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PROJECT FINANCE

# NewsWire

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# Searching for Opportunities in the Inflation Reduction Act

*by Keith Martin, in Washington*

Companies are scrambling to assess the effects of the Inflation Reduction Act on their projects.

The tax equity market will look different. Tax credits after this year can be sold for cash.

Tax benefits on some 2022 projects will be higher than the developers expected.

Bidders to supply electricity or buy projects are reworking bids.

The Internal Revenue Service rushed out guidance on new electric vehicle tax credits the same day that President Biden signed the bill, suggesting that guidance on new wage and apprentice requirements may be out sooner than expected. It will trigger a requirement to pay construction workers the same wages that are paid on federal construction jobs and use qualified apprentices for 10% to 15% of total labor hours on projects that are not under construction within 59 days after the guidance is issued.

Construction may slow for the rest of this year on projects that will qualify for higher tax credits if they are not completed until next year. For example, bonus tax credits may be available, depending on the location and the amount of US-made components, but only on projects placed in service in 2023 or later. New tax credits for batteries and equipment to make clean hydrogen and renewable natural gas, and higher tax credits for installing carbon capture equipment, require delaying completion until next year. */ continued page 2*

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**A NEW SEMICONDUCTOR TAX CREDIT** intended to spur construction of new factories may not lead to much tax equity investment.

Companies entitled to such tax credits can apply to the Internal Revenue Service for cash "refunds."

The tax credits are in a CHIPS Act that President Biden signed in early August to boost US competitiveness with China, including by increasing US output of semiconductors.

A 25% investment tax credit can be claimed on new factories and expansion of existing factories — called "fabs" — to make semiconductors and semiconductor manufacturing equipment. The */ continued page 3*

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## Inflation Reduction Act

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Manufacturers will look to do more manufacturing in the United States. The government will pay part of the cost to make components for solar, wind and storage projects and lithium, graphite and other basic minerals. Manufacturers will qualify for tax credits on each such component or mineral produced and sold during the period 2023 through 2032. They can apply to the Internal Revenue Service for cash "refunds" of the tax credits for up to five tax years. The articles must be made in the United States and sold to an unrelated party.

The dynamics of some contract negotiations will shift.

Some manufacturers who were demanding premiums to sell articles made in the United States to help developers earn bonus credits for using domestic content may find the tables turned now that they qualify for large tax credits.

Utilities that were willing to renegotiate power contracts to accommodate higher-than-expected construction costs due to tangled supply chains and labor shortages may now look to developers to temper their requests.

Batteries will no longer have to be coupled with solar projects in order to qualify for tax credits. This will lead to a change in how power contracts and tolling agreements for use of batteries will be written for future projects. Solar companies will no longer have to be careful to avoid charging during the first five years from the grid for new batteries placed in service after this year.

Solar companies will have to rethink whether to claim production tax credits on the electricity output over 10 years rather than an investment tax credit in the year projects are placed in service. Many developers retained the option in tax equity papers this year to move to production tax credits if the option became available. Tax equity investors for the most part agreed to take a good-faith look at restructuring, but without making a firm commitment.

Some wind and solar projects completed after this year will qualify for production tax credits on the electricity output and an investment tax credit on the battery in cases where the generating equipment and battery are considered separate "facilities."

The race to get more projects under construction before the IRS issues guidance on the new wage and apprentice requirements promises to create a year-end traffic jam in front of main power transformer, nacelle and other vendors.

Municipal utilities, community choice aggregators, rural electric cooperatives, the Tennessee Valley Authority and Indian tribes may rethink whether to own renewable energy projects directly rather than buy electricity. The bill lets them receive cash "refunds" of tax credits from the IRS on projects they own.

Some developers may turn power contracts with such entities into leases to pass through investment tax credits that the lessee may be able to apply to the IRS to have refunded in cash. This structure may require IRS confirmation. It does not work for projects on which production tax credits will be claimed on the electricity output or that will be placed in service before next year.

More carbon capture transactions will become economic. The market will expand focus from the ethanol and fertilizer plants where the economics worked best to the next low-hanging fruit.

Some carbon capture transactions already in process will have to be reworked. The federal government puts a lot of money on the table in the form of carbon capture credits. The deal structure is a function of who needs what share and what labels to put on the money transfers. The higher tax credits may require shifts in the money flows, particularly in projects with low-carbon fuel standard, or LCFS, credits.

**Tax benefits on some 2022 projects will be higher than expected.**

Offshore wind has become a better bet. Developers now have the option to claim production tax credits on the electricity output. They will also have until sometime in the 2030s to start construction to qualify for tax credits at full rates and another 10 years after that to finish construction, giving them a runway into the 2040s to build new projects.

## Basic Points

The Inflation Reduction Act is 728 pages, but it distills to a few basic points.

It restores federal tax credits to the full rate for new renewable energy projects completed in 2022 or later.

The full rate is a 30% investment tax credit or production tax credits of $26 a MWh on the electricity output for 10 years. Production tax credits are adjusted annually for inflation. A new rounding convention for production tax credits will add another $1.50 per MWh for projects completed in 2022 and possibly for projects that are completed in the next two years or that start construction by the end of 2024, depending on the inflation rate.

The tax credits will remain at this level at least into the early 2030s.

The ITC could reach as high as 50% — in some cases even 70% — depending on the location of the project and whether it uses domestic content, but only for projects that are completed in 2023 or later. PTCs would increase as well.

The tax credit amounts would start to phase down after annual greenhouse gas emissions from US electricity generation fall by at least 75% from 2022 levels, but not before 2032.

Projects starting construction two years after the phase down starts would qualify for tax credits at 75% of the full rate. Projects starting construction three years after would qualify for tax credits at 50% of the full rate. Thus, for example, if the phase out trigger is reached in 2032, projects starting construction in 2033 would still qualify for tax credits at the full rate.

The bill provides a new 30% investment tax credit for standalone storage. Pumped-storage hydroelectric projects, which are essentially large water batteries, qualify for this tax credit as standalone storage.

There are also new tax credits for making clean hydrogen or renewable natural gas and for manufacturers who make components for wind, solar and storage projects and basic minerals.

Solar developers will have the option to claim PTCs instead of ITCs on projects placed in service in 2022 or later.

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credit can only be claimed on such facilities put in service in 2023 or later. Any such facility on which tax credits are claimed must be under construction for tax purposes by the end of 2026.

The tax credit may not be claimed on tax basis built up before 2023 if the facility or expansion was under construction by the end of 2022.

The tax basis in the facility must be reduced by the full investment tax credit claimed.

The new tax credits can be found in section 48D of the US tax code.

Investment tax credits can usually be claimed only on new equipment, but not on buildings. In this case, the credit may also be claimed on buildings and "structural improvements," but not the part of the building used for offices, administrative services or other functions unrelated to manufacturing.

The credits cannot be claimed by a company "owned by, controlled by, or subject to the jurisdiction or direction of a government of" China, Russia, North Korea or Iran or by any company that has materially expanded its semiconductor manufacturing capacity in one of the four countries during the same tax year.

In fact, a material expansion of semiconductor manufacturing capacity in one of the four countries at any time during the next 10 years after the new factory or factory expansion is put in service will lead to full recapture of the tax credits. A company will have 45 days after being sent a recapture notice by the IRS to "cease or abandon" the expansion to avoid recapture.

Otherwise, normal recapture rules apply. Thus, for example, a sale of the facility within five years after it is completed would trigger recapture of the unvested investment tax credit. The tax credit vests ratably over five years.

Semiconductor manufacturing facilities are depreciated using five-year MACRS depreciation, meaning on a front-loaded basis. That, plus a 25% investment tax */ continued page 5*

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Tax credits for new transmission lines failed to make the cut. There was a feeling on Capitol Hill that economics are less of an impediment to building new transmission lines than inability to get permits. The Senate majority leader, Chuck Schumer (D-NY), agreed to a separate side deal on permitting reform with Senator Joe Manchin (D-WV) as part of the price for Manchin's support. Democrats will attempt to put the permitting deal through the Senate by folding it into a must-pass bill to keep the federal government operating past the fiscal year end on September 30. (For more details about the possible permitting reforms, see the "Environmental Update" in the August 2022 *NewsWire*.)

Tax credits after this year can be sold for cash.

### Tax Equity

Starting next year, companies will be allowed to sell most energy-related tax credits to other companies without having to resort to complicated tax equity structures. The seller will not have to report the cash purchase price as income.

The buyer must pay cash. It cannot be related to the seller.

The seller can sell all or part of its tax credits. It can decide each year how much to sell.

In cases where a project is owned by a partnership, the partnership sells the tax credits.

The bill also allows most energy-related tax credits that a company cannot use to be carried back three years to get refunds of taxes paid in the past and to carry any remaining tax credits forward for up to 22 years (rather than the current 1-year carryback and 20-year carryforward). This change does not take effect until 2023. Tax credits that are carried backward or forward cannot be sold.

The renewable energy industry had been hoping for a "direct-pay" alternative to tax credits where companies could be paid the full cash value of the tax credits by the IRS under a tax refund mechanism.

A narrow direct-pay provision is in the bill, but with the exception of three types of tax credits, it is limited to tax-exempt entities, state and local governments, rural electric cooperatives, the Tennessee Valley Authority, Indian tribes and Alaskan native claims corporations.

The three types of tax credits that real taxpayers can ask the IRS to pay them in cash are section 45Q credits for capturing carbon emissions, production tax credits for making clean hydrogen and production tax credits for "advanced manufacturing" of components for wind, solar and storage projects and basic minerals.

It will probably be better to wait for an IRS refund for 100% of the credit amount in cash rather than sell these three types of tax credits to third parties for less than the full credit amount. However, direct payments to private parties would only be made for one to five years of credits.

Tax equity will still remain of interest to many developers, particularly those claiming investment tax credits. The tax equity market continued to function during the period 2009 through 2016 when developers had the option to receive cash payments in lieu of tax credits directly from the US Treasury.

The tax basis used to calculate tax benefits can be stepped up to fair market value in a tax equity transaction unlike a direct tax credit sale.

There will be longer time lags to get IRS refunds than for the Treasury cash grants. A developer could apply for a cash grant immediately after a project went into service. Applications for IRS cash "refunds" will lag by a year. The application is filed with the tax return for the year the project went into service.

Developers who want to monetize depreciation will have to do so through tax equity transactions. The tax savings from 5-year MACRS depreciation are worth 14¢ per dollar of capital cost on top of at least 30¢ per dollar of capital cost for tax credits.

On the other hand, tax credit sales will put less strain on cash flow. In most solar partnership flip transactions, project companies are sold to tax equity partnerships near the end of construction. The developer must contribute part of the capital the partnership requires to pay the purchase price. No such contributions would be required in a tax credit sale.

There are tight deadlines to close tax equity deals involving investment tax credits. There will not be the same tight deadlines in tax credit sales.

The direct-sale market will take time to develop.

Direct sales could democratize access to capital in theory. In practice, smaller developers are likely to have trouble finding buyers because buyers will want creditworthy sellers who can stand behind tax indemnities in the event the tax credits are not as promised. In 1981 and 1982 when the US had a version of tax credit sales called "safe-harbor leasing," companies with poor credit had to buy insurance from Lloyd's syndicates to backstop the indemnities.

Tax credit sales may revive interest in paying developer fees that can add to tax basis for calculating tax credits. Interest in such fees waned after Invenergy lost two court cases in which the government successfully disallowed developer fees on two wind projects. (For more detail, see "California Ridge: Developer Fees Struck Down — Again" in the May 2020 *NewsWire*.)

The bill gives the IRS authority to collect 120% of any "excessive payment" where an inappropriately high tax basis is used in a tax credit sale.

## Fine Print

The tax credits in the Inflation Reduction Act come with two sets of fine print.

Project owners must make sure their construction contractors pay laborers and mechanics the same Davis-Bacon wages that are paid on federal construction jobs not only during construction, but also on later repairs and improvements during the period PTCs are claimed or any ITC claimed remains subject to recapture.

The contractor must also use qualified apprentices for 10% to 15% of total labor hours during the same period.

These requirements will not apply to any project on which construction starts no later than 59 days after the IRS issues guidance to implement the wage and apprentice requirements or that is less than one megawatt AC in size.

The IRS started working on the wage and apprentice guidance at the urging of labor unions before the bill was signed.

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credit, would normally make it worthwhile for any company that cannot use the tax benefits efficiently to consider tapping into the tax equity market.

However, the companies entitled to the tax credits can choose to have the IRS pay the cash value. The payment is considered a tax refund and will not be taxed. The refunds would be paid with a time lag. A company must apply for a refund by the due date, including extensions, for its tax return for the year in which the new fab or expansion is placed in service.

In cases where the fab is owned by a partnership, the partnership applies for the refund.

Semiconductor manufacturers without tax capacity may still decide to raise tax equity in some cases.

Raising tax equity provides an opportunity to sell the completed factory or expansion train into a tax equity vehicle at the fair market value of the facility at the end of construction, thereby letting both the tax credit and depreciation be calculated on a higher tax basis.

Applying to the IRS for a refund of the investment tax credit leaves the depreciation unused. The tax savings from depreciation have a present value, if used efficiently, of roughly 14¢ per dollar of capital cost of the factory or factory expansion. The tax credits are worth 25¢ per dollar of capital cost. Failure to monetize the depreciation would leave significant value on the table.

Any sale of the factory or expansion train to a tax equity partnership would have to be done before the facility is placed in service. Otherwise, the tax equity investor will be unable to share in the investment tax credit. (See "Partnership Flips: Structures and Issues" in the February 2021 *NewsWire*.)

A sale-leaseback — another form of tax equity transaction — could be put in place within three months after the facility is placed in service. Another potential structure is an inverted lease where the / continued page 7

## Inflation Reduction Act

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### Possible 50% ITC

The bill has domestic content requirements that are both a carrot and a stick.

The carrot is the ability to claim as much as an extra 10% investment tax credit (or a 10% increase in PTC amount) by using domestic content.

Domestic content means all steel, iron and manufactured products must be produced in the United States. Manufactured products would be considered US made if at least 40% of all the manufactured products used in the project are US made. The percentage would increase for projects that start construction after 2024 and eventually reach 55% for projects with 2027 or later construction-start dates. The percentage for offshore wind projects would start at 20% and increase over time, reaching 55% for projects with 2028 or later construction starts.

The stick is inability to receive a direct cash payment in lieu of tax credits from the IRS. However, since the bill narrowed direct pay essentially to tax-exempt and government entities, this is not much of a stick, other than for carbon capture and hydrogen projects.

Projects in "energy communities" will qualify for as much as another 10% ITC (or another 10% increase in PTC amount).

Energy communities are brownfield sites and two other locations.

One is metropolitan or non-metropolitan statistical areas that have, or had at any time after 2009, at least 0.17% direct employment or at least 25% local tax revenues related to "extraction, processing, transport, or storage of coal, oil, or natural gas" and have an unemployment rate at or above the national average.

The other location is census tracts where a coal mine closed after 1999 or a coal-fired generating "unit" retired after 2009 and any directly-adjoining census tract.

### Other

Community solar projects qualify potentially for two special benefits.

Power projects with maximum net outputs of up to five megawatts AC will be able to claim investment tax credits on the cost of any gen-tie line paid for by the generator and owned by the utility and any network upgrade costs paid by the generator that the utility will not repay through transmission credits.

The bill allows an extra 20% investment tax credit to be claimed on solar and wind facilities with maximum net outputs of less than five megawatts AC that provide at least half of the "financial benefits of the electricity produced" to low- and moderate-income households. An extra 10% ITC could be claimed on small such projects in low-income communities or on Indian land. Anyone with a project in either category would have to apply to the IRS for an allocation of "environmental justice solar and wind capacity limitation."

The IRS will award 1,800 MW of such limitation in each of 2023 and 2024. Any projects given awards must be completed within four years after the award.

Since the tax credits can be stacked, this could get a project to as high as a 70% ITC.

The bill makes it easier for storage projects to contract with tax-exempt or government entities without losing the investment tax credit and accelerated depreciation. Any project leased in substance to such an entity does not qualify for such tax benefits. A safe harbor that ensures currently that power contracts with tax-exempt and government entities are "service contracts" rather than leases would be extended to storage projects.

The bill will let all storage facilities be depreciated using five-year MACRS depreciation.

It also increases and liberalizes section 45Q tax credits for carbon capture and allows a tax credit of up to $3 kilogram for producing clean hydrogen. ◎

# FERC and PJM Tackle Bloated Interconnection Queues

*by Bob Shapiro, in Washington*

The Federal Energy Regulation Commission proposed new rules in June to revamp the way interconnection requests are processed, and PJM, the electricity grid in the mid-Atlantic states and parts of the Midwest, made proposals of its own.

The goal of each is to accelerate interconnection studies and the execution of interconnection agreements by weeding out speculative projects and allowing projects more likely to proceed to commercial operation to leapfrog other projects in line.

The PJM proposal, which was overwhelmingly approved by PJM stakeholders, would apply only to PJM interconnection requests.

On the other hand, the FERC notice of proposed rulemaking, or NOPR, would apply to all regional transmission organizations, including PJM, and all investor-owned public utilities outside of regional transmission organizations. In addition, all municipal and cooperative utilities not regulated by FERC would be subject to the rules to the extent they use any transmission system of a FERC-regulated public utility under a so-called reciprocity tariff requirement.

However, the FERC proposal would not apply to entities in Texas. The ERCOT grid is not subject to FERC jurisdiction.

To the extent that a utility or RTO (a regional grid operator like PJM) has in place an interconnection tariff that is equivalent to or better than the tariff requirements that FERC requires ultimately in its final rule, that utility or RTO can keep its tariff provisions in place.

The window for public comments on the PJM proposal closed in mid- July, and PJM recently provided responses to those comments.

FERC is collecting comments on its proposals until late September.

PJM has proposed that FERC accept its proposal by October 3, 2022, to become effective January 1, 2023. The effective date is important for reasons discussed in more detail below.

On the other hand, the FERC process will */ continued page 8*

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tax credits move to a tax equity investor at a stepped up tax basis while the depreciation remains with the semiconductor company. (For more detail on sale-leasebacks and inverted leases, see "Solar Tax Equity Structures" in the December 2021 *NewsWire*.)

However, one challenge with raising tax equity is the limited time the tax credit is available. It can take several years for the tax equity market to warm to a new market segment.

**RIGHT-SIDE, LEFT-SIDE ISSUES** are getting more attention in tax equity transactions.

It is common in partnership flip transactions involving solar and other renewable energy projects on which investment tax credits will be claimed for the developer to sell the project company to a tax equity partnership, when the project reaches mechanical completion, for the appraised value the project is expected to have at the end of construction.

The partnership uses its purchase price as the starting point for calculating the investment tax credit and depreciation on the project.

In many such transactions, the parties have a single loan agreement for the construction loan, a tax equity bridge loan and the back-levered term debt to which the construction loan will convert at the end of construction.

The developer entity that will sell the project company to the tax equity partnership, and the affiliated developer entity that will be the "class B member" in the tax equity partnership, are sometimes co-borrowers of all the debt during the construction period.

In addition, the parties sometimes treat all of the assets on both the right side of the structure — meaning the developer entity that will sell the project company to the partnership near the end of construction — and the left side — meaning the class B member and tax equity partnership — as one big package of assets that is pledged as collateral to support the construction and tax equity bridge loans, as if there were not two */ continued page 9*

## Interconnection

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take more time to complete. Not only is there a reply comment period following the issuance of the final rule, but FERC's proposals are more far-reaching than PJM's proposals and contain requests for suggested alternative solutions to a number of elements. A final rule would probably not be issued before the end of the first quarter of 2023, with a right for parties to seek rehearing of the final rule. FERC will also have to allow a reasonable period for each RTO and utility to make a compliance filing to amend its interconnection tariff consistent with the final rule. All of this means the FERC final rule is unlikely to be implemented before 2024.

### PJM Approach

Additional elements of the PJM proposal include three types of cluster system-impact studies rather than the current individual feasibility, system-impact study and facilities study.

After a cluster study is completed, each project studied will have 30 days to decide whether to move on to the next study. To do so, the project would have to post a higher amount of credit support, reconfirm its site control, show additional readiness requirements and pay for its share of the study cost.

If the second cluster study shows that the project would be allocated no network upgrade costs or will have an upgrade cost allocation below $5 million, then there would be an expedited process to allow that project to go directly to a project-specific facilities study and generator interconnection agreement or GIA.

If the second study shows allocated network upgrade costs above $5 million, then the project would have to move to the third cluster study and post additional collateral equal to its percentage of the expected costs of the network upgrades, as well as reaffirm its site control and pay the study deposit.

**Developers sitting in bloated interconnection queues may find later projects moving ahead of them in line.**

### Existing Queue Positions

Existing projects in the queue that have received a facilities study or an executable interconnection agreement before the effective date of the PJM proposal, which PJM proposed to be January 1, 2023, will not be subject to the new queue reform and will proceed to interconnection under existing rules on a project-specific basis.

Existing projects that have not received a facilities study or an executable interconnection agreement before the effective date will be subject to transition rules under the new queue reform. Each will be subject to a restudy of its system impact study. If the result is an allocation of network upgrade costs below $5 million, then the project will be on a so-called "fast track" — it will proceed individually to get its study done and GIA executed outside of a cluster study — to be completed in the 2023-2024 time frame.

The basic approach under both the PJM proposed tariff and FERC proposed rule is the same: transition will switch from the current first-come, first-served approach to a first-ready, first-served approach.

This means that instead of evaluating a single project ahead of later-filed projects with minimal cost of entry into the queue, all projects that apply within an application window will be part of a cluster grid-impact study for all projects within that window, and will have to post much higher deposits initially and, after the completion of each level of study, provide more evidence of site control and project development, in addition to payment of the cost of the study itself.

If restudy shows more than $5 million in allocated network upgrade costs, then the project will have to go into a new cluster study with other existing projects and post a readiness deposit, demonstrate site control consisting of land ownership, lease or option to own or lease that is good for at least a year, as well as the study deposit. These cluster studies will not commence until the fast track projects are completed, which probably means 2025 for the start of the studies.

Existing projects with filed dates in the queue from October 2020 through September 2021 will have to wait until the earlier project studies have been completed before their studies can commence, which may mean a deferral until 2026.

All other projects with filed dates from October 2021 through March 2022 and after will have to supplement and update their interconnection requests by providing readiness deposits, demonstrate site control and pay a study deposit of between $75,000 and $400,000, depending on the capacity of the project in megawatts, and their studies will have to await the results of the prior queued studies.

## Refunds

Ten percent of the study deposit is refundable if a project withdraws after the first study cycle.

The deposits become increasingly non-refundable over time. However, if a later cluster study shows that the network upgrade allocation would exceed the prior study's allocation by 25% or more and by more than $10,000 per MW, and the project then withdraws, it can receive a full refund.

In addition, because of the cluster study approach, where a withdrawal or delay could trigger the need for restudies and there is a need to provide certainty in network upgrade cost allocation for remaining projects, PJM has proposed to eliminate the right currently available under PJM interconnection agreements of the project to suspend its application for up to three years.

## FERC Approach

FERC, like PJM, has proposed to move from individual grid-impact studies on a first-come, first-served basis to cluster studies on a first-ready, first-served basis.

FERC noted that several RTOs and utilities outside of RTOs already have moved or are planning to move in the same cluster direction. To the extent that RTOs and utilities can demonstrate that their interconnection procedures are equivalent to or better than the requirements FERC ultimately / continued page 10

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separate sides to the structure.

This is not the best approach.

The project company or development company that owns it should be the borrower of the construction and tax equity bridge debt without the class B member also being a co-borrower.

The lenders will not want to make a tax equity bridge loan to the project without a commitment from the tax equity partnership to buy the project and by the class B member and tax equity investor to make capital contributions to fund the purchase price.

The tax equity partnership should be a party to an equity capital contribution agreement, or ECCA, with the class B member and tax equity investor requiring them to make capital contributions, provided a series of conditions precedent are satisfied.

The tax equity partnership should pledge the ECCA as collateral to secure its obligation under a separate membership interest purchase agreement, or MIPA, to buy the project company. The seller can then pledge the security interest in the ECCA in turn to the lenders. The class B member and tax equity investor should acknowledge the pledge and the ability of the lenders to enforce the capital contribution obligations.

When the project company is sold, the tax equity partnership will have a tax basis for calculating tax benefits equal to the sum of three things. It will pay part of the purchase price in cash. It will be treated for tax purposes as assuming the construction and tax equity bridge debt. It will take the project company with an obligation to pay the construction contractor the remaining amounts owed under the construction contract. The cash portion of the purchase price is the appraised value minus the debt assumed and the remaining amount that will have to be paid to the construction contractor.

If the seller remains liable on the construction and tax equity / continued page 11

## Interconnection

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establishes in the final rule, those RTOs and utilities can retain those procedures.

The first-ready, first-served and cluster study approach will almost certainly be retained in the final rule as will the three cluster study process for all projects applying within an application window.

The studies, which continue to be called feasibility study, system impact study and facilities study, will get priority over subsequent interconnection requests in later application windows. The utilities and RTOs also have to offer an initial optional "informational interconnection study" to prospective projects so that they can decide whether to submit an interconnection request in specific locations.

The new rules will require higher study deposits, more stringent site control, demonstration of commercial readiness, and higher withdrawal penalties that increase with each level of study.

The studies will determine how to allocate any network upgrade costs among projects in each cluster.

### More FERC Details

For the first time, RTOs and utilities will have to pay penalties if they miss a specific deadline for completion of the study.

Failure to issue a required study within 150 days will require payment of $500 per day until the study is completed, capped at the total cost of the study. If a restudy is needed, the RTO or utility has the same 150-day deadline and penalty provision.

The transmission provider must also get affected systems into the process much earlier. Projects must pay currently not only for network upgrade costs on the grid to which they interconnect, but also on neighboring grids, called "affected systems." For example, in the case of an interconnection in PJM, the affected system could be MISO to the west or NYISO to the north. If the direct interconnection is with a utility that is not in a regional grid managed by an RTO, the affected system would be any grid that is interconnected with the transmission system to which the project interconnects. That affected system must be informed of the requests and respond quickly whether there will be an impact on its system. If it has to perform a study, it will have the same 150-day time limit and $500 per day penalty if it fails to meet the affected system study deadline.

At each stage of cluster study process, to proceed to the next level of cluster study, a project has to post higher levels of security and demonstrate site control.

It must also demonstrate commercial readiness by providing an executed binding term sheet for a contract to sell the completed facility or to sell energy, capacity or ancillary services for at least five years, or evidence that the project has been selected in a resource plan or RFP solicitation process by a load serving entity or by a commercial, industrial or other large end-user.

FERC also requested comments about what other comparable evidence of project development might qualify as showing commercial readiness, including a site-specific purchase order for generating equipment specific to the interconnection request.

Alternatively, the project can provide a large commercial readiness deposit of two times the amount of initial study deposit for the initial study, five times the amount of initial study deposit for the system impact study or re-study of the initial system impact study, and seven times the amount of initial study agreement after signing the facilities study agreement. These are in addition to the costs of the studies themselves.

FERC proposed three steps to speed interconnection, but its actions do not apply in Texas.

There are higher withdrawal penalties for interconnection projects that make commercial readiness deposits in lieu of demonstrating commercial readiness.

The project must show it has exclusive land rights necessary to construct the facility. This evidence must be provided with the initial interconnection request and be reconfirmed with each additional study.

The project has the option to post security in lieu of showing site control equal to $10,000 per MW, subject to a floor of $500,000 and ceiling of $2 million. This security could later be applied to interconnection studies or withdrawal penalties. It is in addition to increased study deposits.

The study deposits are proposed to be increased as follows. For projects between 20 and 80 MW, the deposit would be $35,000 plus $1,000 per MW. For projects between 80 and 200 MW, the deposit would be $150,000, and for projects above 200 MW, the deposit would be $250,000. These deposits would be required from each project before going forward to the next phase of cluster study.

In order to execute a GIA, the project would have to provide a deposit of nine times the amount of its initial study deposit. This deposit would be refunded after commercial operation, but could be refunded in whole or in part if a project withdraws without adverse effect on the other projects.

Network upgrade costs would be proportional, based on each cluster project's contribution to the need for network upgrades.

The amount of withdrawal penalties will depend on the impact of a project's withdrawal on the remaining projects.

Penalties will not apply if there is no impact on remaining projects in the cluster, if the withdrawal will not delay the time for study completion for the other projects in the cluster, if the project withdraws after receiving the most recent cluster study that allocates more than 25% of the network upgrade costs to the project compared to a previous cluster study, or if a project withdraws after an individual study report where allocated costs have increased more than 100% compared to a previous cluster study.

Unlike the PJM proposal, which proposes to do away with the right to suspend the interconnection process for up to three years, FERC would retain the three-year suspension right, but the extension would be tied to the commercial operation date proposed in the original interconnection request.

## Already Queued Projects

Existing interconnection projects in the queue will have the option to enter into a serial interconnection study or a transitional cluster study, with commercial / *continued page 12*

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bridge loans after the sale, this calls into question whether the debt was really assumed by the tax equity partnership when the project company was sold. It is like buying a house that is subject to a mortgage. If the buyer assumes the mortgage, that is considered part of its purchase price. If the seller remains liable on the mortgage, the debt may not have been assumed.

It is helpful if the entity selling the project company is a real development company. It is helpful if it uses the cash portion of the purchase price to fund development spending on other projects that it has under development.

Some tax counsel prefer that the seller agree to cover any cost overruns on the construction contract above the remaining amount owed when the project company is sold. This helps to justify any premium the partnership pays above the bare cost to construct the project.

Some tax counsel prefer that the partnership pay the full cash portion of the purchase price when the project company is sold at mechanical completion using capital contributed by the tax equity investor.

**CUSTOMS DETENTIONS** and import tariffs remain obstacles for US solar developers.

A 24-month moratorium is expected to take effect soon on anti-circumvention duties on Chinese-branded solar panels and cells imported from Vietnam, Malaysia, Thailand and Cambodia.

US solar panel manufacturers will then have at least 60 days to file suit to block enforcement.

In the meantime, analysts are reporting that more than 3,000 megawatts of solar panels may have been detained by US Customs due to forced labor concerns since Customs started enforcing the Uyghur Forced Labor Prevention Act on June 21. The number of detained solar panels is expected to grow by year end. (For more / *continued page 13*

## Interconnection

*continued from page 11*

readiness requirements or they may withdraw from the queue without penalty.

Late-stage interconnection projects with a facilities study agreement can continue under the serial study approach and enter into an interconnection agreement if they show commercial readiness to move forward to commercial operation. The RTO or utility would have 90 days to complete the studies for these projects.

If a project has not yet entered into a facilities study agreement, it would have to post a deposit equal to 100% of interconnection facilities and network upgrade costs shown in the system impact study. If the project reaches commercial operation, the deposit can be used toward the construction costs of the interconnection facilities and upgrades. If a project withdraws prior to commercial operation, it will be subject to a withdrawal penalty of nine times the study deposit costs.

Existing projects that opt to enter into a transitional cluster study would be allocated proportional network upgrade costs based on the study outcome.

They would also be subject to an expedited cluster study combining the system impact and facilities studies, and they would have to post a $5 million deposit and meet the same site control and commercial readiness requirements. The transmission providers would have 300 days to complete the studies. The transmission provider would be subject to the same $500 per day penalty for delay.

In short, both the PJM and FERC approaches attempt to eliminate the backlog in processing interconnection requests in similar ways: by studying many projects at once though cluster studies and reducing the number of existing and new applicants by raising deposit and credit support levels after each study and requiring evidence of development progress.

This is intended to induce speculative projects to wait until they are further developed or to withdraw from the queue to make room for those ready to move forward.

The result of this approach may be to leave the field to deep-pocket players or to force more speculative projects and smaller developers to partner with deep-pocket players to maintain their viability in the interconnection process. ◎

# Renegotiating PPAs

Construction delays and cost increases are forcing renegotiation of power purchase agreements before renewable energy projects can be financed. Wholesale electricity prices jumped 2.5% for wind electricity and 8% for solar electricity in just the second quarter this year. Solar power prices were up 30% on average year on year. Corporate PPAs accounted for roughly six in 10 PPAs signed in 2021.

A panel talked about lessons from recent PPA renegotiations at our 31st energy finance conference in South Carolina in mid-June. The following is an edited transcript.

The panelists are Michael Alvarez, COO of Longroad Energy, Michael Rucker, CEO of Scout Clean Energy, Rebecca Cranna, COO of Cypress Creek Renewables, Tom Buttgenbach, CEO of 8minute Solar Energy, and Johan Vanhee, CCO of Origis Energy. The moderator is Caileen Kateri ("Kat") Gamache with Norton Rose Fulbright in Houston.

### Distressed PPAs

MS. GAMACHE: Around half the audience, on a show of hands, said it has been involved with a distressed power purchase agreement in the last two years. Michael Alvarez, what is going on? What is the distress, and how are you dealing with it?

MR. ALVAREZ: There are two basic problems. Construction delays lead to missed deadlines to start delivering electricity and spiraling project costs are making it hard to supply electricity for the prices that were promised. There is a spectrum of distress. We have PPAs where we bid into solicitations some time ago and the PPAs have not been signed yet. We have a PPA that was signed, but not yet approved by the public utility commission. There are operating projects with hedges that are no longer tenable.

MS. GAMACHE: Johan Vanhee, what can you add?

MR. VANHEE: Distress in supply chains is very much our order of the day currently, and it has an impact on project costs. PPAs are often signed years ahead of when electricity deliveries will start. PPAs in the past have had fixed or predetermined prices.

Now we live in an industry where we have the privilege to negotiate the same project PPA twice with the same customer. [Laughter]

MS. GAMACHE: Tom Buttgenbach, have you had to renegotiate any PPAs?

MR. BUTTGENBACH: Yes, several. We are currently renegotiating the timelines and pricing in several of them.

It has been an opportunity to increase value to the customer at the same time by reconfiguring. Energy storage is something that is new to most customers, certainly at the scale of hundreds of megawatt hours of energy storage. In the original PPAs that we signed a year or two ago, some of the assumptions that both sides made turned out not to be so good. It is an opportunity to deliver a better product and to deal with the force majeure issues that have affected all of us.

**Spiraling project costs are making it hard to supply electricity for prices that were promised.**

MS. GAMACHE: You not only reopened the PPAs, but then used that as an opportunity to add storage?

MR. BUTTGENBACH: Not to add storage as much as to modify the storage that was negotiated. The market has shifted. Some offtakers viewed storage as a nice addition to get a foot in the door. By the time we are renegotiating, they realize they need a lot more.

Storage had a lot of supply-chain issues even before the current tariff and forced labor issues that are holding up solar panels.

Reconfiguring the power plant design and adjusting how the solar and storage work together end up being a value driver, which is what everyone is looking for. Most utilities do not just want to negotiate on timelines and price. They want to see some kind of value to their ratepayers.

MS. GAMACHE: What other sorts of concessions have the group of you made as part of the renegotiations?

MR. RUCKER: We have had challenges across the whole spectrum as well. In the last three years, we terminated two hedges — a fixed-shaped product and / continued page 14

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details, see "Customs Gets Tougher on Forced Labor" in the June 2022 *NewsWire*.)

The US Commerce Department proposed a moratorium on June 30 that would shield solar panels and cells imported into the United States from Vietnam, Malaysia, Thailand and Cambodia through June 5, 2024 from any anti-circumvention duties that Commerce decides to impose. The deadline for comments about the proposed moratorium was August 1.

The moratorium will not apply to panels that are made using solar cells that were manufactured in China or Taiwan.

Auxin, a US manufacturer, asked Commerce last February to investigate whether Chinese-branded cells and panels imported from the four Southeast Asian countries are circumventing duties that would have to be paid if they were imported directly from China. Roughly 80% of solar panels imported into the United States last year came from the four countries. Only 1% came from China directly.

Commerce was supposed to make a preliminary decision by August 29, 2022 and a final determination by April 3, 2023. However, Auxin asked it to delay the preliminary decision by three weeks to allow time for submission of more evidence.

The Biden administration is invoking waiver authority under section 318 of the Tariff Act of 1930 to waive duties on "food, clothing, and medical, surgical and other supplies for use in emergency relief work" to suspend any duties that the agency decides to impose for 24 months.

Financings of projects that would be uneconomic if they had to bear the duties may still be delayed until after the market has a chance to assess the merits of any lawsuit. (For more details, see "Tariffs, Inflation and Other Challenges" in the June 2022 *NewsWire*.)

The US has been collecting countervailing and anti-dumping duties on solar panels imported directly from / continued page 15 *continued from page 13*

a proxy generation swap — and restructured a proxy revenue swap.

MS. GAMACHE: Becky Cranna, anything to add?

MS. CRANNA: It might come as a surprise to all of you as fellow developers, but we were overly optimistic in a couple cases on our ability to get projects permitted and through the interconnection queues. The types of issues we have had recently have really related to timing. Our issues are less price-related and more related to milestones set out in the PPA.

MR. ALVAREZ: This isn't a concession, but we have been required to be much more transparent about our costs. When you say X went up by Y, they say show me. If you are not transparent about that, it will be difficult to get them to accept an increased price even though their own procurement departments are having the same problems we are.

Utilities have generally been willing to renegotiate power contracts.

MR. VANHEE: A lot of our customers want to build in more certainty. They say, "Fine, we understand. We all pay more for gas when we fill up our tanks at the gas stations. We understand there is inflation, but you are not going to be able to adjust twice for the same problems." We see a trend in renegotiations that we have to post higher security.

### Utilities v. Corporates

MS. GAMACHE: Is there a difference between how utilities and corporate offtakers react to requests to renegotiate?

MR. BUTTGENBACH: Yes, to some degree. Corporate offtakers are much more commercial, but are also more demanding of transparency.

There is a significant shortage of good projects in the regions where we operate. One of the demands of offtakers has been to increase the volume. They say, "If I help you over here, then I want to see additional megawatt hours." We have been able to do that fortunately, but it is never as simple as haggling over a new price. The offtakers want concessions to make changes.

However, at the end of the day, all of the offtakers want the project. They are worse off without the project, especially in a market where it is very difficult to find additional renewable electricity.

MR. VANHEE: I don't see a difference between the type of customer, but I see a difference in level of sophistication. Some customers, whether they are utilities or corporates, are very sophisticated. They go deep by probing, for example, into whether we have covered the withhold release order risk and forced labor issues. They don't want to have to come back to the negotiating table again.

MR. RUCKER: The differences for us are driven by geography. We work a lot in WECC, for example, where we are going through classic utility RFPs that take a year to complete. In this environment with costs moving constantly, the need to bid something a year before the contract is awarded is absolutely impossible.

The utilities have not figured out a process for procuring power that works commercially in the current market. The processes are not dynamic or responsive enough.

In other ISO markets, corporate PPAs are more prevalent. Corporate offtakers are more commercial. They are more flexible about managing the kinds of supply-chain risks that we all face today.

MS. GAMACHE: Wood Mackenzie told us yesterday that, based on 20 years of data, WECC, SPP, SERC and MISO are the riskiest places to forecast what merchant power prices will be after the power contract ends. Merchant forecasts were more accurate in PJM and ISO-New England. How about during the contract term? Is there a regional winner and loser?

MR. ALVAREZ: We don't evaluate it that way. We leave a piece of projects merchant as an internal hedge.

MS. GAMACHE: Always?

MR. ALVAREZ: Not always, but where we can we do that because some of our origination people think the curve always goes up. We have never hit the curve that we started with — ever. But they see it as a fundamental opportunity to take advantage of dislocation in the market. We do not go fully merchant on anything.

MS. GAMACHE: Do you get financed on the full capacity or only on the contracted revenue?

MR. ALVAREZ: Contracted.

MR. RUCKER: We take a market approach in terms of the percentage of offtake that we want to be contracted. In a market like SPP that has a very high percentage of renewables, particularly wind, we try to get as much contract coverage as we can. In markets like PJM, we leave a merchant sliver open. We are very happy to have that right now with natural gas prices as high as they are.

MR. BUTTGENBACH: Let me go back to a point that was made earlier.

We have gone from negotiating with one party who had a well-understood process, like an RFP, followed by the need to go upstairs for approvals, to a multilayer negotiation, and that is where the big differentiation comes in between the parties. The more commercial offtakers, like corporates, have well-understood internal processes.

The regulated utilities that need PUC approval have never had to explain to a regulatory commission why they are now changing the price, how they justify it, and how they know the new price is market if it was not set by an auction in an RFP. That is what is slowing down the utility renegotiations and making them less commercial.

MS. GAMACHE: Some regulated entities may be inclined to say no to renegotiation because they do not want to have to revisit a contract with their regulators. Have any of you gotten approval for a renegotiated PPA from a regulatory commission? One head shake.

MR. BUTTGENBACH: Not yet, but in process. I thought within about three months, we could renegotiate these PPAs and then go through the approval processes. We are now nine months in, and we are not there yet.

MR. ALVAREZ: Regulators are reluctant to set a process and then change it. There are equity considerations. The power contract may have gone to the lowest bidder whose price proved too optimistic.

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China since December 2012 to offset the effects of Chinese export subsidies and of Chinese manufacturers dumping product on the US market at lower prices than the panels are sold for in China.

The duty amounts are revisited periodically. Commerce made the latest adjustments in early August.

US duties vary depending on the panel supplier. The China-wide rates are 238.95% in anti-dumping duties and 15.87% in countervailing duties. Some companies qualify for lower rates after presenting evidence to Commerce.

For example, Risen panels are subject to anti-dumping duties of 12.24% and countervailing duties of 13.18%. LONGi and BYD solar panels are subject to anti-dumping duties of 14.79% and countervailing duties of 15.87%.

These are the subsidies that Commerce found various Chinese suppliers benefited from on panels imported during calendar year 2019 and dumping margins for the period December 2019 through November 2020, the most recent periods reviewed.

Importers must post cash deposits when the panels pass US Customs.

Adjustments are made to the cash deposits as Commerce revisits the dumping margins and export subsidies over time. In such cases, importers may be required to pay more or receive refunds.

**A TAX EQUITY PARTNERSHIP** does not have to expect a profit apart from tax credits, a US appeals court said in early August.

The decision will help tax equity investors looking to invest in carbon capture transactions.

In such transactions, the owner of a factory may form a partnership with a tax equity investor to install and own capture equipment to trap carbon dioxide emissions from the factory and either bury the CO2 permanently underground or put it

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We had an experience where we signed a contract that over time went out of the money. We renegotiated the contract with the utility and agreed on a new price. The commission rejected the new price. We requested reconsideration. More time went by. The contract fell even more out of the money. We withdrew, and then the commission approved the renegotiated contract.

Many people in this business believe that prices fall over time. Our view is that, with a trillion dollar infrastructure bill, a war in Ukraine that is taking a lot of oxygen out of the system, fuel prices that are not going down or stabilizing and rising interest rates, this is going to be a long-term phenomenon. At least one counterparty with whom we renegotiated with is quite happy with the new price. We reset the price in January, and here we are in June and it is pleased.

### Ukraine

MS. GAMACHE: You just brought up a topic that some in our audience said yesterday they wished we had discussed more, and that is the effect of the Russian invasion of Ukraine on our market. Becky Cranna, are you seeing an effect?

MS. CRANNA: For sure. There were issues with equipment procurement and sourcing of commodities before the war, and the war has made a challenging situation worse.

MR. BUTTGENBACH: I was going to say I was just about to file a force majeure notice when I came in late. [Laughter]

There were serious supply-chain issues on the coffee stand. [Laughter]

The war in Ukraine has wreaked havoc on the supply chain. This is just the latest in a string of difficulties, starting with COVID and the lockdowns in China.

MR. ALVAREZ: I think we have only begun to see the effect. The Defense Department is going to have a higher-priority claim than the rest of us on restocking aluminum, copper, chips, you name it, for the high-tech weapons that are being shipped by the billions of dollars.

Then there will be the rebuilding of Ukraine. We have our own trillion-dollar infrastructure bill already laying claim to construction materials. Think about how much rebar goes into bridges. It is going to be a very difficult to navigate through the next several years.

I am not sure I agree with John Breckenridge's comment yesterday about 10 years of cost increases for batteries. (See "The Evolving Energy Storage Market" in the August 2022 *NewsWire*.) I think the lithium market may be able to rebound more quickly than that. The government does not seem to use as much lithium as we do at the moment.

### Reopeners

MS. GAMACHE: People thought in the past of force majeure provisions as a kind of contract boilerplate. Now such clauses are getting much more attention. What else is getting closer attention today? Put differently, what will you do differently in every PPA you negotiate in the future based on experience over the last two years?

MR. RUCKER: We look for reopeners to cover the risk of commodity price inflation. We want the ability to put through price changes between the time we sign the PPA and when we actually procure equipment and give a notice to proceed with construction. We need a reopener on price if we see completely unexpected results in our final procurement process.

MS. GAMACHE: So not necessarily an escalator, but more of a "Let's get together if this happens."

MR. RUCKER: Just a reopener, although we have also relied in some cases on indexing to major indices. Some of them are just price targets based on feedback that we get from the balance-of-plant construction contractor or network upgrade costs that we get out of transmission studies. There may be a mix of reopener triggers, with everything designed to help us

A shortage of projects is making it hard for them to find renewable energy.

contain the risk of escalating costs before notice to proceed with construction.

MR. ALVAREZ: We have had multiple counterparties ask for a two-way street on this. What goes up must also come down in theory. An example is if a tax bill passes that increases the tax credit, the counterparty wants to see a price reduction. These are difficult provisions to negotiate. It is hard to write down all of the "what ifs" about tax policy.

MS. CRANNA: One lesson is it is best to wait to lock in an electricity price, if possible, until close to when the project is ready to start construction.

MR. BUTTGENBACH: I have been trying to convince offtakers about who I am. I am a great developer, but I do not have a great crystal ball. I can't predict lithium prices, steel prices, labor shortages or how COVID will affect governmental agencies who have to approve projects and timelines. My value add is in delivering a great project, but not in predicting commodity futures.

When you bought a combined-cycle gas turbine from GE, you didn't require GE to guarantee what the gas price was for 20 years. Most offtakers would hedge the gas for five years and then report to their boards on the expected economics of the gas plant. The truth is they had no idea what the economics would be like 20 years out.

The same is true for us as developers. Our value is in knowing how to design and build a great project, but the commodity price risk needs to be taken by the offtaker.

I have found more sympathy for that argument for future projects, which is easy today in a seller's market with available projects in short supply. We will not sign a contract without an index, unless we can get suppliers to take the commodity price risk and, even then, there is a risk. We have had suppliers, including very large balance-sheet suppliers, renege on contracts. A US battery manufacturer comes to mind that reneged on contracts.

This is no different than what utilities have done for the last 50 years every time they negotiated a gas-fired power plant. Fuel prices are volatile. Commodities are volatile. The good news is that once we have built a solar project, we are pretty much done. There is no fuel cost. The uncertainty is a three-year problem and not a 30-year problem.

MR. RUCKER: I agree that the risk tied to those variable costs over time should be put on the loads. They are the ones with the flexibility in their pricing and their regulatory processes to recover the cost increases from the ultimate customers.

We are basically working with a fixed / continued page 18

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to one of two other permitted uses.

In most such transactions, there is no cash coming into the partnership.

The partnership spends money to install and operate the capture equipment, including paying a sequestration company to dispose of the CO2 permanently underground. The only source of "revenue" is section 45Q tax credits of $35 to $50 a metric ton on the CO2 captured.

The Inflation Reduction Act increases the tax credits to $60 to $85 a ton for capture equipment put in service after 2022. (For more information about carbon capture transactions, see "Tax Credits for Carbon Capture" in the February 2021 *NewsWire*, "Stalled Carbon Capture Projects" in the August 2021 *NewsWire* and "Carbon Capture Terms" in the June 2022 *NewsWire*.)

The August court decision involved a refined coal transaction.

Refined coal is coal that has been treated to make it less polluting. The federal government used to offer tax credits as an inducement to make refined coal. The equipment to make the refined coal had to be in service by December 2011 to qualify.

AJG Coal, Inc., an Arthur J. Gallagher affiliate, formed a partnership with the Fidelity Investments management company and Schneider Electric to make refined coal on site at the Cross coal-fired power plant owned by Santee Cooper, an electric utility, in South Carolina.

AJG projected that the partnership would have an after-tax profit of $140 million over the 10 years that tax credits could be claimed for making refined coal. Fidelity paid AJG $4 million and invested another $1.1 million to cover the first two months of expenses for a 51% interest in the partnership. Schneider Electric paid $1.8 million and invested another $654,000 for a 25% interest.

The partnership signed two contracts with Santee Cooper to lease space on the power plant site to put the / continued page 19

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levelized cost of energy over the full term of the contract. We are lucky to get inflation adjustments, although they are now coming back into style. Historically we have had fixed-price long-term contracts, and such contracts are not manageable in the current environment.

Utility regulators are not used to seeing contracts come back with higher prices.

MS. GAMACHE: Will any of you enter into a fixed-price power purchase agreement today?

MR. RUCKER: Yes.

MS. CRANNA: Yes.

[Audience laughter]

MS. GAMACHE: What assumptions will you include in that fixed price?

MR. RUCKER: We do our best in our long-term models to model for inflation. What is it going to be? Forward power pricing? Forward curves? The Wood Mackenzie presentation yesterday was fantastic, but as we know historically, the consultants are always wrong. [Laughter]

### Sleeper Costs

MR. ALVAREZ: There are two areas that worry me.

One is the bias towards prevailing wages that is aimed at us in "Build in America" kinds of legislation. We do 30- and 35-year models like everybody else does — pick your inflation rate — but none of them accounts for how the need to pay the same wages that are paid on federal construction jobs will affect our economics.

The other source of worry is storage costs. You can build in a 35% to 40% forward price increase assumption for lithium, but no one has any idea what lithium will cost 20 or 30 years from now.

MS. GAMACHE: For those of you trying to index, what are you indexing before and after commercial operation?

MR. VANHEE: We try to keep it as simple as possible. We are going to look at commodity indexes and try to get them in the contract. If we are lucky, we may have a general inflation index, but watch out with inflation. It can work against you as well.

MR. BUTTGENBACH: We look closely at force majeure clauses in contracts from our equipment suppliers, and we also look at the choice of venue in the event there is a dispute.

Some suppliers demanding price increases say basically, "Come visit us in Shanghai. Good luck in court here. If you want panels, this is what you have to pay." We respond, "We have a contract." They say, "Yes, very interesting." [Laughter]

That was before the anti-circumvention investigation. We are much more careful today. We are trying to hedge as much as possible in the sense of buying from credible suppliers, with language that is clear about what happens if they do not perform under the contract and that matches the penalties we face if we cannot perform the PPA.

MS. GAMACHE: We heard yesterday that EPC contractors are no longer agreeing to price caps. I know many of you don't sign the EPC contract until you have a signed PPA. Once the EPC contract is signed, is there an index in it for labor costs?

MR. RUCKER: We have not had an index for labor costs in any of our EPC contracts to date.

MR. ALVAREZ: Fuel costs have moved about $1.5 million on a large solar project that we have currently under construction. The contractor is not able to hedge against fuel cost increases. In some cases, the contactor may be able to protect against such cost increases by buying fuel in advance.

### Lender Sensitivities

MS. GAMACHE: There are various forms of electricity price hedges. One is a contract for differences, but it creates electricity basis risk. Winter Storm Uri has made people a lot more careful about hedges. (For more detail, see "How Hedges Have Changed Since Uri" in the June 2022 *NewsWire*.)

MR. RUCKER: We look for blowout protection on electricity basis risk in our contracts. That is a common feature in most contracts today in ISO markets. It is an approach that looks for extreme events. For a wind project, the trigger might be a price gap roughly the size of the PTC value. There may be a cap on the number of hours per year that such a provision can be invoked.

MS. GAMACHE: Is blowout protection a capped price or a switch in the hub or node where the price is set?

MR. RUCKER: It is usually a switch. You can choose a number of hours a year during which you basically have no settlement.

MS. GAMACHE: Where else are you sending lenders a PPA and they send it back and say "fix this"?

MS. CRANNA: Lenders prefer that the contract not be for more than the P99 output of the project. They worry about over-contracting.

MR. VANHEE: There were recent news reports that solar projects are underperforming. I expect lenders will require a correction there. (For more detail, see "Overestimation of Solar Output" in the October 2020 *NewsWire*.)

MR. ALVAREZ: Another pain point is severe convective weather. In just the last month, at least five — maybe six — solar facilities in Texas suffered serious hail damage. At least two were completely wiped out. I am talking about $100 million losses. Insurance policies have high deductibles and then a cap on payments, so lenders are basically wearing not only all of the bottom risk, but also the top-level risk as well. That is causing a severe amount of distress in areas with frequent hailstorms.

MR. RUCKER: We try to bring perfect contracts to our lenders. [Laughter]

We are seeing more use of floor pricing concepts in the last few years, particularly in markets with very high basis or covariant risk for wind production. (For more detail, see "Covariance Risk: What Is It and How to Manage It" in the June 2019 *NewsWire*.) The floor price can be provided through an affiliate PPA. (But see "Section 707(b): Related-Party Electricity Sales" in the June 2021 *NewsWire*.) We are also seeing revenue put options. (For more detail, see "Solar Revenue Puts" in the October 2016 *NewsWire*.)

MR. BUTTGENBACH: On the good news front with the lenders is that they are much more flexible in terms of looking at concurrent merchant revenues. I am not talking about post-PPA, 20 years out. We have quite a few projects now with a significant

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refined coal facility and to buy untreated coal and sell back treated coal for 75¢ less a ton than the partnership paid for the untreated coal. The tax credits could only be claimed on refined coal "sold" to an unrelated person. (For more discussion about whether it is a "sale" to pay someone to take a product, see "Production Tax Credits and 'Sales'" in the October 2019 *NewsWire*.)

The Internal Revenue Service disallowed the tax credits claimed by Fidelity and Schneider Electric on audit after concluding that no real partnership was formed since there was no business from which the parties intended to share profits. The operation was a consistent money loser.

The IRS lost in the US Tax Court. (For a more detailed look at the facts and the Tax Court decision, see "Refined Coal" in the October 2019 *NewsWire*.)

The IRS lost again before a US appeals court in early August.

The case is *Cross Refined Coal, LLC v. Commissioner*.

The appeals court said two things are required to have a real partnership. First, the parties must intend to carry on business as a partnership, meaning the enterprise must be "undertaken for profit or some other legitimate nontax business purpose." A partnership that "has no practical economic effect other than creation of tax losses" is a sham. Second, the parties must intend to share in the profits or losses or both.

The court said a partnership does not have to expect a pre-tax profit. It is enough that it expects to profit after taking into account tax credits that are an inducement to engage in an activity that is uneconomic without them.

This is the second time a federal appeals court has said it makes no sense to require a company to show it does not need tax credits — because the business is profitable without them — in order to claim the tax credits. Another US appeals / continued page 21

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portion of the project uncontracted. Two years ago, that was toxic. The lenders and tax equity investors did not even want to look at that. There has been a shift in thinking it is a good thing at the right ratio.

I wish they would take the same stance on not requiring long-term service agreements for batteries. It is crazy for me to commit for 15 or 20 years to replacing parts on my Ford Model T. [Laughter]

MS. GAMACHE: Have you seen changes in the collateral that buyers have to post?

MR. VANHEE: We try to get as much as we can in collateral, but we have not seen any changes in buyer security. If they ask me to take more risk and more exposure, it goes both ways.

MR. RUCKER: Not much here, either.

MR. BUTTGENBACH: We have seen some increase.

MS. GAMACHE: Audience question.

MR. WARANCH: Andrew Waranch, CEO of Spearmint Energy. We've had a difficult time hedging our lithium using any of the Asian markets. Two-part question. One: have you had any success in any of the Asian future markets hedging the lithium risk? Two: have you been able to transfer lithium in the PPA to others who might be able to hedge the risk for you?

MR. VANHEE: Two times no.

MR. BUTTGENBACH: Two times yes.

MS. CRANNA: No.

MR. RUCKER: We haven't bought a battery yet.

MR. ALVAREZ: We have an index, but it is operating through an integrator whose credit quality is not necessarily sufficiently sleeved to rely on yet. We try to buy direct modules and on occasion direct trackers and inverters. There may be an opportunity to go direct on battery cells in which case, there would be an opportunity to manage that risk. However, you are taking a huge amount of procurement risk when you do that directly as a developer.

### Power Prices

MS. GAMACHE: It seems like PPA prices have been skyrocketing, but unevenly across the US. What are you seeing?

MR. ALVAREZ: I wish they were skyrocketing. They have been going up. A lot of what we are doing now is capacity-based. Solar-plus-storage is all capacity-based, and the capacity payments have gone up compared to what we were bidding on the order of around 20% in a very short period of time.

MR. RUCKER: We have seen PPA pricing going up in every market. The electricity demand from buyers is seemingly insatiable at the moment. We have been lucky during a period of a big runup in demand and inflation to be able basically to increase pre-contract bids for most of our projects. The increase is roughly keeping pace with commodity cost increases, but does not compensate adequately for the volatility risk.

MS. CRANNA: We are seeing similar trends across multiple markets. The increases are being driven by not just commodities, but also the war in Ukraine and interest rates. The increases are pretty consistent across all of the markets where we have projects.

MR. BUTTGENBACH: I believe the Clearway CFO said during an earnings call that his company has seen PPA prices increase by 30% to 50%. It depends on how old the contracts are. For a contract that I signed a year ago, prices now might be 30% higher. For older contracts, prices today might be 50% higher. This is true across the Southwestern US and Texas.

MR. VANHEE: Same trend, I think. We make a distinction between what we call "Perfect Storm 1.0" and "Perfect Storm 2.0." [Laughter]

Storm 1.0 is COVID and everything related there. That was regional and a 15%-ish perfect storm. Now we are seeing a 20% to 25% increase across the board in the second stage.

MS. GAMACHE: Another audience question.

MS. CHRISTIE: Holly Christie, general counsel of Hecate. Two or three years ago, we never would have gone back to renegotiate a power contract. Now it seems like such renegotiations are commonplace. Are you finding some offtakers are not open to renegotiation and, if so, how do you approach those relationships?

MR. ALVAREZ: The knee-jerk reaction is just to say no. You have to be persistent. There is also a bit of a flight to quality, so some of the counterparties trust some people and don't trust the market in general. That goes back to my transparency comment. But they don't really have a choice. Their own procurement departments are seeing the same cost increases. After a while, the resistance breaks down.

MR. RUCKER: We have seen a lot of cooperation, really. The offtakers need a project, and they have procurement and ESG goals. They will have to be flexible to realize them. We have not had a hard no yet. I agree that you have to be persistent.

MS. CRANNA: Relationships matter. Demonstrating that you are credible matters. There are two hurdles in any renegotiation. The first is proving you and your project are credible. You are going to be able to get the project done. The second is proving you have your equipment lined up. Price obviously matters, but it is not all about price.

MR. BUTTGENBACH: I would add to that what additional value you can provide to the customer. They have to sell the price increase internally. There has to be a bit more of a story than "We agreed on a price X, and now we are going to agree on X plus." The story has to be we are getting a better plant, or we are getting more megawatts.

They are all short electricity. The fact that they are looking at contracts that are not going to be performed is a much bigger problem for them than it is even for us. Walking away from development security is painful, but losing X% of your generation that you had planned for can be a serious problem for a lot of utilities. Prices in the resource adequacy market in California have gone up 50% easily. That is just pure shortage. We have not had a single hard no. Persistence, yes.

I remember when I got the news that a major US battery supplier reneged on its contract with us. I came up with a lot of four letter words to describe the supplier. Three months later, we were begging it for more volume. [Laughter]

I am sure the utilities go through the same kind PTSD, and they probably hate you for a little while. But as Becky said, if you have a good relationship and you make your case, we have not had a single one refuse to reopen the contract.

MR. VANHEE: There were a lot of no's in Perfect Storm 1.0. Now it is always maybe. We don't get a no anymore. If they see me show up, they know what is coming. [Laughter]

I already apologize before entering their offices.

MS. GAMACHE: We are getting the hook. Please join me in giving our panelists a big warm thank you. [Audience cheers]

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court said the same thing in a 1995 case called *Sacks v. Commissioner.*

There are two other federal court decisions in cases with messy facts that reached the opposite conclusion.

The IRS has generally shied away from acknowledging this principle. However, numerous private letters rulings were issued to owners of synfuel plants and gas wells that qualified for section 29 tax credits for making synthetic fuel from coal or trapping landfill gas or coal-bed methane acknowledging that no profit was expected in such transactions apart from tax benefits. The IRS also acknowledged in a private letter ruling issued to investors in three early wind partnership flip transactions that the investors did not expect to earn pre-tax profits unless production tax credits were taken into account.

"[A] partnership's pursuit of after-tax profit can be a legitimate business activity for partners to carry on together," the *Cross* appeals court said. "This is especially true in the context of tax incentives, which exist precisely to encourage activity that would not otherwise be profitable."

The appeals court also analyzed whether Fidelity and Schneider Electric were essentially lenders who were assured of getting their money back plus a return by a fixed maturity date. It said they were not.

The two companies went into the transaction expecting to receive $105 million in tax credits over 10 years. They ended up earning only $14.25 million over four years due to two lengthy shutdowns of the refined coal facility. The two lost $2.9 million and $700,000 respectively after investing with AJG in a refined coal facility at another Santee Cooper power plant.

**TWO PROPERTY TAX** cases had frustrating outcomes.

The Missouri Supreme Court set aside a state statute in early */ continued page 23*

# Embracing Hydrogen

Two competing narratives about hydrogen played out the last two years in the press. One was that hydrogen is being pitched by the fossil fuel community as a way for natural gas to retain longer-term relevance. The other is that hydrogen will be an important part of the energy transition. The latter narrative appears to have won.

The cost of electricity is the single largest operating cost for producing green hydrogen. With electricity prices rising, the economics have taken a step backwards. New tax credits in the Inflation Reduction Act of up to $3 a kilogram for producing clean hydrogen will help. Other important issues remain such as how to move hydrogen and where to get scarce water. Nevertheless, a number of start-up hydrogen companies are getting into the sector. Projects are starting to advance.

A panel talked about the challenges and opportunities in the hydrogen sector at our 31st energy finance conference in South Carolina in June. The following is an edited transcript.

The panelists are Rob Morgan, CEO of H Cycle, Dr. Naomi Boness, managing director of the Hydrogen Initiative at Stanford University, Himanshu Saxena, CEO of Starwood Energy, Ivana Jemelkova, a senior managing director with FTI Consulting, and Rachel Crouch, senior counsel with AES Clean Energy. The moderator is Jim Berger with Norton Rose Fulbright in Los Angeles.

## Color Competition

MR. BERGER: Most hydrogen is made currently from natural gas using a process called steam methane reforming. Around 80 million tons of hydrogen are produced annually. It leads to about 830 million tons of carbon dioxide.

Most hydrogen is used to refine petroleum and treat metals.

I have two questions. Is there a way to replace most of the current hydrogen with green hydrogen, and what new markets are developing for hydrogen?

MR. MORGAN: We are going after that existing demand with the refinery market and talking about how we reduce the carbon intensity. The refining market is huge. Refineries have to decarbonize, in multiple markets, all around the world. There are low carbon fuel standards. Those are expanding, not decreasing.

We are using a waste feedstock, so we are helping to reduce carbon emissions as well by avoiding sending waste to landfills where it decomposes over time into methane.

The waste feedstock lets us put our plants closer to hydrogen users. It is easier to move waste than hydrogen.

After refineries, we want to expand into other markets, such as steel, glass and the transportation sector with its heavy-duty trucks.

MR. SAXENA: Renewable energy generators have been decarbonizing electricity for more than 20 years. Decarbonizing heat is harder. Manufacturing and cement production are heavy carbon-intensive industries.

We are starting to see an explosion in hydrogen demand across the board.

People have been making hydrogen for a long time. The question is how to supply the new demand in a carbon-neutral and cost-effective way. I don't think we are going to replace the existing hydrogen production any time soon. We are not looking for grey hydrogen versus blue hydrogen versus green hydrogen. I think it will be all of the above for a long time. All types of hydrogen will have a role to play because the demand that we see is enormous.

All of the industrial gas companies are playing in the space. Others are entering the market as well. BP just announced a $30 billion investment in Australia in hydrogen. Ammonia and methanol, which are hydrogen products, are going to become the next LNG businesses of the world. That's our belief. We expect exponential growth.

DR. BONESS: I agree. It is really important to move away from the colors and think about carbon intensity. Every region will be putting together its own suite of solutions based on local priorities and the local resources available.

In markets that are using SMR hydrogen from natural gas, probably the most cost effective way in the near term to decarbonize is to add carbon capture and underground storage. It would add something like 20¢ per kilogram of hydrogen to shift away from putting $CO_2$ into the atmosphere. Let's keep our eyes on the end goal of reducing emissions.

MR. MORGAN: Amen to Naomi. Colors tend to blur and obscure the conversation.

MS. JEMELKOVA: A good rule of thumb when looking for potential customers for hydrogen is to think about what is heavy, what is long distance or long duration and what is high heat.

I encourage everyone to look at Michael Liebreich's hydrogen ladder. It is an interesting intellectual exercise in where hydrogen provides the highest added value versus where other technologies might be a better solution. We may have different views on some of his suggestions, but it is a great way to wrap one's head around the role that hydrogen can play in the energy system. The same kind of ladder could be made for other technologies, too.

Hydrogen truly shines when it is allowed to play the role of an integrator, where it brings decarbonized, low- or zero-carbon primary energy into the system to do things that electrons and direct electrification simply cannot do.

MS. CROUCH: Our company is probably agnostic as to where the hydrogen ultimately ends up, although there are a lot of interesting discussions to be had on that subject. These are complicated projects that are going to take a long time to build. Developers need to have visibility into the offtake from an early stage. That is really our focus at this point.

## Best Uses

MR. BERGER: Ivana Jemelkova, you mentioned high heat as a potential use for hydrogen. That makes me think of things for which we use natural gas currently, such as heating and cooking. Can you talk more about the types of applications where you think hydrogen is best suited?

MS. JEMELKOVA: We already touched on some of them, but if the goal is decarbonization, the focus should be on potential uses of hydrogen in all areas where other solutions will not do. I would start with the pie chart of global emissions and look at hard-to-abate sectors that contribute the most. That would be the most effective way to reduce industrial carbon intensity.

DR. BONESS: The biggest benefits I see from hydrogen are in applications like steel refining where we do not have any other alternatives.

The hydrogen markets today, particularly in the US, are being dominated by transportation applications. The US catalyst is the low carbon fuel standard credits in California. Hydrogen is being used, for example for heavy-duty trucking. That has the early attention from developers. The next logical step is aviation fuels where there is no other solution.

MR. MORGAN: Hydrogen is an energy molecule. It is also a chemical. The feedstock value of hydrogen is extremely high, and there are many potential applications.

I have been in the power sector for 30 years. Solar and wind have won that race on the marginal cost of electricity, and batteries are helping, so we should electrify everything that we can.

Hydrogen as an electricity source is a low-value use right now. Hydrogen might be a great storage medium as we figure out how to do that, but it is use as a feedstock where hydrogen provides the most value today and where most of the market penetration will be over the next five to 10 years.

MR. SAXENA: We are starting to see a lot of demand from Japan for hydrogen, and a lot of that / *continued page 24*

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August that exempted some solar projects from property taxes. The court said the state legislature had no authority under the state constitution to exempt such projects.

In the other case, a Connecticut appeals court said that wind turbines are real property rather than machinery for property tax purposes.

The Missouri legislature exempted "solar energy systems not held for resale" from property taxes.

A solar company entered into a power contract to supply all of the electricity from a five-megawatt solar project to City Utilities of Springfield. The project is on land belonging to the utility. The utility has an option to buy the solar system at the end of year seven and then again at the end of each subsequent contract year as well as the end of the contract term.

The county assessed property taxes on the solar project starting in 2017. The solar company said the solar system is exempt and pointed to a state law that exempts "solar energy systems not held for resale."

The case landed in the state Supreme Court. The court never reached the question whether the purchase options mean the system is held for resale because it said the legislature has no authority under the state constitution to exempt solar systems from property taxes.

The state constitution has a list of exempted categories of property.

It then says, "All laws exempting from taxation property other than the property enumerated in this article, shall be void."

The solar company argued that the fact that the legislature has authority under the constitution to set different rates for different types of property means it can set a zero rate for some types of property. The court said no.

The case is *Johnson v. Springfield Solar I LLC*.

The taxpayer in the Connecticut case owns two 2.85-megawatt wind turbines that it put in service in late 2015 / *continued page 25*

## Hydrogen

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demand is to displace coal with ammonia to fuel power plants.

Japan Inc. will be looking to procure as much as 90 million tons of ammonia over the next 30 years. The ammonia plant that we are building is only 1.3 million tons, so we are going to need hundreds of these plants just to supply the demands of Japan. We are seeing similar interest from Europe. German utilities are now starting to look to procure ammonia. Ammonia is a way to transport hydrogen overseas.

The Russian invasion of Ukraine may end up pushing the US into the role of the last provider of energy to the world. The Russians are out, and they are going to be out for a long time.

We can take natural gas, convert it into LNG and ship it overseas, which is something that we are already doing, but that is very high in terms of carbon footprint.

Alternatively, we can take natural gas, convert it into blue ammonia, put it on ships and take it to Japan, Germany and other places. A lot of demand is coming from overseas, and that has made the competition for hydrogen and ammonia in this country pretty robust. When we started building our ammonia plant three years ago, the price of ammonia was about $400 a ton. The price of ammonia in the spot market today is about $1,800 a ton, reflecting how global the commodity has become. We are starting to see that hydrogen is a global commodity, very much like natural gas.

MS. JEMELKOVA: We touched on the economics, the carbon impact and the geopolitical implications. Another really critical perspective is consumer perception of hydrogen and consumer readiness for some of these applications. A utility ran an extensive customer survey on what consumers are ready to install in their homes, and whether they want to have gas, molecule-based or electron-based heating, cooling and appliances.

The main conclusion is customers are very reluctant to change. Many of those using gas today are keen to keep it, perhaps with a transition to decarbonized molecules. More broadly, both electricity and hydrogen are facing different consumer acceptance challenges. Electric vehicles are popular but not yet so widespread. Hydrogen is not something that people can commonly touch and feel in their day-to-day lives. We all know electricity plugs. We charge our phones, we charge our laptops, we operate with that type of energy in our daily lives.

DR. BONESS: We used to use hydrogen in the UK. My parents tell stories about how people converted their stoves to burn gas when the North Sea fields were developed. The same thing happened in the eastern US. These are not insurmountable challenges.

MR. MORGAN: Himanshu makes a great point about the spot price of ammonia. One of the consequences of Russia's war on Ukraine is that one of the major ammonia pipelines that exits at the Black Sea and accounts for 15% of the world's ammonia supply has been shut down by the war. Prices went crazy in March. The hydrogen and ammonia markets are global at this point.

MR. BERGER: Do you have a sense for whether consumers would prefer to switch a gas stove to a hydrogen or electric stove?

MR. MORGAN: Are you asking for personal preferences?

MS. JEMELKOVA: We can point you to research. I am happy to share a link to a survey that was conducted on exactly this in the northeastern United States. There are some really interesting insights. It is really a question of where does the market align and where do the consumers align.

MR. SAXENA: The retail application for hydrogen still seems far off. The industrial applications are where I think we will be focusing for the next 10 to 20 years. There is no network of pipelines in this country to transport hydrogen to homes. There is not even a network to transport it to most industrial facilities.

Electricity is the single largest operating cost for producing green hydrogen.

You can't use the existing gas pipeline system to transport hydrogen. There is lots of research underway across the country where people are injecting a small amount of hydrogen molecules into gas pipelines to see what it does. It is on the order of 5% because hydrogen is the smallest molecule. It will escape. You cannot put hydrogen in any meaningful amounts into the pipeline system as it sits today. Refurbishing the pipeline system so that hydrogen can be contained is a very expensive venture.

The point is it is not just a production issue. As Rob said, it is also a transportation issue. Right now we are focused on producing next to the load centers like Texas City in Texas and other places where a hydrogen pipeline system exists already. More widespread applications will require large investments in new pipelines.

MS. CROUCH: I agree. In the medium term, we are going to see hydrogen used in industrial applications where it is difficult, if not impossible, to electrify. It is difficult to electrify all residential applications, but hydrogen is too inefficient to put in our houses.

## Producing Hydrogen

MR. BERGER: Let's move to the production of hydrogen. There is electrolysis, and there is gasification. How will most green hydrogen be produced?

MR. MORGAN: We are a producer that is focused on decarbonizing. There are two ways to make renewable hydrogen in my view. You can start with water, use renewable energy and do electrolysis, or you can start with a hydrocarbon feedstock, organic waste, and release the hydrogen and carbon from that.

We plan to use organic waste because we have two tailwinds. First, we have the steam methane reformation issue you talked about earlier, which is all the CO2 emissions coming from extractive natural gas going to hydrogen. Second, there is a move by US states, and now countries around the world, to stop putting organic waste into landfills in order to reduce methane emissions. That is actually the law in places like California, Oregon and Washington.

Those two tailwinds give us a great benefit. We give municipalities and cities a way to comply with their diversion targets, and we give the low carbon fuel sector a way to get a lower-carbon feedstock into its compliance. We are catering to two compliance markets. We are not even touching tax credits yet. Tax credits would make things even better.

As for technology, I would like to quote one of my old AES friends, Chris Shelton. "We are */ continued page 26*

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near the town of Colebrook.

The local assessor said they were subject to real property taxes. The owner lost an appeal to the board of assessment and lost again in a trial court. It lost again in August in a Connecticut appeals court.

The appeals court said the turbines were so permanently affixed to the land — dismantling them would have required removing 124 anchor bolts set in concrete and cost $3 million — that they should be considered real property.

The trial court analogized the towers to sheds since a number of people could take shelter inside them at a time. The appeals court said it did not matter whether the turbines and towers are "buildings" as the trial court said or merely "structures," since both are taxed as real property. It said it had previously found that a 385-foot communications tower is a structure.

It declined to treat the nacelles as machines. They are not the type of machinery used in a mill or factory and seem permanently affixed to the towers and land. However, the court said that associated equipment, such as cables, wires, poles and underground mains and conduits, are personal property.

The case is *Wind Colebrook South, LLC v. Town of Colebrook*.

*— contributed by Keith Martin in Washington*

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technology agnostic, but highly opinionated." We are a gasification company today, but we are really a renewable hydrogen company, and we will move with the market.

MS. JEMELKOVA: Hydrogen is an energy carrier. It carries energy from any primary source that you want to use. The way you make hydrogen turns on where you feel your primary energy should come from.

The key issue when it comes to production is the lack of standardization. We have those colors that are probably well-intentioned, but at best quite unhelpful in the conversation. What should be the carbon standard for clean or low-carbon hydrogen? We cannot agree internationally, and we cannot agree domestically either.

The US Department of Energy is working with two different standards depending on the intended use of the definition. Clearer guidance and certainty are in the interest of all stakeholders, as they would help address some of the myths and unhelpful emotional conversations that are happening.

### Four Keys

MR. SAXENA: There are four things we look at when we think about what technology is best suited for a certain need. They are scale, cost, location and carbon intensity.

Hydrogen has been in production through steam methane reformation for 50, 60, 100 years. The technology is well proven. You can put carbon capture systems on SMR, remove as much of 95% of the CO2, and produce a blue hydrogen.

Those are very large systems. We are talking about $1 billion plus projects each, especially if you add a carbon capture system.

Scale is next. Electrolyzers tend to be much smaller. There are 20, 40 and 50-megawatt applications. If you are next to a customer, you can build smaller systems so that you do not have to worry about transportation.

Carbon intensity is another point. If you need green hydrogen, you are not going to produce it through steam methane or autothermal reformation; you are going to use electrolysis and do it where the price of renewable power is cheap.

There is no winner or loser in this debate right now. The method for producing hydrogen is case-specific and varies by opportunity.

As investors, we don't bet on technologies. We are not betting on a better electrolyzer 10 years from now. We are investing in what is available today. There are at least three different electrolyzer technologies. Producing hydrogen is not difficult. Producing it cost-effectively is the challenge that we face as an industry.

DR. BONESS: The other thing is that there is no silver bullet in terms of which technology is going to be sustainable. All of these technologies have warts on them. We are dealing with equipment that uses fancy metals that should only be found in a jewelry box. We are dealing with processes that require large quantities of water. CO2 is still part of the equation. We are trying to optimize around lots of different parameters.

The one technology that has not been mentioned and about which I am super excited about is pyrolysis. It is essentially gasification without the oxygen. Instead of CO2, you get solid carbon. At Stanford, we are working on things like making hydrogen with super high value carbon nanotubes as the byproduct that you could imagine being used in construction materials.

MS. JEMELKOVA: Another technology or feedstock primary energy that has not been mentioned is nuclear. There is quite a bit of excitement around nuclear and hydrogen and how these two technologies could work together.

There is no such thing as a perfect solution with energy. The versatility of hydrogen is hydrogen's biggest blessing and also hydrogen's biggest curse. What use cases are economic? What use cases really matter?

MS. CROUCH: To round out the discussion about how we are producing it, my company's sweet spot is building renewable power projects, so we are focused on the electrolysis application, but even within that, there are questions of additionality, what our customers are looking at as alternatives for whatever issues they face, and whether they want the electricity to be delivered behind the meter. There are a lot of permutations for how green you get and what it means to be green, especially in the absence of stringent federal or national standards.

### Location

MR. BERGER: An overriding theme is the old real estate adage, location, location, location.

MS. CROUCH: In the context of green hydrogen from electrolysis, location may not be the biggest thing since a lot goes into putting these projects together, but it is a major consideration for all the reasons that you want to find a good location for your renewable power project.

For a behind-the-meter project, not only are you looking for really good insolation or a really good wind resource, but you are

**Other challenges include how to move the hydrogen and where to find scarce water.**

also looking for both of them in roughly the same place, and you are looking for them not to be very highly correlated in order to maximize the amount of time that you are running your electrolyzers.

Water was mentioned. Water, in addition to electricity, is the critical feedstock. You need a large amount of it.

We also focus on transportation. You must either put your project near the customer or have a viable plan to move the molecules to the customer. Transportation by truck is very expensive.

Another issue is where do policy incentives line up? Many people are eyeing federal money for hydrogen hubs. The California LCFS credits are a game changer for anyone trying to sell into California. There are also ordinary course policy incentives that you might have for developing a project in a particular jurisdiction.

## Economics

MR. SAXENA: The single largest operating cost for an electrolyzer plant is the cost of power. There is a direct correlation between the price of power and the price of green hydrogen. If you buy electricity for $30 megawatt hour, then you can sell your green hydrogen for about $4.50 a kilogram. If it's $40 power, you need at least $5.50 a kilogram for the hydrogen. It is almost linear.

The price of renewable electricity has skyrocketed in the last nine months. Projects that were willing to sell renewable power for $20 a megawatt hour now want $40 to $45 a megawatt hour. We see an effect on the entire green hydrogen food chain because the price of hydrogen is not changing in tandem with the price of electricity, and we think that is a serious challenge.

We are starting to see a blowback effect on everything from cryptocurrencies and data centers to hydrogen suppliers. Green hydrogen is not economic to produce today. People are not going to pay us $5 to $6 a kilogram of hydrogen that we need to make those projects viable. Tax credits for hydrogen are important to close the gap. A $3 tax credit is going to be the difference between green hydrogen taking off and green hydrogen not taking off.

DR. BONESS: Hydrogen is not a fuel that can be sourced directly, except for one well that I know of. It is made from some other energy source, and so it is always tied to the price of whatever material is used to make it.

That is also true for blue hydrogen. It is tied almost linearly to the price of natural gas. I just published a report that discusses the economics of blue hydrogen in California. Now I have to redo all of the figures, especially the comparisons to green hydrogen, which is looking a lot less attractive.

MR. MORGAN: Jim, you raised an interesting point. I think transportation is going to be the linchpin for hydrogen because that is a really important step.

Going back to some of the energy input issues, our business model does not need a hydrogen tax credit because we are using the energy that is already in the hydrocarbon to release it. For example, electrolysis uses 50 or 55 kilowatt hours of electricity to produce effectively 30 kilowatt hours of energy value in the hydrogen. We need only nine kilowatt hours to make 30 kilowatt hours of energy value. The energy equation is critical.

Transportation is going to be the thing that we all have to solve. How do you get it to the customers that need to use it?

MS. JEMELKOVA: There is a lot of excitement about taking hydrogen production to places like Chile, Morocco, Australia and the Middle East, where you could get the cost below $1 a kilogram because the renewable electricity feedstock is so cheap.

Then the question is how to get that hydrogen to Europe where it may be needed. The US has the potential to produce all of its hydrogen supply domestically. / continued page 28

## Hydrogen

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Europe will most likely need to import large quantities. Right now when we look at European targets, they are 10 million tons produced domestically and 10 million tons imported, but no one is able to say yet exactly how that will happen. The European Union is placing various political and financing bets.

MR. SAXENA: People are trying to solve that problem by converting hydrogen into something else, and that something else is ammonia or methanol.

Air Products has a $10 billion project in the Middle East where it would use renewable energy in the Middle East to make green ammonia and then ship it globally. I see a lot of parallels with the LNG trade, where you convert gas into something that can be put on ships. Ammonia is the next LNG in my opinion.

Hydrogen can be converted into ammonia and transported by ship like LNG.

MS. JEMELKOVA: It is not about the cost of the production, but really the cost of the shipping? The shipping costs are a significant component of the final price.

MR. SAXENA: Shipping costs for ammonia are about 20% of the production cost, so it is meaningful, but they are not the core driver from what we have seen so far.

DR. BONESS: I think a big component of the cost is associated with the reconversion of the ammonia to hydrogen. Reconversion is inefficient and absolutely kills the economics, so I really like some of the solutions that people are working on to use ammonia directly. I think you mentioned in coal power plants. There are some turbines that do that. There are obviously some NOx and SOx issues associated with using ammonia directly, but I think it could really improve the economics.

### Hydrogen Hubs

MR. BERGER: The government has authorized $8 billion to authorize construction of four or five hydrogen hubs around the country. How important is this? Where do you expect the hubs to be built?

MR. MORGAN: Joe Manchin is going to get one.

MR. SAXENA: That is the price of build back a little bit better. We are seeing companies and states band together. West Virginia is one. Texas and Louisiana are talking about separate bids.

There is either going to be a blue hydrogen hub or a green hydrogen hub in each location chosen. The blue hydrogen hubs are going to be focused in markets where there is already a lot of geology to sequester CO2 underground, so that will be in the Midwest, in the Marcellus formation in Pennsylvania and New York, and in formations in Texas and Louisiana.

There is a lot of carbon capture and underground storage already. There are CO2 pipelines. It makes sense to put blue hydrogen hubs in the same locations. Maybe two of the four hubs will be blue or maybe three of the four will be two blue and one green. This is a really good start for the hydrogen economy.

MS. CROUCH: The Department of Energy put out a notice in the last two weeks. Six to ten hubs are under consideration. The number before was four or five. We were encouraged to see that slightly smaller projects or hubs appear to have opportunities.

MS. JEMELKOVA: This is a real step change. DOE used to finance mainly research and development and some demonstration projects with funding of a few million dollars at a time, perhaps up a few tens of millions in exceptional cases. Now we have a pot of money that is $8 billion.

It is a huge amount and a whole new challenge for DOE to figure out how to invest it in a smart way that really catalyzes movement in this space. The guiding principle is how to unleash the potential of the sector at large.

We had a look at some of the early candidates and what are likely to be the key success factors in that competition. I am using the words very carefully because I think that it is not about competing against each other but coming together as an industry and placing bets where they make the most sense.

There are about 20 different hubs in various stages of development so far.

There is a lot of quantitative data available about the type of investment, the carbon impact, the sort of jobs and growth impact on certain regions. There is not as much qualitative data on issues such as environmental justice and community engagement, and we all know how challenging those issues can be when it comes to permitting and getting the local communities on board and how important those are to the DOE.

At least 15 governors have come out to support different hydrogen hubs, and the split is pretty much even. There are seven Democrats and eight Republicans. We can expect the political considerations to play an important role as well.

MR. SAXENA: The topic of bringing Democrats and Republicans together is important because it is a refreshing change in the political discourse in this country. We have spent the last 10 to 15 years demonizing fossil fuels. Russia and Ukraine have reminded us that putting all of our eggs in one basket is not the best approach. The lights will go out if we take the demonization too far.

Hydrogen allows natural gas to play a role as a transition fuel by combining natural gas with carbon capture systems in the right markets by producing essentially carbon-free hydrogen. This will enable gas and renewables to coexist for a long time. That coexistence is what is bringing the Republicans and Democrats together. Joe Manchin doesn't really care so much about wind and solar. What he cares about is the natural gas in his state. It is a refreshing change to see people trying to find common ground instead of retreating to rigid positions.

MR. MORGAN: It is a great point because the hubs are going to draw bipartisan support. You are going to see a coal hub: Manchin. You are going to see a gas hub: probably Texas. You are going to see a nuclear hub: probably the Midwest or PJM. Then there will be a California one that is some mix of electrolyzers and other technologies. Those things are all the first level. Six to 10 hubs is the ultimate goal.

You are going to see carbon sequestration in North Dakota and along the Gulf Coast. I don't want to leave the topic without giving a shout out to Jigar Shah and the DOE loan guarantee office because it is doing great work as well.

## Audience Questions

MR. BERGER: We are about out of time. Let's see if we can fit a couple audience questions.

MR. SLOAN: Mike Sloan, CEO of Synergetic, a green hydrogen developer. How do you connect more users of hydrogen with the best production areas, which are probably going to be in the middle of the country or the desert Southwest? Can you speak to the anticipated timing of when you think we might get a pipeline system going for hydrogen?

MR. SAXENA: I am not seeing people talking about building long-haul hydrogen pipelines yet. You either have to move electrons or move molecules.

It is far easier to move electrons because there is already a transmission grid. Aren't you better off building transmission lines to bring renewable electricity closer to places where there is a demand for hydrogen instead of producing molecules in West Texas and trying to transfer those molecules to Houston? AES has been thinking about this a lot, right?

MS. CROUCH: We have. Pipelines are challenging to build. We have been focusing on moving the electricity to where there is demand for hydrogen and on 24/7 type products. Another issue is how to define green. Does the load need be tied to the generation or can the power supply be virtual. That would be another way to free it from being next to the electrolyzer.

MS. JEMELKOVA: Two utilities that are trying to wrap their heads around this are National Grid in the Northeast and Southern California Gas in California. They operate in two completely different markets with different sets of issues, challenges, regulatory environments and so on. One of them plans to try blending, at least in the initial phase. The other is planning to try pure hydrogen and is focused on how quickly it can get to that stage.

Both have published their strategies publicly. There is data behind them. They will provide anyone interested in this topic insights into two different perspectives.

DR. BONESS: I grew up in oil and gas where trying to get permits for any pipelines, regardless of what you are putting in the pipelines, is almost a non-starter.

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## Hydrogen

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We are almost starting from ground zero with the hydrogen hubs. They offer the prospect of getting critical mass, especially around ports. From that start, there will be connections that make sense, particularly along the transportation corridors. At that point, pipelines will probably have a higher chance of being permitted.

MR. BERGER: Last question.

MR. SKELLY: Michael Skelly, CEO of Grid United. The panelists are very nice to one another, but I am wondering if –

MR. SAXENA: We're just good people! [Laughter]

MR. SKELLY: I want to test that. A lot of people who say that if you look at the full lifecycle of natural gas production, the industry has done a horrible job of managing emissions. Blue hydrogen is not nearly as low carbon as many people make it out to be. I am wondering what your response is to that critique. One of you characterized it as an emotional argument. People do get excited about it because, as you all pointed out, it is all about carbon.

DR. BONESS: I also run a program called the Natural Gas Initiative at Stanford. We have a big methane emissions detection and quantification program. We just published a paper saying that the emissions in the Permian Basin are double what was previously thought, so I agree that it is a problem.

However, there are a lot of detection technologies. We have been working with companies on them. The upstream end of the supply chain is now getting a handle on this. With the evolution of satellite detection, there will not be any place for upstream to hide, so I think that we are going to get this under control and that it is less of a concern for the long run for blue hydrogen.

MR. SKELLY: You are more optimistic than I am about the Texas Railroad Commission.

DR. BONESS: I am a rock nerd so I am an optimist at heart.

MR. SAXENA: Michael develops transmission lines, so there is no greater optimist than that, my friend.

MR. MORGAN: I am thinking Michael Skelly has been trying to do this with transmission lines for 10 years, so I am not betting on pipelines.

MR. SAXENA: Look Michael, my view is perfection is the enemy of the good. You are not going to get it perfect for a long time. The energy transition is not happening overnight. The idea that a 50% reduction is not good enough is not the right way to look at it.

Folks think the transition can occur in the next 10 years. It is probably going to take the next 40 years. China is building new coal plants again. Australia is talking about restarting its coal plants. Germany is no longer shutting down its coal plants and is keeping them in reserve. You are starting to see globally that the push for decarbonization is taking a backseat to energy security and reliability.

We do renewable energy. We do conventional energy. We have to be practical, which means that blue hydrogen is a step toward a more glorious future. Let's not lose the intermediate step because, without it, you will never get to the end.

MR. MORGAN: So since Michael invited us, I am taking the gloves off. Carbon capture and storage is the incumbent answer to keep burning fossil fuels. We should change the source of our hydrogen and other feedstocks to renewable resources.

MS. JEMELKOVA: This brings us all back to the start of the conversation. There could not be a better case against hydrogen colors because all blue hydrogen, for example, is not the same. It depends on how good your carbon capture and storage are, how well you manage your fugitive emissions and so on. We need a clear carbon standard that removes the uncertainty and creates an incentive to produce truly clean hydrogen.

MR. SAXENA: But we have to do this in a cost-effective way. I spoke at a Reuters conference last week after the energy minister of Nigeria spoke. He used a term that I had not heard before. It was "energy poverty," and when he talked about energy poverty, it struck a chord.

In the United States, our lights never go out, but in places like Nigeria and India, you have power outages that last 10 to 15 hours. When we talk about global warming, we have to be practical. There is no such thing as an overnight transition. Even in the United States, when energy bills are rising, at some point people say, "I don't care what the carbon footprint looks like. I need cheap electricity, I need it now and I need it to be 100% reliable."

We have to move to clean energy in a methodical way. Abrupt changes are politically fraught and will set us back rather than move us forward. ◎

# The Inflation Reduction Act and DOE Loan Programs

*by Kenneth Hansen, in Washington*

The Inflation Reduction Act upsizes the existing US Department of Energy loan programs.

It also establishes new programs for transmission projects and for revamping existing energy facilities to enable cleaner operation and to remediate associated environmental damage.

## More Subsidized Lending

The Act authorizes another $40 billion for so-called section 1703 loan guarantees. These are loan guarantees, but are typically structured as direct loans from the Federal Financing Bank to finance projects that use innovative technologies. The new authority roughly triples the volume of available funding.

The Act also appropriates $3.6 billion to cover the credit subsidy cost for guarantees issued pursuant to the new capacity, resolving a "self-pay risk" that had discouraged use of the program for the past decade. Credit subsidy cost is basically a premium the borrower must pay to compensate the government for the risk that it might not be repaid.

Financing is subject to a requirement of no double dipping.

The Act also appropriates $3 billion to cover the credit subsidy costs of direct loans to finance new factories to make low-emissions vehicles and vehicle components. There is no cap on this type of federal lending. The program's existing $25 billion cap was repealed, permitting the program to lend whatever amount can be supported by the $3 billion credit subsidy appropriation.

The authorized capacity to make loans to finance energy projects for Indian tribes increased from $2 billion to $20 billion, supported by a $75 million appropriation for credit subsidy costs. Congress increased the maximum allowed guarantee percentage from 90% to 100%, which allows access to lower-cost financing.

The Inflation Reduction Act creates a new program to finance three types of energy infrastructure projects.

One type is projects that retool, repower, repurpose or replace existing energy infrastructure that has ceased operations. Another is efforts to enable operating energy infrastructure to avoid, reduce, use or sequester air pollutants or greenhouse gas emissions. The third type is projects to remediate environmental damage associated with energy infrastructure.

The Act authorizes up to $250 billion in loans for such projects, supported by an appropriation of $5 billion to cover the related credit subsidy costs.

Finally, the Act appropriates $2 billion to fund the credit subsidy costs of direct loans to build new transmission lines or to modify existing lines that have been designated by DOE as necessary in the national interest. No cap on the debt applies other than the amount that can be supported by the credit subsidy appropriation.

## Section 1703

The key development in all this may be the $3.6 billion appropriation (less up to $108 million for administrative expenses) to fund credit subsidy costs for loan guarantees for energy projects that embody innovative technologies.

Borrowers from most federal lending programs never hear about credit subsidy costs since that fee, which is required to be paid as a risk premium to offset any expected losses to the government from making a loan or issuing a loan guarantee, is typically covered by funds appropriated to the lending agency.

Title XVII, as amended in 2020, now requires that fee to be paid by DOE with appropriated funds to the extent available or, if none is available, then by the borrower.

Since the September 30, 2011 statutory sunset of full funding of credit subsidy costs with appropriated funds under the American Reinvestment and Recovery Act in 2009, borrowers have had to assume that they would be responsible for paying the credit subsidy cost of a DOE-guaranteed loan, which cannot be paid with funds borrowed from or otherwise provided by the federal government. The credit subsidy cost became in effect an additional equity requirement payable at closing. Although credit subsidy calculations are not publicly announced, rumors have them ranging from as low as 0% for the Vogtle nuclear power project to above 30%. The risk of a substantial additional equity requirement was made all the worse because the amount required would not be known until shortly before financial close.

The Energy Act of 2020 amended title XVII to require the DOE to pay all credit subsidy costs to the extent that it had available appropriations.

The Advanced Clean Energy Storage hydrogen project in Utah, for which a $504.4 million DOE-guaranteed financing closed June 8 this year, was the first beneficiary of */ continued page 32*

## DOE Loans

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that amendment, but, without the Inflation Reduction Act, there would have been little appropriated funds remaining available to cover the credit subsidy costs for other projects. The fresh appropriation has taken this issue off the table.

### Increased Lending Capacity

The several DOE loan guarantee programs have together carried roughly $40 billion in unutilized capacity — consisting of $22.4 billion for section 1703, $17.7 billion for advanced technology vehicle manufacturing (ATVM) and $2 billion for tribal energy projects — for more than a decade.

Until financings closed in recent weeks for the Utah hydrogen project and Syrah Technologies (in the ATVM program) and with the exception of three closings for the Vogtle nuclear power project, no section 1703 or ATVM financing had closed since September 2011.

No tribal energy project financing has ever closed.

Since Jigar Shah's arrival in March 2021 as executive director, the Loan Programs Office has worked aggressively to build a pipeline of qualifying projects, with so much success that concerns arose that the program's capacity would be insufficient to fund that pipeline. Trebling the available section 1703 resources — and apparently with flexibility to allocate those new resources as needed among the active solicitations for renewable energy and energy efficiency, fossil energy and nuclear energy — alleviates that concern.

The volume of loans and guarantees that can be supported by the new credit subsidy appropriations is necessarily uncertain, depending on the perceived riskiness of the financings. For the new title XVII appropriation to suffice to fund the new capacity fully implies an average credit subsidy rate of 8.73%.

That may be high. The new credit subsidy appropriation together with roughly $110 million (assuming for lack of a better number a credit subsidy cost of 10% for the Utah hydrogen project) could support the total authorized capacity, meaning the existing $21.9 billion plus the new $40 billion, at an average rate of 5.8%. This average may be in the right ballpark to support the authorized loans.

Before the Energy Act of 2020, DOE capped the self-pay amount of credit subsidy cost at 7%, promising prospective applicants that any credit subsidy cost above 7% would be covered by a small reserve of appropriated funds still available to DOE.

While the 7% cap applied, the question was raised whether this was more of a psychological than practical hedge, because the applicable credit subsidy cost for projects that received DOE support might well be expected not to exceed 7%. For lack of clear guidance of what the ultimate credit subsidy cost might be determined to be, 5% was a popular proxy for sponsors' modeling purposes. Even that 5% was often thought to be conservative, meaning there was cause to hope for a lower average rate. Still, if going forward 5% were the actual average credit subsidy rate, then the new section 1703 appropriation would suffice to support $69.8 billion in loan guarantees, meaning all of the new capacity plus $29.8 billion, which substantially exceeds the prior unused capacity.

Unfortunately, the Inflation Reduction Act appears to constrain use of the fresh title XVII credit subsidy appropriation to support the pre-existing authorization.

It provides that the new appropriation is "for the costs of guarantees . . . using the [new $40 billion in] loan guarantee authority . . . ." That could mean that the program once again has two tiers of capacity — the new authorization where the

DOE just got another $40+ billion to help finance innovative projects at low fixed interest rates.

government pays and the pre-existing authorization where the sponsors are responsible to pay anything beyond the roughly $110 million unused credit cost subsidy. That would most likely result in the roughly $21.9 billion in capacity that has gone undeployed since the American Reinvestment and Recovery Act subsidy expired in 2011 continuing to go without takers, at least to the extent the existing minimal pre-Inflation Reduction Act credit subsidy appropriations are exhausted.

This constraint contrasts, and arguably conflicts, with the title XVII ammendments to the Energy Act of 2020, which provided that any credit subsidy cost would be paid by the government to the extent appropriated funds are available. ("Except as provided in paragraph (2), the cost of a guarantee shall be paid by the Secretary using an appropriation made for the cost of the guarantee, subject to the availability of such an appropriation.") The exception applies where "sufficient appropriated funds to pay the cost of a guarantee are not available."

So, what does "available" mean? Here, the program has potential extra appropriated funds available, but by the language in the Inflation Reduction Act, the extra funds may not be available to support the pre-existing $21.9 billion in unused title XVII capacity, even though it has the identical policy purpose as the new appropriation and expanded capacity.

It would be unfortunate for the program not to have the flexibility to use the new appropriation to support the full breadth of section 1703 capacity. Perhaps the new language can be interpreted in a way to provide it.

## Cost of Funds

It will be interesting to see how another variable in all of this plays out.

The "credit-based interest spread" or, as now called by DOE, the "risk-based charge" is a new guarantee fee that arose in a 2017 update to the DOE loan guarantee rules. This fee, which ranges from 0% for a loan rated AA or higher up to 1.625% per annum for a loan rated B-, is to be paid periodically over the life of the loan.

This new fee was a throwback to an idea raised at the title XVII program's inception. The program's purpose is to provide financing notwithstanding innovative technology that could undermine the availability of commercial funding. The goal could have been to offer financing at rates that would correspond to commercial debt for non-innovative energy projects. Since the Federal Financing Bank provided loans at 37.5 basis points above the government's borrowing cost, which was cheaper than any commercial bank or bond market option, the staff considered imposing a guarantee fee to cover the spread between Treasury rates and commercial borrowing costs for comparable non-innovative projects.

Ultimately DOE decided against imposing such a fee, concluding that it should not undermine an apparent Congressional intention to subsidize innovative projects.

The consequence was a feeding frenzy of projects, many of which, at least once the financial crisis had passed, were solid candidates for commercial debt, but worked creatively to incorporate something innovative so as to qualify for the DOE program. This provided the DOE a pipeline of projects that were indeed innovative, but sometimes just barely.

The risk-based charge was initially opposed by prospective program participants who saw it as making the program more expensive. In fact, once the program had entered an era of self-pay for credit subsidy costs, a guarantee fee offered a potential advantage to borrowers. It offsets the credit subsidy cost, and a better reaction was that it enabled credit subsidy costs to be paid over time rather than up front, in effect financing at least some of it.

Although the models used by DOE and the Office of Management and Budget to determine credit subsidy costs are secret, the statutory basis for calculating the credit subsidy cost is not.

The credit subsidy cost is the projected cash flow out from the government because of a call on the DOE guarantee, minus expected receipts for fees paid to the government, plus estimated recoveries on a defaulted loan.

If a periodic guarantee fee were assessed and paid over the life of the loan, the present value of that projected payment stream would reduce the credit subsidy cost. A sufficient guarantee fee could totally offset the up-front payment of credit subsidy cost. Any such fee would at least reduce the amount of the credit subsidy cost payable at closing.

Whether the scheduled amounts would suffice to obviate the credit subsidy cost entirely seems doubtful, but any good sense of that would depend on its application in actual projects, and for the five years following the adoption of this fee, no deals under title XVII closed except for the Utah hydrogen project, but that closed in the wake of the direction in the Energy Act of 2020 to use all remaining appropriations to fund credit subsidy costs. Although no announcement was made, the DOE presumably paid a substantial part of its remaining $161 million credit subsidy appropriation */ continued page 32*

## DOE Loans

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to cover the credit subsidy cost for that financing.

How will all this work going forward?

The "new" guarantee fee may have been in the sponsor's best interest when faced with the up-front payment of credit subsidy cost, but the availability of appropriated funds to cover credit subsidy cost going forward will dispel any enthusiasm for that fee.

The original argument for a guarantee fee could still be seen to have policy merit. DOE will need to decide whether to offer borrowers the cheapest funding possible by foregoing that fee or possibly to reconsider whether the most efficient way forward is to offer innovative projects funding on terms that do not penalize the innovation, but that are not cheaper than non-innovative projects could achieve from banks or in the capital market. Stay tuned.

It also has new funds for transmission projects and revamping energy facilities to enable cleaner operation.

### White House Oversight

The Inflation Reduction Act imposes new oversight by the White House.

The DOE loan guarantee programs have always required interagency input. Financing terms are run by the US Treasury for its blessing. The proposed credit subsidy charge has to be cleared by OMB just before closing.

The Inflation Reduction Act introduces a new layer of oversight from no less than the President of the United States. It provides that:

> "None of the amounts made available under this section for loan guarantees shall be available for any project unless the President has certified in advance in writing that the guarantee and the project comply with the provisions under this section."

This raises two issues. One is complying with the relevant provisions. The second is obtaining the President's certification that you have done so.

As to the first, the relevant provisions consist of a broad prohibition against double dipping.

Projects receiving a loan guarantee should not benefit from any other "federal funds, personnel or property." The restriction, which first arrived in a 2009 appropriation, is both broad and fuzzy. For instance, every project receiving a loan guarantee will have benefitted from the time and effort expended by the federal personnel in the Loan Programs Office working on the transaction. Presumably that is not meant to be prohibited. Clarifications were needed in 2009 and have been repeated in the current law.

Specifically permitted — meaning excluded from the double-dipping prohibition — are tax benefits, use of federal land (where cash rent is paid at fair market value), use of transmission lines owned by the Tennessee Valley Authority or Federal Power Marketing Administrations and nuclear incident insurance. Federal grants are not carved out.

That could be problematic for the section 1703 program. DOE is an important source of grant funding for developing innovative energy technologies. Projects using the very technologies that were deemed worthy of grants could arise as good candidates for the section 1703 program, but be disqualified for double dipping. DOE's inclination in the wake of the 2009 appropriation was to interpret this restriction narrowly. If the grant went to one company, but the borrower of the DOE-guaranteed loan was, as it typically would be, a newly-established special-purpose project company distinct from the grantee, then the borrower had not itself received the grant and so no double dipping had occurred.

The lack of projects taking advantage of the 2009 appropriation has led to little development in the last decade of policies for interpreting this double-dipping limitation, but the program and the applicants have a shared interest in this provision not becoming an impediment to deserving projects, so ways forward will likely be found.

With respect to the second issue, how will the President be in a position to certify a project's compliance?

He or she will not be. With the legislation only hours old at the time of this writing, it is not clear how this will be managed. There is good precedent for such Presidential functions being delegated to a relevant Cabinet member. For example, the statute of the Export-Import Bank of the United States provides that the bank can only consider commercial aspects of a proposed loan unless the President specifically directs it to take into account certain policy concerns such as nuclear proliferation, chemical or biological warfare and environmental issues. The President delegated exercise of that authority to the Secretary of State, where it lies today.

Here, similarly, the responsibility that the Inflation Reduction Act assigns to the President could be delegated to the Secretary of Energy, who would make the necessary finding based on the diligence undertaken by the Loan Programs Office. This new interagency hurdle should be easily cleared.

## Vehicles Manufacturing

The Inflation Reduction Act provided a fresh $3 billion (less up to $25 million for administrative expenses) appropriation to cover the credit subsidy costs of direct loans for advanced technology vehicles and their components.

It also removed the $25 billion authorization cap, so the $17.6 billion remaining from the original 2009 authorization of $25 billion is now moot. Under the Inflation Reduction Act, the DOE is free to provide as much financing as the available credit subsidy will support. The available credit subsidy consists of both the new $2.975 billion plus the amount remaining from 2009 appropriation, which was $4.2 billion before the recent $102.1 million Syrah financing.

Allocations of credit subsidy to individual transactions are not announced by DOE, but 25% might be a reasonably conservative guestimate for Syrah Technologies.

Congress assumed 30% when the program was established and it appropriated $7.5 billion to support a $25 billion authorization. The Congressional Research Service reports that $3.3 billion was used for the original $8.4 billion in ATVM loans that were made, which were the only loans made prior to Syrah Technologies. The average rate for those loans was a high 39.3%. Yet those loans were all made on the heels of the 2008 financial crisis, and $5.9 billion of the total $8.4 billion was allocated to a Ford Motor Company loan in September 2009, which, at the time, was widely seen as a bail out.

Today's environment for ATVM investments, an industry that has advanced in the decade since those original loans, is more propitious. Applying a probably conservative 25% credit subsidy rate to the Syrah Technologies loan would suggest a credit subsidy requirement of $25.5 million. Deducting that from the $4.2 billion in credit subsidy for the ATVM program remaining prior to that transaction, would suggest credit subsidy of about $4.175 billion remaining from the original 2007 appropriation. That, together with the $2.975 billion from the Inflation Reduction Act, suggests about $7.15 billion in credit subsidy available for ATVM loans going forward.

Just how much financing that credit subsidy amount will support depends on the projected riskiness of each transaction. The original Congressional expectation of 30% would suggest up to about $23.8 billion in available ATVM financing. An arguably more likely rate of 10% would imply up to $71.5 billion.

Whatever the average rate, the ATVM program has the capacity to be an important source of capital for converting the country to a cleaner transportation fleet.

## Tribal Loan Guarantees

The tribal energy loan guarantee program offers loan guarantees for loans made to an Indian tribe or a "tribal energy development organization" to provide electricity on Indian land.

A tribal energy development organization is an organization that is wholly or partly owned by one or more Indian tribes and engaged in the development of tribal energy resources.

No loans have been made to date under this program.

A key impediment to this financing was a 90% cap on the amount of the guarantee. The Inflation Reduction Act eliminates that cap, which not only avoids commercial lenders accepting a degree of borrower risk in these loans but also opens the program to funding from the Federal Financing Bank, which reduces both fees and interest cost. These improved terms should make this program more effective.

The tenfold increase in the size of the program from $2 billion to $20 billion in the Inflation Reduction Act, with an additional $75 million appropriated to cover credit subsidy costs, may also help by encouraging larger projects. */ continued page 36*

## DOE Loans

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The $75 million credit subsidy appropriation complements the original, unused credit subsidy appropriation of $8.5 million, resulting in a total credit subsidy cost budget of $83.5 million.

This would suffice to fund the credit subsidy cost for the $20 billion authorization at an average rate of about 4.2%. That might be on the low side, meaning that the program could run out of appropriated funds before it runs out of capacity. But this in any event provides for a substantial expansion of a program that has yet to close its first loan.

As with the section 1703 program, the term of these loans can be up to the lesser of 30 years or 90% of the projected useful life of major physical assets, and loans can fund up to 80% of eligible project costs.

These loan guarantees are also subject to the double-dipping limitation that applies to the section 1703 program, the new section 1706 guarantees, and the new transmission facility financing program.

### Energy Infrastructure

The Inflation Reduction Act establishes a new "section 1706" loan guarantee program to offer financing to clean up existing energy infrastructure used for generating or transmitting electricity or producing, processing and delivering fossil fuels, fuels derived from petroleum or petrochemical feedstocks.

It offers loan guarantees for up to 30 years for projects that do one of three things.

One is to retool, repower, repurpose or replace energy infrastructure that has ceased operations. To qualify, any fossil-fuel power plant must "avoid, reduce, utilize, or sequester air pollutants and anthropogenic emissions of greenhouse gases."

Another type of undertaking that will qualify for a section 1706 loan guarantee is one that enables operating energy infrastructure to "avoid, reduce, utilize, or sequester air pollutants or anthropogenic emissions of greenhouse gases."

Projects to remediate environmental damage associated with energy infrastructure also qualify.

The $5 billion of credit subsidy appropriated to support the authorized program ceiling of $250 billion suggests an average credit subsidy cost rate of 2% to support the authorized amount fully.

This seems low. This program is likely to run short of credit subsidy appropriation before the ceiling is reached. There is plenty of money to test whether the program can be effective. If it proves itself, then credit subsidy appropriations can always catch up.

Unlike the section 1703 program, there is no innovation requirement. However, these guarantees are subject to the same double-dipping restriction as the section 1703 program.

### Transmission

The Inflation Reduction Act includes a $2 billion appropriation to fund the credit subsidy costs of direct loans for the construction or modification of electricity transmission facilities that have been designated by DOE as necessary in the national interest.

That appropriation was made without a corresponding maximum authorization, so DOE is free to lend as much as that credit subsidy appropriation will support, which suggests up to $20 billion if the average credit subsidy cost rate is 10% or twice that if the average rate is 5%.

The program is for "non-federal borrowers," which means that state and local government borrowers as well as private entities would qualify.

These loans are to be on "such terms and conditions as the Secretary determines to be appropriate." However, as with the section 1703 program the loan term cannot be longer than 90% of the projected useful life of the financed facilities and in no event longer than 30 years.

The loan cannot exceed 80% of project costs.

It cannot be subordinate to other financing, and the same double-dipping restriction will apply.

All loans must be fully disbursed by September 30, 2031.

Like other programs that provide access to Federal Financing Bank funding, applicable interest rates will be a small margin above the US Treasury's borrowing cost for obligations with similar average maturities.

This new funding is in addition to the up to $5 billion in loan guarantees for high-voltage direct current (HVDC) systems, transmission to connect offshore wind and facilities sited along rail and highway routes that DOE announced in April as available from the section 1703 program in combination with the tribal energy loan guarantee program.

The statute does not specify where within DOE this program should be housed, but, given its nature as a credit program whose terms mimic the section 1703 program and the existing transmission project loan program, it belongs in the Loan Programs Office and so presumably its implementation will be assigned there.

## Applying

Applications for section 1703 financing are made pursuant to detailed outlines provided in three outstanding solicitations. One is focused on renewable energy and energy efficiency projects, one on fossil-fuel energy projects and one on nuclear energy projects. The solicitations can be found at https://www.energy.gov/lpo/services/solicitations.

The process for applying for the new section 1706 program remains to be determined by DOE, but it is likely to follow a path similar to that for section 1703, subject to three requirements specified in the statute.

The three requirements are the applicant must submit a detailed plan describing the proposed project, an analysis of how the proposed project will engage with and affect associated communities, and, if the applicant is an electric utility, an assurance that the utility will pass on any financial benefit from the guarantee made under this section to the customers of, or associated communities served by, the electric utility.

The transmission facility financing application process remains to be announced, but it can be expected to parallel the DOE's other loan and loan guarantee programs. ◎

## DOE Energy Infrastructure Grants

The DOE has traditionally provided grants to support energy-related research.

Recent legislation has provided very substantial grants to support the construction of clean energy infrastructure. Such grants authorized last November by the Infrastructure Investment and Jobs Act are currently being offered for competitive application on the web page of the DOE Energy Efficiency and Renewable Energy (EERE) office.

The Inflation Reduction Act adds to that by offering grants for plant and equipment in support of reducing greenhouse gas emissions from transportation and industrial production. Each recipient will be required to fund at least 50% of the relevant project's cost.

### Reducing Factory Emissions

The Inflation Reduction Act appropriates $5.812 billion (less $200 million reserved for administrative expenses) to fund financial assistance (including not only grants but also potentially direct loans, rebates or cooperative agreements) on a competitive basis to carry out projects to accelerate progress to net-zero greenhouse gas emissions for domestic, non-federal, non-power industrial or manufacturing facilities engaged in energy-intensive industrial processes, including retrofits, upgrades and operational improvements and related engineering studies.

DOE will prioritize projects based on the extent of expected greenhouse gas emissions reductions, the extent to which the project would provide the greatest benefit for the greatest number of people in the general vicinity of the facility, and whether the recipient participates, or would participate, in a partnership with its customers.

### Manufacturing Vehicles

The Inflation Reduction Act provides DOE with $2 billion for grants to manufacturers to fund a portion of the costs of projects for the domestic production of efficient hybrid, plug-in electric hybrid, plug-in electric drive, and hydrogen fuel cell vehicles and their respective components. Priority will go to the refurbishment or retooling of manufacturing facilities that have recently ceased operation or will cease operation in the near future.

### Grant Applications

Applications will be pursuant to information provided on a portal maintained by DOE's "EERE Exchange" (located at https://eere-exchange.energy.gov). Interested parties need to register, which will provide access to current funding opportunity announcements. Grants offered by the Infrastructure Investment and Jobs Act are there now. The Inflation Reduction Act grants can be expected to follow in due course.

# The Evolving Energy Storage Market

The energy storage market is still in its infancy, but it is evolving rapidly. Portfolios of standalone utility-scale batteries are now being financed on a merchant basis. The market is moving away from traditional power purchase agreements to tolling agreements. Developers are having difficulty finding batteries and then getting them delivered on time.

A panel of storage developers and one investor talked at the 31st energy finance conference in South Carolina about the outlook. The following is an edited transcript.

The panelists are John Breckenridge, CEO of Arevon Energy, a renewable energy development company with about 1,500 megawatt hours of operating storage projects and a similar number under construction, Steve Vavrik, CEO of Broad Reach Power, which has 350 megawatts of operating batteries, another 100 MW under construction and another 30,000 MW of queue positions, Ty Daul, CEO of Primary Solar, which has one of the largest solar-plus-storage projects at 690 MWac of solar and 1,400 MWh of storage under construction near Las Vegas, Andrew Bowman, CEO of Jupiter Power, which has 654 MW of storage either operating or in late stages of commissioning in ERCOT and another 11,000 MW of storage under development, and Sara Graziano, a partner with SER Capital, which owns portfolio companies with storage projects in various stages of development in New York, Texas and California as well as behind-the-meter commercial-and-industrial-scale projects primarily in the Northeast. The moderator is Christy Rivera with Norton Rose Fulbright in New York.

## Looming Cost Increases

MS. RIVERA: John Breckenridge, you said before the panel that supply and cost are the biggest issues this year in the storage market. How so?

MR. BRECKENRIDGE: The industry has not fully digested or understood what is going on in the battery supply chain today.

There are some forecasts that say in order to meet the demand in the next several years, we will need 30 times the current mining capacity of lithium. That means we may not see storage cost again what it did last year for another 10 years. Add interest rates, and the cost skyrockets.

We have bought batteries from Tesla and other suppliers. We spend a lot of time with various forecasters. I don't think their models adequately forecast where costs are headed.

I am also certain that developers who have not actually signed battery contracts do not understand what they are up against today. Tesla is our biggest battery supplier, and it is under pressure to get out of the storage business. It can make a lot more money on vehicles.

People thought in early 2020 that COVID would mean a few weeks at home and then everything would gradually return to normal. It was basically unforecastable how totally unknown a future we face.

We are an industry that has relied on declining prices over time for its equipment. We are in an environment now where, certainly on the storage side, we are going to see cost inflation until sodium or some other new stationary technology takes hold that is not even visible yet on the horizon. This is our biggest issue.

MS. GRAZIANO: I agree if we are talking about two- to four-hour lithium-ion batteries. It is important to keep in mind that the power sector is a very small player in a market for those batteries that is dominated by the automotive suppliers. You have to look not only at what the forecast is for grid-scale batteries, but also what is going on to satisfy EV demand.

The other issue is that the automotive suppliers place big orders. They buy out entire production lines in a factory for years. They have a lot more leverage. They are also willing to take on some of the risk around commodity prices and do indexed contracts, which, historically at least, we in the grid-scale industry do not want to do. You can buy a gas turbine from GE, which is what we all probably started our careers doing, for a fixed price.

## New Model

MR. VAVRIK: We all agree on that as the general state of the market. It is not just lithium. I am chagrinned when people show me a slide I did in October 2021. The world has changed.

To John's point, I don't think future battery prices are forecastable. So give up. It is kind of like playing football and it starts raining or snowing. Why are you passing the ball? We have to go to a ground game. That is good enough to get where we need to go.

We are all responsible for the transition. Forget about the old plays of fixed price delivered to the customer. Let's get more creative.

The good news is we have done this before. We have gone through supply crises before. We have gone through recessions before. We always emerge by being a little more creative.

At the end of the day, the customer has to pay the cost, so instead of going to the grid operator or the utility, focus on the large corporations and data centers that are our potential customers.

They are the ones who really want storage. Let's go to them and say, "That project with a fixed-price PPA in Houston? We can do that, but that project is never going to get built. Why don't you meet us in the middle, with some sort of more flexible contract? It will help meet your carbon goals. It will get the project built. We will work together to figure it out along the way.

The auto companies are willing to take lithium price risk when buying batteries.

It is not guns drawn; it is pencils out. We can figure this out.

MR. DAUL: I agree. The challenges are pretty big in the near term, in part because everyone is so used to a declining cost curve. Everyone — developers, lenders, offtakers — has to understand that we are in a new world. I totally agree it is now a ground game.

MR. BRECKENRIDGE: Let's also not lose sight of the time aspect of this issue. Many of the projects that are being developed at utility scale today will not be built until 2024, 2025, 2026 and beyond. There is a lot of uncertainty, but there is also the possibility during that period that price signals will help increase the supply. There is a lot to like about that picture.

MR. DAUL: Let's also not lose sight that we are dealing with trade issues currently with solar panels. It is not improbable that we will have similar issues with batteries in the next two to three years.

MR. VAVRIK: It is up to us to take that to Washington. We need diversity of supply. Let's talk more about industrial policy. We need more vendors of not just batteries, but also transformers and copper, and we need them from friends.

MR. BRECKENRIDGE: It is reasonable to assume that if you delay a solar project several years, there is a reasonable chance that we will be in a better solar supply situation than we are today. That is not true of batteries. Delay may solve your panel problem. It will not solve your battery problem. That's the real dilemma for solar-plus-storage projects.

The one bright spot is stationary storage technology looks like a better place to invest today than it did before. A couple years ago, anyone would have been worried about the risk of being wiped out by lithium ion. That is no longer true today.

## Contract Issues

MS. RIVERA: Are the cost issues coming up when entering into new contracts or are you having to renegotiate existing contracts? Are battery suppliers coming back and asking for more money?

MR. BRECKENRIDGE: We have a $2 billion contract with Tesla. I would have thought with a contract that size we would be considered a super influential customer, but we are still struggling to get product delivery dates. We have vendors who are willing to walk away and pay huge breakup fees because of the size of the problem.

Anyone who has a contract that has not actually scheduled delivery is at risk of seeing price increases, regardless of what the contract says.

MS. GRAZIANO: That's correct. One of our portfolio companies has a contract with a battery supplier who came back and asked for lithium indexation and an increase in transportation costs because of the logistics issues that we are all seeing.

This is especially a problem for products coming from China where continuing lockdowns are causing factories and ports to close. It is hard to get containers. It is hard to get deliveries.

We have experienced this as well with battery vendors that are buying lithium and other raw materials on a spot basis. If I were running a battery business, I don't think that is how I would do it, but they feel they are suitably / continued page 40

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indexed to the auto companies, who are their biggest customers. They can buy raw materials in the spot market and pass through the cost. They have no incentive to try to fix costs.

MR. BOWMAN: The same pressures are being felt on the offtake side. There is a big gap in time between signing an offtake contract and when the project moves to financing and construction.

MR. DAUL: Anyone who signed a contract two years ago assuming a declining cost curve on solar and energy storage is definitely renegotiating today.

MR. VAVRIK: You know who else wants a long-term contract is the utilities. They are the ones that are now seeking five-, seven- and 10-year contracts. Managing risk with current market conditions and such a contract is double black diamond stuff.

Everyone wants efficient capital. It is going to take some time for energy storage to develop the tool kit that we are used to in the other elements of the energy transition.

### Volatility

MS. RIVERA: Steve Vavrik, you said before the panel that you are seeing strong demand from utilities for reliability. How do you address it?

MR. VAVRIK: One of the themes this morning is volatility is increasing. Let's stipulate that it will persist for a while. Who takes the volatility risk? Ultimately, it is the offtaker or the contractor. They are still feeling their way on how to address it.

They are looking for ancillary services. They are looking for energy spread deals. They are looking for puts and calls. We will figure this out, but it will take some testing to get it financeable.

Look at what is happening currently in ERCOT. A record demand for electricity, and not just on a seasonally adjusted basis. It is record absolute demand. Will the wind be there? Who knows? Who's not going to be there? The heat has knocked six large power plants off line with 2,900 MW of generating capacity. Other plants are offline for maintenance. Thank goodness the Freeport LNG terminal is not offline because things would have been really tight this past week.

This is not going to change. Who ultimately bears the burden? The utilities and their customers, but we are all responsible in the sense that it leads to riskier projects. If we mess this up, we have more blackouts and brownouts.

MR. BOWMAN: The concept of reliability as a market product is really nuanced and is changing and becoming more specific in transactions.

We are still figuring out how to transact around all of the things that batteries can do. We are still figuring out how to structure transactions for the ability to respond very quickly, to respond reliably in certain windows, to respond cleanly, to do any of these things at any particular time when they are most needed and to do something else the rest of the time. That is the complexity of these assets as resources.

We are in the very early stages. These are still ancient times in terms of the history of storage as a business.

How batteries are used, and the revenue streams used to finance them, will be very different two, five or 10 years from now.

MR. BRECKENRIDGE: We are primarily in the California market, where we are operating a number of projects, both standalone and combined with solar.

The contract market has historically followed the cost in this industry, so contracts used to be quite high, and costs were coming down. Now the costs are increasing. This is starting to dawn on customers.

The California grid operator, CAISO, saw the forecasts for high volatility and has been overbuying in the day-ahead market. That has reduced volatility in the broader market.

The market dynamics are swinging in ways that make operating a battery very complicated, particularly standalone batteries in California. Those of us who are operating those batteries are learning new lessons every day.

MR. VAVRIK: The conclusion is batteries will still have to be financed on balance sheets for a while. They will have to rely on equity. We will figure out the capital structure over time.

### Merchant Storage

MS. RIVERA: You went where I was going to go, which is we are saying such great things that all the banks in the room are really excited to give us money right now. [Laughter]

The panel before this one was the banks and tax equity investors. I took notes. The banks are not big fans of new technology risks. They don't like hedges, but they also don't like merchant revenue. Given this, the fact that you are closing any of these deals is really amazing, and you are all awesome.

Andy Bowman, I know Jupiter closed a financing earlier this spring on a portfolio of standalone utility-scale batteries in Texas. How did you do that after everything we have just heard?

MR. BOWMAN: Some aspects of getting it done were novel and challenging. One of them was bringing up to speed the bankers on how the technology works. There is a really good ecosystem emerging of consultants that can provide great advice about all of that to lenders.

Our portfolio was mainly merchant, but we have some hedges. Harmonizing the collateral requirements with the credit requirements on the hedge instruments was challenging.

Ultimately, the biggest surprise was the process was really quite straightforward. There were a number of lenders with whom we could have worked. We had a really wonderful experience working with the lender with whom we did the financing ultimately. We are having conversations about future deals.

I don't think the question is merchant versus contracted. The question is how will the project get built, and then how available is it for a lot of valuable transactions, including short- or long-term contracts as the grid continues to evolve in really interesting and surprising ways with a lot of volatility changing everybody's seat pretty regularly at the table.

MR. VAVRIK: The corollary to that is availability. A good investment is storage service companies. Batteries are tricky. They are new. There are a lot of vendors. Getting them to work right is going to take some time. Servicing batteries is an opportunity.

## Grid v. Distributed

MS. RIVERA: We have been talking a lot about front-of-the-meter or utility-scale stuff. Sara, I know that your company also invests in behind-the-meter storage. When you look at potential investments, are there differences between batteries that are in front or behind the meter?

MS. GRAZIANO: Yes. What we focus on behind the meter is batteries placed at commercial and industrial locations. Most of the uptake in the behind-the-meter market is batteries attached to residential rooftop solar systems. The economics of that don't seem like they pencil out, at least from my perspective, but there is customer demand regardless of the economics.

The main application for which C&I customers are looking is some combination of arbitraging — by trying to reduce peak demand so that they can reduce their demand charges from the utility — and power quality — where they are running a process that is sensitive to voltage fluctuations and things of that nature, and they are in a part of the grid that is suffering as more intermittent resources connect to the grid.

The first issue that we run into a lot in our C&I business is that each of these applications is somewhat bespoke. You have a significant engineering cost for a relatively small project. It weighs on the economics because we have not gotten to a point of standardizing it so that we can avoid having to reengineer it every single time.

The second issue is that most of the customer's power is still coming from the local utility. The utility tariffs are an Alice in Wonderland world. I go down one rabbit hole to avoid a demand charge and, all of a sudden, I am on Rider X-2 of something else that has raised my costs again for some bizarre reason.

It is challenging to figure out the implications on the customer's tariff for each potential action involving the battery and then to use the information to optimize the storage facility. Usually there is some kind of an optimization algorithm or software that governs operation of the battery and that knows when a peak load event is expected to be ready to shift.

## Opportunities

MS. RIVERA: Keith Martin sent me an article from yesterday that reported grid-scale energy storage set a record in Q1 of this year with 2.4 gigawatt hours of installations. Normally deployment is more back-ended late in the year. It was an amazing first quarter, and all trends point up. Where do you see this market in five years?

MR. BOWMAN: Most of us in this room have been involved in renewables and the electricity business for a long time. We have seen new technologies come in, mature and really grow. We have seen it happen with wind and solar. The expectation is the same thing will happen with batteries and storage.

The details are less foreseeable exactly how the supply issues get handled, exactly what revenue streams will support financings long term, exactly what suite of ancillary services will be available in each market, and exactly how grids will address higher renewables penetration.

Bloomberg New Energy Finance announced the energy storage decade starting this year, so those of us who have been working in storage for several years have apparently been laboring in the negative years.

This is year one of the storage decade, and very little of this stuff has been figured out yet.

When you look at each of the regional grids, you can see a growing role for storage to help even out supply and load and to provide greater reliability.

As for five years from now, everybody believes there is going to be a lot of it. Nobody is exactly sure how it is going to be contracted, how it will get financed and */ continued page 42*

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where it is going to come from. And yet we are all highly confident that it is going to happen.

MR. BRECKENRIDGE: The best market for current short- or mid-term, four-hour utility-scale storage is California. The reason is California has a "duck curve." The current storage technology works really well with solar. You get a cycle every day, and you make money every day. The current technology does not work as well with wind because wind can blow for three days and not blow for two days. It is very difficult to make a lithium-ion four-hour battery earn a lot of money in that sector.

The duck curve is most likely to be found in the southwest part of the United States. Some states in that region do not have solar incentives currently. Once such incentives are adopted, you start to see a duck curve. That is where the big markets are going to be.

Because this is such a new market, the market doesn't yet really understand where the limitations are going to be in terms of siting.

In storage, the best application is not out in the desert. It is in the load pockets where you have the most congestion and you cannot build new transmission.

It is hard to see what happens five years from now when you can't find a place in Los Angeles to build a new solar-plus-storage project. That is another big unknown for this sector.

MS. RIVERA: So California is the best place today for standalone utility-scale batteries?

MR. BRECKENRIDGE: That is the only one really that offers opportunities on a large scale today.

MS. GRAZIANO: I would like to put in a plug for my home city of New York City. After I said that at another conference, someone came up to me afterward and said, "Yes, but there is only one place you can interconnect a 100-megawatt battery." And I thought to myself, "Why would you interconnect a 100-megawatt battery in New York City?" New York has a program program called VDER, for the value of distributed energy resources, where you can lock in a 10-year tariff with Con Ed for the value to it of deferring investments in the transmission grid. There are lots of places where you can put five-megawatt batteries.

A lot of us come at this from a utility standpoint. With batteries, that is the exact opposite of what you need to be thinking. You need to be thinking small, in the very specific load pockets, specific customers, specific grid applications. That is where we see a lot of opportunity.

MR. BOWMAN: Actually there are a lot of places in just about every big city with a big industrial site where a large, multi-hundred megawatt hours of battery can fit. We are bullish that these large batteries are going to be a big factor in improving reliability in big load pockets going forward in every market.

MR. VAVRIK: Storage isn't new. What is new is lithium has made it modular and now we can privately finance it.

Follow the fundamentals. Duck curve, load pocket, we are part of a power system. Where is demand greater than supply? You are selling reliability. Put it there.

MR. BRECKENRIDGE: It just feels like outside of California, those other applications feel like peaker-type applications. The grid operators need to create capacity-type markets, which are not really fully in place yet, to attract that type of storage. Investors would then be betting on peaker-type economics, which can be very lucrative, but it is a different kind of game than traditional infrastructure.

MS. RIVERA: We have time for one audience question.

MR. HUTSON: Jamie Hutson, chief investment officer of DSD Renewables. We have a couple hundred megawatt hours of storage operating in VDER. How do you think about round-trip efficiency on these projects? We find that to be a challenge when looking at the economics.

MR. VAVRIK: Case by case. We have a use case in Texas where we are two to three cycles a day. That is a different use case than in California. We will take a look at what the vendors are doing. If costs are going up, someone will figure out a better widget. We are also figuring out ways to recharge batteries to help postpone degradation. The more use cycles per battery, the better the economics.

MR. DAUL: The key is understanding how you want to design for the use cycle. It's essential. If you install the battery to address one use case, and it is operating in a completely different way, you are going to blow out your augmentation and operating forecasts. ◎

# Battery Purchase Contracts: Key Pitfalls

*by Luke Edney in Dallas, Jeremy Tripp in Houston and Lauryn Robinson in Austin*

Anyone developing a battery energy storage project should be prepared to address two main issues.

The first, and the topic of an earlier article, is the general contracting structure. Developers of battery energy storage system, or BESS, projects are using a multi-contractor, split-scope contracting structure instead of the more traditional single-contractor, turnkey approach. (See "Battery Purchase Contracts" in the December 2021 *NewsWire*.)

The second topic, and the focus of this article, is key pitfalls to avoid when negotiating specific contracts.

There are three such pitfalls: failure to use the correct structure for agreements, failure to secure warranties to maximize protection for the project owner, and failure to negotiate a fair price adjustment mechanism that protects the project owner while minimizing contingency pricing by the equipment supplier.

## Agreement Structure

How the procurement agreement is structured is important.

Suppliers will often attempt to structure agreements to pass risk to the developer. Some suppliers may separate projects into individual orders to limit liability with respect to individual projects. Many suppliers propose shipment of equipment "ex works" at the supplier's factory, which places risk of loss during shipment and import tariff risk on the developer.

This creates a heightened potential for disputes after warranty claims, with suppliers claiming defects occurred after the developer picked up the equipment at the factory.

Other suppliers have moved away from firm pricing and ask for price adjustments, including for key material costs or shipping costs.

While suppliers generally accept liquidated damages for delivery delays, many resist liquidated damages tied to final completion of the project and commissioning of the supplied equipment. This can place the developer in a bind if the BESS arrives on site but is not able to be appropriately commissioned, either due to warranty claims or unresponsiveness of the supplier's operations and maintenance personnel.

For developers who are developing multiple projects, whether simultaneously or sequentially, it can help to structure the procurement agreement as a "master agreement" under which individual purchase orders are issued. The master agreement has general terms that apply to all of the purchase orders. More tailored terms applying to specific projects go in the purchase orders.

This structure helps minimize the risk of having to reopen negotiations for each project and allows for a faster order process. It is not unusual to see developers negotiate master agreements with several potential battery suppliers, allowing them to decide later how many orders to place with each. Any subsequent request to suppliers for proposals will then be issued with the expectation that the master agreement will govern for the purchase orders.

This approach saves time later. The later negotiation of purchase orders focuses on price and schedule rather than legal boilerplate.

Developers using a master agreement structure should consider which entities to use for contracting.

The master agreement is usually signed by a general procurement or development company high up the ownership chain. Individual purchase orders are then executed by special-purpose project companies. These can take the form of "daughter contracts" that are considered to incorporate the general terms in the master agreement. Where shorter-form purchase agreements are used, the master agreement should state clearly that each purchase order is a "several" and separate agreement that is considered to incorporate the terms of the master agreement.

The master agreement should allow free assignment of both the master agreement and purchase orders to allow the developer to restructure, finance and sell projects later.

Anyone using a master agreement structure should consider whether a default under one purchase order should be considered a cross default of all the purchase orders.

For a developer, a material breach by a supplier under one purchase order may be a sign of execution issues and a reason to end the relationship with the supplier. While a full-scale termination may seem drastic for a developer, a cross-default provision gives the developer leverage to ensure smaller orders are not dropped or de-prioritized by the supplier after an increase in costs of raw materials, components or shipping. This helps ensure a supplier maintains a "whole of relationship" approach to project delivery. */ continued page 44*

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Developers should expect suppliers to request a quid pro quo cross-default termination right in exchange for giving the developer such a right.

While some developers may be willing to accept this, given that their primary obligation is merely to pay the undisputed contract price, it is important to consider any financing of projects that might occur. Lenders are usually reluctant to accept that a developer default on a different project can cause a default on the financed project. For portfolio financings this may be acceptable where the master agreement and all projects for which purchase orders were issued are covered under a single portfolio financing.

Developers should avoid three pitfalls when negotiating contracts to buy batteries.

Just because a developer has multiple projects does not mean that a master agreement structure is the right course. For example, if a developer has a number of projects supplying battery storage under a single offtake contract, then it might prefer a single battery procurement contract aggregating liability in the collective project, given that liability under the offtake contract may be connected for failure to develop the collective project.

Alternatively, if a developer plans to finance projects individually, then it would be best to avoid cross default provisions.

### Warranty

The supplier's warranty is a key provision of any equipment procurement agreement.

For BESS projects, battery cell degradation is inevitable, but a proper warranty helps ensure that this can be modeled and augmentations planned.

A BESS warranty should include performance testing as part of the commissioning process.

It should include a capacity and degradation guarantee, a round-trip efficiency guarantee and an availability guarantee.

Depending on the type of project and the business model it supports, there may be other guarantees as well, such as for response time, for ramp rate and settling time and for signal-following accuracy.

Warranty testing should be performed as part of annual maintenance, but developers often also ask for the flexibility to require interim testing as necessary to troubleshoot the system. It is a negotiated point whether developer or supplier is responsible for performance of the annual warranty testing, generally dependent on whether the supplier is also providing services under a long-term services agreement or LTSA.

The supplier's primary obligation for failure to meet any warranty guarantees should be a make-whole payment or an obligation to repair or replace the equipment so that it performs as guaranteed. Developers can negotiate a liquidated damages amount for underperformance or downtime. Some suppliers try to include a buy-down right in place of a make-whole payment. Developers should carefully consider the sizing and impact of any buy-down right on the project model. A buy down will not fully compensate a developer for lost revenue associated with the lost capacity.

Many suppliers try to put the BESS warranty terms in a separate document or fold them into the LTSA between the project company and the supplier's operations affiliate. Neither approach is ideal. A separate warranty may include different choice of law, assignment or dispute resolution provisions from, or otherwise have conflicting terms compared to, the master procurement agreement, which can cause material issues with respect to enforcement or when trying to finance the project.

A warranty under an LTSA may be subject to a lower liability cap equal to the annual fee, rather than the actual purchase price of the BESS equipment. The liability cap can be eroded by mixing liabilities for equipment defects with liabilities for a services warranty. Putting the warranty in the LTSA also ties the existence of the warranty to the use of a single O&M provider. In the event the supplier fails to provide an appropriate level of service under the LTSA, a developer may be forced to choose between continuing its warranty and continuing to accept substandard LTSA performance.

Many suppliers attempt to structure procurement agreements so that, following delivery and a short inspection period, any defects in the BESS equipment will be considered automatically to have triggered a warranty claim.

If batteries are shipping on a rolling basis, rather than in one single shipment, this may leave a developer paying additional milestone payments for equipment that it is unable to install due to defects discovered after delivery. Developers should consider tying a sizable milestone payment to commissioning completion and requiring that any defects found before or during commissioning are remedied expediently. This formulation motivates suppliers to test BESS equipment at the factory prior to shipment and to address any issues before shipping.

Liquidated damages may be tied to the commissioning completion milestone to help offset costs incurred by the developer under its construction or offtake agreements due to a delay in completing the project.

Another item to consider is the use case for the BESS equipment. Each developer has a different intended use for the batteries, including charging and discharging frequency and whether batteries will be part of a standalone storage project or a larger renewable energy facility. Many suppliers offer a "one-size-fits-all" warranty and testing regime that will not take a developer's use case into account.

In order to ensure a developer is purchasing equipment that will function as modeled, the use case should be included in the technical specifications in the procurement agreement. Developers should carefully review the supplier's testing and commissioning regime to ensure it aligns with the use case. Long rest periods between charges or reduced charging and discharging rates are commonly included in a testing regime, which leaves the developer with a BESS that passes commissioning and warranty testing, but subsequently fails to perform in the field.

A commonly-included, but under-negotiated, provision of any warranty is the exclusion events where the warranty does not apply.

Exclusion events include failure to comply with supplier recommendations or documentation, including any updates issued after the date of purchase. Developers must be able to plan for the long-term operation of projects. Any parameters for storage, installation, operation and maintenance of the equipment should be attached to the procurement agreement. Later updates to the operating parameters could allow a supplier to fix a defect by limiting the operating parameters of the equipment and destroying the developer's use case and the project model.

Suppliers commonly attempt to limit the warranty to performance of operations and maintenance services by a supplier affiliate.

This can handcuff the warranty to continued use of a specific O&M provider. It is better to have the warranty continue after a change in operator as long as developer complies with the operations and maintenance manuals provided by supplier.

It is fair for suppliers to exclude any damage caused by a developer's improper installation or operation of the equipment. However, a developer should ensure that these provisions do not overly limit the developer's ability to upgrade, assign or move the equipment without permission from the supplier. The developer should negotiate to ensure the agreement works for its use case and allows flexibility to operate, maintain and finance the project.

## Price Adjustment

Developers should negotiate a fair price adjustment mechanism that protects the owner while minimizing contingency pricing by the equipment supplier.

Hard-nosed negotiation rejecting price change for low-risk or reasonable requests by the supplier may offer limited protection for developers while drastically increasing the initial price and delivery schedule offered by suppliers.

The following mechanisms are key negotiation points for a developer procuring a BESS.

The developer should retain flexibility to adjust the delivery schedule for the procured equipment. Many procurement agreements are signed more than a year in advance of anticipated delivery. In the interim period, construction, interconnection or other development issues may arise that require a developer to push back the delivery date or to reallocate equipment to other projects. It is best to negotiate an adjustment mechanism up front. This may include a grace period for storage at the supplier's factory prior to shipment or storage at the port of entry without a price adjustment.

Some developers offer to cover cost and expenses to use the supplier's third party storage after the grace period has run. Developers should ensure that risk of loss and the warranty start date are not affected by this storage, but should be prepared to negotiate degradation for extended storage.

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Over the past two years, force majeure definitions have continued to evolve to account for both COVID and shipping risks.

The arguments for not excusing COVID delays are that two years into the pandemic, suppliers should have contingencies in place to limit the impact of COVID that are priced into the initial order. However, many suppliers are quick to point out that COVID continues to evolve and the risks are ongoing. We also see suppliers have begun to insert clauses into force majeure definitions allowing for relief for delays in shipping, including port congestion or closure.

A developer may placate suppliers by offering limited force majeure relief for unforeseeable, direct impacts of COVID that occur after signing the individual purchase order, subject always to a supplier obligation to mitigate such impacts. This might include relief in certain limited circumstances for port closures or other shipment delays that meet the broad definition of force majeure (events outside the control of both parties that occur after the purchase order is placed).

Offering more limited COVID relief in an initial draft may be the best way for a developer to streamline negotiation and avoid overreaching by the supplier.

A key final category of cost relief is for developer-caused delays.

Suppliers ask for price and schedule relief in the event a developer acts in a manner that directly interferes with performance of the supplier's obligations under the contract. However, developers should insist on certain carveouts.

A developer should always be able to exercise its rights under the procurement agreement, including reviewing and commenting on drawings and documents to ensure compliance with technical specifications.

A supplier should not be granted relief for common-course coordination with the developer's other contractors, including construction contractors and engineering specialists. Interfacing during the design, delivery and commissioning of the project should be priced into the purchase price for the BESS equipment, and developers should avoid language allowing change for "any impact by owner or its subcontractors" or similar formulations. Even in the event a change is otherwise permitted, a supplier should not be entitled to price or schedule relief if the supplier's actions contribute concurrently to the delay. ◎

# Current Financing Challenges

How are tax equity investors and lenders addressing the unusually large number of risks this year?

Tangled supply chains and labor shortages are causing delays. Inflation is making projects more expensive to complete than expected. There is still risk that the US government will collect anti-circumvention duties on the roughly 80% of solar panels that are imported from Southeast Asia despite a proposed 24-month moratorium on such duties. US Customs started enforcing stricter rules on June 21 on importing solar panels and batteries that may have benefited from forced labor. There was uncertainty around whether US tax credits for renewables would be extended and around possible domestic content, wage and apprentice requirements, a possible new book minimum tax and the effects of "Pillar Two" on multinational companies that claim US tax credits.

A group of tax equity investors and lenders talked about these issues at our 31st energy finance conference in South Carolina in mid-June. The following is an edited transcript.

The panelists are Jack Cargas, head of renewable energy tax equity origination for Bank of America, Rubiao Song, head of energy investments for JPMorgan Capital Corporation, Elizabeth Waters, managing director at MUFG, Gisela Kroess, managing director at CoBank, and Mark Williams, managing director at PNC Bank. The moderator is David Burton with Norton Rose Fulbright in New York.

## Delayed Projects

MR. BURTON: Jack Cargas, how much tax equity volume has slipped from 2022 to 2023?

MR. CARGAS: We have seen some significant delays since the cost of capital outlook call that Keith Martin hosted in January. In January, we predicted there would be about the same amount of tax equity this year as we saw for last year, which is about $20 billion. We were predicting this year there would be roughly a 50-50 split between wind on the one hand and solar and storage on the other. (For the earlier transcript, see "Cost of Capital: 2022 Outlook" in the March 2022 *NewsWire*.)

Somewhere between 30% and 50% of the $10 billion in solar and storage tax equity this year is at risk of slipping into 2023. That is $3 to $5 billion of tax equity.

MR. BURTON: Beth Waters, are you seeing the same thing as a lender?

MS. WATERS: We are not seeing as much of an effect on the bank lending market. We expect to have a record year this year. I keep asking our clients what effect supply-chain disruptions and labor shortages are having on their projects. The answer for now at least is not much yet.

MR. BURTON: So tax equity is seeing a bigger slowdown while, for lending, it is more of a trickle effect.

MS. WATERS: That's my experience.

MS. KROESS: Deals have certainly been backed up. We had a few mandates with sponsors that rely on Chinese solar panels. Those deals were uncertain given the pending issues around the Auxin petition and Biden's proclamation.

We see a lot of deals backed up for the second half of this year, but with some slipping into 2023 because all banks have the same staff shortages that are affecting all sectors. There are only so many deals we can do.

MR. BURTON: Rubiao Song, if a significant number of solar deals slips to next year, will there be enough tax equity next year to handle not only the delayed projects, but also what were already expected to be 2023 projects?

MR. SONG: We think we will see 30% to 40% of projects on which investment tax credits will be claimed delayed into 2023. These are transactions to which we committed last year or earlier this year to fund in 2022. Funding will be delayed until 2023.

Demand for new commitments remains strong. There will be more pressure on tax capacity in 2023. We see some new entrants into the market, but not enough to have a meaningful effect on supply of tax equity. Meanwhile, the macroeconomic outlook will affect both demand and supply. Tax equity investors are likely to be more conservative the rest of this year about their tax capacity forecasts for next year.

## New Technologies

MR. BURTON: In what new or different technologies, besides wind and solar, are tax equity investments being made?

MR. CARGAS: The renewable energy finance group, which is where I work at Bank of America, is really still focused on utility-scale wind, utility-scale solar, residential solar and storage. However, we have an adjacent business within our firm called "global sustainable finance," and the people in it are interested in many other assets. We are shifting some of our resources toward things like desalination plants, carbon capture, electric vehicles, offshore wind debt and commercial-and-industrial-scale solar tax equity.

MR. BURTON: Is anybody else expanding beyond the traditional tax equity technologies?

MR. SONG: I agree with Jack in terms of the new areas from a tax equity standpoint. We are looking actively at section 45Q opportunities and offshore wind.

MR. BURTON: Beth Waters?

MS. WATERS: There is a little bit of exploration into hydrogen. We have done one deal, but it is not your typical hydrogen project. It is more like gas stations where hydrogen is used for trucks. We are a Japanese bank, it is a Japanese sponsor, and so it is a toe-dipping exercise.

MR. BURTON: In the US?

MS. WATERS: Yes. Otherwise, we continue to do the traditional types of projects and also gas, diesel and transmission.

MR. BURTON: Jack and Rubiao, you both mentioned section 45Q tax credits for carbon capture. Has either of your institutions actually made a carbon capture investment? Are you aware of any closed deals?

MS. KROESS: Not on the debt side. Banks typically are conservative in nature. They shy away from technology risk.

MR. CARGAS: We haven't closed such an investment yet at Bank of America. We expect one or two transactions to get done in the market this year, but there are some pretty significant challenges with them, despite the seeming attractiveness of the tax credit.

MR. BURTON: Do you want to elaborate on the challenges? What has credit committees concerned?

MR. CARGAS: Credit committees are concerned about a couple of things that we don't see in the renewables sector, such as when you build a carbon sequestration or capture facility tied to a single plant, you worry, from a credit perspective, about there being no secondary source of repayment. What happens if you shut off the feedstock? It may be a little challenging for some firms when they think of their feedstock as being carbon, which is something that some ESG-oriented firms may not really want to be associated with.

There is also a question about the legal separation. If there were a downside scenario at the end of an early termination of a section 45Q transaction, how do you separate, legally, the sequestration asset from the host facility? Those two things are definitely taking up credit committee time.

MR. BURTON: Rubiao, do you have thoughts about that?

MR. SONG: We have evaluated a few section 45Q opportunities. There are different sizes and / continued page 48

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flavors. We have not closed any. We have been awarded one, and we are working on a few others.

They present some new challenges. You have sponsors who may not have the traditional investment-grade credit that investors will be looking for, particularly going into a new field. The deals have supply-or-pay or take-or-pay contracts, but the credit behind those contracts could be challenging.

We believe most, if not all, of the section 45Q deals will be done using a safe-harbor partnership structure. That means 20% of the tax equity investment will have to be made up front with another 30% of the investment paid over time as fixed payments and the balance paid as variable payments plus O&M expenses. That structure provides a lot of structuring flexibility for the investors. Investors will have to get comfortable with the technology and the commodity supply risks.

### Merchant Projects

MR. BURTON: Jack Cargas, what are you seeing in terms of structuring for merchant projects in ERCOT, given the shift away from the fixed-capacity hedges after Winter Storm Uri. Are people no longer financing such projects? Are there new financial products to address the merchant variability?

MR. CARGAS: The entire market is very cautious about any sort of contract that requires a fixed delivery of power. The entire market suffered as a result of Uri in addition to the terrible human loss of life.

We are not seeing new financial products. We are seeing more use of already existing products such as a put structure, where a floor is established for the benefit of the tax equity investor and the upside is retained by the sponsor. We are also seeing more use of a pref structure, where the tax equity investor has a preferred return during the early period of the offtake, which of course is junior to payment of operating expenses, but senior to the cash distributions to the sponsor. Those two products are allowing us to continue to do business.

MR. SONG: Uri put a spotlight on particularly onerous features of some offtake contracts. Some projects have contracts for differences with corporate offtakers. The projects are in very congested parts of the grid, and the electricity basis risk is exploding.

We are seeing some offtakers agree to risk sharing. The electricity price is subject to a floor. The upside is shared between the project and the offtaker. The Wood Mackenzie presentation immediately before this panel looked at the pattern of declining wholesale merchant prices over time. The study should probably have distinguished between wind and solar projects that receive the hub price from the grid, don't have to contend with grid congestion and have no electricity basis risk. Those can earn a very good return.

Investors should look closely at the offtake contracts and avoid projects that have all downside risk and no upside potential.

MR. BURTON: Lenders, any thoughts on ERCOT and merchant projects?

MS. WATERS: At MUFG, we are cautious of ERCOT because of what happened last year. There were losses on the tax equity side in the institution, but not on the debt side. We will not finance a purely merchant project in ERCOT. There has to be a power contract or a hedge.

MS. KROESS: Many of our sponsors have a mixed strategy for ERCOT. They are doing partially contracted merchant projects. We see simple power price hedges for 45% or 50% of generation to establish a price floor. Those are not like the fixed-volume hedges that we saw in the past. We are cautious after what happened last year and would not finance a 100% merchant project in ERCOT today.

### Inflation

MR. BURTON: Mark Williams, we see headlines about inflation. The Fed raised interest rates 75 basis points. Do you think it is a viable strategy for sponsors to try to renegotiate power purchase agreements so that the electricity prices cover their higher construction costs?

MR. WILLIAMS: Yes. It is part of the all-of-the-above strategy that sponsors need to engage in to ensure their projects remain economically viable.

I work in both tax equity and debt. About 40% of the deals on which I am working have had a change in the power purchase agreement to increase the electricity price and extend deadlines to avoid delay damages. We have seen a number of utilities fairly receptive to making those changes, which is unusual. A few years ago, if you tried to suggest that kind of change, it would not have been well received. The amendments, in many cases, require public utility commission approval, which has added to delays.

MR. BURTON: Why do you think utilities are more receptive today to such changes?

MR. WILLIAMS: Various reasons. Some utilities are under pressure to meet renewable portfolio standards. They need the renewable electricity. They are well down the road with a sponsor on a deal, so it does not make sense to scrap an otherwise viable transaction and hope for something better.

MS. WATERS: Historically, it was taboo to touch the PPA. For instance, if banks asked for a change in the PPA because there was a glitch, we were told it was impossible fix because of the risk the utility would ask for something else in exchange.

I have been surveying clients and asking them whether they are having any success renegotiating out-of-market PPAs. The answer in many cases is yes.

Between 25% and 40% of solar projects scheduled for funding this year have slipped at least partly into 2023.

MR. BURTON: How are conversations going with borrowers about rising interest rates?

MS. KROESS: Rising rates affect project valuations. Sponsors are trying to diversify their revenue streams. The era of long-term utility PPAs is long gone. Our margins are still pretty low on the renewables side because of the amount of competition among banks to lend. That is a positive for sponsors.

We have one big deal that has been delayed for a while, but that is unusual because of the risks tied to escalating project costs. The sponsors entered into a pre-deal hedge to lock in interest rates. It is a multi-billion-dollar deal. Not all banks can do that type of hedge. Such hedges are expensive.

MS. WATERS: We see a lot of deal-contingent hedges. (For more information on such hedges, see "Deal-Contingent Hedges" in the October 2017 NewsWire.] The longer the duration of the hedge, the more costly it is.

Banks do not make much money on them. They were quite profitable in the early days, but the market has become much more competitive.

## Crypto Mining

MR. BURTON: We will have a discussion later in the conference about crypto mining. Has anybody financed a project that has crypto mining as an offtake?

MS. KROESS: No. Too eclectic for us.

MS. WATERS: I read about one bank doing a crypto offtake project financing.

MR. BURTON: But not MUFG?

MS. WATERS: No.

MR. SONG: We have a project that has a crypto mining data center as part of the offtake. It is not a new financing. We are seeing some opportunities on the horizon with big sponsors who are entering joint ventures with data center companies.

MR. BURTON: The crypto mining offtake helps mitigate against curtailment risk?

MR. SONG: Yes. These types of offtake contracts would help wind projects.

MR. CARGAS: There is still some reticence on the part of financial institutions with respect to crypto. But I heard an interesting perspective last night that those of us who have financed projects in Texas are already financing electrons that are ultimately used by crypto miners. There may be an intermediary party, but at the end of the day, once the project sells power, that power could end up in the hands of those mining companies.

So some institutions may decide it is not such a big stretch to conclude that we are already doing it. I am not saying that is what we have done, but it was an interesting perspective I heard last night at dinner.

## Rapid Fire

MR. BURTON: We see rising interest rates, but tax equity yields are moving down due apparently to some new entrants in the tax equity market and a shortage of projects. Mark Williams, do you agree?

MR. WILLIAMS: Yes, there has been some downward pressure on flip yields.

There is a dearth of product for 2022 / continued page 50

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because of the delays. If you had a budget to get $X million in tax credits this year, it is a challenge to find projects that are going to get in service by the end of the year. That leads to pressure on pricing. The overall returns have not taken too great a hit. Investors look at the all-in return, assuming the buyout is exercised. Then you look at the return if the buyout is not exercised and you stay in the deal through the entire PPA term. Those returns are still pretty close to where they had been, but there has been some downward pressure on the flip yield.

MR. CARGAS: I promised Mark before the panel that I was going to disagree with him on something, so here it is. We have not observed that phenomenon.

MR. BURTON: When we talk about delays, the things that first come to mind are supply chain issues and tariffs, but what about interconnection queues? Some say that is an even bigger problem than supply chains or tariffs.

MS. KROESS: I disagree with that. We have seen delays on both fronts, but sponsors are generally able to work around interconnection delays and keep to the overall schedule. On tariffs and supply chain issues, some of the impacts have been much more severe and require renegotiating sunset dates. We have had to extend the construction loan maturity by as much as a year.

Also with tariffs and supply chain issues, you have multi-level issues. You have force majeure notices because ports are backed up. There are transportation delays. You have panels stuck in Customs because of forced labor concerns. You have tariff risks.

At least with anti-circumvention duties, there is a reprieve of two years, but we really need a longer-term solution. The question is whether tariffs on Chinese goods are here to stay. There is some discussion that they might be reduced.

MS. WATERS: I agree with Gisela. Developers come to us when a project is ready for financing. They usually have worked out any interconnection issues by then.

MR. CARGAS: Following up on one thing Gisela said, we are not absolutely convinced that the moratorium on anti-circumvention duties is a reprieve for two years. There was a research note that came out this morning from one of the equity analysts indicating that a number of manufacturers are still wary of importing solar panels into the United States because of the risk of litigation over the ultimate legality of the Biden proclamation.

MS. KROESS: That's a valid point. There is a litigation risk, but it feels to many banks like there is a bit of breathing room.

MR. CARGAS: I hate to agree. [Laughter]

MS. WATERS: It is breathing room, but it is a band-aid.

MS. KROESS: You have some sponsors looking at tier-two technology. For example, banks are feeling pressure to accept Indian solar panels, but there is still a fair amount of resistance.

MR. WILLIAMS: The moratorium is a positive development and everybody's hopeful, but to say there is no risk is a little premature.

MR. BURTON: What we are hearing from the trade lawyers is that while it is not intuitive that solar panels are emergency food, clothing or medical supplies, which is what the statute contemplates, the statute also gives the president a fair amount of discretion.

MR. CARGAS: So David, you can give us a "will" opinion on that? [Laughter] Sorry.

MS. WATERS: No comment, I guess.

MR. BURTON: Are labor shortages still an issue?

MS. WATERS: Yes. It is not just a labor shortage, but also increased costs for labor. EPC contractors on large projects are reluctant to cap the costs.

MR. WILLIAMS: There is also a timing issue. Projects that experience delays will lose workers to other projects. You cannot have a crew hanging around waiting for modules to show up.

This then creates issues with financing terms that were set some time ago based on certain assumptions. You have construction lenders that lent against tax equity commitments that have turned into pumpkins. Sponsors then have to scramble and ask the lenders for concessions. If there are several banks involved, it can be a lengthy process.

It has been a very challenging year. I think sponsors have done a very good job scrambling to keep all the plates spinning in the air.

MS. WATERS: Lenders have to make sure there is a cushion. The project should be expected to be completed well before the sunset date of the PPA. It is an unknown how long some of these delays could last.

MR. BURTON: How long a cushion do lenders want in the current market?

MS. WATERS: There is no general rule of thumb. It depends on the project. Three months might be acceptable to one lender while another wants six months to a year.

### Fossil Fuels

MR. BURTON: Any audience questions?

MR. SAXENA: Himanshu Saxena, CEO of Starwood Energy Group. Given the growing concerns about energy security, has there been a shift in mindset around financing conventional assets? I am not talking about financing coal, but about financing gas and carbon capture facilities tied to gas or coal.

It is not the same investment climate as it was a year ago. There is a shortage of natural gas. Australia is talking about burning coal again. India said it will keep burning coal until 2070.

We see the same thing from our equity investors. Increasingly they say, "Gas is good. We don't mind gas," which is different from what we were hearing a year ago.

MR. CARGAS: It is a great question. Energy security is on the tip of many governmental officials' tongues, but it has not translated into interest in financing fossil fuel plants.

MS. WATERS: At our bank, no coal. We are happy to finance gas. However, a lot of banks will not finance gas-fired projects. We have a renewables focus, but we also recognize that you cannot depend solely on wind and solar, even with batteries. You need gas peakers. I think gas is here to stay.

MR. SONG: Banks have to do more analysis to get comfortable when asked to finance a carbon capture project at a fossil fuel plant. They want a life-cycle carbon reduction analysis.

MR. WILLIAMS: My bank provides a lot of liquidity to investor-owned utilities, but does not directly finance gas plants. I don't see that changing.

MS. KROESS: We finance gas peakers, especially portfolio peakers. I not aware of any new baseload combined-cycle gas plants that we have financed. There are some refinancings. We have seen some European banks withdraw from the gas market altogether. ◎

# Bitcoin Mining and Electricity

Bitcoin mining consumes a large amount of electricity. Houlihan Lokey calculated when bitcoins are trading for $50,000 a coin, the electricity is effectively converted into bitcoins for $400 a megawatt hour.

Lately, bitcoin mining companies have been approaching wind, and to a lesser degree solar, companies with ideas for how to help them maintain revenue during periods when their power plants are curtailed, or ordered to reduce output, due to congestion on the electricity grid.

A panel of experts talked about these and other subjects at our 31st energy finance conference in South Carolina in mid-June. The following is an edited transcript.

The panelists are John Belizaire, CEO of Soluna Computing, Dave Perrill, CEO and co-founder of Compute North, PJ Lee, managing partner of Everstream Energy Capital Management and co-founder of Compute North, and Cole Muller, head of Cumulus Growth, a digital infrastructure platform that is owned by Talen Energy. The moderator is Noah Pollak with Norton Rose Fulbright in Washington.

## Magic Machines

MR. POLLAK: John Belizaire, many people may not understand how bitcoin is mined. Can you explain the process briefly?

MR. BELIZAIRE: Think of bitcoin mining as a security system. Bitcoin is a digital commodity that is global in use. You want to make sure that transactions in bitcoin are recorded on a blockchain so that they are clear and there is no funny business happening. This is done on a blockchain, typically a digital ledger.

Imagine each of you is sending money to each other, and there is no central party to manage the process. We are all keeping a list of the transactions. John sends Noah five bitcoins. Noah sends Dave three bitcoins. Everyone is writing down the transactions in the common ledger. The information is translated into a code in the ledger that lets everyone spot when the ledger has been tampered with.

The way we do this is through use of a magic machine. You put the ledger sheet into one side of the machine and out the other side comes a single number that encapsulates everything on the sheet. If you change one digit in / continued page 52

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the ledger, the number coming out of the machine will change, so there is no way to change the ledger without everyone noticing it.

The machine only works in one direction. If I give you the single number, there is no way for you to recreate what is on the ledger page. Take that number and stamp it basically on the top of the ledger page.

Every time a new page is added, it is stamped with a number. You end up with a stack of ledger pages. They are chained together. If you put a new sheet and the number from the previous sheet into the machine, you get a new number that you can stamp on the new ledger page. This essentially connects all of the ledger sheets together starting with the first page.

Each ledger sheet is a "block." The series of ledger pages is a "blockchain." The folder housing all of the ledger pages is the entire history of every transaction since the start of the bitcoin network.

The chaining of those special numbers is done by a process called bitcoin mining.

To turn each ledger page into a single number requires a tremendous amount of computing power. The magic machine is a cryptographic algorithm that was developed by the US National Security Agency called "SHA-256," and its purpose is to record and protect large volumes of information in an efficient way.

How do I encourage privately-owned machines to perform that work?

I keep changing the thing they have to do and make it very specific. Not only do they have to add a piece of information to the page to generate the number on the other side, but the number has to look a certain way. In order to do that, you technically have to keep making changes to the ledger sheet and putting the number through the machine until you get to the right number. Usually, it is a certain number of zeros in front of the special number and, over time as I do this, I find it is a searching algorithm.

All of the privately-owned computer servers are doing this number crunching over a long period of time. The amount of computing power required is massive. The computer servers require energy to run. Thus, bitcoin mining has a direct correlation to energy. Think of it as energy required to protect the network.

Bitcoin mining is a security system on the network. The relationship to energy introduces some opportunities. It can be a powerful catalyst for renewable energy because the computing by any single server or group of servers can be paused and then started again. This flexibility can be used to help integrate more renewables onto the grid.

### Business Models

MR. POLLAK: That's a great segue to the next question. Dave Perrill, talk about what your business has to do with bitcoin mining and how it overlaps with what the renewable energy developers and financiers in this room do.

MR. PERRILL: I have worked for 25 years with data centers and managed services and I co-founded Compute North in 2017 when my co-founder, PJ Lee, and I got really interested in bitcoin.

We believe bitcoin mining is leading the way to what we call TIER 0™ computing. Data centers are classified from tier one to tier four based on the amount of redundancy and, therefore, reliability. Tier four is the big boys: Amazon, Microsoft, Oracle, Google. They are mission critical and, therefore, they require built-in redundancies that make their data centers very expensive.

Bitcoin is at the other end of the spectrum. Our applications are compute intensive and, therefore, energy intensive, but they are not mission critical.

Another data application is machine learning. Examples are use of data to control self-driving

Bitcoin miners are offering to buy curtailed electricity from wind farms.

cars, do genome sequencing or climate modeling. Anything that is compute intensive but can be interrupted, we think will move to a type of model where how energy is procured is important. Compute North is focused on how to marry the energy load to the energy generation.

MR. POLLAK: Cole Muller, describe how your business differs.

MR. MULLER: Talen Energy Corp owns about 13,000 megawatts of generating assets across the US. I run our growth platform called Cumulus Growth that is focused on digital assets that are being built adjacent to our power assets.

Our focus is on offering low-cost, reliable and zero-carbon power to run digital assets. Our first effort has been to connect our 1,000-MW nuclear facility to data centers. There are two 500-MW generating units. We have been focused on building a digital infrastructure campus next to each 500-MW unit, which really has two businesses. One is focused on the hyperscale data centers belonging to people like Facebook and Google as customers. The other business is the tier zero bitcoin mining facilities, as Dave called them.

Our thesis is that there are a couple value chains in the bitcoin mining market. The one that is of most interest to us is vertically integrating all of the pieces of that value chain. Owning everything from the power generation to the computer servers and getting to a "hash rate" that ensures a profit from the bitcoin mining. For us, it is about getting behind the meter, cutting out the middleman if you will, getting lower energy costs and protecting the business across the entire vertically-integrated value chain.

## Synergies

MR. POLLAK: PJ Lee, exactly what is a data center?

MR. LEE: A data center is a facility that hosts different types of server equipment. In many cases, the data is mission critical. For example, it streams Netflix or it is hosting email, or it is a website or it handles e-commerce transactions.

Data centers in a tier-four environment are built and engineered with redundancy in mind: redundant backup power, redundant fiber connectivity. They need to be up 99.999% of the time.

Increasingly new markets are emerging that are computationally heavy, but do not require the redundancy. This is what Dave called TIER 0™. Examples are bitcoin mining, artificial intelligence, machine learning, graphics and image rendering.

As this industry of digital infrastructure continues to evolve, one of the fascinating things that we are helping to accelerate is a hybrid model.

A data center may keep certain workloads on-premise that are important to keep in its own environment, but also rely on third-party providers for certain applications or accessing certain tools. That is already a hybrid model.

TIER 0™ is the third piece of the hybrid model where certain processor-heavy workloads could be outsourced in a non-mission critical fashion and instead of 99.999% of uptime, maybe uptime is merely 90% or 95%.

That is a perfect complement to the intermittency of renewables or to the need for grid stability or frequency regulation for the power grid. At the same time, in this configuration, each of these three different applications — the hyperscale or the TIER 0™ through software — could do something called "workload orchestration," where they could move different processor applications from one location to another location or to multiple locations.

As data centers continue to evolve with the strong desire to lead with ESG as their selling point to the customer base, there is a huge opportunity for renewable energy generators.

MR. POLLAK: John Belizaire, expand on what PJ just said. You do bitcoin mining. Where do you get your electricity?

MR. BELIZAIRE: We look for power plant owners that are having a hard time monetizing all of their energy.

We look for areas where the grid is highly congested and where lots of renewable power plants are coming online and their batteries are insufficient to address transmission concerns.

We partner with those power plant owners and essentially deliver to them a solution to their curtailment challenges. It is a purpose-built data center.

The facility we build is designed to convert the electrons that would otherwise be wasted into a powerful form of computing that is flexible. We do a curtailment assessment. We look for projects with curtailment challenges. We help the owners understand the effects of curtailment on their businesses. Most of them already understand it, but they do not understand how they might introduce a data center on site to address the concern.

Finally, we have a structure that can coexist with the existing project finance structure of the project and ensure that production tax credits are unlocked that otherwise would be lost.

The project owner gets a turnkey solution to its problem. We can do it with wind, solar and hydro facilities all over the world.

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### Economics

MR. POLLAK: Cole Muller, can you dive a little deeper into the problem you are trying to solve and the solution that is being offered?

MR. MULLER: We have 1,000 megawatts of digital infrastructure next to our zero-carbon nuclear facility. My job is to look at the rest of our fleet and figure out what is the next wave of digital computing and what opportunities it offers for another "energy and compute park." We take generating assets, decarbonize them to become baseload lower-carbon sources of generation, pair them with renewables that we are building adjacent to our existing facilities and then ultimately marry the generation to digital infrastructure and computing power.

We think this helps both with the energy transition and with enabling the grid to keep baseload resources on line for when those assets are needed.

For example, we own a bunch of coal plants in PJM. We make our money in the winter when the baseload power is needed, but two years ago, almost none of our coal plants ran during the winter. Folks started saying we no longer need coal. We can move now off fossil fuels rather than wait until 2030 or later to do so. Fast forward 18 to 24 months later and that is clearly not the case.

Our view is it will be a bumpy road as we go through the energy transition. Bitcoin mining and other digital computing applications will help us stairstep down and keep reliable generation on standby for times when it is needed by the grid. At the same time, we can incentivize renewables, battery storage and other kinds of clean energy to come on line more quickly.

### Development Process

MR. POLLAK: Dave Perrill, when you are looking to build a new project, what is your site selection process? What is your development process?

Mr. PERRILL: It comes back to energy first. The latest site that we are building now has a 300-MW load. Load factors are very high: 95+%.

We can site nearly anywhere, which helps to tackle grid congestion and stranded assets.

Last but not least, our operations are interruptible. We have the ability to shut down, and that downtime can be a relatively flexible number, roughly around 5%, but can be greater or less depending on the opportunities.

Beyond that, we start to look at what is the energy mix and how the economics work. We want to find a win-win model that works for all parties involved. We handle the development, design and construction of the data center. Our customers are the bitcoin miners. The electricity generator is our counterparty in a transaction to procure electricity.

MR. LEE: We can connect at the power plant busbar and negotiate a bilateral PPA or we can be grid connected and work with the utility to find a substation where we can interconnect.

We have a different business model than the vertically-integrated miners that typically build a large facility that is intended to remain in place for decades. Our approach is more modular where we mass produce outfitted containers in a contract manufacturing facility. Each 40-foot container is approximately a 2-MW load.

We think in terms of a portfolio where we start with a few different sites with one counterparty and then move some of those compute centers to other locations. The congestion points change with expansion of transmission capacity, so we are always trying to think two or three years ahead to where the puck is going.

MR. POLLAK: John Belizaire, what is your site selection process and how long is your build time for a project?

MR. BELIZAIRE: We try to target nodes where we know there is lots of congestion. We have an energy team that uses AI machine learning to analyze billions of bits of data with lots of different factors and then zooms in on places where we can invest.

We identify potential partners. Sometimes when partners approach us for a curtailment assessment, we tell them on which of their projects we would like to focus because we already identified where the challenges might be. Then we look at the location of the facility, the current leasing structure on the site, the substation and the different counterparties that are going to need to be involved. We have different structures for areas served by coops versus investor-owned utilities. We have strategic relationships with some of the larger transmission service providers that gives us some insight into particular locations.

We look at what has happened in the last four years at the node. Then we look forward in order to understand what will happen in that particular part of the grid. That helps us get a

The worst place for miners to be currently is long bitcoin and short electricity.

sense of the size of the facility we should build.

We also use a modular design for our data centers.

We started as a developer. We lived this pain ourselves in North Africa, building very large wind farms there and designing a vertically integrated solution. We used that experience to determine what the optimal size for a data facility is in a location. We will either sublease the site or partner with the power plant owner to connect us with the land owner so that we can negotiate a lease.

It usually takes six months to have a facility up once all of the main agreements are in place.

## Bitcoin Volatility

MR. POLLAK: Cole Muller, I want to bring this back to bitcoin and crypto as a general matter. All of your businesses to some degree either are dependent on, or derivative of, bitcoin, bitcoin mining, bitcoin revenues, bitcoin prices.

There has been a pretty significant drop in bitcoin prices so far this year from something like $70,000 per bitcoin to less than $20,000. This has led to headlines such as "The music has stopped for crypto."

How has this affected your future goals?

MR. MULLER: Rewind six months ago with bitcoin nearing $70,000 a coin and there were a ton of projects. Everybody was putting down deposits for miners and looking to expand, expand, expand. Now it is the exact opposite. Historically, bitcoin pricing has not stayed in one spot for very long. There is a lot of volatility. The key is to build a sustainable business that can last through the cycle.

It starts with electricity costs. Site selection is super important. Your business model also has to be able to withstand the inevitable down cycles, whether it is a 50% or 80% drop in bitcoin prices.

The trick is to match your revenue — the bitcoin or hash price that you are generating — to your power price and some of your other infrastructure costs. Power generators manage a spark spread. Ours is called a hash spread. You need to lock in a margin.

It is a fascinating space right now. There is a ton of opportunity. The natural inclination in a bitcoin down cycle is to pull back. It is cheaper just to buy the bitcoin right now, but I think developing sites and having an eye for opportunities is really how you are going to win.

MR. POLLAK: PJ Lee, is he right that it is cheaper to buy the bitcoin and, if so, why press ahead with your business model?

MR. LEE: We started five years ago when there was a lot more volatility than what we are experiencing today. Bitcoin prices fell from $20,000 to $3,000. We decided that just being a speculator on a commodity is not where we want to be. Entering into longer-term contracts was a way to reduce our cost of capital, introduce project finance leverage and have more stability.

We switched to a co-location service provider. We are effectively a landlord. We collect a co-location fee, or rent, from our customers every month and, if they pay in bitcoin, we convert it that day to cash or they pay in cash. We have never been focused on the crypto price. We are always focused on stable, contracted, recurring cash flow.

Anyone who is long bitcoin and short power is in a tough place today. That is a spread that you cannot really hedge long term.

There will be consolidation and some dislocation. Mining bitcoin is still profitable, even with depressed prices. The biggest things to get your head around as an investor or lender are whether this industry is here to stay and whether other industries will find other uses for the same type of infrastructure.

Our bet five years ago was "this industry is real." It has a credit profile that is a bit avant-garde, let's say, but bitcoin miners literally print money for a living. They have pretty decent profitability. The value of their equipment in any cycle is pretty high if you need to foreclose.

MR. BELIZAIRE: Let me add to that. There are few things the audience should keep in mind. / continued page 56

## Bitcoin Mining

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I did a professorial introduction to bitcoin mining earlier. There is another concept that we at Soluna call the "golden triangle." The bitcoin network is dynamically attuned to adjust the amount of work required to secure the network as the price begins to move up or down. As the price of the currency starts to drop, the amount of energy required to solve for the next increment of bitcoins also decreases.

Your LCOE, or levelized cost of energy, is also very important. Those who have very high power costs will tend to leave the network, and that leaves more of the pie for existing participants. That means the lowest cost energy allows you to stay in the network.

I have been a technologist for 20+ years. I am not an energy guy. I came to the industry about five years ago. This is a technology that looks very much like the internet did about 25 years ago. It has an incredible amount of potential.

What the technology does is very difficult to do, so the fact that it has continued to perform over the last 14 years is really fascinating.

That's why it fundamentally has value, and it will for the next decade, because of the fact that the technology can be leveraged to catalyze renewables and to do a host of other things. We remain very bullish because we are diversifying and doing lots of different things that essentially make this whole sector a new infrastructure sector, much like batteries or transmission are for the modern grid.

MR. POLLAK: Let's see how many audience questions we can fit in.

### Credit Issues

MR. HOULE: Tom Houle, CEO of Accelergen Energy. I have a two-part question. How are you addressing the avant-garde credit quality in your transactions? Are there alternative uses for the mining equipment or servers, assuming they don't become obsolete?

MR. LEE: Tackling your first question, our business model, as an intermediary or a developer of digital infrastructure, is to have a widely diversified customer base. We have more than 150 customers whose demand for capacity is quite significant. There was a lot of "spend to buy and deploy machines, get your place in line, get those machines quickly." I don't think this industry fully appreciated the complexity of developing large-scale infrastructure. It's hard permitting, negotiating contracts and arranging for interconnection.

There is a massive demand for capacity, such that if one counterparty defaults, there is a long line of other counterparties willing to take that seat.

Maybe that changes over time, but that is the situation right now. That diversity of customer base and the fact that the liquidation value of the equipment is orders of magnitude larger than any financing helps with the credit issue.

There are ways to enhance the credit by inserting lenders that provide equipment finance between the investor and the mining company. It takes a joint lien with the investor over the asset. In case of a default, the investor is looking at the counterparty risk of the financial institution, which has a much better balance sheet than the miner.

As far as whether the equipment will retain its value, the equipment is ASIC — application-specific integrated circuits — which are the workhorse of the bitcoin mining world, and GPUs, also known as graphic processing units.

The GPUs are fungible. There are plenty of other uses for GPUs. The ASIC today is really just designed for one thing: the proof-of-work algorithm for mining bitcoin.

As for the future, that is a whole other panel as to where this industry goes. We think of the SHA-256 algorithm as a sort of physical layer, similar to the internet 25 to 30 years ago. On top of that physical layer, more software application layers can be built. For example, the Lightning Network is a layer two protocol layered on top of the internet that facilitates faster transactions.

It is really early days for where things can go in an internet 3.0 context and what this infrastructure can be used for. It is not even the end of the first inning yet. ◎

# Environmental Update

The Senate majority leader, Chuck Schumer (D-NY), had to agree to a broad outline for a separate permitting reform bill to win support from Senator Joe Manchin (D–WV) for the Inflation Reduction Act. Manchin released a description of what he believes he was promised.

An effort will be made to fold the deal into a must-pass spending measure to keep the federal government open past the September 30 end of the fiscal year. Any such bill will require support from at least 10 Republican Senators, assuming all Democrats remain in line, to clear the Senate.

Some progressive Democrats in the House have already objected to it on grounds that the permitting reforms are not limited to green energy projects and new transmission lines, but would also help gas pipelines and other fossil-fuel projects.

Manchin also secured an agreement that any new leases for offshore wind projects off the US coasts will be coupled with new leases for oil and gas production.

The framework remains a hand-shake agreement. It is a "side deal" because the effort falls squarely outside the bounds of the Senate budget reconciliation process that let Democrats pass one bill — the Inflation Reduction Act — with just 50 votes and a tiebreaker vote by Vice President Kamala Harris. Any other bills require 60 votes in the 100-member Senate.

According to a summary outline released by Manchin, the side deal has five elements.

It would set new two-year maximum timelines for federal agencies to conduct NEPA environmental reviews for "major" projects.

It would streamline government processes for approving energy projects by centralizing decision-making with one lead agency.

The deal would clear the way for approval of the Mountain Valley pipeline, a Manchin priority that would transport Appalachian shale gas about 300 miles from West Virginia to Virginia.

It would limit legal challenges to energy projects and make it harder for government agencies to deny new approvals based on certain environmental impacts that are not directly caused by the project itself.

Finally, it would give the US Department of Energy more authority to approve electric transmission lines that are deemed to be "in the national interest."

The outline remains vague, but its focus is clearly to streamline the build-out of energy infrastructure for all types of energy production, increasing reliability of the greater power infrastructure as well as advancing decarbonization.

Manchin had raised concerns about approving hundreds of billions of dollars in government subsidies for energy projects that could be defeated by red tape or climate lawsuits.

Despite any advances for fossil-fuel-based power, it has been estimated that the climate provisions in the Inflation Reduction Act would cause greenhouse gas emissions would cause US greenhouse gas emissions to fall more than 40% below 2005 levels by 2030.

## NEPA Tensions

The next several months will see much rancor and debate over what to do in response to an increasingly bipartisan consensus that the United States takes too long to vet new infrastructure projects under the National Environmental Policy Act, or NEPA.

Both the Infrastructure Investment and Jobs Act signed into law last November and the new Inflation Reduction Act set speedy development goals in tension with the desire for federal agencies to assess environmental impacts of proposed projects sufficiently before approving them.

The particular development goals of both pieces of landmark legislation will necessarily face NEPA hurdles that critics claim unnecessarily slow or even stymie such development. The delay will not only hit projects like new roads and pipelines, but also development of new renewable energy power plants and storage facilities.

NEPA requires federal agencies to study the environmental effects of their actions before taking them, such as agency decisions whether to issue a required federal permit for a new power project or whether to fund a new highway or bridge.

Environmental impact statements are the most extensive type of impact study that federal agencies are required to conduct under NEPA.

Currently, EIS's are reportedly taking more than four years on average to complete. That period can then drag out further since the statute provides third parties with various opportunities to file suit to challenge NEPA studies.

Both political parties are concerned about the significant

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time required to complete NEPA assessments and then to untangle the particular project from challenges to agency actions that often follow, all of which must be done before shovels can hit the ground.

There is a divide on the environmental side of the equation.

While NEPA's purpose is to protect the environment by weighing impacts before allowing action, the slow pace will only further delay cleaner energy infrastructure of the kind that will help address climate change.

Various options to speed the NEPA process are on the table, most of which would set time limits for agency review. These include setting maximum two-year timelines for agency review of major projects and one-year limits for lower-impact projects.

They also include setting a time limit — such as 180 days — for an agency to fix a NEPA study if a federal court finds it deficient and orders an agency to revise.

It is unclear whether measures will be included to prevent agencies from limiting the effect of such deadlines, such as by delaying acceptance of applications to prevent the clock from even starting to run. It is also unclear whether consequences will be set for failure to meet agency deadlines, such as triggering automatic approval in the absence of agency action.

In addition to systemic fixes, the Inflation Reduction Act adds to permitting resources at several federal agencies. The idea is to ensure the agencies have the staff on hand to do the work needed to move infrastructure projects through the pipeline in a more timely fashion. The additional funding should lead to hiring more permitting staff, developing programmatic environmental documents and buying new equipment for environmental analysis.

The bill will give $40 million to the US Environmental Protection Agency, $150 million to the Department of the Interior, $125 million to the Department of Energy, and $100 million each to the Federal Energy Regulatory Commission, the Agriculture Department and the Department of Transportation to increase permitting capabilities. This money will be spread over five years.

Another $30 million will go to the White House Council on Environmental Quality and $20 million to the National Oceanic and Atmospheric Administration. There is another $350 million for the Federal Permitting Improvement Steering Council, whose job it is to bring agencies together early in the permitting process to coordinate their work.

The Biden administration, through the Council on Environmental Quality, completed the first of a two-phase process of amending federal regulations for implementing NEPA on May 20, 2022.

In so doing, the administration reversed a number of changes made to NEPA during the Trump administration. For example, federal agencies will again consider the climate change impacts from proposed new infrastructure projects and other activities that require federal action.

Despite those reversals, the Biden administration did not strike the timelines adopted by the Trump administration to set an end to agency delay.

Several points of contention are in play over the coming months.

First, there is the side deal to which Senators Schumer and Manchin agreed as the price for Manchin to support the Inflation Reduction Act.

Second, a Republican-backed disapproval resolution is currently pending under the Congressional Review Act to repeal the Biden administration's recently-adopted rule reviving core aspects of NEPA that took effect just a few months ago.

Third, the Council on Environmental Quality is supposed to propose a "phase 2" NEPA rule by summer's end. That could set up further conflict between it and a not-yet-defined legislative action on permitting.

### Clean Water

The Schumer-Manchin side deal includes provisions affecting how states are allowed to review whether federally-permitted projects meet state water quality standards under section 401 of the Clean Water Act.

Section 401 gives states and Indian tribes the ability to review any proposed activity that requires a federal license or permit and that may involve discharges into federally-regulated waters to ensure compliance with appropriate state water quality requirements, but the agreement could further define that scope of review.

If the Machin deal on permitting reforms shapes the scope of water quality review allowed to states and tribes under the

Senate Democrats hope to fold a package of permitting reforms into a must-pass bill to keep the federal government open past September 30.

Clean Water Act, that would raise questions about how it might affect EPA's ongoing rulemaking in the same area.

The description of the permitting reforms released by Manchin suggests they would "improve" section 401 "by incorporating improvements from both the Trump and Biden administrations."

While few details are available on what the legislative language will say, the specifics will determine whether the provisions end up looking more like the Trump or Biden approaches for state water quality certification reviews and whether the Environmental Protection Agency is forced to change its proposed 401 rule revisions to meet the requirements of new legislation, if passed. Again, speeding approval or disapproval by the states appears likely to be a key focus.

## Offshore Wind

Governor Kathy Hochul (D-NY) announced in late July that the New York State Energy Research and Development Authority will release its third competitive offshore wind solicitation.

The third solicitation intends to secure offshore wind renewable energy credits for at least 2,000 megawatts of offshore wind energy, which would be enough to power more than 1.5 million homes.

New York has already contracted for approximately 4,300 MW of offshore wind projects under development and is on its way to meetings a state goal of 9,000 MW of offshore wind energy by 2035.

The New York Climate Leadership and Community Protection Act requires the state to reduce greenhouse gas emissions by 85% by 2050 from 1990 levels and to reach 100% renewable electricity generation by 2040.

This latest procurement requires all bidders to incorporate designs for integration into a "mesh network" offshore grid that would allow the interconnection of a number of wind projects for combined transmission to onshore facilities.

Proposals are due December 22, 2022, with an award to be announced sometime in early 2023.

## Fishing Industry

The US Bureau of Ocean Energy Management (BOEM) issued draft guidance in late June to lessen the impacts of offshore wind development on commercial and recreational fishing.

In March, the Biden administration released a plan to expand offshore wind capacity to 30 gigawatts by 2030.

The fishing industry stands as a potential obstacle to achieving that goal. Negotiations are ongoing to marry the potential conflicting interests among commercial fishermen, developers of offshore wind energy and federal regulators. The US commercial fishing industry generates more than $170 billion in annual sales.

The BOEM guidance is a first step in that direction. It outlines ways for the offshore wind industry and leaseholders to mitigate impacts on fisheries in a myriad of areas, such as wind farm project siting and design, / continued page 48

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construction and operational safety, and potential financial compensation if a particular project disrupts fishing operations.

BOEM suggests its guidance will help ensure consistent use of information across projects and states.

The BOEM guidance also makes several recommendations for offshore wind project design and construction to account for potential impacts to fisheries. It is intended to help both the developers and BOEM assess specific project construction and operation plans, including the design of foundations for wind turbines and minimum depths for burying subsea cables.

The guidance also recommends that project developers establish a process for compensating fisheries for any potential lost income. It suggests that process should last through the construction, operations and decommissioning phases of a project.

Many in the fishing industry have criticized the guidelines as essentially meaningless because they do not put enforceable obligations on project developers.

The fishing industry's concerns include impacts on fish habitats, restricted fishing access and risks, and increased industry competition within smaller sea areas as fishing is restricted within areas of wind development. The industry also perceives that it has been largely excluded from the decision-making process, at least with respect to development of particular offshore wind projects.

Central to the tension may be an overall lack of information regarding the environmental impacts of offshore wind farms, though some projects are funding research and the Biden administration plan also includes research funds.

BOEM admits that it has no legal authority to create a compensation fund or to require project developers to pay into one. The agency also said it cannot require developers to address any regional impacts on fisheries unless those impacts are identified in a specific project's environmental review.

Conflict with the fishing industry has emerged as a major source of tension in the Biden administration's push to expand offshore wind, with fishing companies and industry groups already bringing legal challenges to BOEM's approval of the 800-megawatt Vineyard Wind project off the coast of Massachusetts.

The Vineyard Wind project reportedly set aside $21 million to compensate fishermen for financial losses and agreed to certain changes in turbine orientation to address navigational concerns and to reduce the total number of turbines proposed.

BOEM has been holding a series of public meetings on the draft guidance, suggesting it may finalize it over the summer.

*— contributed by Andrew E. Skroback in New York*