-called deficit hawks among the Republicans may hesitate to support any plan that is not considered revenue neutral. Treasury Secretary Steven Mnuchin predicted that the Trump Plan would be deficit neutral after factoring in economic growth resulting from tax reform, but others have contested that claim.

Given the slim Republican majority in the Senate, any bill may require passage by simple majority through the reconciliation process. Reconciliation allows the bill to pass with only a majority rather than 60 votes, but is only permitted for bills that do not add to the deficit beyond a 10-year window after passage. Accordingly, the tax rate reductions, if enacted, may be temporary unless accompanied by substantial revenue offsets.

The administration has expressed confidence that tax reform can be completed by the end of 2017. Nevertheless, given the differences between the administration and Congress, as well as within Congress, there is expected to be significant opposition to any comprehensive tax reform proposal. Further, the current tax code is incredibly complex, and a comprehensive reworking of it will require a substantial amount of time, with significant input from affected parties and industries. For these reasons, even if tax reform is ultimately passed, the process could continue well beyond this year. In addition, as with any significant change in law, the effective date of such changes is expected to be prospective and, as was the case with the Bush tax cuts, could be phased in over time. Accordingly, comprehensive tax reform, if passed, may not have its full effect for several years.

Effects of Proposed Tax Reform on Renewable Energy Investments

Although many of the core tax reform principles espoused by the Trump administration and the Congress could have a negative effect on renewable energy investments and financing, the extent of that effect is not entirely clear. Again, this is because the details of the administration's and the House Republicans' plans have not been fully fleshed out.

For example, it is not yet known what will happen with renewable energy tax credits in future tax reform. Under current law, investments in solar and wind property generally are eligible for an investment tax credit, but the credit is scheduled to step down over the next several years and, in the case of wind property, the credit will phase out completely. Similarly, the production tax credit available for wind properties will phase out entirely after 2019. These incentives may be targeted as a means to pay for promised rate reductions, although because these credits phase out or will reduce significantly over the next few years, their power as a revenue offset for promised tax rate reductions is less substantial. In addition, the Secretary of the Treasury has previously said that he intends the current renewable energy tax credit regime to remain unaltered.

Even if renewable energy credits survive, however, the reduction in corporate and individual income tax rates, coupled with accelerated business expensing (which could increase materially in the short term after passage), would reduce the value of these credits for tax equity investors, as potential investors will have less overall tax to offset with credits. This could reduce the number of investors and thus increase the before-tax yield demanded by remaining investors. This reduction in value of energy tax credits would not be offset by immediate expensing of renewable energy investments. While immediate expensing would accelerate the tax reduction available from the expense, the deduction would serve to reduce taxable income against which a lower tax rate now applies, reducing its overall effectiveness.

Furthermore, a border adjustment tax, if adopted, would eliminate expensing for renewable energy projects to the extent that the projects use imported goods. While the border adjustment tax would exempt taxes on exports, energy projects generally do not produce anything for export. Further, if a border adjustment tax hampers imports generally, the tax could increase the cost of materials for renewable energy projects. Thus, on balance, a border adjustment tax would have a negative effect on renewable energy projects.

In sum, the broad contours of the tax reform proposals currently being considered by the Trump administration and the Congress potentially have negative effects on the renewable energy industry. Because the details have not yet taken shape, there are open questions as to the likelihood that legislation resembling these proposals will be enacted, as well as the time period over which any enacted reform will take effect. In this regard, because tax reform may well be a slow process, tax law changes may have less of an effect on those contemplating renewable energy investments in the near future. In order to determine the negative effect, if any, that such changes will have on their planned investments, potential investors will need to gauge the likelihood that tax reform will take this direction and, if it does, the time period over which such reform will take effect.

Territorial Restrictions in Gas Supply Contracts in Japan: Antitrust Implications and Experience From the European Union

By James Webber, Anthony Patten, Hideki Utsunomiya and Naoki Ishikawa*

Japan, the world's biggest buyer of liquefied natural gas (LNG), is currently investigating the potential anticompetitive effects of territorial restrictions in LNG supply contracts. Historically, LNG suppliers have used long-term contracts that incorporate territorial restrictions to prevent Japanese buyers from on-selling the LNG outside Japan. The effect of such clauses is to ban exports of LNG bought by Japanese customers, potentially increasing Japanese energy security. LNG suppliers have benefited from the absence of price arbitrage between Japan and neighboring markets. This contractual framework eliminates the buyers' scope to trade LNG with other countries. The concern is that such territorial restrictions could now be resulting in a reduction in trading volumes, liquidity and increasing buy-side risk.

Background

Japan's Ministry of Economy, Trade and Industry (METI) states that it will work to eliminate in their entirety or reduce the scope/effectiveness of territorial restriction clauses in new LNG supply contracts. In its report entitled *Strategy for LNG Market Development*, METI highlights that "[i]n order to develop a flexible and liquid LNG market, these [territorial] restrictions need to be eliminated to the greatest extent possible to increase the number of market players as well as trade volumes and frequencies to a level exceeding a certain critical mass."[1] The Japanese antitrust agency, the Japanese Fair Trade Commission (JFTC), is also understood to have launched an investigation in 2016 to determine to what extent the export bans in LNG supply contracts adversely affect competition. Given that LNG is supplied to Japan under long-term contracts with a typical duration of 25 years, antitrust enforcement is the only tool available to challenge the export bans in existing LNG supply agreements. Prohibiting the use of territorial restrictions could lead to the renegotiation of approximately $600 billion worth of LNG supply contracts already in place.[2] With this reform on the horizon, key Japanese buyers of LNG such as Jera Co. and Osaka Gas Co. have refused to sign new LNG supply contracts containing export bans.[3]

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* Co-authors Hideki Utsunomiya and Naoki Ishikawa practice at the law firm of Mori Hamada & Matsumoto in Tokyo, Japan.

1 *Strategy for LNG Market Development – Creating flexible LNG Market and Developing an LNG Trading Hub in Japan*, Ministry of Economy, Trade and Industry, Government of Japan, 2 May 2016, p. 7.

2 *Japan Said to Review If LNG Contracts Barring Resale Violate Law*, Bloomberg, 14 July 2016, available at https://www.bloomberg.com/news/articles/2016-07-14/japan-said-to-review-if-lng-contracts-barring-resale-violate-law-iqlr1xu7

3 *Another Buyer in World's No. 1 LNG User Resists Resale Curbs*, Bloomberg, 12 September 2016, available at https://www.bloomberg.com/news/articles/2016-09-12/osaka-gas-in-talks-to-ease-lng-contract-terms-barring-resale

Antitrust Challenges

Territorial restrictions in contracts for the supply of gas have been found to infringe antitrust rules in other jurisdictions, notably the European Union (EU). There are strong differences in the structures of the European and Japanese gas markets, which means EU antitrust law has developed using theories of harm that cannot be easily transposed to the Japanese market. A series of decisions from the European Commission (EC) concerning contracts for the supply of gas between (1) undertakings in different Member States and (2) undertakings importing gas into the EU reveal how territorial restrictions have been examined under EU competition law.[4]

The first step the EU took against export bans related to intra-EU supply contracts. The EC held that territorial restriction clauses contained in a transportation and a service contract among Gas de France (GDF), Eni S.p.A (ENI) and Enel S.p.A (ENEL), which prohibited ENI and ENEL from selling the natural gas in France and which GDF transported on their behalf, infringed EU competition law.

The latter category concerned primarily investigations by the EC into supply contracts concluded between Gazprom and European energy companies such as E.ON Ruhrgas,[5] ENI[6] and OMV.[7] The agreements reached between the parties and the EC concluded in the elimination of the territorial restriction that prevented the European energy companies from selling the gas supplied by Gazprom to other Member States.

In both cases, the EC considered that territorial restrictions were a restriction of competition by 'object.' Object restrictions in the EU are effectively equivalent to per-se violations of Section 1 of the Sherman Act, a federal antitrust statute in the United States, and can be assumed to be harmful without needing to prove any actual anticompetitive effect. The specific harm assumed was that the operation of territorial restrictions would allow suppliers to maintain different price areas for the same product, thus undermining the integration of a single European gas market.

Using antitrust enforcement to encourage integration of the EU single market—sometimes called the "single-market imperative"—is a peculiar feature of the EU. It does not generally apply to antitrust regimes elsewhere in the world, including in Japan. Further, the investigation the JFTC is undertaking is different from the previous cases in the EU. The equivalent case in the EU would be a situation where a gas supplier prevented an EU buyer from exporting the gas outside of the EU itself—not between Member States of the EU.

Under EU competition law, clauses prohibiting onward sales outside the single market would not be an object restriction. However, these restrictions could in theory be challenged if it could be shown there was an anticompetitive effect. In practice, such cases are very rare. The EC would take into consideration whether, in the absence of the export ban, there would be a realistic possibility of re-import of the products into the EU.[8] If such were the case, banning exports could lead to a softening of competition in the internal market.

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4 Commission Press Release, 'Commission confirms that territorial restriction clauses in the gas sector restrict competition,' (IP/04/1310), 26 October 2004.

5 Commission Press Release, 'Commission secures changes to gas supply contracts between E.ON Ruhrgas and Gazprom,' (IP/05/710), 10 June 2005.

6 Commission Press Release, 'Commission reaches breakthrough with Gazprom and ENI on territorial restriction clauses,' (IP/03/1345), 6 October 2003.

7 Commission Press Release, 'Commission secures improvements to gas supply contracts between OMV and Gazprom,' (IP/05/195), 17 February 2005.

8 Commission Decision, *SABA (No. 1)*, OJ 1976 L28/19, [1976] 1 CMLR D61.

The Approach of the Japan Fair Trade Commission

Japanese antitrust legislation does not automatically prohibit the use of territorial restrictions. The use of territorial restrictions will constitute a violation of Japanese antitrust law only if they have an anticompetitive effect. There has not been a finding by the JFTC that such clauses are an object restriction of competition or that they necessarily lead to anticompetitive effects in the market. Conversely, there is also no antitrust legislation or finding by the JFTC concluding that territorial restrictions are permissible or compatible with Japanese antitrust law.

Whilst it is clear that METI considers it indispensable to eliminate territorial restrictions to create a more flexible LNG market in Japan[9] and bolster Japan's role as a regional trading hub for LNG, we consider it unlikely that the JFTC could immediately challenge export bans in LNG supply contracts on the basis of illegality. Given the EU's single-market objective, territorial restrictions within the EU have long been considered object restrictions. However, export bans in long-term LNG supply agreements to Japan do not present such an obvious anticompetitive effect; indeed it would be odd if they did since provisions have been a well understood basis for LNG contracting for decades without attracting prior enforcement effort. Consequently, the JFTC would need to embark on an effects analysis. This involves comparing the state of the market with territorial restrictions against the state of the market absent the territorial restrictions. Using accepted economic tools, it would then need to prove empirically that the restrictions distort competition.

There are a number of significant problems in doing this. In particular, the Japanese LNG market is highly fragmented on the supply side.[10] It would be practically impossible for the JFTC to prove that a single long-term LNG supply contract containing an export ban has an adverse effect on competition, since the supplier in question would have no market power. This contrasts with the market structure in the EU, where Russia, Norway and Algerian national oil companies each have significant shares, although even here the EC did not attempt an effects analysis.

Given this issue, to successfully tackle the challenges posed by territorial restriction clauses, the JFTC would have to establish that all LNG supply contracts containing these clauses constitute a network of similar agreements and study the anticompetitive effect that they collectively present. EU competition law also recognizes that the existence of a network of similar agreements reinforce their individual adverse effects on the market and are therefore a factor to consider by antitrust authorities.[11]

In addition, there is a jurisdiction hurdle for the JFTC in tackling territorial restriction clauses as they prohibit the Japanese buyers only from selling the LNG outside of Japan and not from selling to their customers in Japan. However, territorial restriction clauses will reduce trading volumes and liquidity and increase the buy-side risk that can increase the LNG's price level in the Japanese market. The jurisdiction of Japanese antitrust law can be established as long as the conduct has an anticompetitive effect in the Japanese market, and if the JFTC would succeed in establishing the collective anticompetitive effect in the Japanese market, that could mean that the JFTC would have overcome the jurisdictional challenge.

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[9] *See above at* 2, p. 10.

[10] In addition to Australia, Qatar and Malaysia, the USA and Brunei have also penetrated the Japanese LNG market.

[11] See judgment of the General Court in Case T-65/98 *Van den Bergh Foods v Commission* [2003] ECR II-4653; see also judgment of European Court of Justice in Case C-234/89 *Delimitis v Henninger Bräu* [1991] ECR I-935.

Points for LNG Traders/Sellers to Consider

Territorial restriction clauses in new long-term LNG supply contracts to Japan are unlikely to be a sound basis to plan for new liquefaction projects.

Consider whether existing projects supplying LNG to Japan are adversely affected by this reform; in particular, as a matter of contract whether the change to territorial restriction affects the buyer's obligations to purchase gas at the agreed price. These supply contracts typically support limited recourse project financing of liquefaction projects.

Territorial restrictions in LNG supply contracts are unlikely to be removed abruptly. Nevertheless, suppliers are encouraged to engage with the JFTC at an early stage to provide evidence of the disruptive effects that a sudden change in the LNG supply contracts could have for consumers and market stability. Whilst METI is exerting pressure on suppliers to remove export bans, there should be a transition period to allow the parties to renegotiate their contractual arrangements. Parties should consider how long this needs to be.

This renegotiation period will only be efficient if coupled by clear guidance issued by the JFTC explaining exactly what territorial restrictions would breach the antitrust provisions and in which circumstances. Parties and their advisers should consider what sensible thresholds or filters could be used in this guidance.

MEMR Regulation 10 of 2017 of Indonesia: Blurring the Lines

By Bill McCormack and Jean-Louis Neves Mandelli

Indonesia's state-owned power company, PT PLN (Persero) (PLN) has a long track record of successfully financed independent power projects (IPPs) and a very well established form of power purchase agreement (PPA). It has to date succeeded in implementing new government regulations (such as the Currency Law of 2011 requiring the mandatory use of rupiah in transactions within Indonesia) while maintaining the bankability of its PPAs. Regulation 10 of 2017 issued by the Indonesian Ministry of Energy and Mineral Resources (MEMR), which came into force on January 19, 2017, introduces a new regime which applies to all new PPAs entered into by PLN (subject to some exceptions set out below) and potentially to amendments of existing PPAs. This new regime seeks to regulate and—to some extent—amend structures and risk allocations that were previously well understood. It is not yet clear how these will affect the terms of PLN's future PPAs.

This article sets out an analysis of the key terms of Regulation 10 and how it may impact existing and future PLN PPAs.

Scope of Application

Regulation 10 applies to new PPAs to be entered into by PLN after January 19, 2017 in connection with any projects other than "intermittent" power generation projects (which we understand to mean solar and wind projects), hydropower projects below 10MW, biomass power projects and municipal waste-to-power projects (Article 2). PPAs in respect of which the bidding had been completed and PPAs which were at preferred bidder stage, in each case, as at January 19, 2017, are also excluded from the scope of application of Regulation 10 (Article 31).

If Regulation 10 applies to a PPA, then the terms of the PPA cannot conflict with the terms of Regulation 10. However, where a matter is not specifically addressed in Regulation 10, we understand that this can be freely negotiated with PLN. This is a key principle for the interpretation of Regulation 10 and one which may be very helpful when it comes to reflecting its requirements into new PPAs.

It was initially unclear whether and to what extent existing PPAs may be affected by Regulation 10 if they are amended after its entry into force. Based on the discussions we have had to date with the MEMR and PLN, we understand that existing PPAs should be exempted from the terms of Regulation 10 (even if amended in future).

Analysis of Key Potential Changes

Term

Regulation 10 imposes a maximum term of 30 years from the Commercial Operations Date (taking into account the technical features of the particular project) (Article 4(1)). A maximum 30-year operating period for a PPA is consistent with (if not longer than) practice in Indonesia and other jurisdictions. Typically, coal-fired (non-mine-mouth) PPAs in Indonesia have a 25-year term; mine-mouth and hydro PPAs 30 years and gas-fired PPAs 20 – 25 years.

Under Regulation 10, PPA tariffs should include a capital cost recovery component for at least the first 20 years (Article 4(4)). However, PLN's obligation to purchase electricity is expressed as applying "taking into consideration the repayment period under the financing arrangements" (Article 6(3)). We understand that Article 6(3) is not intended to limit PLN's obligation to make tariff payments but to act as a guiding principle to PLN when discussing the structure of the capital cost recovery component. It is not clear how Article 4(4) and 6(3) would operate in the context of a financing with a tenor of less than 20 years from commercial operation. We would expect borrowers and lenders to want to ensure that the capital cost recovery component under the tariff allows for an adequate debt service coverage ratio during the tenor of the loans even if the cost recovery period under the tariff is longer.

This may mean that borrowers will seek a higher cost recovery during the earlier years of the PPA term. This is not uncommon for PLN PPAs, however, if such a structure may no longer be possible in light of MEMR Regulation 24 of 2017 (which came into force on March 23, 2017). This regulation suggests that the tariff applicable to any new PPA entered into by PLN—irrespective of the technology—would be determined by reference to the average generating price for the preceding year in the area where that project is to be located. This had been anticipated for renewable energy projects (see our article on Regulation 12) but not for other power projects.

BOOT Structure

Article 4(3) of Regulation 10 requires all PPAs to be entered into on a "build own operate transfer" basis. Most PLN PPAs signed to date (except for geothermal and hydropower PPAs) have effectively been entered into on a "build own operate transfer" basis, although this was not a legal requirement. As such, the "build own operate transfer" structure should not materially change the risk allocation. However, it would prevent sponsors from seeking to negotiate an extension to the initial PPA term in cases where this was permitted.

Currently, most PLN PPAs contemplate that in case of termination for generator default, there would only be a transfer to PLN if PLN elects to acquire the project assets. We assume that this would continue to be the case for PPAs entered into under Regulation 10.

Changes to Risk Allocation

Although in many respects Regulation 10 codifies a division of risk and responsibilities, which is consistent with PLN's precedent PPAs, it appears to introduce certain changes to this—particularly in respect of political risk and PLN grid risk.

<u>Political risk</u> – Typically, PLN agrees that the generator will be excused from performing its obligations under the PPA to the extent it is prevented from performing its obligations as a result of events of a political nature such as wars, civil disturbances, changes in law and actions or inactions without justifiable cause by Indonesian government instrumentalities. If a change in law or any acts or omissions of Indonesian government instrumentalities prevent the generator from performing its obligations, the generator is also typically entitled to revenue compensation by being deemed to be available to generate power ("Deemed Dispatch Payment"). Should these circumstances persist for a protracted period of time, the generator usually also has the right to terminate the PPA and require PLN to purchase the project in exchange for a termination payment which is intended to allow the repayment of outstanding debt and the recovery of equity investments plus a return. The generator may also be entitled to an adjustment to the tariff to compensate for increased costs resulting from a change in law.

One of the key changes introduced by Regulation 10 relates to the allocation of change in law risk. Article 8(2) states that change in law is a risk that is borne both by the generator and PLN, and Article 28(7) states that PLN would be entitled to relief from its obligations in case a "change in government policy" causes a stoppage of the power plant. This could be read to mean that the generator would no longer be entitled to Deemed Dispatch Payment from PLN.

While PLN is a state-owned enterprise rather than the state itself, meaning there may be a rationale for not taking change in law risk, it is not clear how this risk would now be addressed if the intention is indeed to relieve PLN from its payment obligations in these circumstances. While the generator would remain entitled to a tariff adjustment to recover additional costs resulting from a change in law, this does not appear to allow for recovery of lost revenue.

Article 28 lists both "change in law" and "change in government policy" as different types of force majeure, each giving rise to different consequences, with the former entitling the generator to a tariff adjustment and the latter relieving PLN from its obligations. It is not clear how these two concepts differ. Taking their literal meaning, a change in law is usually the consequence of implementing a change in policy but a change in policy alone may have no impact on Indonesian law (unless it translates into a change in law). It is difficult to understand why a change in policy would affect a project in the absence of a change in law (or why it would grant greater relief to PLN than a change in law).

We also note that the force majeure concept set out in Regulation 10 does not specifically list acts or omissions of Indonesian government instrumentalities. While we understand that the instances of force majeure in Regulation 10 should not be read as exclusive and that—as a matter of law—the parties should be able to agree to additional force majeure circumstances in the PPA negotiations, whether this will be the case in practice will depend on PLN's interpretation of the regulation.

<u>Grid risk</u> – Typically, PLN is required to continue to make capacity payments on a "deemed dispatch" basis under its PPAs even if it is not able to take power as a result of a force majeure event affecting the Indonesian grid. This is consistent with the typical project finance approach. However, Article 6(2) of Regulation 10 provides that PLN will only be required to make these payments if the grid is affected by reasons other than force majeure. This could be read as meaning that there would be no right to receive deemed dispatch payments at all if the grid is affected by a force majeure event, resulting in losses of revenue for the generator and affecting its ability to meet its operating costs and debt service obligations. For natural disasters, the generator will be entitled to an extension to the term of the PPA to recover the lost revenues, which would help mitigate the grid risk. However, this reading would still represent a significant shift from the typical position PLN has taken in its PPAs.

A different view of how Article 6(2) would be implemented is possible. Most recent PLN PPAs include a right to receive deemed dispatch if the grid is affected by force majeure only after a waiting period (usually 14 to 28 days). It may be that there would still be a right to deemed dispatch but subject to a waiting period, as is presently the case. This would be preferable from a bankability perspective.

<u>Fuel risk</u> – Expressed in Regulation 10 as being borne by the generator, this is consistent with the general regime applicable in the context of thermal IPPs (including PLN PPAs), as the generator is typically not considered available to generate power (and entitled to capacity payments) if it does not have access to fuel. We would note that PLN PPAs usually include an exception to this rule in circumstances where there is no fuel as a result of a "government force majeure" (i.e., a political risk which PLN usually takes the risk on). It is not clear whether this would cease to be the case.

We also note that there are circumstances where PLN may be procuring the fuel for the project. This is an option foreseen by Regulation 10. In these circumstances, the generator would not be responsible for supplying fuel. However, it is unclear whether PLN will fully take the supply risk (including compensation for the generator's lost revenues in case of failure to supply). Recent PPAs indicate that if PLN is responsible for supply and there is an interruption, PLN would require a waiting period before entitlement to deemed dispatch. This may be more of an issue for gas/LNG than for coal, since typically coal projects maintain a stockpile on site. Article 14(2)(c) envisages that where PLN is procuring the fuel, the fuel supplier must guarantee the continuity of gas supply and pay penalties in case of failure to supply. We would not usually expect third-party fuel suppliers to IPPs to agree to fully compensate the generator against revenue loss due to the limited value of the fuel supply arrangements. It is not clear whether PLN is proposing that the generator should only be entitled to compensation to the extent provided by the fuel suppliers.

Construction risk – Regulation 10 allows PLN to require the acceleration of the date for the achievement of commercial operations in consideration for an "incentive." We would expect the circumstances in which this right of acceleration can be exercised and the nature (and timing) of the incentive to be subject to significant discussion, as this would have an impact on the construction arrangements and the financing plan.

Operating risk – PLN PPAs typically include a low availability penalty (usually limited to a reduction in revenue) and a heat rate penalty (reducing the fuel cost recovery to the extent the plant is inefficient). Regulation 10 envisages not only these availability and heat rate penalties, but also frequency and ramp rate penalties. It is not clear what impact these may have on the generator's revenues. Regulation 10 also expresses the availability penalties as being calculated on the basis of the amount of costs to be incurred by PLN due to unavailability of energy. This may be over and above a simple reduction in revenue for the generator to the extent of the unavailability. However, there is precedent for both PLN and offtakers in other jurisdictions taking a similar approach. The extent to which this affects a project will depend on the level of penalties PLN is proposing.

Transfer of Ownership

Existing PPAs normally contain a Sponsors Agreement entered into between PLN and the sponsors/shareholders of the generator. Under the Sponsors Agreement, a shareholder typically cannot transfer its shares in the generator until the fifth anniversary of the project's COD except: (i) where it is required under the financing agreements or (ii) to that shareholder's affiliates or to another shareholder's affiliate.

Regulation 10 limits the transfer restriction to COD only. Pre-COD transfers are permitted if a transfer is made to a 90 percent owned affiliate. All other transfers would require PLN consent. We would expect that transfers made by the lenders in the context of an enforcement of share security would be approved up front by PLN.

Conclusion

Regulation 10 introduces some potential key changes to PLN's traditional risk allocation, in particular as concerns the allocation of political risk and grid risk, and the structure of the contract. While Regulation 10 certainly blurs the previously clearly defined lines on which PLN PPAs were structured, whether and to what extent it will affect the bankability of future PLN PPAs is difficult to determine at this stage, and will only become clear as PLN implements PPAs on the basis of this new regulation.

FERC Accelerates Efforts to Integrate Electric Storage Projects Into Jurisdictional Wholesale Markets

By Donna Bobbish

Over the past year, the Federal Energy Regulatory Commission (FERC) has accelerated its efforts to facilitate integration of electric storage projects into wholesale electricity markets subject to its jurisdiction.

Historically, electricity "storage" has consisted of hydroelectric pumped storage projects, which pump water to higher-level reservoirs when electricity demand is low, and allow it to flow downhill through electricity-generating turbines when demand increases. However, over the past two decades, new electricity storage technologies have entered the market. These technologies include batteries (lead acid, lithium ion, sodium sulfur, flow, dry cell); flywheels (mechanical devices that harness rotational energy to deliver instantaneous electricity); compressed air energy storage that uses electricity to compress air, then expand it through a turbine to generate electricity later; electrochemical capacitors that store electricity in an electrostatic charge; and thermal energy storage that either uses heat sinks like molten salts to store heat energy, which can either generate electricity or provide heating later, or uses electricity that can be used to freeze water into ice, which can be used to provide air conditioning later.

As defined by FERC, an "electric storage resource" is a resource "capable of receiving electric energy from the grid and storing it for later injection of electricity back to the grid regardless of where the resource is located on the electrical system."

Within electricity markets, electric storage resources have provided bulk energy services, ancillary services (frequency regulation, energy management, backup power and load leveling), and transmission services (voltage support and grid stabilization).

In April 2016, FERC's staff sent data requests to Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs). These requests sought information about whether barriers exist to the participation of electric storage resources in the capacity, energy and ancillary services markets operated by the six FERC jurisdictional RTOs and ISOs that could lead to unjust and unreasonable rates for wholesale sales of electricity, which are prohibited by the Federal Power Act (FPA). In addition, the staff wanted to know whether any changes to RTO and ISO tariffs are necessary if such barriers exist. (*See Energy Update*, Vol. 3, Issue 3, September 2016). FERC also convened a technical conference in November 2016 to discuss utilization of electric storage resources as transmission assets compensated through transmission rates, for grid support services that are compensated in other ways and for multiple services.

Following its review of the information obtained through the data request and technical conference, and prior to the inauguration of President Trump, FERC took two actions to increase the ability of electric storage resources to participate in wholesale electricity markets and clarified its policy with respect to the rates that may be charged by electric storage resources participating in wholesale markets. In January 2017, FERC issued a Policy Statement giving guidance on the ability of electric storage resources to provide transmission or grid support services at cost-based rates while, at the same time, providing other services, such as power sales, at market-based rates.[12] In mid-November 2016, FERC issued a Notice of Proposed Rulemaking (NOPR) to amend its regulations under the FPA and remove barriers that prevented electric storage resources and distributed energy resource aggregators to participate in the capacity, energy, and ancillary service markets operated by the six RTOs and ISOs subject to FERC jurisdiction.[13] These RTOs and ISOs are NYISO, ISO-NE, PJM, MISO, SPP and CAISO.

FERC Policy Statement on Rates Charged by Electric Storage Resources

In its Policy Statement, FERC observed that electric storage resources can both charge and discharge electricity, provide multiple services and switch from providing one service to another almost instantaneously. Based on these characteristics, FERC found that electric storage resources may fit into one or more of the traditional electricity asset functions of generation, transmission and distribution and, further, that an electric storage resource receiving cost-based rate recovery for providing one service also may be technically capable of providing other market-based rate services.

Section 205 of the FPA requires that the rates, terms and conditions of public utilities for the transmission or sale of electricity at wholesale in interstate commerce be on file with FERC, "just and reasonable" and not unduly discriminatory or preferential. Cost-based rates allow a public utility to recover its costs of providing service, allocated among customer classes, and make a reasonable rate of return on its investment. FERC authorizes market-based rates for wholesale sales of electric energy, capacity and ancillary services, where the utility demonstrates that it and its affiliates do not have or have mitigated market power in the relevant market(s), and for merchant transmission.

In the Policy Statement, FERC clarified that, as a matter of policy, an electric storage resource may provide services at both cost-based and market-based rates at the same time, so long as three issues are addressed: the potential for double recovery of costs by the electric storage resource owner or operator to the detriment of cost-based ratepayers; the potential for cost recovery through cost-based rates to inappropriately suppress competitive prices in wholesale electric markets to the detriment of other competitors who do not receive such cost-based rate recovery; and the level of control in the operation of an electric storage resource by an RTO/ISO that could jeopardize its independence from market participants.

As part of its policy guidance, FERC clarified rulings and statements made in two prior orders addressing rates charged by electric storage resources.

With respect to the potential for double recovery of costs by the electric storage resource owner or operator, FERC clarified that, in addition to the approach it approved in its *Western Grid* order,[14] crediting any market revenues back to the cost-based ratepayers is one possible way to address potential double recovery of costs. In *Western Grid*, FERC authorized Western Grid to charge cost-based transmission rates for the provision of voltage support and thermal overload services protection to CAISO because, among other things, Western Grid would operate the energy storage projects, at CAISO's direction, only as transmission assets, and had committed to forego any sales into CAISO's organized wholesale electric markets.

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[12] *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, Policy Statement, Docket No. PL17-2-000 (Jan. 19, 2017) (the "Policy Statement").

[13] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Notice of Proposed Rulemaking, Docket Nos. RM16-23-000 and AD16-20-000 (Nov. 17, 2016) (the "NOPR").

[14] *Western Grid Dev., LLC*, 130 FERC ¶ 61,056, *reh'g denied*, 133 FERC ¶ 61,029 (2010) ("*Western Grid*").

FERC also indicated that where crediting is utilized to address double recovery of costs, the amount of crediting may vary depending on how the cost-based rate recovery is structured. In a case where the costs of an electric storage resource is recovered through cost-based rates, the electric storage resource owner or operator may credit all projected market revenues earned by the electric storage resource over a reasonable period of time (expected useful life of the asset or the term of the cost-based rate services). Alternatively, the market-revenue off-set can be used to reduce the amount of the revenue requirement to be used in the development of the cost-based rate.

With respect to the second issue, the potential for cost recovery through cost-based rates to inappropriately suppress competitive prices in wholesale electric markets, FERC stated that it was "not convinced" by commenters' arguments that allowing electric storage resources to receive concurrently cost- and market-based revenues for providing separate services will undermine competition or suppress market prices to subcompetitive levels. Denying electric storage resources the opportunity to earn cost-based and market-based revenues on the theory that dual revenue streams undermine competition would require revisiting years of precedent allowing concurrently cost-based and market-based sales for reactive power and market-based rate wholesale sales, and for cost-based sales to captive wholesale requirements customers and off-system market-based rate sales. FERC also said that the concern that electric storage resources would suppress market clearing prices by offering services for which they receive cost-based rates could be addressed by the manner in which the costs that are included in the cost-based rates are established.

With respect to the third issue, maintaining RTO/ISO independence from market participants, FERC clarified its previous conclusion in its *Nevada Hydro*[15] order that it would not be appropriate to require CAISO to assume "any level of operation control" over Nevada Hydro's hydroelectric pumped storage project. "There is nothing unreasonable about an RTO/ISO exercising some level of control over the resources it commits or dispatches where it can be shown that the RTO/ISO independence is not an issue," FERC said. In *Nevada Hydro*, FERC denied Nevada Hydro's request to treat its pumped storage project as a transmission facility under the operational control of CAISO for rate recovery purposes. FERC agreed with CAISO that under Nevada Hydro's proposal, CAISO would have to decide when the LEAPS project would operate, how much energy it would provide and when it would operate the pumps to store water for future electricity generation, compromising CAISO's independence.

FERC further stated that in order to ensure RTO/ISO independence, the provision of market-based rate service should be under the control of the electric storage resource owner or operator, rather than the RTO/ISO. Where a service compensated though cost-based rates is needed, the RTO/ISO should give priority to the dispatch of the electric storage resource to address over the electric storage resource's provision of market-based rate services. Performance penalties could be imposed on the electric storage resource owner or operator for failure to perform at these times.

FERC NOPR on Participation by Electric Storage Resources in Wholesale Electricity Markets

In the NOPR, FERC found that, currently, resource participation in wholesale electric markets operated by RTOs and ISOs is governed by participation models consisting of market rules designed for different types of resources and technical requirements for market services that those resources are eligible to provide. To address this, FERC proposed, among other things, to require each RTO/ISO to revise its tariff to include market rules that accommodate the participation of electric storage resources organized as wholesale electric markets, recognizing the physical and operational characteristics of electric storage resources.

[15] *Nevada Hydro Co., Inc.*, 122 FERC ¶ 61,272 (2008), *reh'g denied*, 133 FERC ¶ 61,155 (2010) ("*Nevada Hydro*").

Under the NOPR, RTO/ISO market rules would have to satisfy numerous requirements.

First, electric storage resources must be eligible to provide all capacity, energy and ancillary services that they are technically capable of providing. With respect to this requirement, FERC also proposes that electric storage resources should be able to provide services that the RTOs/ISOs do not procure through a market mechanism, such as blackstart, primary frequency response and reactive power, if they are technically capable. Where compensation for these services exists, electric storage resources also should receive such compensation commensurate with the services provided. FERC proposes to require each RTO/ISO to revise its tariff to clarify that an electric storage resource may de-rate its capacity to meet minimum run-time requirements to provide capacity or other services. RTOs/ISOs with capacity markets that de-rate capacity value for electric storage resources must be consistent with the quantity of energy required to be offered into the day-ahead energy markets for resources with capacity obligations.

Second, bidding parameters (the physical and operational constraints that a resource would identify when submitting offers to sell capacity, energy or ancillary services or bids to buy energy in wholesale electric markets) incorporated in the participation model must reflect and account for the physical and operational characteristics of electric storage resources. With respect to this requirement, FERC explained that bidding parameters allow the RTO/ISO to model and dispatch the resource consistent with its operational constraints. FERC found that by requiring electric storage resources to use bidding parameters developed for traditional generators or other supply resources, RTOs/ISOs may fail to effectively utilize these resources, possibly precluding electric storage resources from providing all of the services that they are physically and technically capable of providing. FERC found that resource bidding parameters vary greatly between RTOs/ISOs. Some require the same bidding parameters from all resources offering into a specific market, while others tie bidding parameters to specific participation models. FERC proposed that the RTOs/ISOs establish state of charge, upper charge limit, lower charge limit, maximum energy charge rate and maximum energy discharge rate as bidding parameters for the participation model. FERC proposes to require that RTO/ISO participation models include the four bidding parameters that market participants may submit, at their discretion, for their resource based on its physical constraints or desired operation: minimum charge time, maximum charge time, minimum run time and maximum run time. Where the RTO/ISO has reserved for itself the right to manage the state of charge of an electric storage resource, FERC proposes to require that the RTOs/ISOs allow electric storage resources to self-manage their state of charge and upper and lower charge limits.

Third, electric storage resources can be dispatched and set the wholesale market clearing prices as both a wholesale seller and a wholesale buyer consistent with existing rules that govern when a resource can set the wholesale price. FERC proposed to require RTOs and ISOs to accept wholesale bids from electric storage resources to buy energy so that the economic preferences of these resources are fully integrated in the market; the electric storage resource can set the price as a load resource where market rules allow and can be available to the RTO/ISO as a dispatchable demand asset. However, these requirements must not prohibit electric storage resources from participating in wholesale electric markets as price takers.

Fourth, the minimum size requirement for electric storage resources to participate in the organized wholesale electric market must not exceed 100 kW. FERC concluded on a preliminary basis that such a minimum size requirement would balance the benefits of increased competition with the ability of RTO/ISO market clearing software to effectively model and dispatch smaller resources often located on the distribution system. FERC proposed to require each RTO/ISO to revise its tariff to include a participation model for electric storage resources that establishes a minimum size requirement for participation in wholesale markets not exceeding 100 kW, including any minimum capacity requirements, minimum offer requirements and minimum bid requirements for resources participating in these markets under the electric storage resource participation model.

Fifth, the sale of energy from the organized wholesale electric markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price (LMP). With respect to this requirement, FERC states that it previously has found that the sale of energy from the grid that is used to charge electric storage resources for later resale constitutes a FERC jurisdictional wholesale sale and, as such, the just and reasonable rate for that sale is the RTO/ISO market's wholesale price for energy, or LMP. FERC observed that the manner in which an electric storage resource charges (consumes) and discharges (produces) energy will determine whether the electric storage resource is making a jurisdictional sale for resale. In the NOPR, FERC proposes to require each RTO/ISO to revise its tariff to specify that the wholesale LMP is required for the sale of energy from wholesale electric markets to an electric storage resource that the resource then resells back to those markets.

Next Steps

Following its review of comments filed in response to the NOPR, FERC will decide whether to issue a Final Order implementing some or all of the proposals contained in the NOPR. However, FERC cannot issue a Final Order until there is a quorum of Commissioners. It is likely that when the full FERC considers any staff proposal with respect to a Final Order, only one FERC commissioner who voted on the NOPR will still be on the Commission.

Prior to losing its quorum in early February, FERC implemented some of its NOPR proposals in an order granting the request of Indianapolis Power & Light Company (IPL) that it find MISO's tariff to be unjust, unreasonable and unduly discriminatory because it unnecessarily restricts competition by preventing electric storage resources from providing all the services that they are technically capable of providing, which could lead to unjust and unreasonable rates.[16] IPL had argued that its Battery Facility, a grid-scale lithium ion battery-based energy storage system containing a 20 MW array of lithium ion cells, can provide nearly instantaneous primary frequency response and could become a "Load Modifying Resource" under MISO Tariff that could provide five MW of capacity or Planning Reserve Margin Requirement. IPL also argued that its Battery Facility already was providing primary frequency response, but there was no provision in MISO's Tariff to compensate IPL for this reliability service.

In its order responding to IPL's complaint, FERC found that although an electric storage resource, such as IPL's Battery Facility, can participate in MISO as a "Stored Energy Resource," this resource category limits the resource to participation in MISO's regulation market and does not allow it to qualify for capacity, energy, ramp capability and contingency reserves. FERC directed MISO to submit a compliance filing proposing Tariff revisions that accommodate participation of all electric storage resources, regardless of technology, in all MISO markets that they are technically capable of participating in, taking into account their unique physical and operational characteristics. This requirement is similar to the proposed RTO/ISO tariff revisions in the NOPR.

FERC recognized that the issue raised in IPL's complaint currently is being addressed in its NOPR and stated that, in the event that MISO's Tariff revisions conflict with required Tariff revisions in any final rule resulting from the NOPR, MISO may be required to adjust its Tariff to align with FERC's determination in the final rule.

[16] *Indianapolis Power & Light Company v. Midcontinent Independent System Operator, Inc.*, "Order Granting Complaint in Part and Denying Complaint in Part," 158 FERC ¶ 61,107 (2017).

MISO has requested rehearing of FERC's order. As is the case with the NOPR, FERC cannot act on the rehearing request until it has a quorum of Commissioners. On May 8, President Trump announced his intention to nominate Neil Chatterjee, energy policy advisor to Senator Mitch McConnell (R-KY), and Robert F. Powelson, a commissioner on the Pennsylvania Public Utilities Commission and current President of the National Association of Utility Regulatory Commissioners, to two of the open Republican seats on FERC.

Indonesia's MEMR Regulation 12: A Step Forward or a Step Back?

By Bill McCormack and Jean-Louis Neves Mandelli

Despite a significant renewable energy potential, Indonesia currently only produces six percent of its electricity from renewable energy. The Indonesian government is targeting increasing this to 23 percent by 2025. Many view this as ambitious given the pace at which renewable energy projects have been developed in Indonesia in recent years.

The Indonesian government tried to stimulate investment in renewable energy through higher feed in tariffs in 2014. While this may have made Indonesian renewable energy projects a more attractive financial proposition for developers, it also gave rise to disagreements between PT PLN (Persero) (PLN) (Indonesia's state-owned sole offtaker) and other stakeholders on certain projects on the basis that prices were too high.[17] By the end of 2016, the Indonesian government's attitude to renewable energy generation shifted, with new Indonesian energy minister Ignasius Jonan indicating that there was a need to further reform the renewables sector, with a particular focus on reducing feed in tariffs, as it was considered too high compared to the tariffs charged by thermal power plants.[18]

To that effect, the Ministry of Energy and Mineral Resources (MEMR) promulgated Regulation 12 of 2017 ("Regulation 12") on January 30, 2017. Regulation 12 applies to a broad range of renewable energy sources, including solar, wind, hydro, biomass, biogas, municipal waste and geothermal. In respect of each of these renewable energy sources, Regulation 12 imposes: (a) new lower maximum feed in tariffs; and (b) new contracting regimes.

Mr. Jonan has stated that his reforms are intended to encourage investment into the renewable energy sector to help Indonesia reach its 2025 targets.[19] However, many commentators have been critical of these reforms and believe that they may hinder, rather than stimulate, further investment into renewable energy.

Scope of Application

Regulation 12 applies to all renewable projects in Indonesia involving the abovementioned renewable energy sources. There are several exceptions to this including (among others) projects which have signed a power purchase agreement (PPA) with PLN as at the date of the regulation and geothermal projects that have been awarded to a developer.

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[17] http://www.thejakartapost.com/news/2016/01/22/pln-keep-increasing-use-renewable-energy-sources.html

[18] https://en.tempo.co/read/news/2016/12/21/056829535/Jonan-Calls-for-Competitive-Price-for-New-Renewable-Energy

[19] *Ibid.*

Changes to the Feed in Tariffs

One of Mr. Jonan's aims when reforming renewable energy tariffs was to make these more competitive against energy generated from fossil fuels. This is clearly reflected in Regulation 12, which benchmarks all renewable energy tariffs against the "Generating BPP," being the average cost of generating electricity in a local area during the previous year.

As a result, renewable energy tariffs—depending on their location and on the renewable energy source—need to be either lower or equal to the Generating BPP for the relevant area. In respect of all renewable energy sources other than geothermal and urban waste, the maximum permissible tariff is 85 percent of the Generating BPP for the area where the project is to be located (if that area is one where the Generating BPP is above the national average), or the Generating BPP for the area where the project is to be located (if the Generating BPP for that area is less or equal to the national average). Geothermal and urban waste projects have the maximum tariff set at the Generating BPP for projects in areas where the Generating BPP is above the national average. The tariff is subject to negotiation in other areas (including for projects in Sumatra, Java and Bali). The Generating BPP for each area for the period between April 1, 2017 – March 31, 2018 were published by MEMR on March 27, 2017.

If the intention is to require renewable energy projects to have competitive tariffs, benchmarking renewable energy tariffs to the average electricity price in a particular area has—at first glance—an attractive economic logic to it. However, it raises a number of issues.

First, is the average cost of producing electricity in a particular area an appropriate proxy for the cost of producing electricity from renewable energy sources? Most of the power in Indonesia is generated from thermal—and particularly coal-fired—power plants. Not only are these different technologies, but they also have different tariff structures to renewable energy tariffs. For instance, they tend to allow a pass-through of fuel supply costs, which may be affected by changing commodity prices. PLN PPA tariffs also sometimes vary over time (e.g., with capacity charges reducing in later years), meaning that looking at a tariff level for one year may not be representative of the average tariff over the life of a project.

Second, the cost of electricity in Indonesia varies significantly between its regions, tending to be lower in more developed Sumatra, Java and Bali and higher in other areas (which also tend to have lower electrification rates). Linking renewable electricity tariffs to the average local price may lead developers to focus on introducing renewable energy projects in less developed areas—although this may itself come at a higher cost due to the more limited existing infrastructure and grid connectivity.

Third, the Regulation did not clarify certain key aspects of the tariff structure, such as whether it would be US dollar-based (as has been the case for feed in tariffs to date) or rupiah-based. The Generating BPPs published for 2017 – 2018 express the Generating BPP both in rupiahs and US dollars using the average rupiah/US dollar exchange rate for 2016. Having a US dollar Generating BPP is helpful. However, it is not clear whether the PPAs will refer to the US dollar or rupiah value.

Some commentators criticize this approach, noting that it reflects the one taken in respect of geothermal tariffs under Regulation 14/2008, which was reformed shortly after coming into force to allow for the direct negotiation of geothermal tariffs.[20]

[20] http://www.thejakartapost.com/news/2017/02/06/renewable-energy-regulation-repeats-old-mistakes-association.html

Changes to Contracting Regime

Broadly speaking, Regulation 12 introduces two new contracting regimes, one for solar and wind projects, and another (subject to certain variations) for other renewable energy sources. Regulation 12 contemplates the development of a standard set of procurement documents and a standard form PPA for each renewable energy source.

With respect to the form of PPA, based on our experience with PLN to date, we would expect it to broadly follow the terms and risk allocation of precedent PPAs which have been successfully financed, subject to adjustments to reflect the specificities of the relevant renewable energy source.

Solar and Wind Projects

Solar and wind projects will be subject to a tender process based on the capacity that is stated as available in PLN's electricity supply business plan. Each tender package must offer at least 15MW installed capacity and may allow for different locations. This is a departure from the current contracting regime, which is based on a direct negotiation (for wind projects) and the allocation of a capacity quota against a fixed tariff to prequalified developers (for solar projects).

It is unclear whether the price will be the sole criterion for the award of projects to developers. Based on the terms of Regulation 12, it would appear that the bidder offering the lowest price would be awarded the project.

Other Renewable Energy Sources

Projects using other renewable energy sources are subject to either a "reference price" or a direct selection mechanism. There are slight differences between the various renewable energy sources as to which method is used. Hydropower projects seem to allow for both options in all cases, while biomass and biogas projects contemplate a "reference price" mechanism if the project is below 10MW and direct selection if the project is above 10MW, and urban waste and geothermal projects contemplate reference price at all times.

It is not clear from Regulation 12 how the reference price selection mechanism would work, including whether it would be initiated by the developer (as per the direct selection mechanism—see below) or PLN. As this concerns the direct selection mechanism, we assume that this would be similar to the mechanism that has been used in the context of several renewable energy sources so far (such as wind projects), whereby the developer will submit a proposal for a project to PLN for consideration and PLN may, if it considers the project to be eligible for direct selection, propose the direct selection of the project to MEMR.

In the context of hydropower projects, Regulation 12 does not explain in what circumstances a reference price would be used and when a direct selection would be used.

Conclusion

Regulation 12 is a significant departure from the regime previously applicable to renewable energy projects. MEMR's objective of making renewable power tariffs more competitive comes across very clearly in the regulation by benchmarking renewable power tariffs against the average cost of power production in a particular area. Some of the new contracting regimes proposed by MEMR are still unclear. We would expect these will be clarified once the forms of procurement documentation and PPAs are published. While the reduction in renewable tariffs will hopefully encourage PLN to pursue the development of renewable energy projects, whether this new regime will translate into a surge of new renewable energy projects remains to be seen.

Editors

Robert N. Freedman
Partner
New York
T: +1 212 848 4340
robert.freedman@shearman.com

Patricia G. Hammes
Partner
Washington, DC
T: +1 202 508 8110
phammes@shearman.com

Contributing Authors

Bill McCormack
Partner
Singapore
T: +65 6230 3877
wmccormack@shearman.com

Anthony Patten
Partner
Singapore
T: +65 6230 3892
anthony.patten@shearman.com

James Webber
Partner
London
T: +44 20 7655 5691
james.webber@shearman.com

Donna J. Bobbish
Counsel
Washington, DC
T: +1 202 508 8089
donna.bobbish@shearman.com

Gerald M. Feige
Counsel
Washington, DC
T: +1 202 508 8115
gerald.feige@shearman.com

Jean-Louis Neves Mandelli
Associate
Singapore
T: +65 6230 3834
jean-louis.nevesmandelli@shearman.com